SOUTHWEST GAS CORPORATION

Application 24-09-___

Application of
Southwest Gas Corporation
(U 905 G)
For Authority to Increase Rates and
Charges for Natural Gas Service in California,
Effective January 1, 2026

Volume III

TESTIMONY

SOUTHWEST GAS CORPORATION
(U 905 G)

<u>VOLUME III</u>

TESTIMONY

General Rate Case Application
Recorded Years 2019 through 2023
Estimated Years 2024 and 2025
Test Year 2026
Post-Test Years 2027 through 2030

Witnesses

Valerie J. Ontiveroz

Brandy Little

Randi L. Cunningham

Charlene A. Lachica

Kasey D. Bohannon

A. Brooks Congdon

Bradley C. Anderson

Kevin M. Lang

Byron C. Williams

Justin L. Forsberg

Dylan W. D’Ascendis

Valeria S. Annibali

Company Witness:

Valerie J. Ontiveroz

IN THE MATTER OF

SOUTHWEST GAS CORPORATION

APPLICATION 24-09-___

PREPARED DIRECT TESTIMONY

OF

VALERIE J. ONTIVEROZ

ON BEHALF OF

SOUTHWEST GAS CORPORATION

SEPTEMBER 5, 2024

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of
VALERIE J. ONTIVEROZ

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Prepared Direct Testimony
of
VALERIE J. ONTIVEROZ

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Valerie J. Ontiveroz. My business address is 8360 South Durango Drive, Las Vegas, Nevada 89113.

Q. 2 By whom and in what capacity are you employed?

A. 2 I am employed by Southwest Gas Corporation (Southwest Gas or Company) in the Regulation department. My title is Regulatory Manager/California.

Q. 3 Please summarize your educational background and relevant business experience.

A. 3 My educational background and relevant business experience are summarized in Appendix A to this testimony.

Q. 4 Have you previously testified before any regulatory commission?

A. 4 Yes, I have provided written testimony before the California Public Utilities Commission (Commission).

Q. 5 What is the purpose of your prepared direct testimony in this proceeding?

A. 5 I provide an overview of Southwest Gas' Application for rate relief. Additionally, I discuss Southwest Gas' compliance with various Commission decisions issued since the Company's last general rate case (GRC), Application (A.) 19-08-015. I also support Southwest Gas' proposed tariff changes.

Q. 6 Please summarize your prepared direct testimony.

A. 6 My prepared direct testimony consists of the following key issues:

- Overview of the Company.
- Primary reasons for the margin deficiencies in Southwest Gas' Southern California, Northern California, and South Lake Tahoe rate jurisdictions.
- Key metrics relevant to this Application.
- Consolidation of Southwest Gas' Northern California and South Lake Tahoe rate jurisdictions.
- Southwest Gas' compliance with Decision (D.) 15-10-032, D.22-02-035 and D.22-08-023.
- Revisions to the Company's California Gas Tariff to reflect proposals included in this Application.
- Establishment of the Damage Prevention Cost Balancing Account.

II. OVERVIEW OF THE COMPANY

Q. 7 Please provide an overview of Southwest Gas.

A. 7 Southwest Gas provides natural gas service to approximately 2.2 million customers in California, Arizona and Nevada and continues to see strong customer growth across its three state service territories. As of December 31, 2023, the Company served approximately 206 thousand customers in California – approximately 156 thousand customers in Southern California, 29 thousand customers in Northern California and 21 thousand customers in South Lake Tahoe. In California, Southwest Gas' natural gas distribution system is comprised of approximately 6,429 miles of mains and services. Since 2021, the test year in the Company's last GRC, Southwest Gas has had consistent growth in its California service territories as evidenced by first time meter sets at new accounts as demonstrated below:

First Time Meter Sets at New Accounts
Southwest Gas Rate Jurisdictions
Years 2021-YTD 2024

	Southern CA	Northern CA	South Lake Tahoe	Total
2021	1,591	346	66	2,003
2022	2,181	277	121	2,579
2023	1,532	250	203	1,985
YTD 2024[1]	1,060	130	71	1,260

[1] Through August 31, 2024

Southwest Gas remains committed to providing safe and reliable service to its customers in the communities it serves. Additionally, Southwest Gas is committed to supporting its employees, business partners and customers through various Company programs. In 2023, Southwest Gas employees donated approximately $135 thousand to various agencies in California through the Company's FUEL for LIFE employee giving program. The Company also proudly supports and implements its Supplier Diversity program, fostering economic growth of diverse businesses in California. In 2023, Southwest Gas procured $51 million in goods and services with diverse businesses that support the California economy.

In 2024, Southwest Gas was recognized by TIME magazine and Statista Inc. as one of America's Best Mid-Size Companies for 2024[1] based on employee satisfaction, revenue growth and sustainability transparency.

[1] https://time.com/collection/americas-best-midsize-companies-2024/.

III. OVERVIEW OF SOUTHWEST GAS' APPLICATION

Q. 8 Please provide an overview of the Company's Application.

A. 8 In its Application, Southwest Gas is requesting a five-year general rate case cycle, with a 2026 Test Year (TY) for the projected 12-month period ending December 31, 2026, and four attrition years from 2027 through 2030. The Company is requesting TY 2026 rate increases of approximately $38.5 million in Southern California, approximately $63 thousand in Northern California and approximately $10.2 million in South Lake Tahoe. Southwest Gas is also requesting to maintain its Post Test Year Margin (PTYM) adjustments of 2.75 % in each of its three rate jurisdictions. Company witness Randi L. Cunningham supports the reasonableness of this proposal in her prepared direct testimony.

Additionally, Southwest Gas is proposing to continue its three risk-based decision-making programs authorized in its last GRC – the Targeted Pipe Replacement Program (Southern California only), the Meter Protection Program and the School Customer-Owned Yard Line Program – and is proposing a fourth risk program - Annual Leak Survey with Advanced Mobile Leak Detection.[2] The Company is also proposing to continue its five Conservation and Energy Efficiency (CEE) Programs authorized in its last GRC – Residential Equipment Rebates Program, Commercial Equipment Rebates Program, Residential Equipment Direct-Install Program, New Homes Rebates Program, and Solar Thermal Rebate Program – but is proposing an annual increase in funding to $650,000.[3] Finally, Southwest Gas is proposing to consolidate its Northern

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[2] Please refer to the Prepared Direct Testimony of Company witness Kevin L. Lang who supports Southwest Gas' risk-based program proposals.

[3] Please refer to the Prepared Direct Testimony of Company witness Valeria S. Annibali who sponsors Southwest Gas' CEE program portfolio.

California and South Lake Tahoe rate jurisdictions into a single Northern California rate jurisdiction.

IV. PRIMARY REASONS FOR THE MARGIN DEFICIENCIES IN SOUTHWEST GAS' SOUTHERN CALIFORNIA, NORTHERN CALIFORNIA, AND SOUTH LAKE TAHOE RATE JURISDICTIONS

Q. 9 Please describe the primary reasons for Southwest Gas' margin deficiencies in each rate jurisdiction.

A. 9 The primary reasons for the Company's margin deficiency in Southern California, Northern California and South Lake Tahoe rate jurisdictions are: 1) changes in the cost of capital and the cost of debt; 2) updating plant in service costs related to capital investments; 3) increased depreciation expense and property tax expense resulting from changes in the level of plant in service; 4) changes in operations and maintenance (O&M) and administrative and general expenses (A&G); and 5) customer growth.

Q. 10 Please summarize what the Commission approved in Southwest Gas' last GRC (A.19-08-015) with respect to the Company's cost of capital.

A. 10 In Southwest Gas' last GRC, the Company was authorized the following cost of capital:

AUTHORIZED COST OF CAPITAL – A.19-08-015/D.21-03-052						
	SOUTHERN CALIFORNIA RATE JURISDICTION			NORTHERN CALIFORNIA/ SOUTH LAKE TAHOE RATE JURISDICTIONS		
Component	**Weight**	**Rate**	**Weighted Cost**	**Weight**	**Rate**	**Weighted Cost**
Long-Term Debt	48.00%	3.98%	1.91%	48.00%	4.67%	2.24%
Common Equity	52.00%	10.00%	5.20%	52.00%	10.00%	5.20%
Total	100.00%		7.11%	100.00%		7.44%

In addition, Southwest Gas also received approval to continue its Automatic Trigger Mechanism (ATM)[4]. The ATM adjusts the authorized rate of return (ROR) between general rate cases if there are changes in the utility bond yields. Specifically, if the average benchmark yield, measured by the Moody's A Utility Bond Index, changes by more than 100 basis points during the annual measurement period, the ATM is triggered and an adjustment to the Company's ROR is required. The measurement period is the twelve-month period ending September of each year.

Q. 11 Was the Company's ATM triggered since its last GRC resulting in changes to its cost of capital?

A. 11 Yes, the ATM was triggered in 2023 when at the end of the September measurement period, the average Moody's A Utility Bond Yield of 5.47% exceeded the Company's benchmark rate of 3.15% by 232 basis points. This resulted in the following changes to Southwest Gas' cost of capital:

AUTHORIZED COST OF CAPITAL – EFFECTIVE JANUARY 1, 2024						
	SOUTHERN CALIFORNIA RATE JURISDICTION			NORTHERN CALIFORNIA/ SOUTH LAKE TAHOE RATE JURISDICTIONS		
Component	**Weight**	**Rate**	**Weighted Cost**	**Weight**	**Rate**	**Weighted Cost**
Long-Term Debt	48.00%	4.62%	2.22%	48.00%	4.38%	2.10%
Common Equity	52.00%	11.16%	5.80%	52.00%	11.16%	5.80%
Total	100.00%		8.02%	100.00%		7.91%

The above changes resulted in incremental margin increases of approximately $3.3 million $0.7 million and $0.4 million in its Southern California, Northern

[4] The Company's ATM was initially established in D. 08-011-048 and most recently continued in D.21-03-052.

California, and South Lake Tahoe rate jurisdictions, respectively.[5] There were no updates to Southwest Gas' common equity (52.00%) or debt ratio (48.00%).

Q. 12 Please summarize the Company's cost of capital request in this Application.

A. 12 In this Application, Southwest Gas is requesting a target common equity ratio of 50.00% with an increase to its return on common equity (ROE) to 11.35% for its three rate jurisdictions. The proposed ROE is a modest increase from the currently authorized ROE of 11.16%, and within the reasonable range of 10.26%-12.38% when considering Company-specific adjustments as discussed and supported in the Prepared Direct Testimony of Company witness Dylan W. D'Ascendis. The impact on the deficiency related to the proposed change in ROE from currently authorized is an increase of approximately $0.6 million in Southern California, $0.2 million in Northern California and $0.2 million in South Lake Tahoe.

The Company's proposed actual cost of debt rates in this Application are 4.14% and 4.34%, for Southwest Gas' Southern California and Northern California/South Lake Tahoe jurisdictions, respectively. Although only a modest decrease for Northern California/South Lake Tahoe, as discussed in the Prepared Direct Testimony of Company Witness Justin L. Forsberg, Southern California debt rates are projected to decline from 4.62% and 4.38% for Southern California and Northern California/South Lake Tahoe jurisdictions, respectively. The impact on the deficiency related to the change in the cost of

[5] Southwest Gas Advice Letter No. 1275 *2024 Post-Test Year Margin Adjustment, including Excess Accumulated Deferred Income Tax Adjustment Amortization and Rate of Return Adjustment as a result of the Automatic Trigger Mechanism, Authorized in Decision 21-03-052*, approved by the Energy Division effective January 1, 2024.

debt since the last GRC is a reduction of approximately $1.1 million in Southern California, approximately $29 thousand in Northern California and approximately $32 thousand in South Lake Tahoe.

Q. 13 Please describe the Company's capital investments since the last GRC that are included in this Application.

A. 13 Southwest Gas continues to invest in its distribution system to ensure continued safe and reliable service for its customers. In the current GRC cycle, Southwest Gas made capital investments in its system for customer growth, replacements, and enhancements to meet demand and ensure reliability, its three risk-based programs discussed above, its Mobilehome Park Conversion Program, and Customer Data Modernization Initiative (CDMI). Approximately $ 232.9 million, $71.3 million, and $68.3 million in gross plant has been placed into service in the Company's Southern California, Northern California, and South Lake Tahoe rate jurisdictions, respectively since the last GRC. These investments and other rate base changes have increased rate base in the three jurisdictions from the amounts authorized in the last GRC by approximately $181.4 million, $46.7 million and $56.7 million respectively. Southwest Gas' rate base request in this Application is supported in the Prepared Direct Testimony of Company Witness Randi L. Cunningham.

Q. 14 What is the revenue requirement impact for these capital investments and changes in rate base?

A. 14 In the Company's Southern California, Northern California and South Lake Tahoe rate jurisdictions, the revenue requirement impact[6] is approximately

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[6] The revenue requirement impact is based on the sum of the return, depreciation expense and property tax expense.

$26.9 million, $7.1 million[7], and $8.2 million, respectively. Southwest Gas' overall revenue requirement is also supported by Ms. Cunningham.

Q. 15 Please describe the change in direct depreciation expense since the Company's last GRC.

A. 15 Utilizing the deprecation rates authorized in the last GRC, Southern California, Northern California and South Lake Tahoe annualized direct depreciation expenses associated with the addition of new plant discussed above has increased by approximately $6.0 million, $1.1 million, and $ 1.3 million, respectively.

Q. 16 Please describe the change in system allocable depreciation and amortization expense since the Company's last GRC.

A. 16 The change in depreciation and amortization expense related to System Allocable plant investments since its last GRC after allocation to California is approximately $ 2.2 million, $0.5 million and $0.4 million to Southern California, Northern California, and South Lake Tahoe, respectively. Most of this increase in system allocable depreciation and amortization expense is attributable to the Company's CDMI.

Q. 17 Has Southwest Gas prepared a Depreciation Study and included proposed depreciation rates in this Application?

A. 17 Yes. On August 23, 2024, Southwest Gas submitted to the Public Advocates Office Depreciation Studies for its Southern California and Northern California/South Lake Tahoe (combined) rate jurisdictions pursuant to Standard

[7] The revenue requirement on the North Lake Tahoe Lateral through 2023 was included in the PTYM adjustment; therefore, the associated plant investment does not impact the deficiency in this Application.

Practice U-4 and specifically performed for this GRC.[8] The impact of the change of depreciation rates on this GRC is an increase of approximately $0.2 million, a decrease of approximately $0.5 million and a decrease of approximately $0.3 million for Southern California, Northern California and South Lake Tahoe, respectively.

V. KEY METRICS RELEVANT TO THIS APPLICATION

Q. 18 Please summarize the actual O&M and A&G expenses since the Company's last GRC versus authorized and its O&M and A&G expenses proposed for this GRC.

A. 18 The following table provides a comparison between actual and authorized versus proposed O&M and A&G expenses (may be collectively referred to OMAG) in this Application:

	Authorized (D.21-03-052)	Actual at 12/31/2023	Proposed
Southern California			
O&M	$19,380,404	$22,684,905	$26,877,654
A&G	14,483,974	13,767,486	18,381.807
Total OMAG	**$33,864,378**	**$36,452,390**	**$45,259,461**
Northern California			
O&M	$3,367,008	$3,868,197	$4,406,218
A&G	2,973,916	2,074,390	3,943,556
Total OMAG	**$6,340,924**	**$5,942,586**	**$8,349,774**
South Lake Tahoe			
O&M	$3,279,125	$4,362,875	$4,617,383
A&G	2,193,448	2,347,804	3,116,999
Total OMAG	**$5,472,573**	**$6,710,678**	**$7,734,382**

Q. 19 Please quantify the changes in OMAG expenses since the last GRC.

A. 19 Although Southwest Gas' PTYM provided rate relief between GRCs, the PTYM does not assign the margin increase to a specific portion or portions of the cost

[8] Southwest Gas utilized the system allocable rates from the Deprecation Study performed the Company's Nevada GRC in 2023.

of service. The level of proposed OMAG expenses for the 2026 TY are approximately $11.4 million in Southern California, $2.0 million in Northern California and $2.3 million in South Lake Tahoe more than authorized in the Company's last GRC.

Q. 20 How does the Company's OMAG per customer compare to its peer utilities?

A. 20 Southwest Gas compiled its Peer Group[9] OMAG per customer information for years 2019 through 2023. During this time, the Peer Group OMAG per customer ranged from $149.58 to $341.61, with Atmos Energy being the lowest. Southwest Gas (total California average) was second lowest of the Peer Group during this period with an average O&M per customer of $240.01. Southwest Gas' total California average 2023 (base year) O&M per customer was $256.08 compared to the Peer Group average of $279.50.

Q. 21 Have you evaluated the OMAG per customer specific to Southwest Gas' California rate jurisdictions?

A. 21 Yes. As noted above, the 2019-2023 Peer Group average O&M per customer was $251.80. Over this same period, the average O&M per customer for Southern California, Northern California and South Lake Tahoe, was $216.41, $203.73, and $299.89, respectively. For the purpose of Southwest Gas' proposal to consolidate its Northern California and South Lake Tahoe rate jurisdictions (discussed in the next section of my testimony), I have also provided

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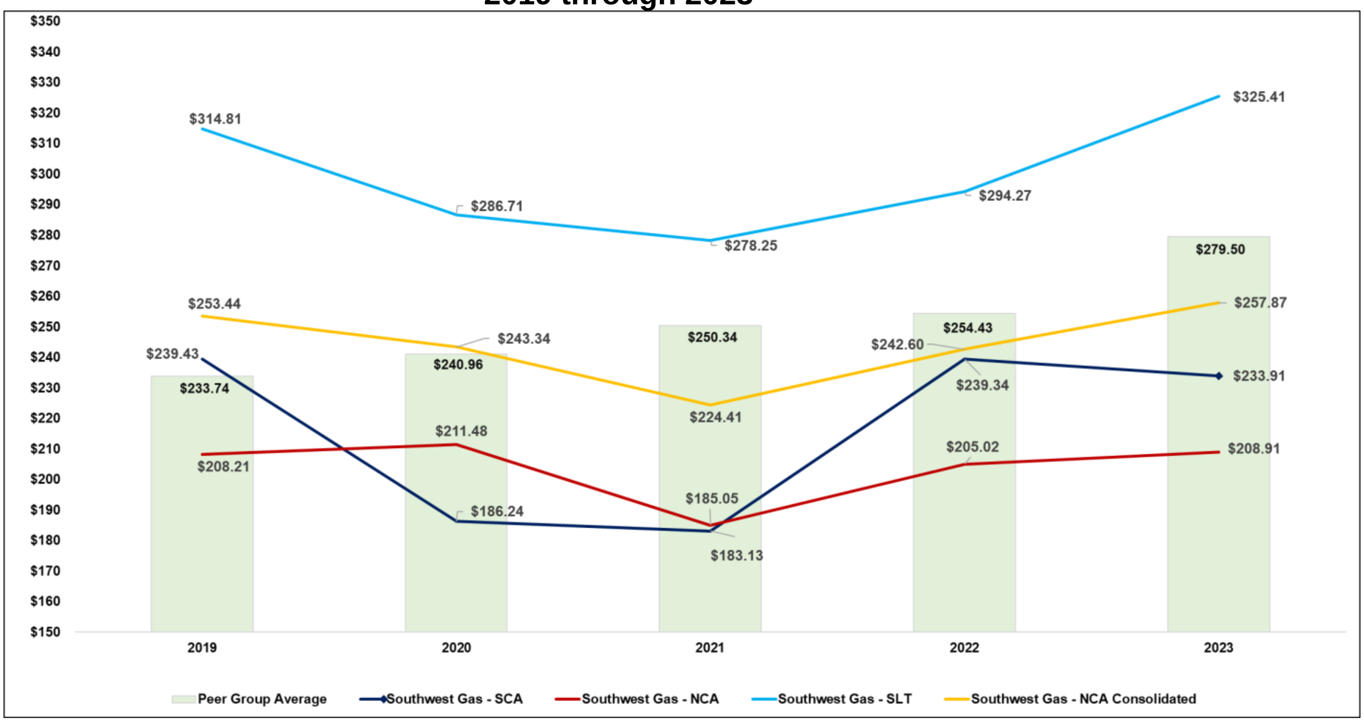
[9] The Peer Group includes Atmos Energy Corporation (ATO), New Jersey Resources Corporation (NJR), NiSource, Inc. (NI), Northwest Natural Gas Company (NWN), One Gas, Inc. (OGS), and Spire, Inc. (SR), and is the same Peer Group used in the analysis performed and presented in the Prepared Direct Testimony of Company witness Dylan W. D'Ascendis. O&M per customer was calculated using the Operations & Maintenance expense and number of customers included in each Peer company 10-K filings, retrieved from their respective websites.

an average O&M per customer for this proposal which is $244.33. With the exception of South Lake Tahoe, the O&M per customer in each of Southwest Gas' rate jurisdictions was below the Peer Group average O&M per customer. Figure 1 below provides a comparison of the average annual O&M per customer by Southwest Gas rate jurisdiction and the Peer Group Average. The underlying data is provided in Exhibit No.__(VJO-1).

Figure 1
OMAG Per Customer Comparisons
Southwest Gas versus Peer Group Average
2019 through 2023



Q. 22 Can the Company explain the differences in O&M per customer between its three California rate jurisdictions.

A. 22 Yes. The differences can generally be attributed to the difference in the number of customers between jurisdictions, so the OMAG cost per customer is lower in Southern California where the largest number of Southwest Gas customers exist. However, in Southern California for years 2022 and 2023, Southwest Gas experienced higher O&M costs per customer due to an increased amount of distribution related cost increases between GRCs, primarily due to increased contractor costs as a result of annual Consumer Price Index (CPI) adjustments.

Q. 23 Please explain why the Company's South Lake Tahoe rate jurisdiction OMAG per customer is significantly higher than the Southern California and Northern California rate jurisdictions.

A. 23 As discussed above and in the next section of my testimony, South Lake Tahoe's high cost of service coupled with the smaller number of customers to spread these costs over contributes to a higher OMAG per customer. As discussed below, when Southwest Gas acquired its South Lake Tahoe facilities from Avista Corporation (Avista) in 2005, there had not been a rate increase in South Lake Tahoe in over twenty years and the system was comprised largely of aging pipe and infrastructure that needed to be replaced and was costlier to maintain. For example, in the Company's first GRC following the acquisition,[10] the average South Lake Tahoe rate base per customer was only $609. In the same rate case, the average rate base per customer for Northern California was $2,090, or approximately 3.4 times more invested on a per customer basis than in South Lake Tahoe. Since that time, as referenced above, the Company has needed to expend much more on a per customer basis to provide the same level of service to its South Lake Tahoe customers as it provides to customers in Northern California and Southern California. This is illustrated by comparing the Company's proposed investment per customer in this case of $5,490 for South

[10] Decision 08-11-048 in Application 07-12-022, effective January 1, 2009.

Lake Tahoe to the proposed amount for Northern California of $4,775, which is 1.15 times more than Northern California. The above comparisons demonstrate the need for more significant investment in South Lake Tahoe.

Q. 24 Is the Company's requested level of OMAG expense reasonable?

A. 24 Yes. When comparing to Southwest Gas' Peer Group, the Company is at or below the per customer average for OMAG demonstrating the reasonableness of the Company's proposed level of OMAG expense.

VI. CONSOLIDATION OF SOUTHWEST GAS' NORTHERN CALIFORNIA AND SOUTH LAKE TAHOE RATE JURISDICTIONS

Q. 25 Discuss the Company's proposal to consolidate its Northern California and South Lake Tahoe rate jurisdictions.

A. 25 In 2005, Southwest Gas was granted authority to acquire Avista gas facilities located in South Lake Tahoe.[11] As part of the acquisition, Southwest Gas accepted responsibility for providing safe and reliable service to approximately 18 thousand new customers, as well as operating, maintaining, and over time, replacing a natural gas system that at the time consisted of 654 thousand feet of steel mains, 576 thousand feet of plastic mains and approximately 19 thousand meters. At that time, the Company was also granted authority to consolidate its northern California natural gas purchases with natural gas purchases for the South Lake Tahoe customers, as well as serve the customers under Southwest Gas' existing gas tariff Rules. It was recognized by the Commission that Southwest Gas' Northern California base margin residential rates (non-gas costs) were higher than Avista's base margin rates for South

[11] Decision (D.) 05-03-010, *Opinion Approving Settlement and Granting Authority for Proposed Acquisition*, approved March 14, 2005.

Lake Tahoe given that these customers had not experienced a general rate increase in over 20 years. The Company agreed to a rate freeze for the new South Lake Tahoe customers for years 2005 through 2008 and would not seek to consolidate base margin rates with its Northern California rate jurisdiction in a future rate case until it could demonstrate that consolidation would provide an overall benefit to customers.[12] During this time South Lake Tahoe customers were served under separate rate schedules and tariff. It was not until Southwest Gas' TY 2009 GRC, that the Company consolidated its tariff rate schedules and began serving all California customers under a single gas tariff, while still maintaining separate base margin rates for South Lake Tahoe. The South Lake Tahoe rate jurisdiction still exists today.

In this Application, Southwest Gas is proposing to consolidate its Northern California and South Lake Tahoe rate jurisdictions into a single Northern California rate jurisdiction. This means Northern California and South Lake Tahoe customers will be billed at the same base margin rates. In addition, and with respect to the Company's tariff, references to South Lake Tahoe in rate schedules will be removed, including the separate Statement of Rates, and these customers will be billed as Northern California customers under the Northern California rate schedules.[13]

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[12] *Ibid*, at pgs. 4-5.

[13] Tariff rate schedules that are currently the same, i.e., applicability and conditions, have one tariff schedule such as Schedule No. GS/GN/SLT-10 – Residential Gas Service. As part of this proposal, for instance, Southwest Gas will remove the SLT references and customers will be billed under Schedule No. GN-10.

Q. 26 Does the Company believe that this consolidation will benefit South Lake Tahoe customers?

A. 26 Yes. As discussed earlier in my testimony, the cost to provide the same level of service to South Lake Tahoe is much higher than for the Company's Northern California and Southern California customers. This is further demonstrated with respect to the Company's OMAG expenses experienced over this last GRC cycle. As discussed further in the Prepared Direct Testimony of Company witness A. Brooks Congdon, the proposed rate increase for South Lake Tahoe residential customers in this Application, before consolidation with the Northern California rates, is approximately 50% higher than current rates. Consolidating the jurisdictions will lessen the proposed increase to approximately 40% given that Southwest Gas will recover these costs from a larger number of customers (approximately 50 thousand customers from the consolidated Northern California rate jurisdiction versus the existing 21 thousand from South Lake Tahoe customers). In terms of the impact to the residential base rates, the proposed base margin rates for South Lake Tahoe customers in this application is $1.22 per therm, whereas their current rates are $0.62 per therm. Consolidating the Northern California and South Lake Tahoe rate jurisdictions results in a proposed base margin rate of $1.12 per therm.

Q. 27 How will the consolidation impact Northern California customers?

A. 27 The consolidation will only moderately impact Northern California customers. Southwest Gas' current base margin rates are $1.13 per therm for Northern California customers compared to the $1.12 per therm under the consolidation proposal. Without the consolidation, Northern California customers would see a slight decrease to $1.07 per therm.

Q. 28 Has the Company considered this consolidation before?

A. 28 Yes, Southwest Gas considered making a similar proposal in its last GRC but given the timing of the implementation and rollout of the Company's new customer billing system, the decision was made to defer the consolidation until this GRC.

Q. 29 Is the Company's proposal to consolidate the Northern California and South Lake Tahoe rate jurisdictions reasonable?

A. 29 Yes, Southwest Gas believes that the proposed consolidation of its Northern Californian and South Lake Tahoe rate jurisdictions is reasonable based on the following: 1) The impact to South Lake Tahoe customers will be substantially lessened through the proposed consolidation and the impact to Northern California customers will be essentially seamless; 2) As demonstrated above, the proposed OMAG for the consolidation is still below the 7.7% CAGR, relative to maintaining the separate jurisdictions; and 3) Southwest Gas believes the consolidation will be administratively less burdensome on the Company as well as the Commission, especially when processing rate requests, including GRCs.

VII. COMPLIANCE WITH PRIOR COMMISSION DECISIONS

Q. 30 Provide a brief overview of D.15-10-032.

A. 30 D.15-10-032 was issued in Rulemaking (R.) 14-03-003,[14] to adopt procedures for natural gas utilities to comply with the regulations promulgated by the California Air Resources Board for the Cap-and-Trade program, such as methodologies to calculate forecasting and recorded greenhouse gas allowance

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[14] *Order Instituting Rulemaking to Address Natural Gas Distribution Utility Cost and Revenue Issues Associated with Greenhouse Gas Emissions*, filed March 13, 2014.

proceeds and costs, recovery of Cap-and-Trade program compliance costs and adopted the California Climate Credit.

Q. 31 How does D.15-10-032 pertain to this Application?

A. 31 In D.14-12-040,[15] the Commission authorized natural gas utilities to establish a Greenhouse Gas Memorandum Account (GHGMA) to track administrative costs directly associated with Cap-and-Trade program compliance.[16] The Commission states in D.15-10-032, that the GHGMA should sunset once the utility has the opportunity to request approval for the new category of costs through a general rate case or similar proceeding.[17] In this Application, Southwest Gas is proposing to amortize the GHGMA balance and close the account. The costs that have been recorded in the account, i.e., annual outreach costs related to the California Climate Credit, which are minimal, and publication fees for compliance costs forecasting, will be subsumed in customary regulatory noticing fees and subscription fees. The closure of the GHGMA is discussed more fully in the Prepared Direct Testimony of Company witness Kasey D. Bohannon.

Q. 32 Provide a brief overview of D.22-02-025.

A. 32 D.22-02-025,[18] approved by the Commission on February 24, 2022, implemented Senate Bill 1440 and set short and medium term renewable natural gas and/or bio-synthetic natural gas (bio-SNG) (collectively, RNG) procurement targets to reduce short-lived climate pollutant emissions, along with adopting a Standard Biomethane Procurement Methodology for cost-effective RNG

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[15] *Decision Resolving Phase 1 Issues and Addressing the Motion of Adoption of Settlement Agreement,* approved December 18, 2014.
[16] *Ibid*, Ordering Paragraph (OP) 3 at pg. 40.
[17] D.15-10-032, at pg. 21.
[18] *Decision Implementing Senate Bill 1440 Biomethane Procurement Program.*

procurement, Renewable Gas Procurement Plan, bio-SNG pilots, an Advice Letter process for evaluating gas utility RNG contracts, and various other directives related to the gas utilities achieving RNG procurement goals.

Q. 33 How does D.22-02-025 pertain to this Application.

A. 33 Consistent with Public Utilities Code Section 729.1, the Commission ordered the respondent natural gas utilities, including Southwest Gas, to consider the impacts of the RNG procurement authorized in D.22-02-025 on California Alternate Rates for Energy (CARE) customer bills and propose any appropriate remediation measures in the rate design phase in their next GRCs or provide justification for not recommending additional discounts for their CARE customers.[19]

Q. 34 Has the Company complied with D.22-02-025 in this Application?

A. 34 Yes. As discussed in the Prepared Direct Testimony of Company Witness A. Brooks Congdon, Southwest Gas evaluated the impacts on CARE customers and proposes no changes to the CARE discount.

Q. 35 Provide a brief overview of D.22-08-023.

A. 35 D.22-08-023[20] implements three affordability metrics (Affordability Ratio (AR), Hours-at-Minimum-Wage, and SocioEconomic Vulnerability Index) that the Commission uses to assess the relative affordability of essential utility service across energy industries and proceedings and directs when and how the affordability framework is applied in Commission proceedings, including energy proceedings.[21]

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[19] D.22-02-025, OP 30 at pg. 63.
[20] *Decision Implementing Affordability Metrics*, approved August 4, 2022.
[21] D.22-08-023 at pg. 2.

Q. 36 How does D.22-08-023 pertain to this Application?

A. 36 The Commission directs the respondent utilities, to include an affordability analysis pursuant to OP 6 in D.22-08-023, which states the changes to the AR 20 by climate zone, AR 50 by climate zone, and Hours-at-Minimum-Wage with the proposed new revenue requested annually for each year in which new revenues are proposed.[22]

Q. 37 Has the Company complied with D.22-08-023 in this Application?

Q. 37 Yes. Company witness A. Brooks Congdon discusses in his Prepared Direct Testimony, the affordability analysis performed by the Company in this GRC.

Q. 38 Are there any other specific Commission decisions that the Company must comply with in this GRC application?

A. 38 I am not aware of any other directives in Commission decisions that pertain to this Application.

VIII. REVISIONS TO THE COMPANY'S CALIFORNIA GAS TARIFF TO REFLECT PROPOSALS INCLUDED IN THIS APPLICATION

Q. 39 Please describe the Company's proposed revisions to its California Gas Tariff.

A. 39 Southwest Gas is proposing tariff modifications that conform with the various proposals made in this Application, including primarily the consolidation of the Company's Northern California and South Lake Tahoe rate jurisdictions, as well as the removal of a memorandum account and the creation of a new balancing account. Southwest Gas' proposed tariff revisions, in both clean and redlined

[22] *Ibid*, at pg. 85.

versions, are included in Chapter 21 of the Application in Volumes II-A – Southern California, B – Northern California and C – South Lake Tahoe.

Q. 40 Please describe the Company's proposed revisions related to the consolidation of its Northern California and South Lake Tahoe rate jurisdictions.

A. 40 Southwest Gas is removing references to South Lake Tahoe within various Preliminary Statements, Rate Schedules and Rules, where applicable, by removing references to "SLT", and making other conforming revisions, i.e., customer forms, tariff title page, etc., with respect to this proposal.

Q. 41 Which memorandum account is the Company proposing to remove from its tariff?

A. 41 As discussed in the Prepared Direct Testimony of Company Witness of Kasey D. Bohannon, Southwest Gas is proposing to remove the Public Purpose Program Memorandum Account (PPPMA) given that the Commission has not extended the PPPMA.

Q. 42 Which new balancing account is the Company proposing?

A. 42 As discussed later in my testimony, Southwest Gas is proposing to establish the Damage Prevention Cost Balancing Account (DPCBA).

Q. 43 Are there other proposed tariff revisions in this Application?

A. 43 Yes. Southwest Gas is updating its daily baseline quantities for the following rate schedules:

- Schedule Nos. GS-10/GN-10/SLT-10 – Residential Gas Service
- Schedule No. GS-11 – Residential Air-Conditioning Gas Service
- Schedule Nos. GS-12/GN-12/SLT-12 – CARE Residential Gas Service
- Schedule Nos. GS-20/GN-20/SLT-20 – Multi-Family Master-Metered Gas Service
- Schedule Nos. GS-25/GN-25/SLT-25 – Multi-Family Master-Metered Gas Service – Submetered

Additionally, Southwest Gas has included illustrative Statement of Rates for each rate jurisdictions. Company witness Mr. Congdon is sponsoring the calculations for the changes to the daily baseline quantities and proposed rates in Chapters 19 and 20 of the Application Schedules (Volumes II-A through C).

IX. ESTABLISHMENT OF THE DAMAGE PREVENTION COST BALANCING ACCOUNT

Q. 44 What is the DPCBA?

A. 44 The DPCBA is a two-way balancing account that will be used to record and recover (or return) certain costs associated with damage prevention expenses, specifically, those related to line locating activities.

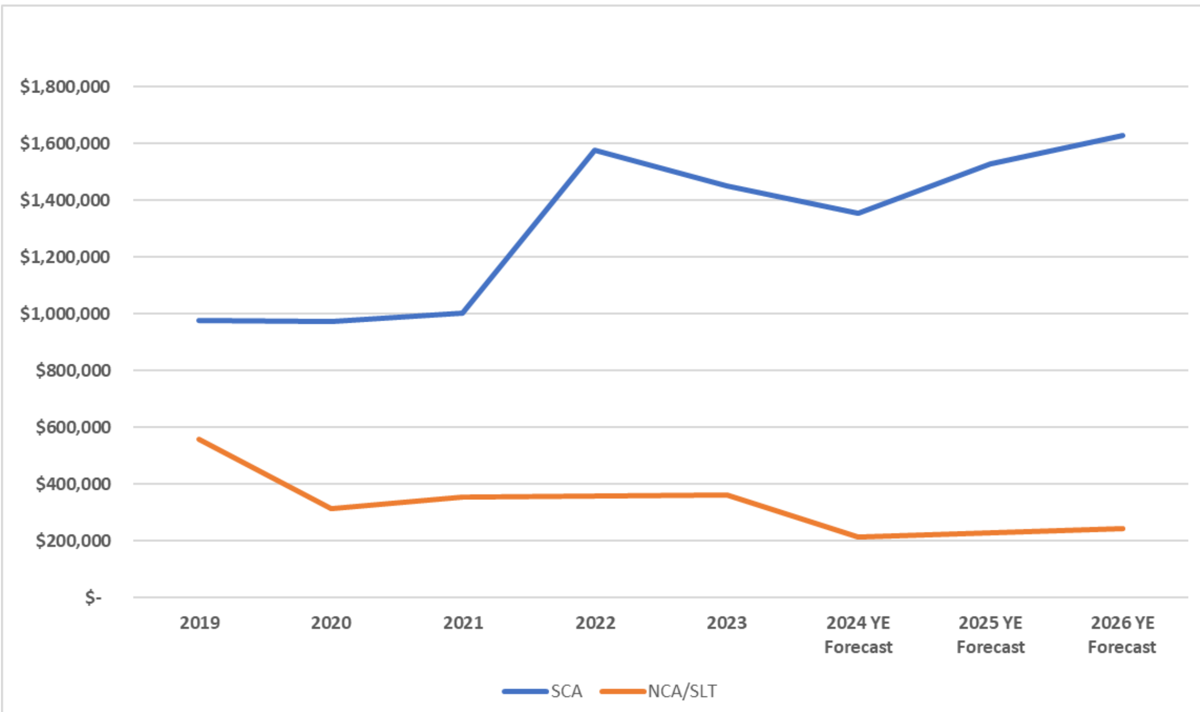
Q. 45 Why is the purpose of the DPCBA and why is it necessary?

A. 45 Damage prevention costs include line locating costs, contractor education and training and outreach (811-Call Before You Dig). As demonstrated in Figure 2 below, Southwest Gas, for example, has experienced an increasing and fluctuating level of expense related to line locating activities, including those for non-gas pipeline projects, i.e., fiber optic installation. California law requires that prior to anyone digging underground, they must call 811[23] prior to subsurface excavation to create a line location ticket to allow underground utilities to mark the lines they own and maintain. Additionally, the work associated with the type of line location ticket Southwest Gas may receive and the associated costs is difficult to predict. For example, based on the type of ticket, different excavation methods may be required due to proximity of high-pressure facilities, or the size and type of project varies, i.e., larger projects like fiber optic installation water

[23] https://www.california811.org/; Southern California - https://www.digalert.org/calaw; Northern California - https://usanorth811.org/

replacement and road improvements versus small projects like swimming pool installation, fencing or residential septic work. Therefore, the level of costs incurred responsive to the require line location activities are driven by economic activity outside of Southwest Gas management's control.

Figure 2
Line Locating Costs
2019-2026



Given this, and the fact that Southwest Gas believes that the costs will continue to fluctuate, the DPCBA is necessary to make the Company whole in between general rate case applications. However, given that the DPCBA is a two-way balancing account, in the event that actual costs are lower that authorized, Southwest Gas will return the difference as discussed further below.

Q. 46 Is the DPCBA an interest-bearing account?

A. 46 No. The Company is not seeking to recover any carrying costs associated with the balance the DPCBA will carry until the unrecovered costs are included in rates. Southwest Gas only proposes to recover the difference between authorized and actual expenses incurred – no more, and no less – between GRCs.

Q. 47 What is the proposed ratemaking treatment for the DPCBA?

A. 47 Southwest Gas will record in the DPCBA the difference between authorized damage prevention expenses established in this Application versus actually incurred expenses. The Company will recover or return the difference through a DPCBA surcharge from all customers on an equal cents per therm basis. The DPCBA surcharge will be adjusted through Southwest Gas' Annual Balancing Account Adjustment Advice Letter. The proposed tariff is included in Chapter 21 of the Application (Volumes II-A through C).

Q. 48 Does this conclude your prepared direct testimony?

A. 48 Yes.

SUMMARY OF QUALIFICATIONS
VALERIE J. ONTIVEROZ

I am a graduate of Southern Methodist University having received a Bachelor of Arts in Psychology in 1995.

From 2001 to present, I have been employed by Southwest Gas Corporation (Southwest Gas), initially as an analyst in the State Regulatory Affairs department. I was subsequently promoted to various positions of increasing responsibility within State Regulatory Affairs. In 2014, I was promoted to my current position of Regulatory Manager/California. My responsibilities include strategic leadership, guidance, and direction in the alignment of the Company’s regulatory strategy, while ensuring technical accuracy, and regulatory compliance.

During my tenure with Southwest Gas, I have provided written testimony before the California Public Utilities Commission.

SOUTHWEST GAS CORPORATION
CALIFORNIA RATE JURISDICTIONS AND PROPOSED NORTHERN CALIFORNIA CONSOLIDATED
OPERATIONS & MAINTENANCE (O&M) EXPENSE PER CUSTOMER VERSUS PEER GROUP

Line No.	Description	Reference	2018	2019	2020	2021	2022	2023	2026 GRC Proposed	2019-2023 Average	2019-2023 CAGR	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
	Operations and Maintenance Expense											
1	Atmos Energy (ATO)	[1]	461,048	480,222	472,460	501,209	518,443	565,179			4.16%	1
2	New Jersey Resources (NJR)	[1]	203,627	171,198	162,792	203,740	198,546	226,780			2.18%	2
3	Northwest Natural (NWN)	[1]	155,225	169,091	168,869	188,762	204,845	244,669			9.53%	3
4	One Gas (OGS)	[1]	411,702	429,126	431,115	449,676	472,265	508,399			4.31%	4
5	Spire (SR)	[1]	449,700	441,700	421,300	422,200	413,300	461,800			0.53%	5
6	NiSource (NI)	[1]	1,908,100	935,700	1,138,000	993,800	1,045,300	1,061,300			-11.07%	6
7	Southwest Gas - SCA	[1]	33,027	35,631	28,168	28,037	37,118	36,452	$ 45,259		1.99%	7
8	Southwest Gas - NCA	[1]	5,536	5,692	5,834	5,163	5,785	5,943	$ 8,351		1.43%	8
9	Southwest Gas - SLT	[1]	5,321	6,342	5,809	5,674	6,040	6,711	$ 7,958		4.75%	9
10	Southwest Gas - NCA Consolidated	Ln 8 + Ln 9	10,857	12,034	11,642	10,837	11,825	12,653	$ 16,309		3.11%	10
	Customers											
11	Atmos Energy (ATO)	[1]	3,256,336	3,291,835	3,333,181	3,397,249	3,442,224	3,486,384			1.37%	11
12	New Jersey Resources (NJR)	[1]	538,717	547,626	558,166	563,905	569,300	576,000			1.35%	12
13	Northwest Natural (NWN)	[1]	750,421	762,877	774,476	785,897	794,497	799,250			1.27%	13
14	One Gas (OGS)	[1]	2,179,000	2,194,000	2,220,000	2,241,000	2,256,000	2,265,000			0.78%	14
15	Spire (SR)	[1]	1,692,826	1,698,042	1,713,173	1,725,929	1,732,665	1,735,633			0.50%	15
16	NiSource (NI)	[1]	3,482,015	3,509,941	3,212,633	3,229,069	3,251,222	3,270,613			-1.24%	16
17	Southwest Gas - SCA	[1]	147,375	148,816	151,249	153,100	155,087	155,842	$ 160,992		1.12%	17
18	Southwest Gas - NCA	[1]	27,082	27,337	27,585	27,899	28,218	28,445	$ 29,246		0.99%	18
19	Southwest Gas - SLT	[1]	20,025	20,145	20,260	20,393	20,526	20,622	$ 20,684		0.59%	19
20	Southwest Gas - NCA Consolidated	Ln 18 + Ln 19	47,106	47,482	47,845	48,293	48,744	49,068	$ 49,930		0.82%	20
	O&M Per Customer											
21	Atmos Energy (ATO)	(Ln 1 * 1000) / Ln 11	$ 141.58	$ 145.88	$ 141.74	$ 147.53	$ 150.61	$ 162.11		$ 149.58	2.74%	21
22	New Jersey Resources (NJR)	(Ln 2 * 1000) / Ln 12	$ 377.99	$ 312.62	$ 291.66	$ 361.30	$ 348.75	$ 393.72		$ 341.61	0.82%	22
23	Northwest Natural (NWN)	(Ln 3 * 1000) / Ln 13	$ 206.85	$ 221.65	$ 218.04	$ 240.19	$ 257.83	$ 306.12		$ 248.77	8.16%	23
24	One Gas (OGS)	(Ln 4 * 1000) / Ln 14	$ 188.94	$ 195.59	$ 194.20	$ 200.66	$ 209.34	$ 224.46		$ 204.85	3.51%	24
25	Spire (SR)	(Ln 5 * 1000) / Ln 15	$ 265.65	$ 260.12	$ 245.92	$ 244.62	$ 238.53	$ 266.07		$ 251.05	0.03%	25
26	NiSource (NI)	(Ln 6 * 1000) / Ln 16	$ 547.99	$ 266.59	$ 354.23	$ 307.77	$ 321.51	$ 324.50		$ 314.92	-9.95%	26
27	Peer Group Average	Avg Lns 21-26	$ 288.17	$ 233.74	$ 240.96	$ 250.34	$ 254.43	$ 279.50		$ 251.80	-0.61%	27
28	Southwest Gas - SCA	(Ln 7 * 1000) / Ln 17	$ 224.10	$ 239.43	$ 186.24	$ 183.13	$ 239.34	$ 233.91	$ 281.13	$ 216.41	0.86%	28
29	Southwest Gas - NCA	(Ln 8 * 1000) / Ln 18	$ 204.43	$ 208.21	$ 211.48	$ 185.05	$ 205.02	$ 208.91	$ 285.55	$ 203.73	0.43%	29
30	Southwest Gas - SLT	(Ln 9 * 1000) / Ln 19	$ 265.71	$ 314.81	$ 286.71	$ 278.25	$ 294.27	$ 325.41	$ 384.76	$ 299.89	4.14%	30
31	Southwest Gas - NCA Consolidated	(Ln 10 * 1000) / Ln 20	$ 230.48	$ 253.44	$ 243.34	$ 224.41	$ 242.60	$ 257.87	$ 326.65	$ 244.33	2.27%	31

[1] 10-K for each company listed. Southwest Gas - SCA, Southwest Gas - NCA and Southwest Gas - SLT information obtained from Company records.

Company Witness:
Brandy Little

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
APPLICATION 24-09-__

PREPARED DIRECT TESTIMONY
OF
BRANDY LITTLE

ON BEHALF OF
SOUTHWEST GAS CORPORATION

SEPTEMBER 5, 2024

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of
Brandy Little

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Prepared Direct Testimony
of
Brandy Little

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Brandy Little. My business address is 8360 S. Durango Drive, Las Vegas, Nevada 89113.

Q. 2 By whom and in what capacity are you employed?

A. 2 I am employed by Southwest Gas Corporation (Southwest Gas or Company) in the Demand Planning & Analysis department. My title is Economist.

Q. 3 Please summarize your educational background and relevant business experience.

A. 3 My educational background and relevant business experience are summarized in Appendix A to this testimony.

Q. 4 Have you previously testified before any regulatory commission?

A. 4 Yes. I have previously provided testimony before the California Public Utilities Commission (Commission) and the Public Utilities Commission of Nevada.

Q. 5 What is the purpose of your prepared direct testimony in this proceeding?

A. 5 I sponsor Southwest Gas' billing determinants (number of bills and therms) for the Southern California, the Northern California, and South Lake Tahoe rate jurisdictions presented in Chapter 9, Billing Determinants, of the Application. For each rate jurisdiction, Chapter 9 includes: (1) a summary of the methodology used to develop the billing determinants; (2) the number of bills and recorded therms for calendar year 2023; and (3) the forecasted number of bills and therms for 2024, 2025, and for test year 2026.

Q. 6 Please summarize your prepared direct testimony.

A. 6 My prepared direct testimony consists of the following key issues:

- The regression analysis utilized to forecast the sales volumes for the heat sensitive customer classes;
- The development of forecasts utilized in sales volume projections for non-heat sensitive customers and for transportation customers; and
- The methodology utilized to forecast the number of bills.

II. REGRESSION ANALYSIS

Q. 7 Please describe the technique relied upon to forecast the sales volumes for the heat sensitive customer classes.

A. 7 The forecasted sales volumes were developed at the operating district level within each rate jurisdiction, by customer class. The operating districts include Barstow District 11, Victorville District 12, Big Bear District 13 and Needles District 19 (Southern California), Northern California District 14 and Truckee District 15 (Northern California) and South Lake Tahoe District 16 (South Lake Tahoe). Sales volumes were developed as the multiplicative product of forecasted number of bills and forecasted consumption per customer. Regression analysis was used to forecast consumption per customer for the heat-sensitive customer classes.

The regression equations include monthly heating degree day variables (monthly dummy variables multiplied by heating degree days) to capture the varying sensitivity of consumption to temperature between months. Other explanatory variables considered during the equation specification process included monthly dummy variables to account for varying consumption across months not significantly affected by temperature. A careful review of the regression statistics for each equation was conducted and the plausibility of the forecasts were carefully reviewed.

III. FORECASTED SALES VOLUME PROJECTS

Q. 8 Please describe the technique relied upon to forecast the sales volumes for both the non-heat sensitive sales and transportation customers.

A. 8 The sales projections for the non-heat sensitive customer classes and the transportation customers were developed based upon customer-specific information. Historical usage patterns and customer contact information provided by division personnel in the operating divisions conversant with local conditions were utilized to develop the projections.

IV. FORECASTED METHODOLOGY

Q. 9 Please describe the methodology utilized to forecast the number of bills.

A. 9 The forecasted number of bills were developed at the operating district level by customer class. The forecasts were produced based on recent customer levels and trends, and customer growth information provided by division personnel conversant with local conditions.

Q. 10 Is the forecast methodology for therms and number of bills in this rate case filing the same as the methodology used in Southwest Gas' prior California rate cases?

A. 10 Yes . Southwest Gas has consistently utilized the same forecasting methodology to develop the billing determinants. The Commission has accepted Southwest

Gas' methodological approach for forecasting therm sales volumes and number of bills since at least 1985.

Q. 11 What heating degree day normal did Southwest Gas utilize to forecast heat-sensitive consumption per customer?

A. 11 Southwest Gas utilized ten-year arithmetic averages of heating degree days to represent normal weather conditions.

Q. 12 Is the use of the ten-year average heating degree day assumption consistent with Southwest Gas' prior practices for general rate cases in California?

A. 12 Yes. The Commission has consistently accepted Southwest Gas' utilization of a ten-year average heating degree day assumption methodology to forecast test period sales in every California general rate case filed since 1985.

Q. 13 Does this conclude your prepared direct testimony in this matter?

A. 13 Yes.

Company Witness:
Randi L. Cunningham

IN THE MATTER OF

SOUTHWEST GAS CORPORATION

APPLICATION 24-09-___

PREPARED DIRECT TESTIMONY

OF

RANDI L CUNNINGHAM

ON BEHALF OF

SOUTHWEST GAS CORPORATION

SEPTEMBER 5, 2024

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of
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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Prepared Direct Testimony
of
Randi L. Cunningham

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Randi L. Cunningham. My business address is 8360 S. Durango Drive, Las Vegas, Nevada 89113.

Q. 2 By whom and in what capacity are you employed?

A. 2 I am employed by Southwest Gas Corporation (Southwest Gas or Company) in the Regulation department. My title is Director.

Q. 3 Please summarize your educational background and relevant business experience.

A. 3 My educational background and relevant business experience are summarized in Appendix A to this testimony.

Q. 4 Have you previously testified before any regulatory commission?

A. 4 Yes. I have previously testified before the California Public Utilities Commission (CPUC or Commission), the Arizona Corporation Commission, and the Public Utilities Commission of Nevada. I have also prepared written testimony submitted to the Federal Energy Regulatory Commission.

Q. 5 What is the purpose of your prepared direct testimony in this proceeding?

A. 5 I sponsor the Company's revenue requirement, including several schedules and supporting workpapers. I also sponsor the Summary of Earnings in Chapter 6.

Q. 6 Please summarize your prepared direct testimony.

A. 6 My prepared direct testimony consists of the following key issues:

- A general overview of Southwest Gas' results of operations in each rate jurisdiction for the projected test year (TY) ending December 31, 2026, including the margin increases requested by the Company in this proceeding.
- Support for Chapter 8A and Chapters 11B through 15 in Application Volumes II-A – Southern California, B – Northern California and C – South Lake Tahoe,[1] which include the development of Southwest Gas' TY 2026 Operations and Maintenance (O&M) and Administrative and General (A&G) expenses for its three California rate jurisdictions.
- Support for Chapter 8B, System Allocable Rate Base, related to the portion of the corporate rate base and depreciation and amortization expense allocated to the Company's three California rate jurisdictions.
- Support for payroll tax in Chapter 16, Taxes.
- Support for Chapter 17, Rate Base, except working capital and regulatory amortizations, for each of the Company's three California rate jurisdictions.
- Support for Chapter 18, Pensions and Benefits.
- Support for Chapter 22, Post-Test Year Ratemaking Mechanism (PTYM), for the years 2027 through 2030.

II. RESULTS OF OPERATIONS

Q. 7 What is the test year used by Southwest Gas in this general rate case filing?

A. 7 The TY is the projected 12-month period ending December 31, 2026. Southwest Gas also requests annual post-test year adjustments to rates for 2027 through 2030.

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[1] Subsequent references to Chapters in my testimony are intended to refer to the Application Volumes as defined for Results of Operations schedules.

Q. 8 Please summarize the Company's results of operations.

A. 8 Chapter 6, Summary of Earnings, summarizes the results of operations for Southern California (SCA), Northern California (NCA), and South Lake Tahoe (SLT), for the projected TY ending December 31, 2026.

Chapter 6, Sheet 1, Column (d) illustrates that in SCA, the Company requires an overall margin increase of $38,499,807 to allow it a reasonable opportunity to earn the proposed SCA rate of return of 7.74 percent. In NCA, the Company requires a margin increase of $62,810 to allow it a reasonable opportunity to earn the proposed NCA rate of return of 7.85 percent. In SLT, the Company requires a margin increase of $10,185,232 to allow it a reasonable opportunity to earn the proposed SLT rate of return of 7.85 percent.

Margin refers to the revenues derived from base rates, excluding revenues and expenses related to the natural gas commodity. Natural gas commodity-related revenues and expenses are subject to a separate purchased gas cost adjustment mechanism for ratemaking and are not included in base rates. The overall rate of return is slightly lower for SCA because of the availability of certain tax-exempt Industrial Development Revenue Bonds. This is explained more thoroughly in the prepared direct testimony of Southwest Gas witness Justin S. Forsberg.

For each rate jurisdiction, Chapter 6, Sheet 2 summarizes the capital structure and overall rate of return proposed by the Company in this Application. Mr. Forsberg provides support and testimony for the proposed capital structure and cost of debt for each rate jurisdiction. Company witness Dylan W. D'Ascendis provides support and testimony for the proposed return on common equity (ROE) for each rate jurisdiction.

For each rate jurisdiction, Chapter 6, Sheet 3 sets forth the gross revenue conversion factor (GRCF). The GRCF is the ratio of gross revenue required to produce a one dollar change in net operating income for TY 2026. The GRCF is 1.41412 for SCA and 1.41979 for NCA and SLT.

Q. 9 What are some of the major contributors of the deficiency for TY 2026?

A. 9 Major contributors of the deficiency for TY 2026 include:

- <u>Significant increases in plant investment necessary to provide safe and reliable service:</u> This includes investments projected through the TY, as well as investments recovered through various regulatory mechanisms between rate cases, including the Infrastructure Reliability and Replacement Adjustment Mechanism (IRRAM), the California Mobile Home Park (MHP) Conversion Balancing Account (MHPCBA) for to-the-Meter costs, and the Customer Data Modernization Initiative (CDMI) Balancing Account (CDMIBA). These capital expenditures have conforming impacts to depreciation expense and property taxes.
- <u>Customer growth</u>: The Company's authorized PTYM adjustment is a flat 2.75 percent rate for attrition for years 2022-2025. Actual margin is balanced to authorized margin for each year; therefore, any margin related to customer growth flows back to customers through the Fixed Cost Adjustment Mechanism (FCAM) until they are included in developing the revenue requirement for the next general rate case (GRC).
- <u>Operations and maintenance expenses (O&M), administrative and general expenses (A&G), collectively OMAG</u>: OMAG costs generally increased due

to inflationary pressures. As discussed further below, these costs were projected through to the TY to reset these costs to current costs that result in just and reasonable rates.

Q. 10 Why does the revenue requirement on plant investments that have been recovered through balancing accounts between GRCs have an impact on the deficiency?

A. 10 The reason the deficiency is impacted by the revenue requirement on plant investments recovered through balancing accounts is that this Application is the first time that these plant investments have been included in the calculation of the revenue requirement in base rates.

The Company will continue to calculate the revenue requirement on this plant investment through December 2025 for recovery through their respective balancing accounts for recovery through those mechanisms. Once rates from this proceeding are effective January 1, 2026, deferrals will no longer be calculated for inclusion in those mechanisms because the related investments will be recovered through the rates authorized by the Commission in this proceeding. Once these deferrals are fully collected through their respective mechanisms and the rates are reset, these investments will no longer impact customer rates through those surcharges. I refer to the cessation of calculating a revenue requirement on plant investments recovered through a balancing account to the inclusion of the revenue requirement on these plant investments to be recovered through a GRC as “roll into base rates”.

Q. 11 Does the revenue requirement on plant investments authorized to be recovered through the PTYM adjustment have a similar impact on the deficiency?

A. 11 No. Base margin has already been adjusted for the revenue requirement on any plant investment included in the PTYM adjustment. For example, in the last GRC, Southwest Gas was authorized to include the revenue requirement associated with the North Lake Tahoe Lateral (NLTL) replacement project as an PTYM adjustment once each phase of the NLTL project is placed into service and operational. These PTYM adjustments for NLTL began in 2022.

Q. 12 What is the amount of gross plant investment the Company is proposing to roll into base rates from the IRRAM, MHPCBA, and the CDMIBA?

A. 12 The Company is proposing that gas plant placed into service between January 1, 2017 and December 31, 2023 will be rolled into base rates effective January 1, 2026. The gross plant amount by jurisdiction and mechanism is as follows ($ in millions):

Mechanism	SCA	NCA	SLT	Total
MHP	$8.4	$0	$2.72	$11.61
CDMI	$9.0	$1.6	$1.8	$12.4
IRRAM	$63.9	$0.6	$3.8	$68.3
TOTAL	**$81.3**	**$2.2**	**$8.3**	**$91.8**

Q. 13 What is the deficiency impact of the rolled-in plant investments shown in the table above?

A. 13 The deficiency impact of the rolled-in plant investments is approximately $10.0 million in SCA, $0.3 million in NCA and $1.0 million in SLT.

Q. 14 Southwest Gas is proposing to consolidate its NCA and SLT rate jurisdictions into a single rate jurisdiction. Is it necessary to provide a consolidated revenue requirement model?

A. 14 No. The combined revenue requirement is determined simply by adding NCA and SLT together. Certain revenue requirement items, like uncollectibles expense and franchise tax expense, already use a combined rate based on data consisting of both rate jurisdictions to determine the expense for NCA and SLT individually. Please refer to the prepared direct testimonies of Company witnesses A. Brooks Congdon and Valerie J. Ontiveroz for justification for the proposed consolidation of the NCA and SLT rate jurisdictions. Mr. Congdon specifically supports the consolidated class cost of service studies and rate design models.

III. ESCALATION (CHAPTER 7)

Q. 15 Are you sponsoring Chapter 7?

A. 15 No. Please refer to the prepared direct testimony of Company witness Charlene A. Lachica for general testimony on Chapter 7. I provide more insight into the labor escalation factors used, particularly the labor escalation factor for 2024.

Q. 16 The labor escalation factor for 2024 is noticeably higher than the labor escalation factors in historical years. Please explain why this is the case.

A. 16 During 2024, the Company's Human Resources Department partnered with Mercer Consultants to conduct a compensation study to ensure market alignment of Southwest Gas' job compensation levels and structures. Jobs were benchmarked using nationally recognized compensation surveys with input from the Company's leadership, to ensure the benchmarks were appropriate for the positions being matched. The results of the study indicated that the compensation ranges for many positions in the Company did not align with the market. Market adjustments were made to non-exempt positions, and to exempt positions in select cases, in July 2024.

The market study increases were not granted to Southern California Division non-exempt employees due to recent union representation. As explained in the Company's response to Master Data Request (MDR)-001, Southwest Gas does not currently have any union contracts. However, in April 2024, certain nonexempt employees in the Company's Southern California Division elected representation by the United Steel Workers union. Contract negotiations are currently underway. For the purpose of determining the projected wage increases from a ratemaking perspective in this GRC, since the result of contract negotiations are unknown at the time of filing, the Company used similar increases as a placeholder for represented non-exempt employees in Southern California Division. The Company plans to file a two-way balancing account to track actual increases versus the placeholder increases for these newly represented Southern California Division employees so customers are paying fair and reasonable labor costs.

IV. SYSTEM ALLOCABLE EXPENSES (CHAPTER 8A)

Q. 17 What are System Allocable expenses?

A. 17 System Allocable (i.e. common) expenses, contained in Chapter 8, Tab A, are primarily A&G costs that originate from the Company's Corporate-level activities that are not directly assigned to one or more rate jurisdictions. As such, these costs must be allocated to each rate jurisdiction for ratemaking purposes.

Q. 18 Which Company witness is sponsoring the methodologies Southwest Gas uses to allocate System Allocable expenses?

A. 18 Please refer to Ms. Lachica's prepared direct testimony for a description of the allocation methodologies used by Southwest Gas to allocate common costs. Refer to Chapter 8C for the allocation percentages proposed by Southwest Gas for the projected years.

Q. 19 Please provide a general description of how test year distribution expenses in Chapter 8, Tab A were developed.

A. 19 Projected test year customer accounts expenses in Chapter 8A were developed by escalating recorded 2023 costs, apart from the adjustments outlined below:

- <u>Miscellaneous Expenses</u>: an adjustment was made to remove $571,800 of system allocable A&G expenses, before allocation to California, from the GRC. After allocation, the impact to California was a reduction in operating expenses of $43,540 for SCA, $8,749 for NCA, and $7,760 for SLT. Please refer to Ch 8A supporting workpaper (WP), Sheet 11 for more details regarding the adjustment.[2]
- <u>Officer Compensation</u>: an adjustment was made to remove $11,371,523 of system allocable A&G expenses from the GRC. The impact to California was a reduction in operating expenses of $865,883 for SCA, $173,986 for NCA, and $154,316 for SLT. Please refer to Ch 8A WP, Sheet 12 for more details regarding the adjustment.

[2] Subsequent references to WP Chapters in my testimony are intended to refer to the Supporting Workpapers Volumes IV-A – Southern California, B – Northern California and C – South Lake Tahoe that accompany the Application but are not filed.

- Account 925: there are two separate adjustments to Account 925, Injuries and Damages:
    - All injuries and damages expenses except Self-Insured Retention (SIR): an adjustment was made to remove $8,214,010 of system allocable A&G expenses, before allocation to California, from the GRC based on normalizing these costs over five years. The impact to California was a reduction in operating expenses of $625,455 for SCA, $125,675 for NCA, and $111,467 for SLT. Please refer to Ch 8A WP, Sheet 13 for more details regarding the adjustment.
    - SIR: an adjustment was made to remove $720,000 of system allocable A&G expenses, before allocation to California, from the GRC based on normalizing settlements over five years. The impact to California was a reduction in operating expenses of $54,824 for SCA, $11,016 for NCA, and $9,771 for SLT. Please refer to Ch 8A WP, Sheets 14-15 for more details regarding the adjustment.
- Non-Service Post-Retirement Benefits Normalization: an adjustment was made to add $51,209,362 of system allocable A&G expenses, before allocation to California, to the GRC based on normalizing these costs over five years. The impact to California was an increase in operating expenses of $3,899,332 for SCA, $783,510 for NCA, and $694,931 for SLT. Please refer to Ch 8A WP, Sheet 16 for more details regarding the adjustment.
- Annualization of allocations from Southwest Gas Holdings: an adjustment was made to add $635,014 of system allocable A&G expenses, before allocation to California, to the GRC based on normalizing these costs over

five years. The impact to California was an increase in operating expenses of $48,353 for SCA, $9,716 for NCA, and $8,617 for SLT. Please refer to Ch 8A WP, Sheet 17 for more details regarding the adjustment.

Please refer to Chapter 8, Tab A narratives for more information regarding these adjustments.

V. SYSTEM ALLOCABLE RATE BASE (CHAPTER 8B)

Q. 20 Please describe Chapter 8B, System Allocable Rate Base.

A. 20 Chapter 8B consists of System Allocable plant, annual depreciation and amortization expense, and accumulated provision for depreciation and amortization.

Q. 21 What is System Allocable plant?

A. 21 System Allocable plant represents the fixed assets that support all the Company's rate jurisdictions and utility operations. Note that the Company relocated its Corporate Headquarters since its last California GRC. As such, the projection of any component of general plant or the accumulated reserve for depreciation and amortization excluded the activity associated with the disposal of these assets. These fixed assets are comprised of intangible plant (software development projects and software applications) and general plant.

Q. 22 What amortization period is used for intangible plant?

A. 22 The amortization period for intangible plant is project-specific and ranges from three to fifteen years, depending on the expected useful life of the project.

Q. 23 How is System Allocable depreciation and amortization expense calculated?

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A. 23 System Allocable depreciation and amortization expense is calculated using the depreciation rates that were used to establish margin rates for the Company's 2021 test year GRC, which includes post-test years 2022 through 2025. The System Allocable depreciation and amortization rates for TY 2026 are based on the System Allocable depreciation study approved in the Company's last Nevada GRC in Docket No. 23-09012. Using the more recent System Allocable depreciation study is consistent with prior California GRCs and is necessary so the same system allocable depreciation rates are used in the three states in which Southwest Gas operates.

Q. 24 What methodology is used to allocate the System Allocable plant, annual amortization and depreciation expense, and accumulated provision for amortization and depreciation?

A. 24 The System Allocable plant, annual amortization and depreciation expense, and accumulated provision for amortization and depreciation are allocated to the Company's three California rate jurisdictions using the 4-factor allocation methodology developed in Chapter 8C.

Q. 25 How did the Company develop the estimated years 2024, 2025 and TY 2026 additions for intangible plant?

A. 25 The intangible plant additions for the projected years are either identified on a project-specific basis, or in buckets for the Office of Continuous Improvement and Optimization (OCIO) and the Enterprise Project Management Office (EPMO). These two departments have budgets to cover multiple projects, which will be identified, prioritized, and optimized based on the Company's needs during the estimated years in the current GRC cycle. Estimated years 2024, 2025 and test year 2026 were developed based on the 2024 budget, with any known updates at the time of filing considered.

Q. 26 How did the Company develop the estimated years 2024, 2025 and TY 2026 additions for general plant?

A. 26 General plant additions for estimated years 2024, 2025 and TY 2026 were developed based on the 2024 budget, with any known updates at the time of filing considered. General plant projections for retirements, cost of removal and salvage were generally developed based on a three-year average, then escalated with the material and expenses escalator factors in Chapter 7. Overhead costs are not applied to System Allocable intangible and general plant.

VI. DIRECT O&M AND A&G EXPENSES (CHAPTERS 11B THROUGH 15)

Q. 27 What are "direct" expenses?

A. 27 Direct expenses are expenses which were either incurred directly by a rate jurisdiction, or directly charged to a rate jurisdiction for expenses incurred on its behalf, whether by employees or automatically within the general ledger based on pre-defined percentages. These costs can be identified in the general ledger based on the accounting control key used to record these expenses. As such, allocation of these costs for ratemaking purposes is not necessary.

Q. 28 Which chapters of the Application filing contain direct O&M and A&G expenses?

A. 28 Chapter 11, Tab B contains gas supply and distribution expenses. Chapter 12 contains customer accounts expenses. Chapter 13 contains customer service and information expenses. Chapter 14 contains sales expenses. Chapter 15 contains A&G expenses. The narratives preceding each chapter supplement this testimony in describing how TY expenses were developed. In most cases, TY labor expense and materials and expenses were based on escalated 2023 expenses. Significant deviations from this methodology are described below.

Q. 29 Please provide a general description of how TY 2026 distribution expenses in Chapter 11, Tab B were developed.

A. 29 When projecting distribution costs, viewing the distribution function as a whole is appropriate since each individual account within the distribution function may vary widely from year to year based on work requirements. Costs have generally been increasing during the current GRC cycle. As such, Southwest Gas based its initial projection for distribution expenses on 2023 expenses, apart from adjustments in the accounts noted below. Finally, the escalation factors are applied to the 2023 base year amounts to recognize cost increases after the base year due to inflation.

Q. 30 Does Southwest Gas propose an adjustment related to the Pension Balancing Account (PBA) in Chapter 11B?

A. 30 Yes. The Company proposes removing the PBA journal entries from O&M costs, because: 1) it will be addressed in Regulatory Amortizations in this GRC, and 2) allowing those journal entries to remain in Account 880 distort the actual costs in the account related to distribution operations. Please refer to Chapter 11B, Sheet 22 for non-labor costs in Account 880 with and without the PBA entries.

Q. 31 Does Southwest Gas propose any other adjustments to distribution expenses?

A. 31 Yes, the Company included a “cost changes” adjustment to include costs incremental to the 2023 base year costs. Further details for the cost changes to develop projected TY 2026 costs are contained in the Chapter 11, Tab B narratives. This adjustment increased operating expenses by $564,413 in SCA and reduced operating expenses by $85,135 in NCA and $270,323 in SLT.

Q. 32 Please provide a general description of how TY 2026 customer accounts expenses in Chapter 12 were developed.

A. 32 Projected TY customer accounts expenses in Chapter 12 were developed by escalating recorded 2023 base year costs, apart from uncollectibles expense.

Q. 33 Is the TY 2026 amount for Account 904, Uncollectible Accounts, comparable to the amounts recorded during prior years?

A. 33 No. The amounts in Account 904 represent the entire amount of uncollectible expense for the Company. However, only the margin portion of uncollectible expense should be included for recovery in the cost of service because the remainder is recovered in gas costs. Therefore, Southwest Gas has included only the margin portion of uncollectible expense proposed for the TY in Account 904 and has modified historical uncollectibles expense to show only the margin portion of this expense.

Q. 34 Please provide a general description of how TY 2026 customer service and information expenses in Chapter 13 were developed.

A. 34 Projected TY 2026 customer service and information expenses in Chapter 13 were developed by escalating recorded 2023 base year costs, apart from adjustments made in the projection adjustment. Further details are contained in the Chapter 13 narratives.

<u>Account 910</u>: this account was normalized based on a five-year average since these costs can vary from year to year. This adjustment decreased operating expenses by $25,492 in SCA and increased operating expenses by $10,881 in NCA and decreased operating expenses by $551 in SLT.

Q. 35 Is Southwest Gas requesting recovery of sales expenses in Chapter 14?

A. 35 No. All sales expenses were removed from the cost of service and are not being requested for recovery in this Application.

Q. 36 Please provide a general description of how TY 2026 A&G expenses in Chapter 15 were developed.

A. 36 Projected TY 2026 A&G expenses in Chapter 15 were developed by escalating recorded 2023 base year costs, apart from adjustments outlined below. Further details are contained in the Chapter 15 narratives.

- Account 925 Injuries and Damages: there are two separate adjustments to Account 925:
  1. All injuries and damages expense except SIR: an adjustment was made to normalize these costs over five years, consistent with prior GRCs. The impact to California is an increase in operating expenses of $38,217 for SCA, a reduction in operating expenses of $13,439 for NCA and $6,367 for SLT. Please refer to Ch 15 WP, Sheet 8 for more details regarding the adjustment.
  2. SIR: an adjustment was made to normalize California state settlements over five years, as these costs vary widely from year to year. This adjustment is then allocated to each California jurisdiction based on their relative California 4-Factor. This adjustment was made consistent with prior GRCs. The impact is an increase in operating expenses of $474,407 for SCA, $103,116 for NCA, and $91,458 for SLT. Please refer to Ch 15 WP, Sheets 9-10 for more details regarding the adjustment.

- Account 928, Rate Case Expense: was adjusted to reflect the difference between the projected $895,000 incremental rate case expenses expected to be incurred in this GRC and the 2023 recorded amortization of expenses from the prior GRC. This difference is then allocated to the California rate jurisdictions based on the California-only 4-Factor. The impact is an increase in operating expenses of $14,458 for SCA, $3,507 for NCA, and $5,179 for SLT. Please refer to Ch 15 WPs, Sheets 13-14 for more details regarding the adjustment.
- Account 930.2, Miscellaneous General Expense: was adjusted to reflect the Company's proposal to increase Research Development and Demonstration (RD&D) expenses in its California jurisdictions to $400,000 per year beginning in TY 2026 to support additional RD&D initiatives as described below. This amount will be allocated to each California ratemaking jurisdiction based on its weighted 4-Factor relative to the total California 4-Factor percentage. The impact is an increase in operating expenses of $94,195 for SCA, $18,927 for NCA, and $16,787 for SLT. Please refer to Ch 15 WP, Sheet 15 for more details regarding the adjustment.

Q. 37 Please explain how Southwest Gas determined the amount of the adjustment for RD&D expenses.

A. 37 Southwest Gas is currently authorized $250,000 per year of RD&D expenses. Since the recorded amount of RD&D expense may vary somewhat in a given calendar year due to the timing of invoices or credits, the Company used the $270,090 recorded in 2023 as the base and made an adjustment of $179,910 to get to $450,000 per year.

Q. 38 Please explain how Southwest Gas proposes to use these incremental RD&D funds.

A. 38 The additional funds would be earmarked for a broad range of initiatives, from advancing emission reduction technologies and enhancing operational efficiency through improved leak detection and damage prevention, to deploying cutting-edge digital innovations and emerging technologies that support system integrity. For example, the investment in a pioneering camera inspection tool for small-diameter distribution pipelines, which integrates artificial intelligence for more innovative integrity management, exemplifies such initiatives. This project not only bolsters proactive integrity management but will generate royalties upon its commercial deployment, providing a continuous funding stream for further RD&D pursuits. Southwest Gas' active participation in industry projects through national research consortiums underscores the Company's strategic commitment to achieving environmental sustainability and meeting rigorous operational and safety standards through RD&D and emerging technologies.

Q. 39 Please describe the collaboration and evaluation process for Southwest Gas' engagement in RD&D.

A. 39 Southwest Gas's engagement in RD&D is facilitated through its memberships in the Operations Technology Development (OTD) group and NYSEARCH, research consortia dedicated to the natural gas sector. These partnerships enable us to pool expertise and resources, ensuring the Company's RD&D initiatives are innovative and aligned with industry advancements while avoiding duplicative efforts. Southwest Gas prioritizes projects that align with regulatory requirements, environmental policies, and the Company's sustainability and operational goals, underscoring its leadership, commitment to industry, and environmental stewardship. Southwest Gas' RD&D efforts are driven by subject matter experts (SMEs) across various departments, including Operations, Lab Services, Safety & Quality, and System Integrity, who spearhead projects that directly advance the Company's environmental and operational objectives. These projects often enhance compliance and operational efficacy. When new opportunities arise, SMEs rigorously evaluate project briefs outlining the benefits, background, technical approaches, and expected deliverables. Supported projects are further refined through regular technical advisory meetings, where utility members provide ongoing feedback, steer the research direction, and ensure alignment with strategic goals. This comprehensive evaluation process, involving executive leadership, a Steering Committee, and SMEs, guarantees investments that yield operational advantages and contribute to long-term sustainability. The inclusion of SMEs in kickoff, update, and closing meetings ensures ongoing qualitative oversight and project direction.

Q. 40 Please describe Southwest Gas' focus areas for RD&D investment.

A. 40 The proposed increase in the RD&D budget will allow Southwest Gas to prioritize initiatives that significantly reduce its environmental footprint, enhance digital integration, and bolster safety and operational practices. This includes the development of technologies aimed at reducing methane emissions and advanced leak detection systems that mitigate environmental hazards. Investments in digital technologies are critical, improving data analysis and operational efficiencies in areas such as line locating, damage prevention, leak detection, mapping, and predictive modeling for integrity management. These investments are vital for continuously improving the Company's safety and reliability of its gas system and in turn reducing its environmental impact.

Q. 41 Please describe the benefits of RD&D programs to Southwest Gas customers and the community at large.

A. 41 RD&D investments yield dual benefits: they enhance operational efficiencies and could significantly reduce Southwest Gas' environmental impact. The technological innovations stemming from the Company's participation in RD&D efforts are designed to address future challenges with sustainable solutions, providing customers and the broader community with reliable energy services and a diminished environmental footprint. This proactive investment adapts to change and drives it, securing a sustainable future for all stakeholders.

Q. 42 Are local franchise taxes included in Chapter 15?

A. 42 Yes. While Southwest Gas charges franchise taxes to Account 408.1, the Public Advocates Office at the Commission (Cal Advocates) previously requested that Southwest Gas include local franchise taxes in Account 927, an A&G account, for California ratemaking purposes. Therefore, Southwest Gas has included the margin-related portion of local franchise taxes proposed for the TY in Account 927. The local franchise tax to be recovered in gas costs is not included in Account 927, and historical amounts were modified to show only the margin portion of local franchise taxes.

Q. 43 Do you sponsor testimony regarding the calculation of local franchise taxes or the related projections?

A. 43 No. Company witness Byron C. Williams provides prepared direct testimony regarding local franchise taxes; I sponsor only the inclusion of local franchise taxes in the revenue requirement.

VII. TAXES (CHAPTER 16)

Q. 44 Do you sponsor the entirety of Chapter 16?

A. 44 No. Company witness Byron C. Williams sponsors testimony for all of Chapter 16 except for payroll taxes, which I address in my testimony.

Q. 45 Does the Company run payroll taxes through its labor loading process?

A. 45 Yes. However, consistent with guidance received from the Commission in prior GRCs, the Company made an adjustment to remove payroll taxes from labor loading in Chapter 18 and include them in Chapter 16 in this Application.

Q. 46 Please explain how TY 2026 payroll taxes for FICA (Medicare and Social Security), federal unemployment insurance (FUI) and state unemployment insurance (SUI) were determined.

A. 46 The base year 2023 tax base and rates were applied to TY employees to determine test year 2026 FUI and SUI. Base year 2023 rates were applied to salaries eligible for social security taxes to calculate social security, and to total salaries to calculate Medicare.

VIII. RATE BASE (CHAPTER 17)

Q. 47 Please describe Chapter 17, Rate Base.

A. 47 Chapter 17 provides the various components comprising rate base for each California rate jurisdiction, beginning in the year 2019 and ending with the 2026 TY. The average rate base is provided by year, as is the direct depreciation and amortization expense for each of those years.

Gas Plant In-Service (GPIS) and the Accumulated Provision for Depreciation and Amortization (Accumulated Depreciation) use recorded balances as of December 31, 2018, and are adjusted for: 1) projected plant additions; 2) projected plant retirements; and 3) other changes to accumulated depreciation (i.e., salvage, removal cost, etc.) for the subsequent years.

TY 2026 depreciation and amortization expense is comprised of an annual depreciation provision based on the GPIS at the beginning of the year, with the half-year convention being applied to plant added during the year. The depreciation rates used in the TY were provided on August 23, 2024, to Cal Advocates pursuant to Commission Standard Practice U-4. The requested working capital consists of materials and supplies; customer advances; and a cash working capital component determined by a lead-lag study.

Q. 48 Please describe how the Company determined the estimated years 2024, 2025 and TY 2026 plant additions.

A. 48 Plant additions for estimated years 2024, 2025 and TY 2026 were developed based on the 2024 budget, taking into consideration any known updates at the time of this Application filing. Plant additions for projects included in the IRRAM beyond 2023 were excluded from projected rate base as they will be recovered through the IRRAM surcharge.

Q. 49 Costs associated with the NLTL pipe replacement project in NCA was included in rates as part of the PTYM adjustment prior to the filing of this GRC. Please describe the costs included in this GRC for the NLTL.

A. 49 All actual NLTL capital expenditures incurred and placed into service through 2023, as well as an additional $14,850,000 expected to be incurred through 2024, are being requested to be recovered through base rates in this proceeding. Part of the reason there is a minimal deficiency in NCA was due to the timelier recovery of the $4,685,609[3] revenue requirement associated with this project through the PTYM adjustment between GRCs. The incremental revenue requirement for the NLTL Project in this GRC is related only to the NLTL projected to be placed into service in 2024.

Q. 50 What is the current status of the NLTL Project?

A. 50 There are approximately 3.5 miles remaining to complete the NLTL Project, at an estimated cost of $30 million. The California Department of Transportation (CalTrans) informed Southwest Gas this year that they were moving forward with a fiber optics project in 2024 and intend to complete a full re-pavement of the highway in 2025. Should the re-pavement occur, CalTrans is expected to place a five-year no-dig moratorium on the highway. The Company does not expect to know whether CalTrans will move forward with the re-pavement project until 2025. The projected capital expenditures for 2024 are to complete tie overs, associated service replacements, and abandonment of existing facilities, which allows Southwest Gas to be prepared to continue the NLTL replacement in 2025 or delay the remaining work until the no-dig moratorium is lifted and work can continue.

Q. 51 Please describe the capital investment needed to serve the new large SCA customer, National Army Training Center (NTC) at Fort Irwin, California,[4] that is requested for recovery in this GRC.

A. 51 At this time, it is anticipated that an Incremental Facilities Agreement (IFA) will be finalized and signed in the near future to serve NTC, which will also identify

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[3] Advice Letter (AL) 1280 for 2024 (a reduced amount was included in AL 1241 for 2023 and AL 1195 for 2022).

[4] Commission D.24-04-014, approved April 18, 2014, granted Southwest Gas a Certificate of Public Convenience and Necessity to extend its service territory in Northeast Barstow, California to provide service to NTC.

the minimum annual volume that NTC is required to take after a ramp up period. The projected capital expenditures of approximately $25.5 million (net of CIAC) that is required to serve NTC are projected to be placed into service in 2026. Due to the average rate base convention, only one half of the projected rate base associated with this capital addition will be reflected in the revenue requirement proposed in this Application. The Company proposes to recover any remaining rate base additions for NTC in the PTYM adjustment, as discussed further below.

Q. 52 What methodology was used to derive working capital?

A. 52 Working capital consists of materials and supplies; customer advances; and a cash working capital component determined by a lead-lag study.

Materials and supplies are projected based on five-year historic average of 13-month average balances, consistent with the Company's methodology in prior GRCs. In this GRC, the Company is also proposing to include System Allocable materials and supplies. The System Allocable materials and supplies are projected based on five-year historic average of 13-month average balances and allocated to each jurisdiction based on the 4-factor allocation methodology.

Q. 53 Please explain how the Company projected customer advances.

A. 53 Since line extension allowances were eliminated in California for new gas extension contracts executed on or after July 1, 2023, the Company projected when existing customer advances would be refunded through 2026, reducing the customer advances balance existing at December 31, 2023 accordingly.

Q. 54 Please describe the development of the lead lag study.

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A. 54 The lead-lag study compares differences between the Company's revenue lag and expense leads. The revenue lag measures the number of days from the time natural gas service is provided to customers to the time payment is received from customers. The expense leads measure the number of days from the time goods and services used to provide natural gas service are provided to the Company to the time payments are made by the Company for those goods and services. The lag and leads are measured in days for individual expenses, converted to "dollar-days" that reflect a weighting by expense amount, and then summed across all expenses.

Q. 55 Please describe the development of the revenue lag.

A. 55 The revenue lag measures the number of days from the time natural gas service is provided to customers to the time payment is received from customers. The revenue lag consists of three components: (1) the service lag; (2) the billing lag; and (3) the collection lag.

The service lag measures the average number of days in the service period; i.e., the time between the start and end of the billing month. The point in time at which meters are read indicates the end of the billing month. The service lag in this lead-lag study was based on the midpoint of the service period, which reflects that natural gas is delivered evenly over the service period.

The billing lag measures the number of days from the time meters are read to the time bills are recorded and sent to customers. The billing lag was based on the Company's meter reading schedule. The collection lag measures the number of days from the time bills are recorded and sent to customers to the time customer payments are received (i.e., funds are available to the Company).

The collection lag in this lead-lag study was based on analysis of the Company's accounts receivables data.

Q. 56 Please describe the development of the expense lead.

A. 56 Lead days for O&M expenses were determined by first separating the expenses into four groups: (1) Cost of Gas; (2) O&M expenses, separated between labor and non-labor expenses; (3) Income Taxes and (4) Taxes Other than Income Taxes. The lead days for each group were measured separately.

Lead days for cost of gas expenses were based on the service lead (i.e., the midpoint of the service period) and payment lead (i.e., the number of days between the end of the service period and payment date).

The lead days for regular payroll expenses were based on the number of days from the midpoint of the pay period to the payment date. The study also made an adjustment for incentive payments. The adjustment measures the number of days from the midpoint of the performance period to the payment date.

Lead days associated with other O&M expenses were based on a sample of invoices with a $25,000 minimum paid by the Company from January 1, 2023 through December 31. 2023. Lead days were measured for each invoice in the sample as the number of days from the midpoint of the service period to the payment date. Invoices were then dollar-weighted to determine lead days for Other O&M expenses.

Lead days associated with federal and state income taxes were measured as the number of days from the midpoint of the calendar year to the payment date. The study used the midpoint of the calendar year because federal and state income taxes are based on annual earnings.

Lead days associated with taxes other than income taxes were measured for the following groups: (1) Property taxes, (2) Sales and Use taxes, (3) Mill Assessments, and (4) Franchise taxes.

Lead days associated with these taxes were based on an analysis of payments from January 1, 2023 through December 31, 2023. Lead days were measured as the number of days from the midpoint of the taxing period (i.e., the period for which the tax was assessed) to the payment date.

Q. 57 Please describe the development of Other Working Capital Requirement.

A. 57 Other Working Capital Requirement was calculated using a thirteen-month average balance, ended December 31, 2023. Certain accounts are specific to non-California jurisdictions, so those are removed in the adjustment column. A deferred tax rate is also applicable to certain accounts, which is included in the 13-month averages. System Allocable accounts were allocated using the 4-factor allocation method. California-only accounts were allocated using the California-only 4-factor allocation method.

<u>IX. PENSION AND BENEFITS (CHAPTER 18)</u>

Q. 58 Please describe Chapter 18.

A. 58 Chapter 18 provides an itemized list of pension and benefits (P&B), including paid time off (i.e. indirect time), included in the labor loading percentage projection. P&B expenses are incurred on a total Company basis. Because Southwest Gas has rate jurisdictions in three states as well as two FERC jurisdictions, these costs are distributed through a mechanism called “labor loading”.

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Q. 59 How are the labor loading percentages determined?

A. 59 For each labor dollar charged to an account, an additional amount (i.e. labor loading) is charged to that account. This additional amount represents the pensions, benefits, and payroll taxes that relate to those labor dollars. Payroll taxes were removed from recorded labor loadings, as discussed in more detail below.

Q. 60 Were labor loadings escalated using the escalation factors in Chapter 7?

A. 60 Yes. Chapter 18, Sheet 6 shows which P&B were escalated using the labor escalation factor, and which P&B were escalated using the materials and expenses escalation factor.

Q. 61 Five years of historical data was provided for pension expense. Do these amounts represent the pension expense Southwest Gas recorded to Account 926 on its books?

A. 61 No. Southwest Gas uses the accrual method for pension accounting in accordance with Financial Accounting Standards Board (FASB) Statement No. 87 (FAS 87) issued December 1985, which is consistent with the ratemaking treatment for pension expense in Arizona and Nevada. However, in D.88-03-072, Ordering Paragraph 2, the Commission rejected FAS 87 for California ratemaking purposes. Therefore, Southwest Gas used the cash method for reporting historical pension expense, as well as to project test year pension expense for California ratemaking purposes. The actuarial studies supporting historical PBOP and SERP amounts are provided in response to MDR-077.

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Q. 62 How were test year P&B projected?

A. 62 Most P&B were projected based on escalated 2023 base year expenses. The P&B adjustments are shown on Chapter 18 WP, sheets 4-6. The adjustments include:

- Removal of certain Officer Compensation in relation to Senate Bill (SB) 901, which repealed PU Code Section 706 and added new language prohibiting an electrical or gas corporation from recovering from ratepayers any annual salary, bonus, benefits or other consideration of any value, paid to an officer of the electrical corporation or gas corporation, and requires that compensation instead be funded solely by shareholders of Southwest Gas.
- Removal of certain miscellaneous benefits costs from the cost of service that is not being requested for recovery.
- The substitution of pension funding for pension accruals for pension expense and the normalization of post-retirement costs over five years.

Please see the Chapter 18 narratives for additional information.

Q. 63 Are payroll taxes included in the projected labor loading percentages?

A. 63 No. Southwest Gas includes payroll taxes in its labor loading mechanism for book purposes. However, Cal Advocates previously requested that Southwest Gas include payroll taxes in Chapter 16, Taxes. Therefore, recorded labor loading amounts in the various chapters were modified to remove the portion of labor loading dollars related to payroll taxes, and the projected labor loading percentages do not include payroll taxes.

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X. PTYM ADJUSTMENT (CHAPTER 22)

Q. 64 Please describe the PTYM adjustment approved by the Commission in Decision (D.) 21-23-052 issued in Southwest Gas' last GRC.

A. 64 D. 21-23-052 approved an all-party settlement that included a PTYM adjustment. The PTYM adjustment increased margin annually by 2.75 percent for each of the three California rate jurisdictions. The PTYM adjustment also included an Automatic Trigger Mechanism (ATM) which provided for an adjustment to the Company's authorized cost of capital should preset changes occur. Please refer to Mr. Forsberg's prepared direct testimony for further discussion of the ATM. The PTYM adjustment also included an adjustment for Excess Accumulated Deferred Income Taxes (EADIT). Please refer to Mr. Williams' prepared direct testimony for further discussion of the EADIT adjustment.

Q. 65 In retrospect, how did the PTYM adjustment work?

A. 65 In the Company's opinion, the PTYM adjustment was effective in conjunction with its authorized balancing accounts, and requests continuation of the mechanism. The ATM was triggered in 2024[5]. The Company's response to Master Data Request-003 provides an actual to authorized comparison of the results of operations. While the Company's actual results generally appeared to be below authorized, part of the reason results for 2021 through 2023 were lower than authorized in the TY 2021 GRC was higher than anticipated inflation from 2021 to 2023. In general, this indicates that the PTYM adjustment was appropriate and worked as expected. It also allowed timely recovery of the

[5] Advice Letter No. 1275 submitted on November 3, 2024, approved December 23, 2023, effective January 1, 2024.

revenue requirement associated with the NLTL Project discussed above, a sizable and necessary pipe replacement project in NCA.

Q. 66 Is Southwest Gas proposing any changes to the PTYM adjustment in this proceeding?

A. 66 Yes. Southwest Gas is proposing an additional PTYM adjustment for SCA for the timely recovery of the full revenue requirement associated with the addition of a large customer, NTC discussed above, along with the increases in revenue that will be generated each year from this customer as their usage ramps up, to ensure that revenue from this customer matches the net investment in facilities required to serve them.

The Company proposes to make annual margin and cost of service adjustments (to account for the rate base impact, depreciation expenses, property and income taxes) for NTC, to account for the difference in margin and cost of service included in rates for the previous year and actual costs and margin. The usage, and associated margin, for NTC will ramp up starting in 2026 and is not expected to reach the estimated contracted amount until approximately 2030. Since test year 2026 is based on average rate base, only ½ of the NTC rate base is included in the test year. To properly match investment in NTC with the revenue that customer will generate, the Company believes this PTYM adjustment is fair and reasonable and should be approved by the Commission.

Q. 67 Is Southwest Gas requesting any other changes to the PTYM adjustment?

A. 67 No. Southwest Gas requests that the PTYM percentage to adjust margin for PTYM years 2027-2030 remain unchanged at 2.75 percent annually. This is reasonable because it is consistent with the PTYM percentage authorized in the last GRC, within the range of the Company's historical wage increases and the historical compound annual growth rate in the consumer price index, as well as the escalation percentages provided for labor and materials and expenses in Chapter 7 for 2024 through 2026.

The PTYM for years 2027 through 2030 are reflected in Chapter 22. The Company is also proposing to continue the annual adjustments for EADIT, and the ATM in the years it is triggered. The Company is also proposing to retain the NLTL component of the PTYM adjustment, so it is available when work can resume on the project.

Q. 68 Does this conclude your prepared direct testimony?

A. 68 Yes.

Company Witness:

Charlene A. Lachica

IN THE MATTER OF

SOUTHWEST GAS CORPORATION

APPLICATION 24-09-___

PREPARED DIRECT TESTIMONY

OF

CHARLENE A. LACHICA

ON BEHALF OF

SOUTHWEST GAS CORPORATION

September 5, 2024

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Prepared Direct Testimony
of
Charlene A. Lachica

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Prepared Direct Testimony
of
Charlene A. Lachica

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Charlene A. Lachica. My business address is 8360 S. Durango Drive, Las Vegas, Nevada 89113.

Q. 2 By whom and in what capacity are you employed?

A. 2 I am employed by Southwest Gas Corporation (Southwest Gas or Company) in the Regulation department. My title is Senior Analyst.

Q. 3 Please summarize your educational background and relevant business experience.

A. 3 My educational background and relevant business experience are summarized in Appendix A to this testimony.

Q. 4 Have you previously testified before any regulatory commission?

A. 4 Yes. I have previously testified before the Public Utilities Commission of Nevada.

Q. 5 What is the purpose of your prepared direct testimony in this proceeding?

A. 5 I sponsor Southwest Gas' constant dollar, escalation, and allocation factors.

Q. 6 Please summarize your prepared direct testimony.

A. 6 My prepared direct testimony consists of the following key issues:

- Southwest Gas' constant dollar factors applied in its three California rate jurisdictions (Southern California, Northern California, and South Lake Tahoe);

- The labor and materials and supplies escalation factors employed by Southwest Gas for projected years 2024, 2025, and test year 2026 in the Company's three California rate jurisdictions;
- The development of allocation factors to assign system allocable expenses and Administrative and General (A&G) expenses to Southwest Gas' three California rate jurisdictions; and
- The methodology to create new allocation factors for the proposed consolidation of the Northern California and South Lake Tahoe rate jurisdictions, into a single Northern California rate jurisdiction.

II. CONSTANT DOLLAR FACTORS (CHAPTER 7)

Q. 7 Please describe Southwest Gas' use of constant dollar factors in this application.

A. 7 Southwest Gas provides five years (2019-2023) of historical expenses for Southern California, Northern California, South Lake Tahoe, and System Allocable (also referred to as corporate common). This historical data is stated in both nominal and constant dollars (also referred to as real dollars) that have been adjusted for inflation.

The constant dollar factors were computed using the compounded escalation factors obtained from the Consumer Price Index – All Urban Consumers from the U.S. Department of Labor Bureau of Labor Statistics. The indices were then recalculated to set 2023 as the base year (i.e. 2023 = 100). *See* Chapter 7 Workpapers, Sheet 3.

III. ESCALATION FACTORS (CHAPTER 7)

Q. 8 Please describe the use of escalation factors by Southwest Gas in this application.

A. 8 Southwest Gas used 2023 as its final (base) year of recorded data. The test year in this proceeding is 2026. Therefore, Southwest Gas escalated its labor and non-labor expenses for the projected years of 2024, 2025, and test year 2026 for expected cost increases due to inflation.

Southwest Gas used a 9.08 percent of labor increases granted to employees for its 2024 labor escalation factor, which consists of the average wage increase granted during 2024 and additional wage increases that were granted after an external market compensation study was completed. Please refer to the direct testimony of Company witness Randi L. Cunningham for an explanation of why the 2024 escalation factor is significantly higher than historical amounts. For 2025 and 2026, Southwest Gas used a five-year average (from 2019 through 2023) of 3.10 percent per year for its labor escalation factor.

The escalation of non-labor expenses is discussed below.

Q. 9 Did the Company consider different options when selecting a price escalation index for Materials & Expenses (M&E) costs?

A. 9 Yes. For the escalation of M&E expenses, Southwest Gas evaluated the non-labor price index distributed in the monthly Public Advocates Office's (PAO) Escalation Memorandum published by their Water Branch[1]. Southwest Gas also considered the forecasted U.S. Consumer Price Index – Urban (CPI-U) inflation

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[1] Public Advocates Office: Estimates of Non-labor and Wage Escalation Rates for 2023 through 2028 from the June 2024 IHS Global Insight U.S. Economic Outlook, dated June 25, 2024.

factors from Blue Chip Economic Indicators[2], whose approach was uncontested and adopted in Decision 14-06-028[3].

Q. 10 Please summarize the non-escalation price index published in the Cal Advocates' Escalation Memorandum.

A. 10 The Cal Advocates' Escalation Memorandum contains an index based on a composite of ten Producer Price Indexes and the U.S. Consumer Price Index – Wage Earners (CPI-W) weighted at 5% of the total index. The CPI-W measures consumer prices for items such as machinery, office furniture, chemicals, and allied products.

Q. 11 Why has Southwest Gas elected to propose the CPI-U price index to escalate M&S expenses?

A. 11 Southwest Gas proposes to use the CPI-U because it is a common factor used to represent general inflation. The Company has found Wolters Kluwer Blue Chip Economic Indicators, first published in 1976, as a reliable forecast source for economic indicators due to contributions from 50-plus leading economists and financial analysts from reputable manufacturers, banks, insurance companies, and brokerage firms. Every month the survey publishes these individual predictions along with an average of their forecasts. This consensus approach helps balance out individual biases and errors and the frequency of monthly publications incorporates current data and data trends. These indicators are widely accepted, cited, and used by national media outlets, popular market indexes, investors, and businesses.

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[2] Blue Chip Economic Indicators, Vol 49, No. 3, March, 2024 Edition, pgs 4-5 and 17.
[3] Southwest Gas' Test Year 2014 General Rate Case, Application 12-12-024.

<u>IV. SYSTEM ALLOCABLE EXPENSES (CHAPTER 8A and 8C)</u>

Q. 12 What are System Allocable expenses?

A. 12 System Allocable expenses, included in Chapter 8, Tab A, are Southwest Gas' Administrative and General (A&G) expenses incurred at the corporate level and generally allocated across the Company's three state jurisdictions[4] (California, Arizona and Nevada) and two Federal Energy Regulatory Commission (FERC) regulated jurisdictions - Great Basin Gas Transmission Company (Great Basin) and Southwest Gas Transmission Company (SGTC).

Q. 13 Please describe the allocation factors Southwest Gas uses to allocate System Allocable expenses across its various rate jurisdictions.

A. 13 The allocation factors are included in Chapter 8, Tab C. Southwest Gas uses the Modified Massachusetts Formula (MMF) to allocate a portion of corporate common costs to Great Basin and SGTC. The remaining costs are then allocated to the state rate jurisdictions based on the 4-Factor methodology, with two exceptions. Property Insurance (Account 924) is allocated to each state rate jurisdiction based on Factor II, average gross plant in service, since insurance premiums are based on insurable property. Administrative Expenses Transferred to Capital (Account 922) are allocated to each state rate jurisdiction based on the A&G Overhead factor, since the expenses reflect capital costs. This approach is described in more detail below and in the narrative summary to Chapter 8, Tab C.

The MMF is calculated from the following three items, which are equally weighted to determine the recorded MMF: direct labor, margin, and gross plant.

[4] The Company's three-state jurisdiction contemplate six separate rate jurisdictions: Northern California, South Lake Tahoe, Southern California, Arizona, Northern Nevada and Southern Nevada.

The projected MMF factors are based on the calculation from data recorded during 2023.

The 4-Factor allocation methodology is calculated from the following four items, which are equally weighted to determine the recorded 4-Factor percentages: Factor I: direct operating expenses; Factor II: average direct gas plant in service; Factor III: direct labor; and Factor IV: average number of customers. The projected 4-Factors are based on the calculation from data recorded during 2023.

The A&G overhead factor is used to capitalize a percentage of A&G recorded in Accounts 920 and 921 to construction. The credit is recorded to A&G in Account 922 and is allocated to the various ratemaking jurisdictions based on the A&G overhead factor. The recorded overhead factor is calculated based on each jurisdiction's relative percentage of construction. The projected A&G overhead factors are based on a five-year historical average.

Q. 14 Is Southwest Gas proposing any changes in this application that will impact the Company's allocation factors?

A. 14 Yes. Southwest Gas is proposing to consolidate its Northern California and South Lake Tahoe rate jurisdictions into a single Northern California rate jurisdiction. This proposal is discussed in more detail in the prepared direct testimonies of Randi L. Cunningham and A. Brooks Congdon.

Q. 15 Please explain the computation of the allocation factors for the proposed consolidation of the Northern California and South Lake Tahoe rate jurisdictions.

A. 15 Each component of the MMF, 4-Factor, and A&G Overhead factor for Northern California and South Lake Tahoe will simply be added together to create the combined MMF, 4-Factor, and A&G Overhead percentages for the combined Northern California and South Lake Tahoe.

Q. 16 Does this conclude your prepared direct testimony?

A. 16 Yes.

SUMMARY OF QUALIFICATIONS
CHARLENE A. LACHICA

I graduated from the University of Phoenix with a Bachelor of Science in Accounting in 2017.

From 2016 to present, I have been employed by Southwest Gas Corporation (Company), initially as an Administrative Representative in the Regulation department. I was promoted to Analyst I/Regulation in 2017, Analyst II/Regulation in 2021 and Senior Analyst/Regulation in 2023. My responsibilities as a Senior Analyst primarily have included acting as lead on all margin, rate development, and implementation filings and tariff interpretation and administration for the Company's California rate jurisdiction, as well as contributing to the Company's Nevada rate jurisdiction's General Rate Case and Annual Rate Adjustment Applications. In 2024, my responsibilities shifted to working on regulatory filings and projects related to the Company's revenue requirements and cost of service, as well as preparing and analyzing components of the Company's annual budget.

Company Witness:

Kasey D. Bohannon

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
APPLICATION 24-09-___

PREPARED DIRECT TESTIMONY
OF
KASEY D. BOHANNON

ON BEHALF OF
SOUTHWEST GAS CORPORATION

SEPTEMBER 5, 2024

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of
Kasey D. Bohannon

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Prepared Direct Testimony
of
KASEY D. BOHANNON

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Kasey D. Bohannon. My business address is 1600 E. Northern Avenue, Phoenix, Arizona 85020.

Q. 2 By whom and in what capacity are you employed?

A. 2 I am employed by Southwest Gas Corporation (Southwest Gas or Company) in the Regulation department. My title is Director of Regulation.

Q. 3 Please summarize your educational background and relevant business experience.

A. 3 My educational background and relevant business experience are summarized in Appendix A to this testimony.

Q. 4 Have you previously testified before any regulatory commission?

A. 4 Yes. I have previously provided testimony to the New Mexico Public Regulation Commission and the Arizona Corporation Commission.

Q. 5 What is the purpose of your prepared direct testimony in this proceeding?

A. 5 The purpose of my prepared direct testimony is to present the 2026 Test Year General Rate Case proposals for the regulatory accounts and development of the regulatory amortizations for Southwest Gas' three California rate jurisdictions: Southern California, Northern California, and South Lake Tahoe.

Q. 6 Please summarize your prepared direct testimony.

A. 6 My prepared direct testimony will discuss the Company's proposals for regulatory accounts consisting of the following key issues:

- *Development of test year 2026 regulatory amortizations;*
- *Disposition of regulatory account balances;*
- *Continuation of existing regulatory accounts;*
- *Closure of regulatory accounts; and*
- *Creation of new regulatory accounts.*

II. Disposition of Regulatory Account Balances

Q. 7 What is Southwest Gas' proposal for the disposition of the regulatory accounts discussed herein?

A. 7 Southwest Gas is proposing to amortize the remaining balances either at year-end 2023 or projected balances at year-end 2025 over the five-year rate case cycle as discussed further below, beginning with the effective date of rates approved in this application.

A. Environmental Compliance Costs Memorandum Account (ECCMA)

Q. 8 What is the purpose of the ECCMA?

A. 8 The purpose of the ECCMA is to record Southwest Gas' allocated portion of California Air Resources Board (CARB) administrative fees associated with the implementation of Assembly Bill (AB) 32, the California Global Warming Solutions Act of 2006. Costs recorded in the EECMA apply to all customer classes, excluding the Company's "self-reporting" customers that are directly billed by the CARB.

Q. 9 What is the balance in the ECCMA and what is the proposed ratemaking treatment of the balance in the account?

A. 9 The balance as of December 31, 2023 was $966,550 undercollected. Southwest Gas will estimate the balance through December 31, 2025 by projecting the administrative fees for 2024 and 2025 and reducing the balance by the currently authorized annual amortization of $199,680 approved in Decision (D.) 21-03-052, which results in a projected balance of $908,228. Each California rate jurisdiction is allocated a portion of this amount based on its weighted 4-factor relative to the Total California 4-factor. The Company is proposing to amortize the projected balance in base rates.

B. Infrastructure Reliability and Replacement Adjustment Mechanism (IRRAM)

Q. 10 What is the purpose of the IRRAM?

A. 10 The purpose of the IRRAM is to balance the difference between the revenue requirements associated with Commission-approved programs with recorded revenues to recover these costs. The IRRAM allows Southwest Gas to establish rates to recover the revenue requirement on the authorized infrastructure programs approved for recovery through the IRRAM between general rate cases. A separate IRRAM account is maintained for Southwest Gas' three California ratemaking jurisdictions (Southern California, Northern California and South Lake Tahoe)

Q. 11 What is the balance in the IRRAM and what is the proposed ratemaking treatment of the balance in the account?

A. 11 The balance as of December 31, 2023 was a $7,845,928 undercollection ($6,994,695 for Southern California, $726,103 for South Lake Tahoe and $125,130 for Northern California). Southwest Gas is proposing to amortize the balance in base rates, and, to avoid double recovery, will discontinue recording the capital deferrals for the projects included in base rates in this Application upon the effective date.

C. Mobile Home Park Conversion Balance Account (MHPCBA)

Q. 12 What is the purpose of the MHPCBA?

A. 12 The MHPCBA is a two-way balancing account used for recording and recovering the incremental revenue requirement associated with converting submetered residents at mobile home parks from master-metered natural gas service to direct utility service in accordance with the Mobilehome Park (MHP) Conversion Pilot Program provisions adopted in Decision (D.) 14-03-021 and extended pursuant to Resolution E-4958. D.20-04-004 further authorized a ten-year Mobilehome Park Conversion Program, beginning January 1, 2021. The Company established the MHPCBA pursuant to D.14-03-021 and continued to record MHP program expenses in the MHPCBA in accordance with D.20-04-004. A separate MHPCBA has been maintained for each of Southwest Gas' California rate jurisdictions.

Q. 13 What are the balances in the MHPCBAs and what is the proposed ratemaking treatment of the balances in the accounts?

A. 13 The balances for the To the Meter (TTM) MHPCBAs as of December 31, 2023 are $1,818,975 for Southern California, $24,097 for Northern California, and $242,107 for South Lake Tahoe. The Company is proposing to continue to recover these costs through the MHPCBA Adjustment rate. Southwest Gas will discontinue recording the capital deferrals for the parks in-service and requested in base rates in this Application as of December 31, 2025, or upon the effective date of the rates in this Application to avoid double recovery. The MHPCBA

Beyond the Meter (BTM) balances for each rate jurisdiction through December 31, 2023 are: $3,547,930 for Southern California, $29,629 for Northern California and $457,198 for South Lake Tahoe. Each project is amortized over 10 years per D.14-03-021. The MHPCBA BTM also includes a line item for the annual amortization of the BTM investment because the revenue requirement deferrals on these assets will cease at December 31, 2025, and these investments are not included in Southwest Gas' GPIS balances. The amounts requested are $572,173 for Southern California, $3,593 for Northern California and $66,902 for South Lake Tahoe.

D. Residential Disconnection Protections Memorandum Account (RDPMA)

Q. 14 What is the purpose of the RDPMA?

A. 14 The purpose of the RDPMA is to the track Southwest Gas' incremental costs associated with the implementation of the customer protections required by D. 22-08-037. Southwest Gas was authorized to establish the RDPMA in December 2022, upon the approval of Advice Letter (AL) No. 1234.

Q. 15 What is the balance in the RDPMA and what is the proposed ratemaking treatment of the balance in the account?

A. 15 The balance as of December 31, 2023 was $0. Southwest Gas did not incur administrative costs with respect to the customer protections adopted in D.22-08-037. However, the Company is proposing to keep the account open to track costs associated with waived reconnection charges beginning in 2024 and will seek recovery of any recorded costs in a future general rate case.

. . .

. . .

E. Pension Balancing Account (PBA)

Q. 16 What is the purpose of the PBA?

A. 16 The PBA is a two-way balancing account recorded in Southwest Gas' general ledger. The purpose of the PBA is to balance the difference between authorized and actual amounts associated with the Company pension fund that are allocable to California. The PBA was established in 2014 pursuant to D.14-06-028.

Q. 17 What is the balance in the PBA and what is the proposed ratemaking treatment of the balance in the account?

A. 17 The balance as of December 31, 2023 was $16,167,113, ($12,335,439 for Southern California, $2,108,364 for Northern California, and $1,723,310 for South Lake Tahoe). Southwest Gas is proposing to amortize the balance in base rates and will continue to track the difference between the actual and authorized pension fund amounts in the PBA.

III. Continuation of Existing Regulatory Accounts

A. New Environmental Regulatory Balancing Account (NERBA)

Q. 18 What is the purpose of the NERBA?

A. 18 The NERBA is a two-way balancing account used for recording and recovering the revenue requirement associated with the implementation of the Natural Gas Leak Abatement Program 26 Best Practices adopted in D.17-06-015. Southwest Gas was authorized to establish the NERBA pursuant to D.17-06-015. A separate NERBA is maintained for each of Southwest Gas' three California ratemaking jurisdictions.

Q. 19 What is the balance in the NERBA and what is the proposed ratemaking treatment of the balance in the account?

A. 19 The balance as of December 31, 2023 was $43,546 ($27,223 for Southern California, $8,391 for Northern California, and $7,932 for South Lake Tahoe). Because Southwest Gas does not anticipate recording additional costs to this account at this time, the Company is proposing to continue to recover the balance through the NERBA adjustment rate and move any remaining balance as of January 1, 2026 to the Fixed Cost Adjustment Mechanism (FCAM) account. The NERBA adjustment rate will be reset to zero at that time.

Q. 20 Does Southwest Gas propose to keep the NERBA open and in the Company's tariff?

A. 20 Yes. D.17-06-015 also requires the respondent natural gas utilities, including Southwest Gas, to file a biennial compliance plan (Emissions Mitigation Plan) to report on the Company's emission reduction efforts and adherence to the Commission's twenty-six Best Practices (BPs) for emission reduction. During this time, Southwest Gas may propose new programs or procedures related to the BPs for cost recovery through the NERBA as the need arises. Therefore, Southwest Gas proposes to keep the NERBA open until such time the Commission no longer requires compliance with the BPs pursuant to D.17-06-015 and the potential to incur costs no longer exists.

B. Natural Gas Leak Abatement Program Balance Account (NGLAPBA)

Q. 21 What is the purpose of the NGLAPBA?

A. 21 The NGLAPBA is a one-way balancing account for the purpose of recording and recovering costs related to Southwest Gas' authorized Emissions Mitigation Plan Pilot Projects and Research and Development activities. The Company was authorized to establish the NGLAPBA pursuant to D.17-06-015. A separate NGLAPBA is maintained for each of Southwest Gas' three California ratemaking jurisdictions.

Q. 22 What is the balance in the NGLAPBA and what is the proposed ratemaking treatment of the balance in the account?

A. 22 The balance as of December 31, 2023 was $1,522,9334 ($1,395,416 for Southern California, $72,533, for Northern California, and $54,984 for South Lake Tahoe). Because Southwest Gas does not anticipate recording additional costs to this account at this time, the Company proposes to continue to recover the balance through the NGLAPBA adjustment rate and move any remaining balance as of January 1, 2026 to the FCAM account. The NERBA adjustment rate will be reset to zero at that time.

Q. 23 Does Southwest Gas propose to keep the NGLAPBA open and in the Company's tariff?

A. 23 Yes. The same reason stated above for the NERBA, Southwest Gas will keep the NGLAPBA open until such time that the Commission no longer requires compliance with the BPs adopted in D.17-06-015 and the potential to incur costs no longer exists.

C. Natural Gas Leak Abatement Program Memorandum Account (NGLAPMA)

Q. 24 What is the purpose of the NGLAPMA?

A. 24 Also established pursuant to D.17-06-015, the NGLAPMA tracks Southwest Gas' incremental administrative costs associated with the implementation of the Natural Gas Leak Abatement Program BPs.

Q. 25 What is the balance in the NGLAPMA?

A. 25 The balance as of December 31, 2023 was $0.

Q. 26 Does Southwest Gas propose to keep the NGLAPMA open and in the Company's tariff?

A. 26 Yes, similar to the NERBA and NGLAPBA, Southwest Gas proposes to keep the NGLAPMA open until such time that the Commission no longer requires compliance with the BPs adopted in D.17-06-015 and the potential to incur related costs no longer exists.

D. Conservation and Energy Efficiency Balancing Account (CEEBA)

Q. 27 What is the purpose of the CEEBA?

A. 27 The purpose of the CEEBA is to balance the difference between Southwest Gas' Commission-authorized Conservation and Energy Efficiency (CEE) program costs, including outreach, administrative, and program audit costs, with the Public Purpose Program (PPP) Surcharge revenue collected to recover these costs. The CEEBA is a one-way balancing account that Southwest Gas was authorized to establish in D.14-06-028.

Q. 28 What was the balance in the CEEBA and what is the proposed ratemaking treatment of the balance in the account?

A. 28 The balance as of December 31, 2023 was $243,811. Southwest Gas is proposing to continue to collect the CEEBA balance as a component of the PPP surcharge and will adjust the CEEBA rate when it adjusts its PPP surcharges by October 31 for a January 1 effective date the following year.

Q. 29 Is Southwest Gas proposing any changes to the CEEBA?

A. 29 No. Southwest Gas keep the CEEBA open to recover costs related to its CEE programs.

. . .

E. Greenhouse Gas Balancing Account (GHGBA)

Q. 30 What is the purpose of the GHGBA?

A. 30 The GHGBA is a two-way balancing account established pursuant to D.14-12-040 for the purpose of tracking and recording costs incurred to comply with the CARB natural gas supplier Cap-and-Trade Program and revenues from consignment of Southwest Gas' natural gas supplier greenhouse gas (GHG) allowances for auction under the Cap-and-Trade Program. The GHGBA consists of four subaccounts, the Cap-and-Trade Program compliance costs and revenues subaccounts, a subaccount to record emissions costs related to Lost and Unaccounted for Gas for Covered Entities under the Cap-and-Trade Program, and a subaccount for $652,000, Southwest Gas' set aside share to fund a bio-synthetic natural gas (bio-SNG) pilot at its discretion pursuant to D.22-02-025.

Q. 31 Is Southwest Gas proposing to modify the GHGBA or any of its subaccounts?

A. 31 **No.**

Q. 32 What is the proposed ratemaking treatment of the balance in the account?

A. 32 Southwest Gas proposes to continue to recover the balance in Cap-and-Trade compliance costs and LUAF costs through the GHGBA surcharge adjusted annually through its Annual Balancing Account Adjustment (BAA) AL (Annual BAA AL). The revenues subaccount will be disposed of through the annual California Climate Credit to customers that is adjusted in the Annual BAA AL. The bio-SNG subaccount will be adjusted if Southwest Gas develops an eligible bio-SNG pilot, Otherwise the balance will be returned to customers through the California Climate Credit if unused proceeds remain as of December 31, 2032.

F. Biomethane Injection Incentive Program Balancing Account (BIIPBA)

Q. 33 What is the purpose of the BIIPBA?

A. 33 . The BIIPBA is a two-way balancing account established pursuant to D.15-06-29 for the purpose of tracking and recording Southwest Gas payments for eligible interconnection costs made to biomethane gas suppliers as set forth in the Company's Tariff Rule No. 22 – Standard Renewable Gas Interconnections to the Utility's Pipeline System. The payments are made in accordance with the Commission's monetary incentive program established in D.15-06-029 and D.20-12-031.

Q. 34 What was the balance in the BIIPBA and what is the proposed ratemaking treatment of the balance in the account?

A. 34 The balance as of December 31, 2023 was $0. Any future balance will be collected through the BIIPBA surcharge rate and adjusted, as necessary, through Southwest Gas' Annual BAA AL effective January 1 of the following year.

G. Biomethane Procurement and Administrative Cost Balancing Account (BPACBA)

Q. 35 What is the purpose of the BPACBA?

A. 35 The BPACBA is an interest-bearing two-way balancing account established pursuant to D.22-02-025 for the purpose of recording and recovering costs related to Southwest Gas' compliance with D.22-02-025, which implemented Senate Bill (SB) 1440 and established short- and medium-term biomethane (i.e., renewable natural gas and/or bio-SNG) procurement targets to reduce short-lived climate pollution emissions. The BPACBA consists of two subaccounts: The Biomethane Commodity Cost Subaccount (to record incremental above-market biomethane commodity costs) and the Biomethane Procurement Administrative Cost Subaccount (to record program administrative costs related to SB 1440 procurement goals).

Q. 36 What was the balance in the BPACBA and what is the proposed ratemaking treatment of the balance in the account?

A. 36 The balance as of December 31, 2023 was $0 given that no SB 1440 renewable gas procurements have been made nor has Southwest Gas incurred any program related administrative costs to date. Any future balance will be collected through the BPACBA surcharge rate and adjusted, as necessary, through the Annual BAA AL, effective January 1 of the following year.

H. Residential Uncollectible Balancing Account (RUBA)

Q. 37 What is the purpose of the RUBA?

A. 37 The RUBA is an interest-bearing two-way balancing account established pursuant to D.22-08-037 for the purpose of recording and recovering costs related to the difference between authorized revenues associated with uncollectible expense for residential customers and actual residential customer bad debt expense. A separate RUBA is maintained for each of Southwest Gas' three California ratemaking jurisdictions.

Q. 38 What was the balance in the RUBA and what is the proposed ratemaking treatment of the balance in the account?

A. 38 The balance as of December 31, 2023 was $2,531,192. Southwest Gas will continue to collect the RUBA balance through the RUBA surcharge that is adjusted through the Annual BAA AL, effective January 1 of the following year.

. . .

I. Catastrophic Event Memorandum Account (CEMA) (possible exclusion)

Q. 39 What is the purpose of the CEMA?

A. 39 The purpose of the CEMA is to record all costs incurred by Southwest Gas associated with a catastrophic event (a federal or state declared disaster or state of emergency). The Company will record the costs for the following in CEMA: 1. Restoring service to the Company's customers; 2. Repairing, replacing, or restoring damaged Company facilities; and 3. Complying with governmental agency orders.

Q. 40 What was the balance in the CEMA and what is the proposed ratemaking treatment of the balance in the account?

A. 40 The balance as of December 31, 2023 was $0. Southwest Gas will continue to keep the account open and will seek recovery of any future costs recorded in the CEMA in a future general rate case.

J. Tax Memorandum Account (TMA)

Q. 41 What is the purpose of the TMA?

A. 41 The purpose of the TMA is to track any revenue difference resulting from select differences between Southwest Gas' authorized income tax expenses and its actually incurred income tax expenses, including repair deductions and bonus depreciation. The TMA was established in accordance with D.17-06-006.

Q. 42 What was the balance in the TMA and what is the proposed ratemaking treatment of the balance in the account?

A. 42 The balance as of December 31, 2023 was a $3,939,567 liability. The current annual amortization of ($1,242,703) was approved in D.21-03-052, therefore the balance will be zero as of December 31, 2025. The TMA will remain open to account for potential future tax changes and until a Commission decision closes the account.

K. Emergency Customer Protections Memorandum Account (ECPMA)

Q. 43 What is the purpose of the ECPMA?

A. 43 Established pursuant to D.18-08-004, the purpose of the ECPMA is to record all incremental costs incurred by Southwest Gas associated with providing the residential and nonresidential emergency customer protections set forth in D.18-08-004 for any disasters where the Governor of California has declared a State of Emergency that includes areas within the Company's service territories and where the disaster has either: (1) resulted in the loss or disruption of the delivery or receipt of utility service; and/or (2) resulted in the degradation of the quality of utility service. Should such a disaster occur, the Company shall file a Tier 1 AL within 15 days of the Governor's State of Emergency Proclamation reporting its compliance with D.18-08-004.

Q. 44 What was the balance in the ECPMA and what is the proposed ratemaking treatment of the balance in the account?

A. 44 The balance as of December 31, 2023 was $0. Southwest Gas will keep the ECPMA account open to account for incremental emergency protection costs that may occur in the future.

L. Customer Data Modernization Initiative Balancing Account (CDMIBA)

Q. 45 What is the purpose of the CDMIBA?

A. 45 The CDMIBA is a two-way balancing account established in accordance with D.20-07-016 for the purpose of recording and recovering the revenue requirement for the incremental operations and maintenance (O&M) and capital costs associated with Customer Data Modernization Initiative (CDMI) to replace two of Southwest Gas legacy systems, the Customer Service System (CSS) and the Gas Transaction System (GTS). A separate CDMIBA is maintained for each of Southwest Gas' three California rate jurisdictions.

Q. 46 What was the balance in the CDMIBA and what is the proposed ratemaking treatment of the balance in the account?

A. 46 The balance in the CDMIBA as of December 31, 2023 was $1,788,372 related to the CSS replacement and implementation portion of the CDMI project. The related revenue requirement in the CDMIBA will cease the day before rates are effective in in this Application. At that time, the revenue requirement recorded in the CDMIBA will roll into the base margin revenue requirement. The CDMIBA adjustment rate will remain in place until the revenue requirement and incremental O&M costs recorded in the CDMIBA are fully collected and will be adjusted annually as necessary in Southwest Gas' Annual BAA AL. The CDMIBA will remain open to record the revenue requirement related to the GTS portion of the CDMI project.

M. Officer Compensation Memorandum Account-2019 (OCMA-2019)

Q. 47 What is the purpose of the OCMA-2019?

A. 47 The OCMA-2019 is a memorandum account established pursuant to Public Utilities Code Section 706, as enacted by Senate Bill 901 (2018, Dodd). Public Utilities Code Section 706 requires, among other things, that all forms of compensation for officers of electrical or gas corporations shall be paid solely by shareholders. The purpose of the OCMA-2019 is to track the California allocable difference between (1) compensation for officers of the utility that is authorized in General Rate Cases (GRCs) or resolutions and; (2) all compensation as defined by Public Utilities Code Section 706. The term "officer" shall be defined as those employees of the investor-owned utilities in positions with titles of Vice President or above, consistent with Rule 240.3b-7 of the Securities Exchange Act.

Q. 48 What was the balance in the OCMA and what is the proposed ratemaking treatment of the balance in the account?

A. 48 The balance as of December 31, 2023 was $0. Southwest Gas excluded the total compensation of officers as defined by the Securities Exchange Act in its last general rate case (Test Year 2021; A.19-08-015), therefore, there was no difference to track. Although Southwest Gas will continue to exclude amounts pursuant to Public Utilities Code Section 706 from the cost of service as a proforma adjustment in the Company's future general rate case Applications, the OCMA-2019 will remain open until closed at the direction by the Commission.

<u>V. Closure of Regulatory Accounts</u>

Q. 49 Is Southwest Gas proposing to close any regulatory Accounts?

A. 49 Yes. Southwest Gas is proposing to close all the regulatory accounts listed in this section. Once the amortization of the account balances in these accounts is complete, the Company will no longer have a need for them. The entire balance for each of these is accounts is being proposed for a five-year amortization (2026-2030).

A. Public Purpose Program Memorandum Account (PPPMA)

Q. 50 What is the purpose of the PPPMA?

A. 50 Established pursuant to D.11-11-009, the purpose of the PPPMA was to record the difference between Southwest Gas PPP revenue requirement authorized in D.11-11-009 and that requested by the Company in Application (A.)11-06-019. D.14-11-005 extended the PPPMA on a month-to-month basis beginning January 1, 2015, until the Commission adopted a final decision approving

Southwest Gas' 2015-2017 (A.15-02-001) ESA and CARE Program Budget Application. D.19-11-005 was issued in A.15-02-001, effective November 7, 2019.

Q. 51 What was the balance in the PPPMA and what is the proposed ratemaking treatment of the balance in the account?

A. 51 The balance as of December 31, 2023 was $0. Given that the Commission has not extended the PPPMA, Southwest Gas is proposing to close this account.

B. Greenhouse Gas Memorandum Account (GHGMA)

Q. 52 What is the purpose of the GHGMA?

A. 52 The GHGMA, established pursuant to D.14-12-040, is used to track Southwest Gas' administrative and outreach costs incurred to comply with the CARB's Cap-and-Trade Program.

Q. 53 What was the balance in the GHGMA and what is the proposed ratemaking treatment of the balance in the account?

A. 53 The balance in the GHGMA as of December 31, 2023 was $20,750. A $4,140 annual regulatory amortization was approved in D.21-03-052 so Southwest Gas is proposing to amortize the remaining balance of $12,470 at December 31, 2025 over five years (2026-2030) at approximately $2,494 annually. Each California rate jurisdiction is allocated a portion of this amount based on its weighted 4-factor relative to the Total California 4-factor. Pursuant D.15-10-032, the GHGMA should sunset once Southwest Gas has the opportunity to request approval of natural gas GHG-related administrative costs in a general rate case.[1] Therefore,

[1] D.15-10-032 – *Decision Adopting Procedures Necessary for Natural Gas Corporations to Comply with the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms (Cap-and-Trade Program)*, at pgs. 21 and 60.

Southwest Gas proposes to close the account once the balance is fully amortized.

C. COVID-19 Pandemic Protections Memorandum Account (CPPMA)

Q. 54 What is the purpose of the CPPMA?

A. 54 Established pursuant to Resolution M-4842, dated April 16, 2020, the purpose of the CPPMA is to record incremental costs and waived charges incurred by Southwest Gas associated with its implementation of the COVID-19 customer protections. The COVID-19 customer protections applied to all Residential and Small Business Customers (as defined in the Company's tariff).

Q. 55 What was the balance in the CPPMA and what is the proposed ratemaking treatment of the balance in the account?

A. 55 The balance as of December 31, 2023 was $1,403,613. Southwest Gas is proposing to amortize the balance and include in base rates. This will result in a $280,723 annual amortization. Each California rate jurisdiction is allocated a portion of this amount based on its weighted 4-factor relative to the Total California 4-factor. Southwest Gas proposes to close the CPPMA once the balance is fully amortized.

<u>VI. Creation of New Regulatory Accounts</u>

A. Damage Prevention Cost Balancing Account (DPCBA)

Q. 56 What is the DPCBA?

A. 56 Southwest Gas proposes to establish the DPCBA, a two-way balancing account, to record and recover costs associated with damage prevention costs. The DPCBA proposal is discussed further in the Prepared Direct Testimony of Company Witness Valerie J. Ontiveroz,

Q. 57 Does this conclude your Prepared Direct Testimony?

A. 57 Yes.

SUMMARY OF QUALIFICATIONS

KASEY D. BOHANNON

Kasey D. Bohannon is the Director of Regulation for Southwest Gas Corporation (Southwest Gas). In this role, she oversees revenue requirement activities in Arizona, California, and Nevada.

Kasey has worked in the utility industry for over 15 years. Prior to joining Southwest Gas in January 2020, she held various roles in Accounting, Finance and Regulatory at Arizona Public Service. More recently, she was the Regulatory Manager at EPCOR, a gas and water utility, where she oversaw all regulatory activities in three jurisdictions (Arizona, New Mexico, and Texas). In her previous roles, she was responsible for preparing and reviewing rate case filings, including cost of service studies, testimony, and compliance filings.

Mrs. Bohannon graduated from Northern Arizona University with Bachelor of Science in Business Administration in Finance. She also received her Master of Business Administration with an emphasis in Accounting.

Company Witness:
A. Brooks Congdon

IN THE MATTER OF

SOUTHWEST GAS CORPORATION

APPLICATION 24-09-___

PREPARED DIRECT TESTIMONY

OF

A. BROOKS CONGDON

ON BEHALF OF

SOUTHWEST GAS CORPORATION

SEPTEMBER 5, 2024

Table of Contents
Prepared Direct Testimony
of
A. Brooks Congdon

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Prepared Direct Testimony
of
A. Brooks Congdon

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Anthony Brooks Congdon. My business address is 8360 S. Durango Drive, Las Vegas, Nevada 89113.

Q. 2 Please describe your current position.

A. 2 I am currently employed by Southwest Gas Corporation (Southwest Gas or Company) as Manager in the Regulation Department.

Q. 3 Please summarize your educational background and relevant business experience.

A. 3 My educational background and relevant business experience are summarized in Appendix A to this testimony.

Q. 4 Have you previously testified before any regulatory commission?

A. 4 Yes. I have previously testified before the California Public Utilities Commission (Commission), the Arizona Corporation Commission, and the Public Utilities Commission of Nevada.

II. PURPOSE OF TESTIMONY

Q. 5 What is the overall purpose of your testimony?

A. 5 The purpose of my testimony is to discuss Southwest Gas' rate design proposals for its three California rate jurisdictions (Southern California, Northern California and South Lake Tahoe), including: the utilization of the class cost of service study (CCOSS) in designing the Company's proposed rates presented in this case, the Company's proposal to consolidate its Northern California and South Lake Tahoe rate jurisdictions into a single Northern California rate jurisdiction, and the Company's decision to remove the City of Victorville (COV) from this rate case proceeding. Lastly, I discuss the resulting customer bill and customer affordability impacts associated with the Company's requested base revenue increase and rate design proposals.

III. IDENTIFICATION AND SUMMARY OF EXHIBITS

Q. 6 Are you sponsoring any exhibits in support of your testimony?

A. 6 Yes, I am sponsoring Exhibit Nos._(ABC-1), (ABC-2), (ABC-3), and (ABC-4), displaying the results of Southwest Gas' proposed consolidation of the Northern California and South Lake Tahoe rate jurisdictions, and Exhibit No._(ABC-5) displaying detailed affordability metrics of Southwest Gas' proposed residential rate designs.

IV. CLASS COST OF SERVICE STUDY

A. Overview

Q. 7 Please describe the purpose of a CCOSS.

A. 7 The purpose of a CCOSS is to allocate a utility's overall cost of service to its various classes of service in a manner that reflects the relative costs of providing service to each class. The results of the CCOSS can be utilized to determine the relative cost of service for each rate class and to help determine the revenue responsibility each class should assume. The utility can then leverage the results as guidance when designing proposed rates for their rate classes.

Q. 8 Please describe how a CCOSS is typically developed.

A. 8 A CCOSS is typically developed by identifying the relationship between the service requirements for each rate class and their respective cost drivers, which is accomplished by following a process that consists of three key steps: 1) Cost Functionalization; 2) Cost Classification; and 3) Cost Allocation. This approach is well established in industry literature and is consistent with Southwest Gas' approach authorized by the Commission in its Test Year (TY) 2014 and TY 2021 general rates cases, Application (A.)12-12-024 and A.19-08-015, respectively.[1]

Q. 9 Please describe the Cost Functionalization step.

A. 9 Cost Functionalization is the first step, which consists of categorizing plant investment costs and operating expenses by the operational functions with which they are associated. These operational function categories are largely related to either production, storage, transmission, or distribution.

Q. 10 Please describe the Cost Classification step.

A. 10 Cost Classification is the second step, which consists of separating the functionalized cost items further, dependent upon the three primary factors that determine the amount of the costs incurred. These factors are: 1) the number of customers; 2) the need to meet the peak demand requirements that customers place on the system; and 3) the quantity of gas commodity consumed.

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[1] Decision (D.) 14-06-028, - *Alternate Proposed Decision Adopting Test Year 2014 General Rate Increases for Southwest Gas Corporation's Southern California, Northern California and South Lake Tahoe Rate Jurisdictions,* approved June 12, 2014; and D.21-03-052 – *Decision Granting Joint Motion for Approval of Settlement Between Southwest Gas Corporation, Public Advocates Office and City of Victorville Adopting Test Year 2021 General Rate Increases*, approved March 25, 2021.

Q. 11 Please describe the Cost Allocation step.

A. 11 Cost Allocation is the third and final step, which consists of allocating each functionalized and classified cost element to the individual customer(s) or rate class.

B. <u>Southwest Gas' CCOSS</u>

Q. 12 Did the Company utilize the same approach described above to develop its CCOSS?

A. 12 Yes, Southwest Gas utilized the same approach as described above in the development of its CCOSS.

Q. 13 Please describe the data the Company utilized to prepare its CCOSS.

A. 13 Southwest Gas' CCOSS is based on test year data for the period January 1, 2026 through December 31, 2026. The study includes the number of expected customers, sales, and revenues for the test year, by rate classification. Projected test year sales are reflective of normal weather conditions. Projected revenues at current rates are reflective of Southwest Gas' 2025 authorized margin approved in D.21-03-052.

Q. 14 What rate base items were included as part of the Company's CCOSS?

A. 14 Southwest Gas' CCOSS includes rate base items such as intangible plant, distribution plant, and general plant-in-service. Other rate base items, such as cash working capital, materials & supplies, customer deposits and deferred income taxes were also included in the CCOSS.

Q. 15 Were any additions or reductions to rate base included?

A. 15 Yes, cash working capital, and materials and supplies were included as additions to rate base, while deferred income taxes and customer deposits were included as reductions to rate base.

Q. 16 What operations and maintenance (O&M) expense items were included as part of the Company's CCOSS?

A. 16 Southwest Gas' CCOSS includes O&M expense items such as other gas supply, distribution, customer accounts, customer service & information, sales, and administrative and general. Taxes such as payroll and property taxes were also included as O&M expense items.

Q. 17 Please discuss the Company's approach regarding the functionalization step of its CCOSS.

A. 17 Since Southwest Gas does not currently have any production or storage and has an insignificant amount of transmission throughout its three California rate jurisdictions,[2] the Company functionalized all cost of service as distribution.

Q. 18 Please discuss the Company's approach regarding the classification step of its CCOSS.

A. 18 Southwest Gas classified its cost of service into one of the following three categories:

1) Customer Related – costs associated with providing customers access to the natural gas system, as well as providing on-going customer services, such as meter reading and billing.

2) Demand Related – costs associated with meeting customer peak demand requirements, such as the installation of high-pressure distribution mains.

3) Commodity Related – costs associated with meeting customer commodity requirements, such as the cost of natural gas odorant.

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[2] Southwest Gas has approximately 628 feet of transmission pipeline in its Southern California service territory and no transmission pipeline in its Northern California service territories (including South Lake Tahoe.)

Costs were either classified into one singular category, e.g., the cost of meter reading was classified as solely customer related, or into more than one category, e.g., the cost of distribution mains was classified as both customer related and demand related.

Q. 19 How did the Company classify distribution mains?

A. 19 The classification of distribution mains is reflective of two key cost drivers: 1) number of customers and 2) peak or "design day" demand. Southwest Gas used the same approach to classify distribution mains as approved in D.14-06-028 and D.21-03-052, 50 percent customer-related and 50 percent demand-related.

Q. 20 How did the Company classify its other rate base items?

A. 20 Other rate base items were similarly classified based on their underlying cost driver(s). For example, meter cost, meter installation, service cost, and regulator investments were all classified as customer related since they provide customers access to the natural gas system. Rate base items not directly associated with one of the classification categories, such as general plant, were classified through a composite classifier based on the related costs.

Q. 21 How did the Company classify O&M expenses?

A. 21 Southwest Gas classified O&M expenses in a manner similar to their respective plant items. For example, Maintenance of Services was allocated based on the allocation of Services Plant O&M expenses not directly associated with one of the classification categories, such as administrative and general expenses, were classified through a composite classifier based on related costs.

Q. 22 Please discuss the Company's approach regarding the allocation step of its CCOSS.

A. 22 Southwest Gas allocated costs to each rate class based on the costs incurred to serve that class, which required the development of three types of cost allocators that reflect the design of the Company's natural gas system:

1) Class Determinants – class characteristics, such as number of customers, consumption, and revenues by rate class;

2) Special Studies – detailed analysis of specific plant or expense items, such as meters; and

3) Internal – composite of how other costs are allocated.

Q. 23 How did the Company develop the demand allocator utilized in this CCOSS?

A. 23 The demand allocator utilized was developed based on January demands and reflects each rate classes' responsibility to January sales, consistent with Southwest Gas' approach approved in D.14-06-028 and D.21-03-052.

Q. 24 Please describe the process used to develop the special studies allocators utilized in this CCOSS?

A. 24 There were four special studies developed to allocate meter investments, meter installations, service investments, regulators, and industrial customer investments. The allocators were developed separately for each of Southwest Gas' three rate jurisdictions:

- <u>Meters and Meter Installation investments</u> were allocated based on the current cost of meters by meter type in each rate class weighted by the number of meters. The calculation recognizes there are certain types of meter costs specific to each rate class and establishes a weighting based on current records.

- Service investment was allocated based on the current cost of service line installations for and average service length required to serve customers in each rate class weighted by the number of customers in each class. The calculation recognizes there are certain types of service installation costs specific to each rate class and establishes a weighting based on current records.
- Industrial customer investment was allocated based on the investment in meters to serve the largest customers on the system.

Q. 25 How did the Company allocate rate base items to its various rate classes?

A. 25 First, Southwest Gas allocated plant investment by individual FERC account to each rate class based on an allocator that most accurately reflected the underlying cost driver. Then, the additions and deductions to net plant investment were allocated amongst each rate class based on an allocator that most accurately reflected the underlying cost driver.

Southwest Gas utilized the same allocation of rate base approved in D.14-06-028 and D.21-03-052. Plant investment designed to meet customer peak demands was allocated to each rate class based on the demand allocator. Plant investments designed to connect customers to the distribution system was allocated to each rate class based on the number of customers and/or one of the special studies described above.

The process used to allocate rate base to customer classes is included in Chapter 19 workpapers.

Q. 26 How did the Company allocate O&M expense items to its various rate classes?

A. 26 Southwest Gas allocated O&M expenses in a manner similar to their respective plant items. For example, Maintenance of Services was allocated based on the allocation of Service Plant. The process used to allocate O&M expenses to customer classes is included in Chapter 19 workpapers.

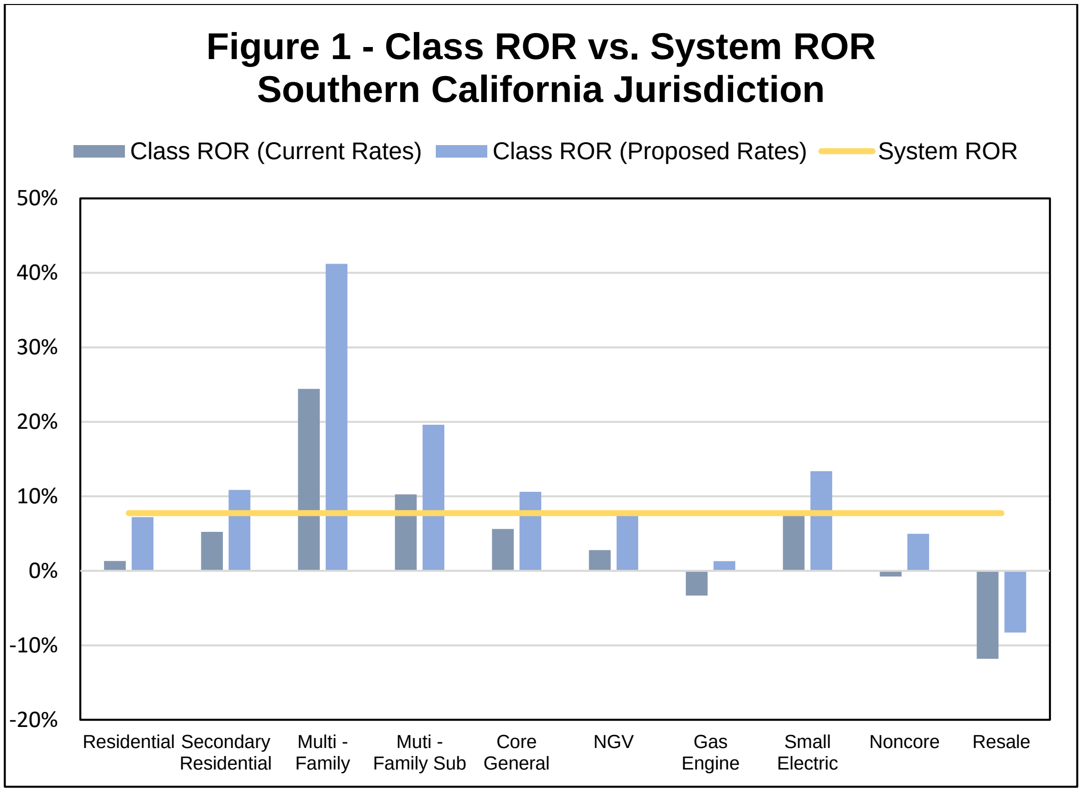
C. <u>Results of CCOSS</u>

Q. 27 Please describe the overall results of the Company's CCOSS.

A. 27 The results of the CCOSS are shown in Figures 1, 2 and 3. The Figures compare the calculated Rate of Return (ROR) on rate base for each rate class based on current rates and on proposed rates to the system average or overall ROR. Results in Figures 2 and 3 for Northern California and South Lake Tahoe reflect the results of Southwest Gas' proposed consolidated Northern California jurisdictional rates.

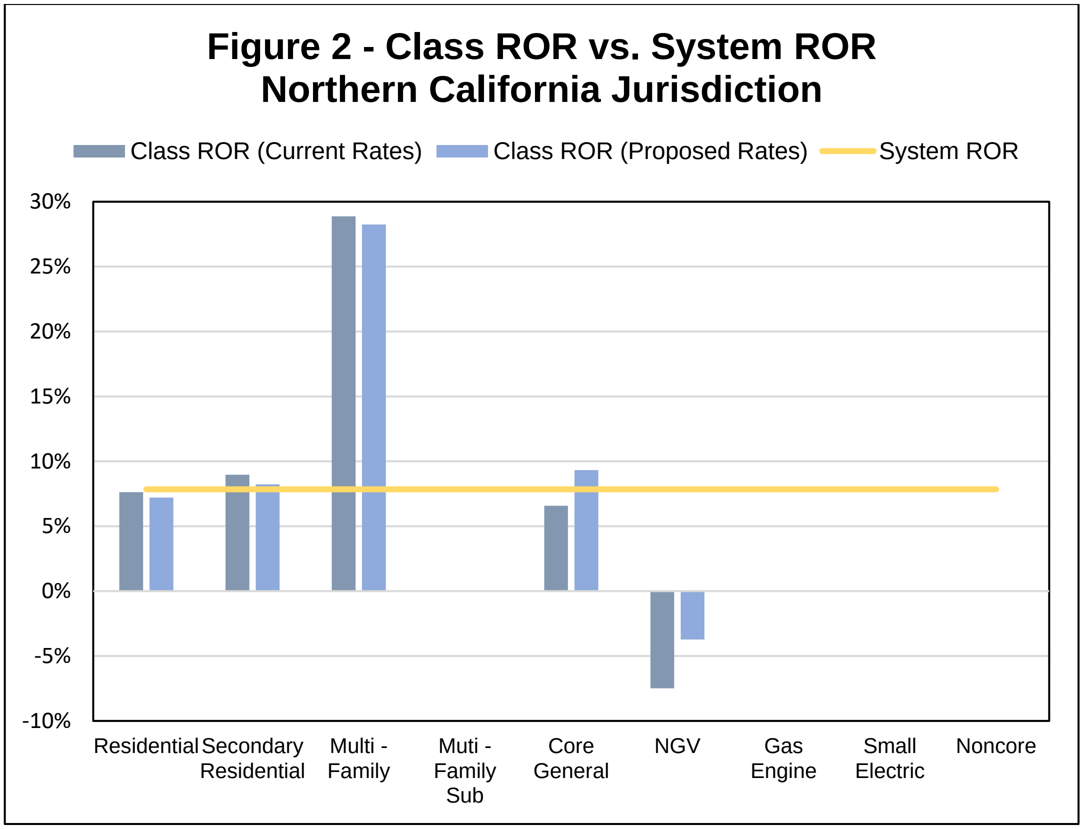
Q. 28 Please discuss the results of the Company's CCOSS regarding its Southern California Rate jurisdiction.

A. 28 Figure 1 shows that for Southern California Residential, Secondary Residential, Core General, Natural Gas Vehicle, Gas Engine, Noncore, and GS-VIC produce RORs at current rates that are less than the proposed system ROR indicating that rates produce less than their cost of service. The remaining rate classes produce RORs that are higher than the system ROR indicating the rates for those classes recover more than their cost of service.



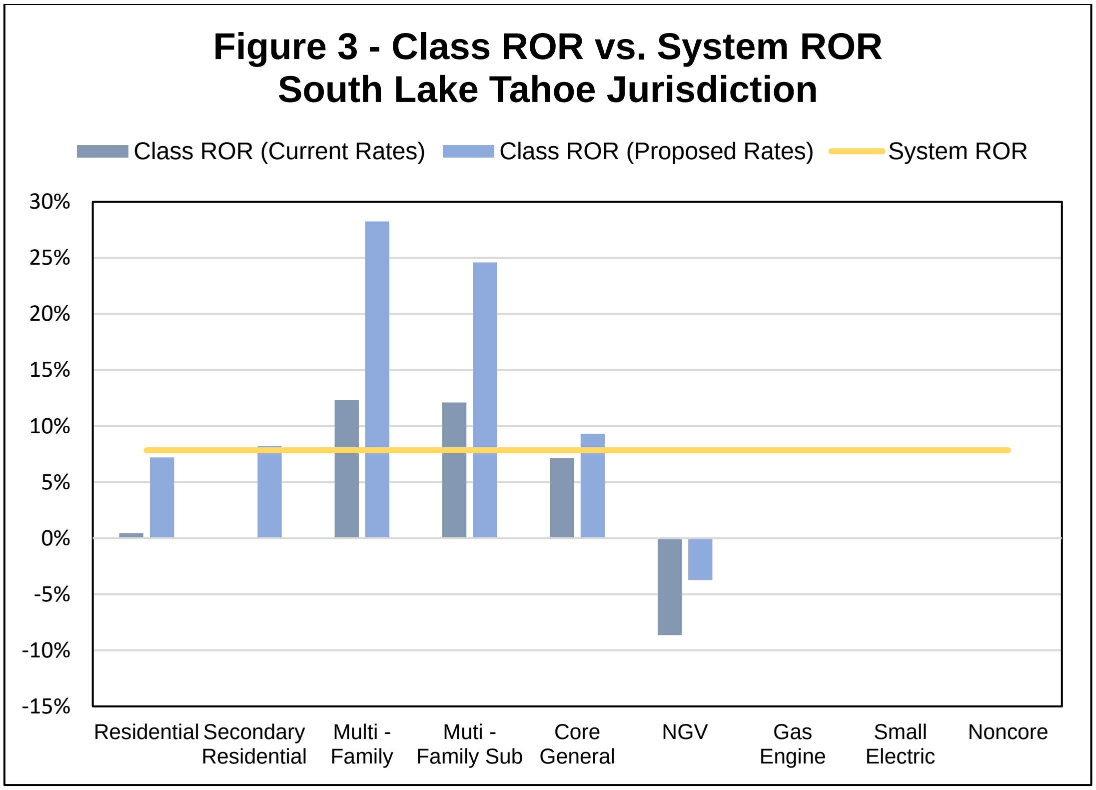
Q. 29 Please discuss the results of the Company's CCOSS regarding its Northern California Rate jurisdiction.

A. 29 Figure 2 shows that Northern California Residential, Core General, and Natural Gas Vehicle produce RORs at current rates that are less than the proposed system ROR indicating that rates produce less than their cost of service. The remaining rate classes (excluding classes where no customers are currently served) produce RORs that are higher than the system ROR indicating the rates for those classes recover more than their cost of service.



Q. 30 Please discuss the results of the Company's CCOSS regarding its South Lake Tahoe Rate jurisdiction.

A. 30 Figure 3 shows that for South Lake Tahoe Residential, Secondary Residential, Core General, and Natural Gas Vehicle produce RORs at current rates that are less than the proposed system ROR indicating that rates produce less than their cost of service. The remaining rate classes (excluding classes where no customers are currently served) produce RORs that are higher than the system ROR indicating the rates for those classes recover more than their cost of service.



Q. 31 What conclusion(s) can be reached when a rate class's ROR is higher or lower than the Company's system ROR?

A. 31 If a rate class produces a ROR that is lower than the system ROR, then it is reasonable to conclude that the revenues recovered from that class are not sufficient in covering the cost to serve that class and that class's rates should be increased in some capacity. Conversely, if a rate class produces a ROR that is higher than the system ROR, it is reasonable to conclude that the revenues recovered from that class cover more than the cost to serve that class and that class's rates should be decreased in some capacity.

Q. 32 How were the results of the CCOSS used in the Company's proposed rate design?

A. 32 The results of Southwest Gas' CCOSS support a movement toward a more equitable rate structure where class RORs move closer to the proposed system average ROR. Southwest Gas used the results of the CCOSS as a guide to allocate revenues to its various rate classes throughout its California rate jurisdictions in an attempt to move each class's ROR as close to the proposed system ROR as possible. Customer bill impacts were also considered in determining the final revenue allocation, which I will discuss later in my testimony.

V. Revenue Allocation and Rate Design

A. Overview

Q. 33 Please provide a summary of the Company's current rate schedules.

A. 33 Figure 4 lists Southwest Gas' current rate schedules.

Figure 4 - Current Rate Classifications

Rate Schedule	Description
GS-10/GN-10/SLT-10	Residential Gas Service
GS-11	Residential Air-Conditioning Gas Service
GS-12/GN-12/SLT-12	CARE Residential Gas Service
GS-15/GN-15/SLT-15	Secondary Residential Gas Service
GS-20/GN-20/SLT-20	Multi-Family Master-Metered Gas Service
GS-25/GN-25/SLT-25	Multi-Family Master-Metered Gas Service - Submetered
GS-35/GN-35/SLT-35	Agricultural Employee Housing and Nonprofit Group Living Facility Gas Service
GS-40/GN-40/SLT-40	Core Commercial General Gas Service
GS-50/GN-50/SLT-50	Core Natural Gas Service for Motor Vehicles

GS-60/GN-60/SLT-60	Core Internal Combustion Engine Gas Service
GS-66/GN-66/SLT-66	Core Small Electric Power Generation Gas Service
GS-70/GN-70/SLT-70	Noncore General Gas Transportation Service
GS-VIC	City of Victorville Natural Gas Service
GN-T	Core Transportation Service of Customer-Secured Natural Gas

Q. 34 Please provide an overview of the Company's current rate structure.

A. 34 Customers are currently served under one of the several rate schedules listed above, dependent upon the type of service and load characteristics required to meet the customers natural gas service needs. Southwest Gas' current rate structure consists of basic service charges, base margin rates, gas commodity rates, and several other miscellaneous rates and surcharges.

B. Removal of The City of Victorville

Q. 35 Why is the City of Victorville (COV) removed from the Company's CCOSS and proposed rate design?

A. 35 COV is currently undergoing the construction of natural gas pipeline facilities which would allow the COV to receive natural gas service directly from Kern River Gas Transmission Company, and upon completion, allows COV to "bypass" gas service from Southwest Gas except for a very small portion of its annual load.

Q. 36 Why is the removal of the COV necessary?

A. 36 The removal of the majority of COV's load from this rate case is necessary because the COV's anticipated completion date of its natural gas pipeline facilities construction is currently October 2024, which is well before the effective date of Southwest Gas' 2026 TY. For Southwest Gas' proposed rates to most accurately reflect expected future load, it is necessary to make a downward adjustment to projected bills and volumes associated with the COV from the test year.

Q. 37 Are there any exceptions to the removal of the COV?

A. 37 Yes, there is one exception pertaining to a small COV meter that will continue to be served by Southwest Gas during, and after test year on GS-VIC.

Q. 38 How is the Company proposing to handle this meter?

A. 38 Southwest Gas proposes to utilize volumes for the above-mentioned meter as the basis to calculate the GS-VIC rate. When the COV has completed construction of its natural gas pipeline facilities, and if it no longer requires any service from Southwest Gas under GS-VIC, the Company requests it be authorized to make a Tier 2 Advice Letter filing to remove the GS-VIC rate schedule from its tariff.

C. Revenue Allocation

Q. 39 What revenue requirement was used as the basis for the Company's proposed rate design?

A. 39 Revenue requirements of approximately $130.1 million, $31.3 million and $25.7 million for Southern California, Northern California and South Lake Tahoe, respectively, were used as the basis for Southwest Gas' proposed rate design.

Q. 40 Please provide an overview of the Company's allocation process for the proposed base rate increase.

A. 40 The proposed revenue targets for each rate class are based on Southwest Gas' Proportional Cost Responsibility Method (PCRM) that moves each rate class closer to the system ROR subject to limitations addressing customer bill impact considerations consistent with the approach adopted by the Commission in the Company's last two general rate cases.

Since, as shown in Figures 1, 2 and 3, each customer rate class presently produces a ROR that is different than the system ROR the starting point for setting class revenue targets was based on the relationship between the current revenues and revenues at equalized rates of return. Specifically, the PCRM adjusts the percent increase for each rate class by multiplying the system average percentage increase by the ratio of the margin at the system ROR to the margin at the current revenue for each customer rate class. Consistent with its last two general rate cases, Southwest Gas proposes that no class receive an increase more than twice the system average percent increase.

The proposed revenue targets result in higher-than-system rate increases for rate classes where the class RORs are less than the system average ROR and lower-than-system rate increases for those customer rate classes where class RORs are greater than the system ROR.

D. Basic Service Charges

Q. 41 When did the Company last change any of its basic services charges?

A. 41 The Commission authorized Southwest Gas to increase its Residential basic service charges in its TY 2021 rate case A.19-08-015.

Q. 42 Is the Company proposing any changes to its currently effective basic service charges in this proceeding?

A. 42 Yes. Southwest Gas is proposing to increase the basic service charge applicable to Master Meter Mobile Home Park (MMMHP) customers currently served on rate Schedules SLT-20 and SLT-25 from the current monthly rate of

$11.00 to $25.00. With this change, all Southwest Gas' California MMMHP customers will pay the same monthly basic service charge of $25.00.

E. Volumetric Baseline Rates

Q. 43 Is the Company proposing any changes to its three-season baseline rate structure or seasonal allowances approved in D.21-03-052?

A. 43 No. Southwest Gas is not proposing any changes to its current three-season baseline rate structure. However, the Company is proposing updates to its daily baseline allowances as needed to provide at least 60 percent of customers' summer season usage and at least 70 percent of winter season usage at baseline rates.

Q. 44 What are the Company's currently effective daily baseline allowances?

A. 44 Southwest Gas' currently effective daily baseline allowances are listed below in Figure 5.

Figure 5 - Current Seasonal Baseline Allowances
(Baseline Daily Quantity in Therms)

Climate Zone	Summer (May - Oct)	Winter Off-Peak (Mar, Apr & Nov)	Winter Peak (Dec - Feb)
Barstow	0.39	1.12	2.11
Needles	0.23	0.53	0.92
Victorville	0.39	1.25	2.04
	Summer (Jun - Oct)	**Winter Off-Peak (Apr, May & Nov)**	**Winter Peak (Dec - Mar)**
Big Bear	0.46	1.45	2.83
North Lake Tahoe	0.66	2.11	3.09
South Lake Tahoe	0.72	2.04	3.09
Truckee	0.72	2.17	3.55

Q. 45 What are the new daily baseline allowances that the Company is proposing?

A. 45 The new daily baseline allowances Southwest Gas is proposing in this Application are listed below in Figure 6.

Figure 6 - Proposed Seasonal Baseline Allowances
(Baseline Daily Quantity in Therms)

Climate Zone	Summer (May - Oct)	Winter Off-Peak (Mar, Apr & Nov)	Winter Peak (Dec - Feb)
Barstow	0.39	1.12	1.91
Needles	0.23	0.53	0.92
Victorville	0.46	1.45	2.11
	Summer (Jun - Oct)	**Winter Off-Peak (Apr, May & Nov)**	**Winter Peak (Dec - Mar)**
Big Bear	0.46	1.64	2.76
North Lake Tahoe	0.66	2.17	3.22
South Lake Tahoe	0.66	2.10	3.02
Truckee	0.79	2.30	3.62

F. Rate Consolidation of Northern California and South Lake Tahoe

Q. 46 Please describe the Company's proposal to consolidate its rates for its Northern California and South Lake Tahoe rate jurisdictions.

A. 46 Southwest Gas is proposing to consolidate its existing Northern California and South Lake Tahoe rate jurisdictions into a single Northern California rate jurisdiction. Although these customers are currently in two different rate jurisdictions, in some cases they are close together geographically, and have for years been paying the same rates for gas cost related expenses and Public Purpose Programs.[3] The only difference in their rates is their base margin rates. Southwest Gas believes it is beneficial for both the Company and its customers to complete this rate consolidation.

Q. 47 Why does the Company believe it is beneficial for itself and its customers to complete this rate consolidation?

A. 47 Southwest Gas believes there are several reasons why the consolidation of rates for the Northern California and South Lake Tahoe rate jurisdictions it is beneficial for both the Company and its customers. First having customers in a geographically compressed service area paying different rates may, in some cases, result in customer confusion. Second, administrative efficiencies can be gained by consolidating the cost of service and rate design for the two areas both for the Commission and Southwest Gas by not maintaining multiple rates, and not auditing and processing seemingly multiple rate applications, i.e., for this Application Southwest Gas has prepared and the Commission must review in essence three separate rate filings in one. Third, sharing the cost recovery

[3] Public Purpose Programs are California Alternate Rates for Energy (CARE) program and the Energy Savings Assistance (ESA) program.

for required investment(s) in facilities over a larger customer base lessens increases to any one area.

Q. 48 What approach is the Company proposing to use to complete this rate consolidation?

A. 48 Southwest Gas developed stand-alone revenue requirements, CCOSS, and rate design for its Northern California and South Lake Tahoe rate jurisdictions. The results of the stand-alone rate design for Northern California are shown in Volume II-B and the results of the stand-alone rate design for South Lake Tahoe are shown in Volume II-C of the Company's Application.

The stand-alone revenue requirements at the individual account level and the stand-alone rate class bills and volumes were summed and used to calculate a consolidated (or combined) CCOSS and rate design. Schedules were then developed to show the difference in customer bill impacts between the proposed consolidated rate design and stand-alone rate designs. Exhibit No.__(ABC-1) to my Prepared Direct Testimony reflects the results of the consolidated CCOSS and the calculation of the consolidated rate design and summaries of bill impacts are shown in Exhibit No.__(ABC-2). Calculation of the combined attrition year revenue and rates are contained in Exhibit No.__(ABC-3) to my Prepared Direct Testimony.

Q. 49 What impact does this consolidation have on the Company's proposed revenue requirement?

A. 49 The consolidation has no impact on the overall proposed revenue requirement. As I mentioned earlier in my testimony, revenue requirements of approximately $31.3 million for Northern California and $25.7 million for South Lake Tahoe were used as the basis for Southwest Gas' proposed stand-alone rate design.

This results in a consolidated Northern California revenue requirement of $56.9 million. Southwest Gas' proposed rates reflecting the consolidated Northern California rate design are reflected in Exhibit No.__(ABC-4) to my Prepared Direct Testimony.

VI. CUSTOMER BILL IMPACTS

A. Overview

Q. 50 Please provide a general overview of the estimated impacts that the Company's proposed rate design has on residential customer bills.

A. 50 Figure 7 shows the effect of Southwest Gas' proposed rate design on average Residential customer bills. The impacts of the proposed rates on average Residential monthly bills vary depending on rate district and season as shown in Figure 7. Specifically, the Figure shows the proposed rates will increase Winter bills for the average Residential customer in Barstow using 64 therms by $29.42 per month, or 23.5 percent. The Figure also shows the proposed rates will increase Winter Off-Peak bills for the average Residential customer in Barstow using 32 therms by $14.06 per month, or 21.5 percent. Finally, the Figure also shows the proposed rates will increase Summer bills for the average Residential customer in Barstow using 13 therms by $5.68 per month, or 18.8 percent.

Figure 7 - Average Monthly Residential Bill Impact					
	Average Monthly Usage (Therms)	Current Bill	Proposed Bill	Difference ($)	Difference (%)
Winter					
Barstow	64	$125.27	$154.69	$29.42	23.5%
Victorville	72	$141.89	$174.88	$32.99	23.2%
Big Bear	88	$175.20	$215.25	$40.05	22.9%
Needles	25	$52.44	$63.42	$10.99	21.0%
North Lake Tahoe [1]	108	$180.24	$181.81	$1.57	0.9%
Truckee [1]	124	$206.09	$208.54	$2.45	1.2%
South Lake Tahoe [1]	111	$137.55	$187.75	$50.20	36.5%
Winter Off-Peak					
Barstow	32	$65.51	$79.57	$14.06	21.5%
Victorville	39	$79.64	$96.80	$17.16	21.5%
Big Bear	41	$83.81	$101.85	$18.04	21.5%
Needles	13	$30.03	$35.74	$5.71	19.0%
North Lake Tahoe [1]	69	$116.76	$118.02	$1.26	1.1%
Truckee [1]	66	$111.40	$112.79	$1.40	1.3%
South Lake Tahoe [1]	67	$84.72	$114.77	$30.06	35.5%
Summer					
Barstow	13	$30.27	$35.96	$5.68	18.8%
Victorville	16	$36.52	$43.53	$7.01	19.2%
Big Bear	16	$36.52	$43.53	$7.01	19.2%
Needles	9	$22.56	$26.51	$3.96	17.5%
North Lake Tahoe [1]	26	$47.37	$48.64	$1.27	2.7%
Truckee [1]	24	$44.41	$44.67	$0.27	0.6%
South Lake Tahoe [1]	24	$34.07	$45.15	$11.08	32.5%

[1] Proposed rates reflect the consolidation of Northern California and South Lake Tahoe rates.

Bill impact analyses for Southwest Gas proposed consolidated Northern California and South Lake Tahoe rate design evaluating a wide range of customer monthly usage across the rate classes are included in Exhibit No._(ABC-2) to my Prepared Direct Testimony, Bill impact analyses for Southwest Gas' proposed Southern California rate design are included in Chapter 20 of Volume II-A of the Company's Application, and Volumes II-B and II-C of the Company's Application show results for stand-alone Northern California and South Lake Tahoe rate designs.

B. Consolidation of Northern California and South Lake Tahoe Impacts

Q. 51 Please provide detail of the impacts on customer bills resulting from the Company's proposal to consolidate its Northern California and South Lake Tahoe rate jurisdictions.

A. 51 Figure 8 shows the effect on average customer bills for Southwest Gas' proposed consolidated rate design versus stand-alone rate designs for Residential customers in Northern California and South Lake Tahoe rate jurisdictions. The impacts of the proposed rates on average Residential monthly bills vary depending on district and season as shown in Figure 8. Specifically, the Figure shows the proposed consolidated rates will increase average bills for Residential customers in Northern California and decrease average bills for Residential customers in South Lake Tahoe versus stand-alone rate designs.

Figure 8 - Residential Bill Comparison
Stand Alone vs. Consolidated

			Stand Alone Rate Design			Consolidated Rate Design		
	Average Monthly Usage (Therms)	Average Bill at Present Rates	Average Bill at Proposed Rates	Difference ($)	Difference (%)	Average Bill at Proposed Rates	Difference ($)	Difference (%)
Winter								
North Lake Tahoe	108	$180.24	$172.93	($7.31)	-4.1%	$181.81	$1.57	0.9%
Truckee	124	$206.09	$198.01	($8.08)	-3.9%	$208.54	$2.45	1.2%
South Lake Tahoe	111	$137.55	$203.68	$66.13	48.1%	$187.75	$50.20	36.5%
Winter Off-Peak								
North Lake Tahoe	69	$116.76	$112.14	($4.61)	-3.9%	$118.02	$1.26	1.1%
Truckee	66	$111.40	$107.17	($4.23)	-3.8%	$112.79	$1.40	1.3%
South Lake Tahoe	67	$84.72	$124.26	$39.54	46.7%	$114.77	$30.06	35.5%
Summer								
North Lake Tahoe	26	$47.37	$46.44	($0.93)	-2.0%	$48.64	$1.27	2.7%
Truckee	24	$44.41	$42.63	($1.78)	-4.0%	$44.67	$0.27	0.6%
South Lake Tahoe	24	$34.07	$48.53	$14.46	42.4%	$45.15	$11.08	32.5%

Exhibit No._(ABC-2) includes additional detailed bill impact analyses of the consolidated and stand-alone rate designs evaluating a wide range of customer monthly usage across the rate class.

VII. CUSTOMER AFFORDABILITY ANALYSIS

A. Overview

Q. 52 Please describe the purpose of performing a customer affordability analysis.

A. 52 In accordance with D.22-08-023,[4] Southwest Gas performed a customer affordability analysis to calculate an Affordability Ratio (AR), which is an attempt at quantifying the percentage of a customer's household income that would be required to pay for an essential utility service after non-discretionary costs, such as housing and other essential utility services, are removed from the household income. An AR is calculated by dividing the essential usage bill by the discretionary income for a given geography.[5]

Q. 53 Please describe what an essential bill represents.

A. 53 An essential bill represents the average monthly bill customers would pay for their essential energy, water, or telecommunications usage. In terms of natural

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[4] D.22-08-023, Ordering Paragraph 6 states, "Beginning 30 days after the issuance of this decision, in any initial filing in any proceeding with a revenue increase estimated to exceed one percent of currently authorized revenues systemwide for a single fuel…Southwest Gas Corporation…shall introduce changes in the Affordability Ratio 20 (AR20) by climate zone, Affordability Ratio 50 (AR50) by climate zone, and Hours-at-Minimum-Wage associated with the proposed new revenue requested, annually for each year in which new revenues are proposed, and shall also include:
a. Essential usage bills by climate zone, underlying the affordability metrics associated with proposed revenues;
b. Average usage bills by climate zone associated with proposed revenues; and
c. For climate zones with Areas of Affordability Concern (AAC) as defined in the most recent annual Affordability Report, AR20 by climate zones subdivided by Public Use Microdata Area.
d. If the proceeding is a General Rate Case, concurrent with any modeling effort necessary to represent bill impacts of an authorized revenue requirement associated with a Proposed Decision, the same entity updating the rates associated with an authorized revenue requirement shall update the affordability metrics for production in the same Commission document that presents the rate impacts."

gas service, essential usage represents the baseline allocation of gas in a given baseline climate zone. To calculate an essential bill, the baseline allowance for individually metered gas residential customers is multiplied by the residential baseline rate and added to the monthly basic service charge.

B. Southwest Gas' Affordability Analysis

Q. 54 How did the Company develop its customer affordability analysis?

A. 54 Southwest Gas calculated essential bills, as described above, for each of its baseline climate zones and then utilized the Commission's affordability calculator available on the CPUC website.[6]

C. Results of Analysis

Q. 55 Please summarize the results of the affordability analysis.

A. 55 Figures 9 and 10 below show the results of the affordability analysis for AR)$_{20}$ and AR_{50} for TY 2026 in this rate case application. Figure 9 summarizes results for Southwest Gas Residential customers and Figure 10 summarizes results for CARE Residential customers.

Figure 9 - Test Year 2026 Affordability Analysis
Non-Care Customers

	Winter		Winter Off-Peak		Summer	
	Weighted Avg. Gas AR_{20}	Weighted Avg. Gas AR_{50}	Weighted Avg. Gas AR_{20}	Weighted Avg. Gas AR_{50}	Weighted Avg. Gas AR_{20}	Weighted Avg. Gas AR_{50}
Barstow	15.60%	3.95%	8.55%	2.17%	3.36%	0.85%
Big Bear	13.01%	3.38%	6.85%	1.78%	2.42%	0.63%
Needles	7.61%	1.84%	4.65%	1.12%	2.37%	0.57%
North Lake Tahoe	10.41%	2.20%	7.13%	1.51%	2.42%	0.51%
South Lake Tahoe	6.87%	2.30%	4.85%	1.63%	1.69%	0.57%
Truckee	14.03%	2.94%	9.09%	1.91%	3.40%	0.71%
Victorville	8.23%	2.78%	5.16%	1.74%	1.83%	0.62%

[6] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/affordability

Figure 10 - Test Year 2026 Affordability Analysis
Care Customers

	Winter		Winter Off-Peak		Summer	
	Weighted Avg. Gas AR_{20}	Weighted Avg. Gas AR_{50}	Weighted Avg. Gas AR_{20}	Weighted Avg. Gas AR_{50}	Weighted Avg. Gas AR_{20}	Weighted Avg. Gas AR_{50}
Barstow	12.42%	3.15%	6.78%	1.72%	2.63%	0.67%
Big Bear	10.37%	2.69%	5.44%	1.41%	1.90%	0.49%
Needles	6.02%	1.45%	3.65%	0.88%	1.83%	0.44%
North Lake Tahoe	8.29%	1.75%	5.67%	1.20%	1.89%	0.40%
South Lake Tahoe	5.47%	1.83%	3.86%	1.29%	1.33%	0.44%
Truckee	11.18%	2.35%	7.22%	1.52%	2.68%	0.56%
Victorville	6.55%	2.21%	4.10%	1.38%	1.43%	0.48%

The calculation of Southwest Gas' essential bills and additional affordability results for years 2027, 2028 and 2029 (the remaining years available in the affordability calculator), including data calculated by Public Use Microdata Areas (PUMAs), are shown in Exhibit No._(ABC-5) of my Prepared Direct Testimony.

Q. 56 Did Southwest Gas consider the impact biomethane purchases may have on CARE customers pursuant to ordering paragraph 30 of D.22-02-025?

A. 56 Yes. Southwest Gas believes that its currently effective CARE program benefits, i.e. a 20 percent reduction in the baseline and tier II effective sales rates per therm and a 30 percent reduction to the monthly basic service charge address the incremental costs of biomethane purchases on CARE customers. In addition to the existing CARE benefits, Southwest Gas intends to continue its current aggressive outreach programs alerting customers most in need of the CARE program and other available no-cost or low-cost energy saving programs to help alleviate incremental costs associated with biomethane purchases.

Q. 57 Does this conclude your prepared direct testimony at this time?

A. 57 Yes, it does.

SUMMARY OF QUALIFICATIONS
A. BROOKS CONGDON

From 1976 to 1980, I was employed by General Telephone of the Midwest in the Company's Columbus, Nebraska office. My primary responsibilities involved projecting growth in demand for telephone service in eastern Nebraska and western Iowa.

From 1980 to 1984, I was employed by Pacific Power and Light Company in the Company's Portland, Oregon corporate office. My primary responsibilities involved performing customer class cost of service studies and designing customer class rates for the Company's electric and water utilities.

From 1984 to 1987, I was employed by Kansas Electric Power Cooperative in the Cooperative's Topeka, Kansas office. My primary responsibilities involved coordination of intervention in wholesale power rate cases at the Federal Energy Regulatory Commission and preparation of the Cooperative's rate case activity before the Kansas Corporation Commission.

From 1987 to present, I have been employed by Southwest Gas Corporation in the Company's Las Vegas, Nevada corporate office. I began my employment as a Rate Specialist and have held positions of increasing responsibility including Manager/Pricing and Tariffs. In October 2014, I was assigned to be Manager/Energy Efficiency. In May 2018, the Company's Rates and Regulatory Analysis and Energy Efficiency departments were combined and I assumed my current position as Manager/Regulation. My primary responsibilities have involved preparation of customer class cost of service studies, rate design and the development and administration of energy efficiency programs for the Company's three-state operating jurisdictions.

I have submitted prepared written and oral testimony before the Public Utilities Commission of Nevada, the California Public Utilities Commission and the Arizona Corporation Commission.

Prior to beginning my professional career, I received a Bachelor of Science degree in Economics from Iowa State University in 1975.

SOUTHWEST GAS CORPORATION
PROPOSED NORTHERN CALIFORNIA AND SOUTH LAKE TAHOE RATE JURISDICTION
CLASS COST OF SERVICE STUDY SUMMARY - PRESENT RATES AT PRESENT RATE SCHEDULES
TEST YEAR TWELVE MONTHS ENDED DECEMBER 31, 2026

Line	Description	Total Amount	Residential	Secondary	Multi- Family	Muti- Fam	Core General	NGV	Gas Engine	Small EG	Noncore	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
	Rate Base											
1	Total Direct Net Plant	$ 280,254,731	$ 173,612,348	$ 64,078,696	$ 960,185	$ 483,726	$ 40,943,286	$ 176,490	$ 0	$ 0	$ 0	1
2	Total System Allocable Net Plant	$ 8,842,864	$ 5,477,982	$ 2,021,872	$ 30,297	$ 15,263	$ 1,291,882	$ 5,569	$ 0	$ 0	$ 0	2
3	Cash Working Capital	$ 7,791,996	$ 4,826,990	$ 1,781,597	$ 26,696	$ 13,449	$ 1,138,357	$ 4,907	$ 0	$ 0	$ 0	3
4	Materials & Supplies	$ 3,312,265	$ 2,051,884	$ 757,331	$ 11,348	$ 5,717	$ 483,899	$ 2,086	$ 0	$ 0	$ 0	4
5	Other Debits and Credits	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	5
6	Customer Deposits	$ (163,927)	$ (153,649)	$ (4,726)	$ 0	$ 0	$ (5,552)	$ 0	$ 0	$ 0	$ 0	6
7	Deferred Taxes	$ (46,252,462)	$ (28,652,499)	$ (10,575,370)	$ (158,466)	$ (79,833)	$ (6,757,166)	$ (29,127)	$ 0	$ 0	$ 0	7
8	Total Rate Base	$ 253,785,468	$ 157,163,056	$ 58,059,400	$ 870,060	$ 438,323	$ 37,094,705	$ 159,924	$ 0	$ 0	$ 0	8
	Revenue											
9	Net Operating Margin	$ 46,496,462	$ 28,093,729	$ 11,042,821	$ 253,418	$ 106,402	$ 7,002,340	$ (2,248)	$ 0	$ 0	$ 0	9
10	Special Contracts	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	10
11	Other Revenue	$ 321,095	$ 247,120	$ 42,713	$ 0	$ 0	$ 31,263	$ 0	$ 0	$ 0	$ 0	11
12	Total Revenue	$ 46,817,557	$ 28,340,849	$ 11,085,534	$ 253,418	$ 106,402	$ 7,033,603	$ (2,248)	$ 0	$ 0	$ 0	12
	Operating Deductions											
13	Operations & Maintenance Exps	$ (9,023,601)	$ (5,974,417)	$ (2,106,146)	$ (24,445)	$ (6,914)	$ (908,303)	$ (3,377)	$ (0)	$ 0	$ (0)	13
14	Administrative & General Exps	$ (7,060,555)	$ (4,674,708)	$ (1,647,963)	$ (19,127)	$ (5,410)	$ (710,705)	$ (2,642)	$ (0)	$ 0	$ (0)	14
15	Regulatory Amortization	$ (1,201,162)	$ (744,096)	$ (274,639)	$ (4,115)	$ (2,073)	$ (175,481)	$ (756)	$ 0	$ 0	$ 0	15
16	Depreciation Expenses	$ (10,503,497)	$ (6,506,712)	$ (2,401,567)	$ (35,986)	$ (18,129)	$ (1,534,489)	$ (6,615)	$ 0	$ 0	$ 0	16
17	Taxes other than Income	$ (4,019,015)	$ (2,489,701)	$ (918,926)	$ (13,770)	$ (6,937)	$ (587,150)	$ (2,531)	$ 0	$ 0	$ 0	17
18	Total Operating Deductions	$ (31,807,830)	$ (20,389,634)	$ (7,349,240)	$ (97,443)	$ (39,463)	$ (3,916,129)	$ (15,921)	$ (0)	$ 0	$ (0)	18
	State Income Tax											
19	Taxable Income before Interest Exp	$ 15,009,726	$ 7,951,214	$ 3,736,294	$ 155,975	$ 66,939	$ 3,117,474	$ (18,169)	$ (0)	$ 0	$ (0)	19
20	State Interest Expenses	$ (5,533,718)	$ (3,428,031)	$ (1,265,254)	$ (18,959)	$ (9,551)	$ (808,438)	$ (3,485)	$ 0	$ 0	$ 0	20
21	Total State Taxable Income	$ 9,476,008	$ 4,523,184	$ 2,471,040	$ 137,016	$ 57,387	$ 2,309,036	$ (21,654)	$ (0)	$ 0	$ (0)	21
22	State Taxable Income	$ 837,679	$ 399,849	$ 218,440	$ 12,112	$ 5,073	$ 204,119	$ (1,914)	$ (0)	$ 0	$ (0)	22
	Federal Income Tax											
23	Taxable Income before Interest Exp	$ 14,172,047	$ 7,551,365	$ 3,517,854	$ 143,863	$ 61,866	$ 2,913,355	$ (16,255)	$ (0)	$ 0	$ (0)	23
24	Federal Interest Expenses	$ (5,533,718)	$ (3,428,031)	$ (1,265,254)	$ (18,959)	$ (9,551)	$ (808,438)	$ (3,485)	$ 0	$ 0	$ 0	24
25	Federal Taxable Income	$ 8,638,329	$ 4,123,334	$ 2,252,600	$ 124,903	$ 52,314	$ 2,104,917	$ (19,740)	$ (0)	$ 0	$ (0)	25
26	Federal Income Taxes	$ 1,814,049	$ 865,900	$ 473,046	$ 26,230	$ 10,986	$ 442,033	$ (4,145)	$ (0)	$ 0	$ (0)	26
27	Investment Tax Credit (I.T.C.)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	27
28	Federal Deferred Provision	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	28
29	Total Federal Income Tax	$ 1,814,049	$ 865,900	$ 473,046	$ 26,230	$ 10,986	$ 442,033	$ (4,145)	$ (0)	$ 0	$ (0)	29
30	Excess Deferred Amortization	$ (288,905)	$ (178,971)	$ (66,057)	$ (990)	$ (499)	$ (42,207)	$ (182)	$ 0	$ 0	$ 0	30
31	Total Net Income	$ 12,646,903	$ 6,864,436	$ 3,110,864	$ 118,623	$ 51,378	$ 2,513,530	$ (11,928)	$ (0)	$ 0	$ (0)	31
32	Rate of Return on Rate Base	4.98%	4.37%	5.36%	13.63%	11.72%	6.78%	(7.46%)	0.00%	0.00%	0.00%	32

SOUTHWEST GAS CORPORATION
PROPOSED NORTHERN CALIFORNIA AND SOUTH LAKE TAHOE RATE JURISDICTION
CLASS COST OF SERVICE STUDY SUMMARY - CLASS REVENUE AT SYSTEM AVERAGE RATE OF RETURN
TEST YEAR TWELVE MONTHS ENDED DECEMBER 31, 2026

Line	Description	Total Amount	Residential	Secondary	Multi- Family	Muti- Fam	Core General	NGV	Gas Engine	Small EG	Noncore	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
	Rate Base											
1	Total Direct Net Plant	$ 280,254,731	$ 173,612,348	$ 64,078,696	$ 960,185	$ 483,726	$ 40,943,286	$ 176,490	$ 0	$ 0	$ 0	1
2	Total System Allocable Net Plant	$ 8,842,864	$ 5,477,982	$ 2,021,872	$ 30,297	$ 15,263	$ 1,291,882	$ 5,569	$ 0	$ 0	$ 0	2
3	Cash Working Capital	$ 7,791,996	$ 4,826,990	$ 1,781,597	$ 26,696	$ 13,449	$ 1,138,357	$ 4,907	$ 0	$ 0	$ 0	3
4	Incremental Cash Working Capital Ad	$ (568,218)	$ (352,000)	$ (129,920)	$ (1,947)	$ (981)	$ (83,013)	$ (358)	$ 0	$ 0	$ 0	4
5	Materials & Supplies	$ 3,312,265	$ 2,051,884	$ 757,331	$ 11,348	$ 5,717	$ 483,899	$ 2,086	$ 0	$ 0	$ 0	5
6	Other Debits and Credits	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	6
7	Customer Deposits	$ (163,927)	$ (153,649)	$ (4,726)	$ 0	$ 0	$ (5,552)	$ 0	$ 0	$ 0	$ 0	7
8	Deferred Taxes	$ (46,252,462)	$ (28,652,499)	$ (10,575,370)	$ (158,466)	$ (79,833)	$ (6,757,166)	$ (29,127)	$ 0	$ 0	$ 0	8
9	Total Rate Base	$ 253,217,251	$ 156,811,056	$ 57,929,480	$ 868,113	$ 437,342	$ 37,011,693	$ 159,566	$ 0	$ 0	$ 0	9
	Revenue											
10	Net Operating Margin	$ 56,744,500	$ 35,782,189	$ 13,087,175	$ 184,418	$ 83,169	$ 7,575,861	$ 31,688	$ 0	$ 0	$ 0	10
11	Special Contracts	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	11
12	Other Revenue - Labor	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	12
13	Other Revenue - Parts & Material	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	13
14	Other Revenue - Returned Item Fee	$ 19,751	$ 15,561	$ 3,471	$ 0	$ 0	$ 718	$ 0	$ 0	$ 0	$ 0	14
15	Other Revenue - Rental Gas Property	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	15
16	Late Charges	$ 158,810	$ 97,961	$ 35,132	$ 0	$ 0	$ 25,717	$ 0	$ 0	$ 0	$ 0	16
17	Service Establishment Charges	$ 141,414	$ 132,548	$ 4,077	$ 0	$ 0	$ 4,790	$ 0	$ 0	$ 0	$ 0	17
18	Reconnect / Reread Charges	$ 1,120	$ 1,050	$ 32	$ 0	$ 0	$ 38	$ 0	$ 0	$ 0	$ 0	18
19	Total Revenue	$ 57,065,595	$ 36,029,308	$ 13,129,888	$ 184,418	$ 83,169	$ 7,607,124	$ 31,688	$ 0	$ 0	$ 0	19
	Operating Deductions											
20	Operations & Maintenance Exps	$ (9,023,601)	$ (5,974,417)	$ (2,106,146)	$ (24,445)	$ (6,914)	$ (908,303)	$ (3,377)	$ (0)	$ 0	$ (0)	20
21	Incremental O&M Expenses	$ (21,803)	$ (15,270)	$ (5,215)	$ (40)	$ (3)	$ (1,274)	$ (1)	$ 0	$ 0	$ 0	21
22	Administrative & General Exps	$ (7,060,555)	$ (4,674,708)	$ (1,647,963)	$ (19,127)	$ (5,410)	$ (710,705)	$ (2,642)	$ (0)	$ 0	$ (0)	22
23	Regulatory Amortization	$ (1,201,162)	$ (744,096)	$ (274,639)	$ (4,115)	$ (2,073)	$ (175,481)	$ (756)	$ 0	$ 0	$ 0	23
24	Depreciation Expenses	$ (10,503,497)	$ (6,506,712)	$ (2,401,567)	$ (35,986)	$ (18,129)	$ (1,534,489)	$ (6,615)	$ 0	$ 0	$ 0	24
25	Incremental O&M Expense	$ (203,532)	$ (122,977)	$ (48,339)	$ (1,109)	$ (466)	$ (30,652)	$ 10	$ 0	$ 0	$ 0	25
26	Taxes other than Income	$ (4,019,015)	$ (2,489,701)	$ (918,926)	$ (13,770)	$ (6,937)	$ (587,150)	$ (2,531)	$ 0	$ 0	$ 0	26
27	Total Operating Deductions	$ (32,033,165)	$ (20,527,881)	$ (7,402,793)	$ (98,593)	$ (39,932)	$ (3,948,054)	$ (15,913)	$ (0)	$ 0	$ (0)	27
	State Income Tax											
28	Taxable Income before Interest Exp	$ 25,032,430	$ 15,501,427	$ 5,727,095	$ 85,825	$ 43,237	$ 3,659,070	$ 15,775	$ 0	$ 0	$ 0	28
29	State Interest Expenses	$ (5,533,718)	$ (3,428,031)	$ (1,265,254)	$ (18,959)	$ (9,551)	$ (808,438)	$ (3,485)	$ 0	$ 0	$ 0	29
30	State Taxable Income	$ 19,498,711	$ 12,073,397	$ 4,461,841	$ 66,866	$ 33,686	$ 2,850,631	$ 12,291	$ 0	$ 0	$ 0	30
31	Total State Income Tax	$ 1,723,686	$ 1,067,288	$ 394,427	$ 5,911	$ 2,978	$ 251,996	$ 1,086	$ 0	$ 0	$ 0	31
	Federal Income Tax											
32	Taxable Income before Interest Exp	$ 23,308,744	$ 14,434,139	$ 5,332,668	$ 79,914	$ 40,260	$ 3,407,074	$ 14,689	$ 0	$ 0	$ 0	32
33	Federal Interest Expenses	$ (5,521,414)	$ (3,420,408)	$ (1,262,441)	$ (18,917)	$ (9,530)	$ (806,641)	$ (3,477)	$ 0	$ 0	$ 0	33
34	Federal Taxable Income	$ 17,787,330	$ 11,013,731	$ 4,070,227	$ 60,997	$ 30,729	$ 2,600,433	$ 11,212	$ 0	$ 0	$ 0	34
35	Federal Income Tax	$ 3,735,339	$ 2,312,883	$ 854,748	$ 12,809	$ 6,453	$ 546,091	$ 2,354	$ 0	$ 0	$ 0	35
36	Investment Tax Credit (I.T.C.)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	36
37	Federal Deferred Provision	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	37
38	Total Federal Income Tax	$ 3,735,339	$ 2,312,883	$ 854,748	$ 12,809	$ 6,453	$ 546,091	$ 2,354	$ 0	$ 0	$ 0	38
39	Excess Deferred Amortization	$ (288,905)	$ (178,971)	$ (66,057)	$ (990)	$ (499)	$ (42,207)	$ (182)	$ 0	$ 0	$ 0	39
40	Net Income	$ 19,862,309	$ 12,300,227	$ 4,543,977	$ 68,095	$ 34,305	$ 2,903,190	$ 12,516	$ 0	$ 0	$ 0	40
41	Rate of Return on Rate Base	7.84%	7.84%	7.84%	7.84%	7.84%	7.84%	7.84%	0.00%	0.00%	0.00%	41

SOUTHWEST GAS CORPORATION
PROPOSED NORTHERN CALIFORNIA AND SOUTH LAKE TAHOE RATE JURISDICTION
CLASS COST OF SERVICE STUDY SUMMARY - PROPOSED RATES
TEST YEAR TWELVE MONTHS ENDED DECEMBER 31, 2026

Line	Description	Total Amount	Residential	Secondary	Multi- Family	Muti- Fam	Core General	NGV	Gas Engine	Small EG	Noncore	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
	Rate Base											
1	Total Direct Net Plant	$ 280,254,731	$ 173,612,348	$ 64,078,696	$ 960,185	$ 483,726	$ 40,943,286	$ 176,490	$ 0	$ 0	$ 0	1
2	Total System Allocable Net Plant	$ 8,842,864	$ 5,477,982	$ 2,021,872	$ 30,297	$ 15,263	$ 1,291,882	$ 5,569	$ 0	$ 0	$ 0	2
3	Cash Working Capital	$ 7,791,996	$ 4,826,990	$ 1,781,597	$ 26,696	$ 13,449	$ 1,138,357	$ 4,907	$ 0	$ 0	$ 0	3
4	Incremental Cash Working Capital Adj	$ (568,218)	$ (352,000)	$ (129,920)	$ (1,947)	$ (981)	$ (83,013)	$ (358)	$ 0	$ 0	$ 0	4
5	Materials & Supplies	$ 3,312,265	$ 2,051,884	$ 757,331	$ 11,348	$ 5,717	$ 483,899	$ 2,086	$ 0	$ 0	$ 0	5
6	Other Debits and Credits	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	6
7	Customer Advances	$ (163,927)	$ (153,649)	$ (4,726)	$ 0	$ 0	$ (5,552)	$ 0	$ 0	$ 0	$ 0	7
8	Deferred Taxes	$ (46,252,462)	$ (28,652,499)	$ (10,575,370)	$ (158,466)	$ (79,833)	$ (6,757,166)	$ (29,127)	$ 0	$ 0	$ 0	8
9	Total Rate Base	$ 253,217,251	$ 156,811,056	$ 57,929,480	$ 868,113	$ 437,342	$ 37,011,693	$ 159,566	$ 0	$ 0	$ 0	9
	Revenue											
10	Net Operating Margin	$ 56,744,500	$ 34,386,715	$ 13,394,235	$ 431,062	$ 185,466	$ 8,341,009	$ 6,013	$ 0	$ 0	$ 0	10
11	Special Contracts	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	11
12	Other Revenue - Labor	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	12
13	Other Revenue - Parts & Material	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	13
14	Other Revenue - Returned Item Fee	$ 19,751	$ 15,561	$ 3,471	$ 0	$ 0	$ 718	$ 0	$ 0	$ 0	$ 0	14
15	Other Revenue - Rental Gas Property	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	15
16	Late Charges	$ 158,810	$ 97,961	$ 35,132	$ 0	$ 0	$ 25,717	$ 0	$ 0	$ 0	$ 0	16
17	Service Establishment Charges	$ 141,414	$ 132,548	$ 4,077	$ 0	$ 0	$ 4,790	$ 0	$ 0	$ 0	$ 0	17
18	Reconnect / Reread Charges	$ 1,120	$ 1,050	$ 32	$ 0	$ 0	$ 38	$ 0	$ 0	$ 0	$ 0	18
19	Total Revenue	$ 57,065,595	$ 34,633,835	$ 13,436,948	$ 431,062	$ 185,466	$ 8,372,272	$ 6,013	$ 0	$ 0	$ 0	19
	Operating Deductions											
20	Operations & Maintenance Exps	$ (9,023,601)	$ (5,974,417)	$ (2,106,146)	$ (24,445)	$ (6,914)	$ (908,303)	$ (3,377)	$ (0)	$ 0	$ (0)	20
21	Incremental O&M Expenses	$ (21,803)	$ (15,270)	$ (5,215)	$ (40)	$ (3)	$ (1,274)	$ (1)	$ 0	$ 0	$ 0	21
22	Administrative & General Exps	$ (7,060,555)	$ (4,674,708)	$ (1,647,963)	$ (19,127)	$ (5,410)	$ (710,705)	$ (2,642)	$ (0)	$ 0	$ (0)	22
23	Regulatory Amortization	$ (1,201,162)	$ (744,096)	$ (274,639)	$ (4,115)	$ (2,073)	$ (175,481)	$ (756)	$ 0	$ 0	$ 0	23
24	Depreciation Expenses	$ (10,503,497)	$ (6,506,712)	$ (2,401,567)	$ (35,986)	$ (18,129)	$ (1,534,489)	$ (6,615)	$ 0	$ 0	$ 0	24
25	Incremental O&M Expense	$ (203,532)	$ (122,977)	$ (48,339)	$ (1,109)	$ (466)	$ (30,652)	$ 10	$ 0	$ 0	$ 0	25
26	Taxes other than Income	$ (4,019,015)	$ (2,489,701)	$ (918,926)	$ (13,770)	$ (6,937)	$ (587,150)	$ (2,531)	$ 0	$ 0	$ 0	26
27	Total Operating Deductions	$ (32,033,165)	$ (20,527,881)	$ (7,402,793)	$ (98,593)	$ (39,932)	$ (3,948,054)	$ (15,913)	$ (0)	$ 0	$ (0)	27
	State Income Tax											
28	Taxable Income before Interest Exp	$ 25,032,429	$ 14,105,954	$ 6,034,155	$ 332,469	$ 145,534	$ 4,424,217	$ (9,900)	$ (0)	$ 0	$ (0)	28
29	State Interest Expenses	$ (5,533,718)	$ (3,428,031)	$ (1,265,254)	$ (18,959)	$ (9,551)	$ (808,438)	$ (3,485)	$ 0	$ 0	$ 0	29
30	State Taxable Income	$ 19,498,711	$ 10,677,923	$ 4,768,900	$ 313,510	$ 135,983	$ 3,615,779	$ (13,384)	$ (0)	$ 0	$ (0)	30
31	State Income Tax	$ 1,723,686	$ 943,928	$ 421,571	$ 27,714	$ 12,021	$ 319,635	$ (1,183)	$ (0)	$ 0	$ (0)	31
	Federal Income Tax											
32	Taxable Income before Interest Exp	$ 23,308,743	$ 13,162,025	$ 5,612,584	$ 304,755	$ 133,513	$ 4,104,583	$ (8,716)	$ (0)	$ 0	$ (0)	32
33	Federal Interest Expense	$ (5,521,414)	$ (3,420,408)	$ (1,262,441)	$ (18,917)	$ (9,530)	$ (806,641)	$ (3,477)	$ 0	$ 0	$ 0	33
34	Federal Taxable Income	$ 17,787,329	$ 9,741,617	$ 4,350,143	$ 285,838	$ 123,983	$ 3,297,942	$ (12,194)	$ (0)	$ 0	$ (0)	34
35	Federal Income Tax	$ 3,735,339	$ 2,045,740	$ 913,530	$ 60,026	$ 26,036	$ 692,568	$ (2,561)	$ (0)	$ 0	$ (0)	35
36	Investment Tax Credit (I.T.C.)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	36
37	Federal Deferred Provision	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	37
38	Total Federal Income Tax	$ 3,735,339	$ 2,045,740	$ 913,530	$ 60,026	$ 26,036	$ 692,568	$ (2,561)	$ (0)	$ 0	$ (0)	38
39	Excess Deferred Amortization	$ (288,905)	$ (178,971)	$ (66,057)	$ (990)	$ (499)	$ (42,207)	$ (182)	$ 0	$ 0	$ 0	39
40	Net Income	$ 19,862,309	$ 11,295,257	$ 4,765,110	$ 245,719	$ 107,975	$ 3,454,222	$ (5,974)	$ (0)	$ 0	$ (0)	40
41	Rate of Return on Rate Base	7.84%	7.20%	8.23%	28.30%	24.69%	9.33%	-3.74%	0.00%	0.00%	0.00%	41

SOUTHWEST GAS CORPORATION
NORTHERN CALIFORNIA RATE JURISDICTION
COMPARISON OF PRESENT AND PROPOSED REVENUE BY CLASS
TEST YEAR TWELVE MONTHS ENDED DECEMBER 31, 2026

				Stand-Alone Revenue Increase			Consolidate Revenue Increase			
					Increase / (Decrease)			Increase / (Decrease)		
Line No.	Description	Schedule No.	Currently Effective [1]	Proposed [2]	Dollars	Percent	Proposed [3]	Dollars	Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
	Primary Residential Gas Service	GN-10/ GN-12								
1	Basic Service Charge		$ 1,352,009	$ 1,352,009	$ 0	0.00%	$ 1,352,009	$ 0	0.00%	1
	Commodity									
2	Baseline		$ 15,853,057	$ 16,257,288	$ 404,231	2.55%	$ 16,819,234	$ 966,177	6.09%	2
3	Tier II		$ 8,280,153	$ 7,909,553	$ (370,600)	(4.48%)	$ 8,148,234	$ (131,919)	(1.59%)	3
4	Total Primary Residential Gas Service		$ 25,485,219	$ 25,518,850	$ 33,631	0.13%	$ 26,319,477	$ 834,258	3.27%	4
	Secondary Residential Gas Service	GN-15								
5	Basic Service Charge		$ 577,950	$ 577,950	$ 0	0.00%	$ 577,950	$ 0	0.00%	5
	Commodity Charge									
6	All Usage		$ 10,277,546	$ 10,291,135	$ 13,589	0.13%	$ 11,080,395	$ 802,849	7.81%	6
7	Total Secondary Residential Gas Service		$ 10,855,496	$ 10,869,085	$ 13,589	0.13%	$ 11,658,345	$ 802,849	7.40%	7
8	Total Residential Gas Service		$ 36,340,715	$ 36,387,935	$ 47,220	0.13%	$ 37,977,822	$ 1,637,107	4.50%	8
	Multi-Family Master Metered Gas Service	GN-20								
9	Basic Service Charge		$ 600	$ 600	$ 0	0.00%	$ 600	$ 0	0.00%	9
	Commodity									
10	Baseline		$ 16,756	$ 16,770	$ 14	0.08%	$ 17,350	$ 594	3.54%	10
11	Tier II		$ 235	$ 242	$ 7	2.98%	$ 250	$ 15	6.38%	11
12	Total Multi-Family Master Metered Gas Service		$ 17,591	$ 17,612	$ 21	0.12%	$ 18,200	$ 609	3.46%	12
	Multi-Family Master Metered Gas Service - Submeterec	GN-25								
13	Basic Service Charge		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	13
14	Submeter Discount		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	14
	Commodity									
15	Baseline		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	15
16	Tier II		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	16
17	Total Multi-Family Submetered		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	17
18	Total Multi-Family Master Metered & Submetered		$ 17,591	$ 17,612	$ 21	0.12%	$ 18,200	$ 609	3.46%	18
	Core General Gas Service	GN-35/ GN-40								
19	Basic Service Charge		$ 213,862	$ 213,862	$ 0	0.00%	$ 213,862	$ 0	0.00%	19
20	Transportation Service Charge		$ 9,360	$ 9,360	$ 0	0.00%	$ 9,360	$ 0	0.00%	20
	Commodity Charge									
21	First 100		$ 1,474,992	$ 1,477,066	$ 2,074	0.14%	$ 1,781,047	$ 306,055	20.75%	21
22	Next 500		$ 2,167,488	$ 2,170,208	$ 2,720	0.13%	$ 2,521,698	$ 354,210	16.34%	22
23	Next 2400		$ 1,510,200	$ 1,511,800	$ 1,600	0.11%	$ 1,640,038	$ 129,838	8.60%	23
24	Over 3000		$ 1,072,344	$ 1,072,896	$ 552	0.05%	$ 1,140,096	$ 67,752	6.32%	24
25	Total Core General Gas Service		$ 6,448,246	$ 6,455,192	$ 6,946	0.11%	$ 7,306,101	$ 857,855	13.30%	25

SOUTHWEST GAS CORPORATION
NORTHERN CALIFORNIA RATE JURISDICTION
COMPARISON OF PRESENT AND PROPOSED REVENUE BY CLASS
TEST YEAR TWELVE MONTHS ENDED DECEMBER 31, 2026

Line No.	Description	Schedule No.	Currently Effective [1]	Stand-Alone Revenue Increase Proposed [2]	Stand-Alone Increase / (Decrease) Dollars	Stand-Alone Increase / (Decrease) Percent	Consolidate Revenue Increase Proposed [3]	Consolidate Increase / (Decrease) Dollars	Consolidate Increase / (Decrease) Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
	Core Natural Gas Service for Motor Vehicles	GN-50								
26	Basic Service Charge		$ 600	$ 600	$ 0	0.00%	$ 600	$ 0	0.00%	26
	Commodity									
27	All Usage		$ 49,612	$ 58,234	$ 8,622	17.38%	$ 57,705	$ 8,093	16.31%	27
28	Total Core Natural Gas Service for Motor Vehicles		$ 50,212	$ 58,834	$ 8,622	17.17%	$ 58,305	$ 8,093	16.12%	28
	Core Internal Combustion Engine Gas Service	GN-60								
29	Basic Service Charge		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	29
	Commodity Charge									
30	All Usage		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	30
31	Total Core Internal Combustion Engine Gas Service		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	31
	Core Small Electric Power Generation Gas Service	GN-66								
32	Basic Service Charge		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	32
	Commodity Charge									
33	All Usage		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	33
34	Total Core Small Electric Power Generation Gas Service		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	34
	Noncore General Gas Transportation Service	GN-70								
35	Basic Service Charge		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	35
36	Transportation Service Charge		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	36
	Commodity Charge									
37	All Usage		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	37
38	Total Noncore General Gas Transportation Service		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	38
39	Total Full Margin Schedules		$ 42,856,764	$ 42,919,573	$ 62,809	0.15%	$ 45,360,428	$ 2,503,664	5.84%	39
40	Special Contract Gas Service	G-T	$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	40
41	Other Operating Revenues		$ 163,483	$ 163,483	$ 0	0.00%	$ 163,483	$ 0	0.00%	41
42	Total		$ 43,020,247	$ 43,083,056	$ 62,809	0.15%	$ 45,523,911	$ 2,503,664	5.82%	42

[1] Volume II-B, Chapter 20, Sheets 7-8.
[2] Volume II-B, Chapter 20, Sheets 5-6.
[3] Exhibit No._(ABC-2), Sheet 5.

SOUTHWEST GAS CORPORATION
NORTHERN CALIFORNIA RATE JURISDICTION
COMPARISON OF PRESENT AND PROPOSED MARGIN BY CLASS
TEST YEAR TWELVE MONTHS ENDED DECEMBER 31, 2026

				Stand-Alone Margin Increase			Consolidate Margin Increase			
					Increase / (Decrease)			Increase / (Decrease)		
Line No.	Description	Schedule No.	Currently Effective [1]	Proposed [2]	Dollars	Percent	Proposed [3]	Dollars	Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
	Primary Residential Gas Service	GN-10/ GN-12								
1	Basic Service Charge		$ 1,352,009	$ 1,352,009	$ 0	0.00%	$ 1,352,009	$ 0	0.00%	1
	Commodity									
2	Baseline		$ 11,517,343	$ 11,816,492	$ 299,149	2.60%	$ 12,378,438	$ 861,095	7.48%	2
3	Tier II		$ 6,180,309	$ 5,914,790	$ (265,519)	(4.30%)	$ 6,153,471	$ (26,838)	(0.43%)	3
4	Total Primary Residential Gas Service		$ 19,049,661	$ 19,083,291	$ 33,630	0.18%	$ 19,883,918	$ 834,257	4.38%	4
	Secondary Residential Gas Service	GN-15								
5	Basic Service Charge		$ 577,950	$ 577,950	$ 0	0.00%	$ 577,950	$ 0	0.00%	5
	Commodity Charge									
6	All Usage		$ 7,867,003	$ 7,880,592	$ 13,589	0.17%	$ 8,669,852	$ 802,849	10.21%	6
7	Total Secondary Residential Gas Service		$ 8,444,953	$ 8,458,542	$ 13,589	0.16%	$ 9,247,802	$ 802,849	9.51%	7
8	Total Residential Gas Service		$ 27,494,614	$ 27,541,833	$ 47,219	0.17%	$ 29,131,720	$ 1,637,106	5.95%	8
	Multi-Family Master Metered Gas Service	GN-20								
9	Basic Service Charge		$ 600	$ 600	$ 0	0.00%	$ 600	$ 0	0.00%	9
	Commodity									
10	Baseline		$ 12,173	$ 12,189	$ 16	0.13%	$ 12,769	$ 596	4.90%	10
11	Tier II		$ 175	$ 181	$ 6	3.43%	$ 189	$ 14	8.00%	11
12	Total Multi-Family Master Metered Gas Service		$ 12,948	$ 12,970	$ 22	0.17%	$ 13,558	$ 610	4.71%	12
	Multi-Family Master Metered Gas Service - Submetered	GN-25								
13	Basic Service Charge		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	13
14	Submeter Discount		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	14
	Commodity									
15	Baseline		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	15
16	Tier II		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	16
17	Total Multi-Family Submetered		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	17
18	Total Multi-Family Master Metered & Submetered		$ 12,948	$ 12,970	$ 22	0.17%	$ 13,558	$ 610	4.71%	18
	Core General Gas Service	GN-35/ GN-40								
19	Basic Service Charge		$ 213,862	$ 213,862	$ 0	0.00%	$ 213,862	$ 0	0.00%	19
20	Transportation Service Charge		$ 9,360	$ 9,360	$ 0	0.00%	$ 9,360	$ 0	0.00%	20
	Commodity Charge									
21	First 100		$ 1,010,185	$ 1,012,259	$ 2,074	0.21%	$ 1,316,240	$ 306,055	30.30%	21
22	Next 500		$ 1,324,796	$ 1,327,516	$ 2,720	0.21%	$ 1,679,006	$ 354,210	26.74%	22
23	Next 2400		$ 779,422	$ 781,022	$ 1,600	0.21%	$ 909,260	$ 129,838	16.66%	23
24	Over 3000		$ 269,402	$ 269,954	$ 552	0.20%	$ 337,154	$ 67,752	25.15%	24
25	Total Core General Gas Service		$ 3,607,027	$ 3,613,973	$ 6,946	0.19%	$ 4,464,882	$ 857,855	23.78%	25

SOUTHWEST GAS CORPORATION
NORTHERN CALIFORNIA RATE JURISDICTION
COMPARISON OF PRESENT AND PROPOSED MARGIN BY CLASS
TEST YEAR TWELVE MONTHS ENDED DECEMBER 31, 2026

Line No.	Description	Schedule No.	Currently Effective [1]	Stand-Alone Margin Increase: Proposed [2]	Stand-Alone Increase / (Decrease): Dollars	Stand-Alone Increase / (Decrease): Percent	Consolidate Margin Increase: Proposed [3]	Consolidate Increase / (Decrease): Dollars	Consolidate Increase / (Decrease): Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
	Core Natural Gas Service for Motor Vehicles	GN-50								
26	Basic Service Charge		$ 600	$ 600	$ 0	0.00%	$ 600	$ 0	0.00%	26
	Commodity									
27	All Usage		$ (2,980)	$ 5,642	$ 8,622	(289.33%)	$ 5,113	$ 8,093	(271.58%)	27
28	Total Core Natural Gas Service for Motor Vehicles		$ (2,380)	$ 6,242	$ 8,622	(362.27%)	$ 5,713	$ 8,093	(340.04%)	28
	Core Internal Combustion Engine Gas Service	GN-60								
29	Basic Service Charge		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	29
	Commodity Charge									
30	All Usage		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	30
31	Total Core Internal Combustion Engine Gas Service		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	31
	Core Small Electric Power Generation Gas Service	GN-66								
32	Basic Service Charge		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	32
	Commodity Charge									
33	All Usage		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	33
34	Total Core Small Electric Power Generation Gas Service		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	34
	Noncore General Gas Transportation Service	GN-70								
35	Basic Service Charge		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	35
36	Transportation Service Charge		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	36
	Commodity Charge									
37	All Usage		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	37
38	Total Noncore General Gas Transportation Service		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	38
39	Total Full Margin Schedules		$ 31,112,209	$ 31,175,018	$ 62,809	0.20%	$ 33,615,873	$ 2,503,664	8.05%	39
40	Special Contract Gas Service	G-T	$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	40
41	Other Operating Revenues		$ 163,483	$ 163,483	$ 0	0.00%	$ 163,483	$ 0	0.00%	41
42	Total		$ 31,275,692	$ 31,338,501	$ 62,809	0.20%	$ 33,779,356	$ 2,503,664	8.01%	42

[1] Volume II-B, Chapter 20, Sheets 7-8.
[2] Volume II-B, Chapter 20, Sheets 5-6.
[3] Exhibit No._(ABC-2), Sheet 5.

SOUTHWEST GAS CORPORATION
SOUTH LAKE TAHOE RATE JURISDICTION
COMPARISON OF PRESENT AND PROPOSED REVENUE BY CLASS
TEST YEAR TWELVE MONTHS ENDED DECEMBER 31, 2026

Line No.	Description	Schedule No.	Currently Effective [1]	Stand-Alone Revenue Increase: Proposed [2]	Stand-Alone Increase / (Decrease): Dollars	Stand-Alone Increase / (Decrease): Percent	Consolidate Revenue Increase: Proposed [3]	Consolidate Increase / (Decrease): Dollars	Consolidate Increase / (Decrease): Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
	Primary Residential Gas Service	SLT-10/ SLT-12								
1	Basic Service Charge		$ 1,060,846	$ 1,060,846	$ 0	0.00%	$ 1,060,846	$ 0	0.00%	1
	Commodity									
2	Baseline		$ 8,628,267	$ 13,065,032	$ 4,436,765	51.42%	$ 12,282,380	$ 3,654,113	42.35%	2
3	Tier II		$ 4,025,034	$ 6,151,334	$ 2,126,300	52.83%	$ 5,829,651	$ 1,804,617	44.83%	3
4	Total Primary Residential Gas Service		$ 13,714,147	$ 20,277,212	$ 6,563,065	47.86%	$ 19,172,877	$ 5,458,730	39.80%	4
	Secondary Residential Gas Service	SLT-15								
5	Basic Service Charge		$ 281,838	$ 281,838	$ 0	0.00%	$ 281,838	$ 0	0.00%	5
	Commodity Charge									
6	All Usage		$ 3,390,532	$ 5,529,936	$ 2,139,404	63.10%	$ 4,939,097	$ 1,548,565	45.67%	6
7	Total Secondary Residential Gas Service		$ 3,672,370	$ 5,811,774	$ 2,139,404	58.26%	$ 5,220,935	$ 1,548,565	42.17%	7
8	Total Residential Gas Service		$ 17,386,517	$ 26,088,986	$ 8,702,469	50.05%	$ 24,393,812	$ 7,007,295	40.30%	8
	Multi-Family Master Metered Gas Service	SLT-20								
9	Basic Service Charge		$ 11,880	$ 27,000	$ 15,120	127.27%	$ 27,000	$ 15,120	127.27%	9
	Commodity									
10	Baseline		$ 335,037	$ 500,215	$ 165,178	49.30%	$ 470,250	$ 135,213	40.36%	10
11	Tier II		$ 32,111	$ 62,059	$ 29,948	93.26%	$ 58,814	$ 26,703	83.16%	11
12	Total Multi-Family Master Metered Gas Service		$ 379,028	$ 589,274	$ 210,246	55.47%	$ 556,064	$ 177,036	46.71%	12
	Multi-Family Master Metered Gas Service - Submetered	SLT-25								
13	Basic Service Charge		$ 924	$ 2,100	$ 1,176	127.27%	$ 2,100	$ 1,176	127.27%	13
14	Submeter Discount		$ (54,741)	$ (115,290)	$ (60,549)	110.61%	$ (90,802)	$ (36,061)	65.88%	14
	Commodity									
15	Baseline		$ 253,194	$ 386,524	$ 133,330	52.66%	$ 363,369	$ 110,175	43.51%	15
16	Tier II		$ 5,151	$ 9,417	$ 4,266	82.82%	$ 8,925	$ 3,774	73.27%	16
17	Total Multi-Family Submetered		$ 204,528	$ 282,751	$ 78,223	38.25%	$ 283,592	$ 79,064	38.66%	17
18	Total Multi-Family Master Metered & Submetered		$ 583,556	$ 872,025	$ 288,469	49.43%	$ 839,656	$ 256,100	43.89%	18
	Core General Gas Service	SLT-35/ SLT-40								
19	Basic Service Charge		$ 171,204	$ 171,204	$ 0	0.00%	$ 171,204	$ 0	0.00%	19
20	Transportation Service Charge		$ 9,360	$ 9,360	$ 0	0.00%	$ 9,360	$ 0	0.00%	20
	Commodity Charge									
21	First 100		$ 997,303	$ 1,688,128	$ 690,825	69.27%	$ 1,425,208	$ 427,905	42.91%	21
22	Next 500		$ 1,755,519	$ 2,442,930	$ 687,411	39.16%	$ 2,145,288	$ 389,769	22.20%	22
23	Next 2400		$ 1,641,647	$ 1,754,209	$ 112,562	6.86%	$ 1,657,652	$ 16,005	0.97%	23
24	Over 3000		$ 1,362,142	$ 1,065,527	$ (296,615)	(21.78%)	$ 1,009,278	$ (352,864)	(25.91%)	24
25	Total Core General Gas Service		$ 5,937,175	$ 7,131,358	$ 1,194,183	20.11%	$ 6,417,990	$ 480,815	8.10%	25

SOUTHWEST GAS CORPORATION
SOUTH LAKE TAHOE RATE JURISDICTION
COMPARISON OF PRESENT AND PROPOSED REVENUE BY CLASS
TEST YEAR TWELVE MONTHS ENDED DECEMBER 31, 2026

Line No.	Description	Schedule No.	Currently Effective [1]	Stand-Alone Revenue Increase Proposed [2]	Stand-Alone Increase / (Decrease) Dollars	Stand-Alone Increase / (Decrease) Percent	Consolidate Revenue Increase Proposed [3]	Consolidate Increase / (Decrease) Dollars	Consolidate Increase / (Decrease) Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
	Core Natural Gas Service for Motor Vehicles	SLT-50								
26	Basic Service Charge		$ 132	$ 132	$ 0	0.00%	$ 300	$ 168	127.27%	26
	Commodity									
27	All Usage		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	27
28	Total Core Natural Gas Service for Motor Vehicles		$ 132	$ 132	$ 0	0.00%	$ 300	$ 168	127.27%	28
	Core Internal Combustion Engine Gas Service	SLT-60								
29	Basic Service Charge		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	29
	Commodity Charge									
30	All Usage		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	30
31	Total Core Internal Combustion Engine Gas Service		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	31
	Core Small Electric Power Generation Gas Service	SLT-66								
32	Basic Service Charge		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	32
	Commodity Charge									
33	All Usage		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	33
34	Total Core Small Electric Power Generation Gas Service		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	34
	Noncore General Gas Transportation Service	SLT-70								
35	Basic Service Charge		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	35
36	Transportation Service Charge		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	36
	Commodity Charge									
37	All Usage		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	37
38	Total Noncore General Gas Transportation Service		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	38
39	Total Full Margin Schedules		$ 23,907,380	$ 34,092,501	$ 10,185,121	42.60%	$ 31,651,758	$ 7,744,378	32.39%	39
40	Special Contract Gas Service	G-T	$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	40
41	Other Operating Revenues		$ 157,612	$ 157,612	$ 0	0.00%	$ 157,612	$ 0	0.00%	41
42	Total		$ 24,064,992	$ 34,250,113	$ 10,185,121	42.32%	$ 31,809,370	$ 7,744,378	32.18%	42

[1] Volume II-C, Chapter 20, Sheets 7-8.
[2] Volume II-C, Chapter 20, Sheets 5-6.
[3] Exhibit No._(ABC-2), Sheet 6.

SOUTHWEST GAS CORPORATION
SOUTH LAKE TAHOE RATE JURISDICTION
COMPARISON OF PRESENT AND PROPOSED MARGIN BY CLASS
TEST YEAR TWELVE MONTHS ENDED DECEMBER 31, 2026

Line No.	Description	Schedule No.	Currently Effective [1]	Stand-Alone Margin Increase: Proposed [2]	Stand-Alone Increase / (Decrease): Dollars	Stand-Alone Increase / (Decrease): Percent	Consolidate Margin Increase: Proposed [3]	Consolidate Increase / (Decrease): Dollars	Consolidate Increase / (Decrease): Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
	Primary Residential Gas Service	SLT-10/ SLT-12								
1	Basic Service Charge		$ 1,060,846	$ 1,060,846	$ 0	0.00%	$ 1,060,846	$ 0	0.00%	1
	Commodity									
2	Baseline		$ 5,344,841	$ 9,822,105	$ 4,477,264	83.77%	$ 9,039,453	$ 3,694,612	69.12%	2
3	Tier II		$ 2,638,381	$ 4,724,181	$ 2,085,800	79.06%	$ 4,402,498	$ 1,764,117	66.86%	3
4	Total Primary Residential Gas Service		$ 9,044,068	$ 15,607,132	$ 6,563,064	72.57%	$ 14,502,797	$ 5,458,729	60.36%	4
	Secondary Residential Gas Service	SLT-15								
5	Basic Service Charge		$ 281,838	$ 281,838	$ 0	0.00%	$ 281,838	$ 0	0.00%	5
	Commodity Charge									
6	All Usage		$ 2,316,030	$ 4,455,434	$ 2,139,404	92.37%	$ 3,864,595	$ 1,548,565	66.86%	6
7	Total Secondary Residential Gas Service		$ 2,597,868	$ 4,737,272	$ 2,139,404	82.35%	$ 4,146,433	$ 1,548,565	59.61%	7
8	Total Residential Gas Service		$ 11,641,936	$ 20,344,404	$ 8,702,468	74.75%	$ 18,649,230	$ 7,007,294	60.19%	8
	Multi-Family Master Metered Gas Service	SLT-20								
9	Basic Service Charge		$ 11,880	$ 27,000	$ 15,120	127.27%	$ 27,000	$ 15,120	127.27%	9
	Commodity									
10	Baseline		$ 207,541	$ 376,054	$ 168,513	81.20%	$ 346,089	$ 138,548	66.76%	10
11	Tier II		$ 21,049	$ 47,661	$ 26,612	126.43%	$ 44,416	$ 23,367	111.01%	11
12	Total Multi-Family Master Metered Gas Service		$ 240,470	$ 450,715	$ 210,245	87.43%	$ 417,505	$ 177,035	73.62%	12
	Multi-Family Master Metered Gas Service - Submetered	SLT-25								
13	Basic Service Charge		$ 924	$ 2,100	$ 1,176	127.27%	$ 2,100	$ 1,176	127.27%	13
14	Submeter Discount		$ (54,741)	$ (115,290)	$ (60,549)	110.61%	$ (90,802)	$ (36,061)	65.88%	14
	Commodity									
15	Baseline		$ 156,843	$ 290,583	$ 133,740	85.27%	$ 267,428	$ 110,585	70.51%	15
16	Tier II		$ 3,376	$ 7,232	$ 3,856	114.22%	$ 6,740	$ 3,364	99.64%	16
17	Total Multi-Family Submetered		$ 106,402	$ 184,625	$ 78,223	73.52%	$ 185,466	$ 79,064	74.31%	17
18	Total Multi-Family Master Metered & Submetered		$ 346,872	$ 635,340	$ 288,468	83.16%	$ 602,971	$ 256,099	73.83%	18
	Core General Gas Service	SLT-35/ SLT-40								
19	Basic Service Charge		$ 171,204	$ 171,204	$ 0	0.00%	$ 171,204	$ 0	0.00%	19
20	Transportation Service Charge		$ 9,360	$ 9,360	$ 0	0.00%	$ 9,360	$ 0	0.00%	20
	Commodity Charge									
21	First 100		$ 625,396	$ 1,316,221	$ 690,825	110.46%	$ 1,053,301	$ 427,905	68.42%	21
22	Next 500		$ 1,038,733	$ 1,726,144	$ 687,411	66.18%	$ 1,428,502	$ 389,769	37.52%	22
23	Next 2400		$ 902,987	$ 1,015,549	$ 112,562	12.47%	$ 918,992	$ 16,005	1.77%	23
24	Over 3000		$ 647,633	$ 351,018	$ (296,615)	(45.80%)	$ 294,769	$ (352,864)	(54.49%)	24
25	Total Core General Gas Service		$ 3,395,313	$ 4,589,496	$ 1,194,183	35.17%	$ 3,876,128	$ 480,815	14.16%	25

SOUTHWEST GAS CORPORATION
SOUTH LAKE TAHOE RATE JURISDICTION
COMPARISON OF PRESENT AND PROPOSED MARGIN BY CLASS
TEST YEAR TWELVE MONTHS ENDED DECEMBER 31, 2026

				Stand-Alone Margin Increase			Consolidate Margin Increase			
					Increase / (Decrease)			Increase / (Decrease)		
Line No.	Description	Schedule No.	Currently Effective [1]	Proposed [2]	Dollars	Percent	Proposed [3]	Dollars	Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
	Core Natural Gas Service for Motor Vehicles	SLT-50								
26	Basic Service Charge		$ 132	$ 132	$ 0	0.00%	$ 300	$ 168	127.27%	26
	Commodity									
27	All Usage		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	27
28	Total Core Natural Gas Service for Motor Vehicles		$ 132	$ 132	$ 0	0.00%	$ 300	$ 168	127.27%	28
	Core Internal Combustion Engine Gas Service	SLT-60								
29	Basic Service Charge		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	29
	Commodity Charge									
30	All Usage		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	30
31	Total Core Internal Combustion Engine Gas Service		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	31
	Core Small Electric Power Generation Gas Service	SLT-66								
32	Basic Service Charge		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	32
	Commodity Charge									
33	All Usage		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	33
34	Total Core Small Electric Power Generation Gas Service		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	34
	Noncore General Gas Transportation Service	SLT-70								
35	Basic Service Charge		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	35
36	Transportation Service Charge		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	36
	Commodity Charge									
37	All Usage		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	37
38	Total Noncore General Gas Transportation Service		$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	38
39	Total Full Margin Schedules		$ 15,384,253	$ 25,569,372	$ 10,185,119	66.20%	$ 23,128,629	$ 7,744,376	50.34%	39
40	Special Contract Gas Service	G-T	$ 0	$ 0	$ 0	0.00%	$ 0	$ 0	0.00%	40
41	Other Operating Revenues		$ 157,612	$ 157,612	$ 0	0.00%	$ 157,612	$ 0	0.00%	41
42	Total		$ 15,541,865	$ 25,726,984	$ 10,185,119	65.53%	$ 23,286,241	$ 7,744,376	49.83%	42

[1] Volume II-C, Chapter 20, Sheets 7-8.
[2] Volume II-C, Chapter 20, Sheets 5-6.
[3] Exhibit No._(ABC-2), Sheet 6.

SOUTHWEST GAS CORPORATION
NORTHERN CALIFORNIA RATE JURISDICTION
CALCULATION OF REVENUES BY CLASS AT PROPOSED RATES
TEST YEAR TWELVE MONTHS ENDED DECEMBER 31, 2026

Line No.	Description	Schedule No.	Forecasted Billing Units: Number of Bills	Volumes: Transport	Volumes: Sales	Authorized Margin: Rates	Authorized Margin: Revenues	Upstream Charges: Rates	Upstream Charges: Revenues	Gas Cost: Rates	Gas Cost: Revenues	Total Annual Revenues	Total Present Revenue	Dollars	Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	
	Primary Residential Gas Service	GN-10 /														
1	Basic Service Charge	GN-12	235,132			$ 5.75	$ 1,352,009					$ 1,352,009	$ 1,352,009	$ 0		1
	Commodity Charge															
2	Baseline Quantities			11,042,636	11,042,636	$ 1.12097	$ 12,378,438	$ 0.20210	$ 2,231,717	$ 0.20005	$ 2,209,079	$ 16,819,234	$ 15,853,057	$ 966,177		2
3	Tier II			4,960,246	4,960,246	$ 1.24056	$ 6,153,471	$ 0.20210	$ 1,002,466	$ 0.20005	$ 992,297	$ 8,148,234	$ 8,280,153	$ (131,919)		3
4	Total Primary Residential Gas Service		235,132	16,002,882	16,002,882		$ 19,883,918		$ 3,234,183		$ 3,201,376	$ 26,319,477	$ 25,485,219	$ 834,258	3.27%	4
	Secondary Residential Gas Service	GN-15														
5	Basic Service Charge		96,325			$ 6.00	$ 577,950					$ 577,950	$ 577,950	$ 0		5
	Commodity Charge															
6	All Usage			5,994,139	5,994,139	$ 1.44639	$ 8,669,852	$ 0.20210	$ 1,211,415	$ 0.20005	$ 1,199,128	$ 11,080,395	$ 10,277,546	$ 802,849		6
7	Total Secondary Residential Gas Service		96,325	5,994,139	5,994,139		$ 9,247,802		$ 1,211,415		$ 1,199,128	$ 11,658,345	$ 10,855,496	$ 802,849	7.40%	7
8	Total Residential Gas Service		331,457	21,997,021	21,997,021		$ 29,131,720		$ 4,445,598		$ 4,400,504	$ 37,977,822	$ 36,340,715	$ 1,637,107	4.50%	8
	Multi-Family Master Metered Gas Service	GN-20														
9	Basic Service Charge		24			$ 25.00	$ 600					$ 600	$ 600	$ 0		9
	Commodity Charge															
10	Baseline Quantities			11,391	11,391	$ 1.12097	$ 12,769	$ 0.20210	$ 2,302	$ 0.20005	$ 2,279	$ 17,350	$ 16,756	$ 594		10
11	Tier II			152	152	$ 1.24056	$ 189	$ 0.20210	$ 31	$ 0.20005	$ 30	$ 250	$ 235	$ 15		11
12	Total Multi-Family Master Metered Gas Service		24	11,543	11,543		$ 13,558		$ 2,333		$ 2,309	$ 18,200	$ 17,591	$ 609	3.46%	12
	Multi-Family Master Metered Gas Service - Submet	GN-25														
13	Basic Service Charge		0			$ 25.00	$ 0					$ 0	$ 0	$ 0		13
14	Submeter Discount		0			$ (17.76)	$ 0					$ 0	$ 0	$ 0		14
	Commodity Charge															
15	Baseline Quantities			0	0	$ 1.12097	$ 0	$ 0.20210	$ 0	$ 0.20005	$ 0	$ 0	$ 0	$ 0		15
16	Tier II			0	0	$ 1.24056	$ 0	$ 0.20210	$ 0	$ 0.20005	$ 0	$ 0	$ 0	$ 0		16
17	Total Muti- Fam Sub		0	0	0		$ 0		$ 0		$ 0	$ 0	$ 0	$ 0	0.00%	17
18	Total Multi-Family Master Metered Gas Service		24	11,543	11,543		$ 13,558		$ 2,333		$ 2,309	$ 18,200	$ 17,591	$ 609	3.46%	18
	Core General Gas Service	GN-35 /														
19	Basic Service Charge	GN-40	19,442			$ 11.00	$ 213,862					$ 213,862	$ 213,862	$ 0		19
20	Transportation Service Charge		12			$ 780.00	$ 9,360					$ 9,360	$ 9,360	$ 0		20
	Commodity Charge															
21	First 100			1,156,402	1,155,202	$ 1.13822	$ 1,316,240	$ 0.20210	$ 233,709	$ 0.20005	$ 231,098	$ 1,781,047	$ 1,474,992	$ 306,055		21
22	Next 500			2,098,453	2,092,453	$ 0.80012	$ 1,679,006	$ 0.20210	$ 424,097	$ 0.20005	$ 418,595	$ 2,521,698	$ 2,167,488	$ 354,210		22
23	Next 2400			1,831,502	1,802,702	$ 0.49646	$ 909,260	$ 0.20210	$ 370,147	$ 0.20005	$ 360,631	$ 1,640,038	$ 1,510,200	$ 129,838		23
24	Over 3000			2,271,690	1,718,734	$ 0.14842	$ 337,154	$ 0.20210	$ 459,109	$ 0.20005	$ 343,833	$ 1,140,096	$ 1,072,344	$ 67,752		24
25	Total Core General Gas Service		19,442	7,358,047	6,769,091		$ 4,464,882		$ 1,487,062		$ 1,354,157	$ 7,306,101	$ 6,448,246	$ 857,855	13.30%	25
	Core Natural Gas Service for Motor Vehicles	GN-50														
26	Basic Service Charge		24			$ 25.00	$ 600					$ 600	$ 600	$ 0		26
	Commodity Charge															
27	All Usage			130,778	130,778	$ 0.03910	$ 5,113	$ 0.20210	$ 26,430	$ 0.20005	$ 26,162	$ 57,705	$ 49,612	$ 8,093	16.31%	27
28	Total Core Natural Gas Service for Motor Vehicles		24	130,778	130,778		$ 5,713		$ 26,430		$ 26,162	$ 58,305	$ 50,212	$ 8,093		28

SOUTHWEST GAS CORPORATION
NORTHERN CALIFORNIA RATE JURISDICTION
CALCULATION OF REVENUES BY CLASS AT PROPOSED RATES
TEST YEAR TWELVE MONTHS ENDED DECEMBER 31, 2026

Line No.	Description	Schedule No.	Forecasted Billing Units: Number of Bills	Volumes: Transport	Volumes: Sales	Authorized Margin: Rates	Authorized Margin: Revenues	Upstream Charges: Rates	Upstream Charges: Revenues	Gas Cost: Rates	Gas Cost: Revenues	Total Annual Revenues	Total Present Revenue	Dollars	Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	
	Core Internal Combustion Engine Gas Service	GN-60														
29	Basic Service Charge		0			$ 25.00	$ 0					$ 0	$ 0	$ 0		29
	Commodity Charge															
30	All Usage			0	0	$ 0.47087	$ 0	$ 0.20210	$ 0	$ 0.20005	$ 0	$ 0	$ 0	$ 0		30
31	Total Core Internal Combustion Engine Gas Service		0	0	0		$ 0		$ 0		$ 0	$ 0	$ 0	$ 0	0.00%	31
	Core Small Electric Power Generation Gas Service	GN-66														
32	Basic Service Charge		0			$ 25.00	$ 0					$ 0	$ 0	$ 0		32
	Commodity Charge															
33	All Usage			0	0	$ 0.47087	$ 0	$ 0.20210	$ 0	$ 0.20005	$ 0	$ 0	$ 0	$ 0		33
34	Total Core Small Electric Power Generation Gas Service		0	0	0		$ 0		$ 0		$ 0	$ 0	$ 0	$ 0	0.00%	34
	Noncore General Gas Transportation Service	GN-70														
35	Basic Service Charge		0			$ 100.00	$ 0					$ 0	$ 0	$ 0		35
36	Transportation Service Charge		0			$ 780.00	$ 0					$ 0	$ 0	$ 0		36
	Commodity Charge															
37	All Usage			0	0	$ 0.14842	$ 0	$ 0.00000	$ 0	$ 0.00000	$ 0	$ 0	$ 0	$ 0		37
38	Total Noncore General Gas Transportation Service		0	0	0		$ 0		$ 0		$ 0	$ 0	$ 0	$ 0	0.00%	38
39	Total All Schedules		350,947	29,497,389	28,908,433		$ 33,615,873		$ 5,961,423		$ 4,428,975	$ 45,360,428	$ 42,856,764	$ 2,503,664	5.84%	39
40	Special Contract Gas Service	G-T					$ 0					$ 0	$ 0	$ 0	0.00%	40
41	Other Operating Revenues						$ 163,483					$ 163,483	$ 163,483	$ 0	0.00%	41
42	Total Operating Revenue						$ 33,779,356					$ 45,523,911	$ 43,020,247	$ 2,503,664	5.82%	42
43	Total Revenue Requirement						$ 31,338,501									43
44	Over/Under Recovery						$ 2,440,854									44

SOUTHWEST GAS CORPORATION
PROPOSED NORTHERN CALIFORNIA AND SOUTH LAKE TAHOE RATE JURISDICTION
CALCULATION OF REVENUES BY CLASS AT PROPOSED RATES
TEST YEAR TWELVE MONTHS ENDED DECEMBER 31, 2026

Line No.	Description	Schedule No.	Forecasted Billing Units: Number of Bills	Volumes: Transport	Volumes: Sales	Authorized Margin: Rates	Authorized Margin: Revenues	Upstream Charges: Rates	Upstream Charges: Revenues	Gas Cost: Rates	Gas Cost: Revenues	Total Annual Revenues	Total Present Revenue	Dollars	Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	
	Primary Residential Gas Service	GN-10/ GN-12														
1	Basic Service Charge		419,627			$ 5.75	$ 2,412,855					$ 2,412,855	$ 2,412,855	$ 0		1
	Commodity Charge															
2	Baseline Quantities			19,106,610	19,106,610	$ 1.12097	$ 21,417,891	$ 0.20210	$ 3,861,446	$ 0.20005	$ 3,822,277	$ 29,101,614	$ 24,481,324	$ 4,620,290		2
3	Tier II			8,509,052	8,509,052	$ 1.24056	$ 10,555,969	$ 0.20210	$ 1,719,679	$ 0.20005	$ 1,702,236	$ 13,977,884	$ 12,305,187	$ 1,672,697		3
4	Total Primary Residential Gas Service		419,627	27,615,662	27,615,662		$ 34,386,715		$ 5,581,125		$ 5,524,513	$ 45,492,353	$ 39,199,366	$ 6,292,987	16.05%	4
	Secondary Residential Gas Service	GN-15														
5	Basic Service Charge		143,298			$ 6.00	$ 859,788					$ 859,788	$ 859,788	$ 0		5
	Commodity Charge															
6	All Usage			8,666,032	8,666,032	$ 1.44639	$ 12,534,447	$ 0.20210	$ 1,751,405	$ 0.20005	$ 1,733,640	$ 16,019,492	$ 13,668,078	$ 2,351,414		6
7	Total Secondary Residential Gas Service		143,298	8,666,032	8,666,032		$ 13,394,235		$ 1,751,405		$ 1,733,640	$ 16,879,280	$ 14,527,866	$ 2,351,414	16.19%	7
8	Total Residential Gas Service		562,925	36,281,694	36,281,694		$ 47,780,950		$ 7,332,530		$ 7,258,153	$ 62,371,633	$ 53,727,232	$ 8,644,401	16.09%	8
	Multi-Family Master Metered Gas Service	GN-20														
9	Basic Service Charge		1,104			$ 25.00	$ 27,600					$ 27,600	$ 12,480	$ 15,120		9
	Commodity Charge															
10	Baseline Quantities			320,132	320,132	$ 1.12097	$ 358,858	$ 0.20210	$ 64,699	$ 0.20005	$ 64,042	$ 487,599	$ 351,793	$ 135,806		10
11	Tier II			35,955	35,955	$ 1.24056	$ 44,604	$ 0.20210	$ 7,267	$ 0.20005	$ 7,193	$ 59,064	$ 32,346	$ 26,718		11
12	Total Multi-Family Master Metered Gas Service		1,104	356,087	356,087		$ 431,062		$ 71,966		$ 71,235	$ 574,263	$ 396,619	$ 177,644	44.79%	12
	Multi-Family Master Metered Gas Service - Submete	GN-25														
13	Basic Service Charge		84			$ 25.00	$ 2,100					$ 2,100	$ 924	$ 1,176		13
14	Submeter Discount		5,112			$ (17.76)	$ (90,802)					$ (90,802)	$ (54,741)	$ (36,061)		14
	Commodity Charge															
15	Baseline Quantities			238,569	238,569	$ 1.12097	$ 267,428	$ 0.20210	$ 48,215	$ 0.20005	$ 47,726	$ 363,369	$ 253,194	$ 110,175		15
16	Tier II			5,433	5,433	$ 1.24056	$ 6,740	$ 0.20210	$ 1,098	$ 0.20005	$ 1,087	$ 8,925	$ 5,151	$ 3,774		16
17	Total Muti- Fam Sub		84	244,002	244,002		$ 185,466		$ 49,313		$ 48,813	$ 283,592	$ 204,528	$ 79,064	38.66%	17
18	Total Multi-Family Master Metered Gas Service		1,188	600,089	600,089		$ 616,528		$ 121,279		$ 120,048	$ 857,855	$ 601,147	$ 256,708	42.70%	18
	Core General Gas Service	GN-35/ GN-40														
19	Basic Service Charge		35,006			$ 11.00	$ 385,066					$ 385,066	$ 385,066	$ 0		19
20	Transportation Service Charge		24			$ 780.00	$ 18,720					$ 18,720	$ 18,720	$ 0		20
	Commodity Charge															
21	First 100			2,081,795	2,079,395	$ 1.13822	$ 2,369,541	$ 0.20210	$ 420,731	$ 0.20005	$ 415,983	$ 3,206,255	$ 2,472,295	$ 733,960		21
22	Next 500			3,883,821	3,871,821	$ 0.80012	$ 3,107,508	$ 0.20210	$ 784,920	$ 0.20005	$ 774,558	$ 4,666,986	$ 3,923,007	$ 743,979		22
23	Next 2400			3,682,606	3,625,006	$ 0.49646	$ 1,828,251	$ 0.20210	$ 744,255	$ 0.20005	$ 725,182	$ 3,297,688	$ 3,151,847	$ 145,841		23
24	Over 3000			4,257,795	3,283,926	$ 0.14842	$ 631,923	$ 0.20210	$ 860,500	$ 0.20005	$ 656,949	$ 2,149,372	$ 2,434,486	$ (285,114)		24
25	Total Core General Gas Service		35,006	13,906,017	12,860,148		$ 8,341,009		$ 2,810,406		$ 2,572,672	$ 13,724,087	$ 12,385,421	$ 1,338,666	10.81%	25

SOUTHWEST GAS CORPORATION
PROPOSED NORTHERN CALIFORNIA AND SOUTH LAKE TAHOE RATE JURISDICTION
CALCULATION OF REVENUES BY CLASS AT PROPOSED RATES
TEST YEAR TWELVE MONTHS ENDED DECEMBER 31, 2026

Line No.	Description	Schedule No.	Forecasted Billing Units: Number of Bills	Volumes: Transport	Volumes: Sales	Authorized Margin: Rates	Authorized Margin: Revenues	Upstream Charges: Rates	Upstream Charges: Revenues	Gas Cost: Rates	Gas Cost: Revenues	Total Annual Revenues	Total Present Revenue	Dollars	Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	
	Core Natural Gas Service for Motor Vehicles	GN-50														
26	Basic Service Charge		36			$ 25.00	$ 900					$ 900	$ 732	$ 168		26
	Commodity Charge															
27	All Usage			130,778	130,778	$ 0.03910	$ 5,113	$ 0.20210	$ 26,430	$ 0.20005	$ 26,162	$ 57,705	$ 49,612	$ 8,093	16.31%	27
28	Total Core Natural Gas Service for Motor Vehicles		36	130,778	130,778		$ 6,013		$ 26,430		$ 26,162	$ 58,605	$ 50,344	$ 8,261		28
	Core Internal Combustion Engine Gas Service	GN-60														
29	Basic Service Charge		0			$ 25.00	$ 0					$ 0	$ 0	$ 0		29
	Commodity Charge															
30	All Usage			0	0	$ 0.47087	$ 0	$ 0.20210	$ 0	$ 0.20005	$ 0	$ 0	$ 0	$ 0		30
31	Total Core Internal Combustion Engine Gas Service		0	0	0		$ 0		$ 0		$ 0	$ 0	$ 0	$ 0	0.00%	31
	Core Small Electric Power Generation Gas Service	GN-66														
32	Basic Service Charge		0			$ 25.00	$ 0					$ 0	$ 0	$ 0		32
	Commodity Charge															
33	All Usage			0	0	$ 0.47087	$ 0	$ 0.20210	$ 0	$ 0.20005	$ 0	$ 0	$ 0	$ 0		33
34	Total Core Small Electric Power Generation Gas Service		0	0	0		$ 0		$ 0		$ 0	$ 0	$ 0	$ 0	0.00%	34
	Noncore General Gas Transportation Service	GN-70														
35	Basic Service Charge		0			$ 100.00	$ 0					$ 0	$ 0	$ 0		35
36	Transportation Service Charge		0			$ 780.00	$ 0					$ 0	$ 0	$ 0		36
	Commodity Charge															
37	All Usage			0	0	$ 0.14842	$ 0	$ 0.00000	$ 0	$ 0.00000	$ 0	$ 0	$ 0	$ 0		37
38	Total Noncore General Gas Transportation Service		0	0	0		$ 0		$ 0		$ 0	$ 0	$ 0	$ 0	0.00%	38
39	Total All Schedules		599,155	50,918,578	49,872,709		$ 56,744,500		$ 10,290,645		$ 7,404,363	$ 77,012,180	$ 66,764,144	$ 10,248,036	15.35%	39
40	Special Contract Gas Service	G-T					$ 0					$ 0	$ 0	$ 0	0.00%	40
41	Other Operating Revenues						$ 321,095					$ 321,095	$ 321,095	$ 0	0.00%	41
42	Total Operating Revenue						$ 57,065,595					$ 77,333,275	$ 67,085,239	$ 10,248,036	15.28%	42
43	Total Revenue Requirement						$ 57,065,595									43
44	Over/Under Recovery						$ (0)									44

SOUTHWEST GAS CORPORATION
PROPOSED NORTHERN CALIFORNIA AND SOUTH LAKE TAHOE RATE JURISDICTION
CALCULATION OF REVENUES BY CLASS AT PROPOSED RATES
TEST YEAR TWELVE MONTHS ENDED DECEMBER 31, 2026

Line No.	Description	Schedule No.	Forecasted Billing Units: Number of Bills	Volumes: Transport	Volumes: Sales	Authorized Margin: Rates	Authorized Margin: Revenues	Upstream Charges: Rates	Upstream Charges: Revenues	Gas Cost: Rates	Gas Cost: Revenues	Total Annual Revenues	Total Present Revenue	Dollars	Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	
	Primary Residential Gas Service	GN-10/ GN-12														
1	Basic Service Charge		419,627			$ 5.75	$ 2,412,855					$ 2,412,855	$ 2,412,855	$ 0		1
	Commodity Charge															
2	Baseline Quantities			19,106,610	19,106,610	$ 1.12097	$ 21,417,891	$ 0.20210	$ 3,861,446	$ 0.20005	$ 3,822,277	$ 29,101,614	$ 24,481,324	$ 4,620,290		2
3	Tier II			8,509,052	8,509,052	$ 1.24056	$ 10,555,969	$ 0.20210	$ 1,719,679	$ 0.20005	$ 1,702,236	$ 13,977,884	$ 12,305,187	$ 1,672,697		3
4	Total Primary Residential Gas Service		419,627	27,615,662	27,615,662		$ 34,386,715		$ 5,581,125		$ 5,524,513	$ 45,492,353	$ 39,199,366	$ 6,292,987	16.05%	4
	Secondary Residential Gas Service	GN-15														
5	Basic Service Charge		143,298			$ 6.00	$ 859,788					$ 859,788	$ 859,788	$ 0		5
	Commodity Charge															
6	All Usage			8,666,032	8,666,032	$ 1.44639	$ 12,534,447	$ 0.20210	$ 1,751,405	$ 0.20005	$ 1,733,640	$ 16,019,492	$ 13,668,078	$ 2,351,414		6
7	Total Secondary Residential Gas Service		143,298	8,666,032	8,666,032		$ 13,394,235		$ 1,751,405		$ 1,733,640	$ 16,879,280	$ 14,527,866	$ 2,351,414	16.19%	7
8	Total Residential Gas Service		562,925	36,281,694	36,281,694		$ 47,780,950		$ 7,332,530		$ 7,258,153	$ 62,371,633	$ 53,727,232	$ 8,644,401	16.09%	8
	Multi-Family Master Metered Gas Service	GN-20														
9	Basic Service Charge		1,104			$ 25.00	$ 27,600					$ 27,600	$ 12,480	$ 15,120		9
	Commodity Charge															
10	Baseline Quantities			320,132	320,132	$ 1.12097	$ 358,858	$ 0.20210	$ 64,699	$ 0.20005	$ 64,042	$ 487,599	$ 351,793	$ 135,806		10
11	Tier II			35,955	35,955	$ 1.24056	$ 44,604	$ 0.20210	$ 7,267	$ 0.20005	$ 7,193	$ 59,064	$ 32,346	$ 26,718		11
12	Total Multi-Family Master Metered Gas Service		1,104	356,087	356,087		$ 431,062		$ 71,966		$ 71,235	$ 574,263	$ 396,619	$ 177,644	44.79%	12
	Multi-Family Master Metered Gas Service - Submete	GN-25														
13	Basic Service Charge		84			$ 25.00	$ 2,100					$ 2,100	$ 924	$ 1,176		13
14	Submeter Discount		5,112			$ (17.76)	$ (90,802)					$ (90,802)	$ (54,741)	$ (36,061)		14
	Commodity Charge															
15	Baseline Quantities			238,569	238,569	$ 1.12097	$ 267,428	$ 0.20210	$ 48,215	$ 0.20005	$ 47,726	$ 363,369	$ 253,194	$ 110,175		15
16	Tier II			5,433	5,433	$ 1.24056	$ 6,740	$ 0.20210	$ 1,098	$ 0.20005	$ 1,087	$ 8,925	$ 5,151	$ 3,774		16
17	Total Muti- Fam Sub		84	244,002	244,002		$ 185,466		$ 49,313		$ 48,813	$ 283,592	$ 204,528	$ 79,064	38.66%	17
18	Total Multi-Family Master Metered Gas Service		1,188	600,089	600,089		$ 616,528		$ 121,279		$ 120,048	$ 857,855	$ 601,147	$ 256,708	42.70%	18
	Core General Gas Service	GN-35/ GN-40														
19	Basic Service Charge		35,006			$ 11.00	$ 385,066					$ 385,066	$ 385,066	$ 0		19
20	Transportation Service Charge		24			$ 780.00	$ 18,720					$ 18,720	$ 18,720	$ 0		20
	Commodity Charge															
21	First 100			2,081,795	2,079,395	$ 1.13822	$ 2,369,541	$ 0.20210	$ 420,731	$ 0.20005	$ 415,983	$ 3,206,255	$ 2,472,295	$ 733,960		21
22	Next 500			3,883,821	3,871,821	$ 0.80012	$ 3,107,508	$ 0.20210	$ 784,920	$ 0.20005	$ 774,558	$ 4,666,986	$ 3,923,007	$ 743,979		22
23	Next 2400			3,682,606	3,625,006	$ 0.49646	$ 1,828,251	$ 0.20210	$ 744,255	$ 0.20005	$ 725,182	$ 3,297,688	$ 3,151,847	$ 145,841		23
24	Over 3000			4,257,795	3,283,926	$ 0.14842	$ 631,923	$ 0.20210	$ 860,500	$ 0.20005	$ 656,949	$ 2,149,372	$ 2,434,486	$ (285,114)		24
25	Total Core General Gas Service		35,006	13,906,017	12,860,148		$ 8,341,009		$ 2,810,406		$ 2,572,672	$ 13,724,087	$ 12,385,421	$ 1,338,666	10.81%	25

SOUTHWEST GAS CORPORATION
PROPOSED NORTHERN CALIFORNIA AND SOUTH LAKE TAHOE RATE JURISDICTION
CALCULATION OF REVENUES BY CLASS AT PROPOSED RATES
TEST YEAR TWELVE MONTHS ENDED DECEMBER 31, 2026

Line No.	Description	Schedule No.	Forecasted Billing Units: Number of Bills	Volumes: Transport	Volumes: Sales	Authorized Margin: Rates	Authorized Margin: Revenues	Upstream Charges: Rates	Upstream Charges: Revenues	Gas Cost: Rates	Gas Cost: Revenues	Total Annual Revenues	Total Present Revenue	Dollars	Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	
	Core Natural Gas Service for Motor Vehicles	GN-50														
26	Basic Service Charge		36			$ 25.00	$ 900					$ 900	$ 732	$ 168		26
	Commodity Charge															
27	All Usage			130,778	130,778	$ 0.03910	$ 5,113	$ 0.20210	$ 26,430	$ 0.20005	$ 26,162	$ 57,705	$ 49,612	$ 8,093	16.31%	27
28	Total Core Natural Gas Service for Motor Vehicles		36	130,778	130,778		$ 6,013		$ 26,430		$ 26,162	$ 58,605	$ 50,344	$ 8,261		28
	Core Internal Combustion Engine Gas Service	GN-60														
29	Basic Service Charge		0			$ 25.00	$ 0					$ 0	$ 0	$ 0		29
	Commodity Charge															
30	All Usage			0	0	$ 0.47087	$ 0	$ 0.20210	$ 0	$ 0.20005	$ 0	$ 0	$ 0	$ 0		30
31	Total Core Internal Combustion Engine Gas Service		0	0	0		$ 0		$ 0		$ 0	$ 0	$ 0	$ 0	0.00%	31
	Core Small Electric Power Generation Gas Service	GN-66														
32	Basic Service Charge		0			$ 25.00	$ 0					$ 0	$ 0	$ 0		32
	Commodity Charge															
33	All Usage			0	0	$ 0.47087	$ 0	$ 0.20210	$ 0	$ 0.20005	$ 0	$ 0	$ 0	$ 0		33
34	Total Core Small Electric Power Generation Gas Service		0	0	0		$ 0		$ 0		$ 0	$ 0	$ 0	$ 0	0.00%	34
	Noncore General Gas Transportation Service	GN-70														
35	Basic Service Charge		0			$ 100.00	$ 0					$ 0	$ 0	$ 0		35
36	Transportation Service Charge		0			$ 780.00	$ 0					$ 0	$ 0	$ 0		36
	Commodity Charge															
37	All Usage			0	0	$ 0.14842	$ 0	$ 0.00000	$ 0	$ 0.00000	$ 0	$ 0	$ 0	$ 0		37
38	Total Noncore General Gas Transportation Service		0	0	0		$ 0		$ 0		$ 0	$ 0	$ 0	$ 0	0.00%	38
39	Total All Schedules		599,155	50,918,578	49,872,709		$ 56,744,500		$ 10,290,645		$ 7,404,363	$ 77,012,180	$ 66,764,144	$ 10,248,036	15.35%	39
40	Special Contract Gas Service	G-T					$ 0					$ 0	$ 0	$ 0	0.00%	40
41	Other Operating Revenues						$ 321,095					$ 321,095	$ 321,095	$ 0	0.00%	41
42	Total Operating Revenue						$ 57,065,595					$ 77,333,275	$ 67,085,239	$ 10,248,036	15.28%	42
43	Total Revenue Requirement						$ 57,065,595									43
44	Over/Under Recovery						$ (0)									44

SOUTHWEST GAS CORPORATION
PROPOSED NORTHERN CALIFORNIA AND SOUTH LAKE TAHOE RATE JURISDICTION
PROPORTIONAL COST RESPONSIBILITY METHODOLOGY
TEST YEAR TWELVE MONTHS ENDED DECEMBER 31, 2026

Line No.	Description	Total	Residential	Secondary Residential	Multi- Family	Muti- Fam Sub	Core General	NGV	Gas Engine	Small EG	Noncore	Other Revenue	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
1	Allocated Margin Revenue [1]	$ 57,065,595	$ 35,782,189	$ 13,087,175	$ 184,418	$ 83,169	$ 7,575,861	$ 31,688	$ 0	$ 0	$ 0	$ 321,095	1
2	Margin at Present Rates [2]	$ 46,817,557	$ 28,093,729	$ 11,042,821	$ 253,418	$ 106,402	$ 7,002,340	$ (2,248)	$ 0	$ 0	$ 0	$ 321,095	2
3	Difference (Line 1 - Line 2)	$ 10,248,038											3
4	System Average Percentage Increase (Line 3 / Line 2)	21.89%											4
5	Ratio of Margin at System Return to Margin at Present Rates (Line 1 / Line 2)	1.2189	1.2737	1.1851	0.7277	0.7817	1.0819	(14.0961)	0.0000	0.0000	0.0000	0.0000	5
6	Adjusted Percentage Increase (Line 4 * 2)	26.68%	27.88%	25.94%	15.93%	17.11%	23.68%	43.78%	0.00%	21.89%	0.00%	0.00%	6
7	Adjusted Dollar Increase (Line 2 X Line 6)	$ 12,413,057	$ 7,832,473	$ 2,864,692	$ 40,368	$ 18,205	$ 1,658,303	$ (984)	$ 0	$ 0	$ 0	$ 0	7
8	Adjusted Margin Requirement (Line 2 + Line 7)	$ 59,240,089	$ 35,926,202	$ 13,907,513	$ 293,786	$ 124,607	$ 8,660,643	$ 6,244	$ 0	$ 0	$ 0	$ 321,095	8
9	(Over) / Under Collection (Line 8 - Line 2 ratio per Line 8)	$ (2,174,494)	$ (1,325,911)	$ (513,278)	$ (10,843)	$ (4,599)	$ (319,634)	$ (230)	$ 0	$ 0	$ 0	$ 0	9
10	Margin Requirement (Greater of Line 9 or 10 + Line 11)	$ 57,065,595	$ 34,600,291	$ 13,394,235	$ 282,943	$ 120,008	$ 8,341,009	$ 6,013	$ 0	$ 0	$ 0	$ 321,095	10
11	Margin Allocation	$ 57,065,595	$ 34,600,291	$ 13,394,235	$ 282,943	$ 120,008	$ 8,341,009	$ 6,013	$ 0	$ 0	$ 0	$ 321,095	11
12	Dollar Change From Present Margin	$ 10,248,038	$ 6,506,562	$ 2,351,414	$ 29,525	$ 13,606	$ 1,338,669	$ 8,261	$ 0	$ 0	$ 0	n/a	12
13	Percent Change From Present Margin	21.89%	23.16%	21.29%	11.65%	12.79%	19.12%	(367.49%)	0.00%	0.00%	0.00%		13
14	Rate of Return at Present Rates	4.98%	4.37%	5.36%	13.63%	11.72%	6.78%	(7.46%)	0.00%	0.00%	0.00%	n/a	14
15	Present Rate of Return Indices	1.0	0.9	1.1	2.7	2.4	1.4	(1.5)	0.0	0.0	0.0		15
16	Rate of Return at Proposed Rates	7.84%	7.20%	8.23%	28.30%	24.69%	9.33%	(3.74%)	0.00%	0.00%	0.00%	n/a	16
17	Proposed Rate of Return Indices	1.0	0.9	1.0	3.6	3.1	1.2	(0.5)	0.0	0.0	0.0		17

[1] Exhibit No._(ABC-1), Sheet 3.
[2] Exhibit No._(ABC-2), Sheets 1, 2, 5 and 6.

SOUTHWEST GAS CORPORATION
NORTHERN CALIFORNIA RATE JURISDICTION
TYPICAL MONTHLY BILL COMPARISON - PRIMARY RESIDENTIAL GAS SERVICE
TEST YEAR TWELVE MONTHS ENDED DECEMBER 31, 2026

			Northern California							Truckee							
				Stand-Alone Increase			Consolidate Increase				Stand-Alone Increase			Consolidate Increase			
					Increase / (Decrease)			Increase / (Decrease)				Increase / (Decrease)			Increase / (Decrease)		
Line No.	Monthly Therms		Present Rates [1]	Proposed [1]	Dollars	Percent	Proposed [2]	Dollars	Percent	Present Rates [1]	Proposed [1]	Dollars	Percent	Proposed [2]	Dollars	Percent	Line No.
	(a)		(b)	(c)	(d)	(e)				(f)	(g)	(h)	(i)				
	Winter Comparison																
1	5		$ 13.75	$ 13.43	$ (0.32)	(2.33%)	$ 13.86	$ 0.11	0.77%	$ 13.75	$ 13.43	$ (0.32)	(2.33%)	$ 13.86	$ 0.11	0.77%	1
2	15		$ 29.76	$ 28.80	$ (0.96)	(3.23%)	$ 30.08	$ 0.32	1.07%	$ 29.76	$ 28.80	$ (0.96)	(3.23%)	$ 30.08	$ 0.32	1.07%	2
3	50		$ 85.78	$ 82.58	$ (3.20)	(3.73%)	$ 86.84	$ 1.06	1.24%	$ 85.78	$ 82.58	$ (3.20)	(3.73%)	$ 86.84	$ 1.06	1.24%	3
4	108	[3]	$ 180.24	$ 172.93	$ (7.31)	(4.06%)	$ 182.11	$ 1.86	1.03%	$ 178.63	$ 171.71	$ (6.93)	(3.88%)	$ 180.91	$ 2.28	1.28%	4
5	124	[4]	$ 207.70	$ 199.47	$ (8.23)	(3.96%)	$ 209.97	$ 2.27	1.09%	$ 206.09	$ 198.01	$ (8.08)	(3.92%)	$ 208.54	$ 2.45	1.19%	5
6	150		$ 252.32	$ 242.61	$ (9.71)	(3.85%)	$ 255.25	$ 2.93	1.16%	$ 250.70	$ 241.14	$ (9.57)	(3.82%)	$ 253.81	$ 3.11	1.24%	6
7	200		$ 338.12	$ 325.56	$ (12.56)	(3.72%)	$ 342.32	$ 4.20	1.24%	$ 336.51	$ 324.09	$ (12.42)	(3.69%)	$ 340.89	$ 4.38	1.30%	7
	Winter Off-Peak																
8	10		$ 21.76	$ 21.12	$ (0.64)	(2.94%)	$ 21.97	$ 0.21	0.97%	$ 21.76	$ 21.12	$ (0.64)	(2.94%)	$ 21.97	$ 0.21	0.97%	8
9	20		$ 37.76	$ 36.48	$ (1.28)	(3.39%)	$ 38.19	$ 0.42	1.12%	$ 37.76	$ 36.48	$ (1.28)	(3.39%)	$ 38.19	$ 0.42	1.12%	9
10	45		$ 77.78	$ 74.90	$ (2.88)	(3.71%)	$ 78.73	$ 0.95	1.23%	$ 77.78	$ 74.90	$ (2.88)	(3.71%)	$ 78.73	$ 0.95	1.23%	10
11	66	[4]	$ 111.61	$ 107.17	$ (4.44)	(3.98%)	$ 112.79	$ 1.18	1.06%	$ 111.40	$ 107.17	$ (4.23)	(3.80%)	$ 112.79	$ 1.40	1.25%	11
12	69	[3]	$ 116.76	$ 112.14	$ (4.61)	(3.95%)	$ 118.02	$ 1.26	1.08%	$ 116.55	$ 111.78	$ (4.77)	(4.09%)	$ 117.66	$ 1.11	0.95%	12
13	100		$ 169.95	$ 163.57	$ (6.38)	(3.75%)	$ 172.00	$ 2.05	1.21%	$ 169.74	$ 163.08	$ (6.66)	(3.92%)	$ 171.52	$ 1.78	1.05%	13
14	125		$ 212.85	$ 205.05	$ (7.81)	(3.67%)	$ 215.54	$ 2.69	1.26%	$ 212.64	$ 204.56	$ (8.08)	(3.80%)	$ 215.06	$ 2.42	1.14%	14
	Summer Comparison																
15	5		$ 13.75	$ 13.43	$ (0.32)	(2.33%)	$ 13.86	$ 0.11	0.77%	$ 13.75	$ 13.43	$ (0.32)	(2.33%)	$ 13.86	$ 0.11	0.77%	15
16	15		$ 29.76	$ 28.80	$ (0.96)	(3.23%)	$ 30.08	$ 0.32	1.07%	$ 29.76	$ 28.80	$ (0.96)	(3.23%)	$ 30.08	$ 0.32	1.07%	16
17	24	[4]	$ 44.17	$ 43.12	$ (1.05)	(2.37%)	$ 45.15	$ 0.99	2.24%	$ 44.41	$ 42.63	$ (1.78)	(4.01%)	$ 44.67	$ 0.27	0.60%	17
18	26	[3]	$ 47.37	$ 46.44	$ (0.93)	(1.97%)	$ 48.64	$ 1.27	2.68%	$ 47.84	$ 45.95	$ (1.89)	(3.96%)	$ 48.16	$ 0.32	0.66%	18
19	50		$ 85.78	$ 86.25	$ 0.47	0.55%	$ 90.43	$ 4.65	5.42%	$ 89.03	$ 85.76	$ (3.26)	(3.67%)	$ 89.95	$ 0.93	1.04%	19

Present Rates [1]	
Basic Service Charge	$ 5.75
Charge per Therm	
Baseline Quantities	$ 1.60067
Tier II	$ 1.71602

Proposed Rates [2]	
Basic Service Charge	$ 5.75
Charge per Therm	
Baseline Quantities	$ 1.62187
Tier II	$ 1.74146

Winter Baseline Allowances	Present	Proposed
North Lake Tahoe	94	98
Truckee	108	110

Winter Off-Peak Baseline Allowances	Present	Proposed
North Lake Tahoe	64	66
Truckee	66	70

Summer Baseline Allowances	Present	Proposed
North Lake Tahoe	20	20
Truckee	22	24

[1] Volume II-B, Sheets 12-14.
[2] Exhibit No._(ABC-4), Sheets 2-4.
[3] Average Summer and Winter use for North Lake Tahoe.
[4] Average Summer and Winter use for Truckee.

SOUTHWEST GAS CORPORATION
SOUTH LAKE TAHOE RATE JURISDICTION
TYPICAL MONTHLY BILL COMPARISON - PRIMARY RESIDENTIAL GAS SERVICE
TEST YEAR TWELVE MONTHS ENDED DECEMBER 31, 2026

			Stand-Alone Increase			Consolidate Increase			
				Increase / (Decrease)			Increase / (Decrease)		
Line No.	Monthly Therms	Present Rates [1]	Proposed [1]	Dollars	Percent	Proposed [2]	Dollars	Percent	Line No.
	(a)	(b)	(c)	(d)	(e)				
	Winter Comparison								
1	56	$ 71.29	$ 104.52	$ 33.23	46.60%	$ 96.57	$ 25.28	35.46%	1
2	83	$ 102.90	$ 152.14	$ 49.25	47.86%	$ 140.36	$ 37.47	36.41%	2
3	111 [3]	$ 137.55	$ 203.68	$ 66.13	48.08%	$ 188.05	$ 50.50	36.72%	3
4	167	$ 209.28	$ 308.78	$ 99.50	47.54%	$ 285.57	$ 76.29	36.45%	4
5	222	$ 279.74	$ 412.02	$ 132.28	47.29%	$ 381.35	$ 101.62	36.33%	5
	Winter Off-Peak Comparison								
6	34	$ 45.54	$ 65.72	$ 20.17	44.29%	$ 60.89	$ 15.35	33.70%	6
7	50	$ 64.27	$ 93.94	$ 29.67	46.16%	$ 86.84	$ 22.57	35.12%	7
8	67 [3]	$ 84.72	$ 124.26	$ 39.54	46.68%	$ 114.77	$ 30.06	35.48%	8
9	101	$ 128.27	$ 188.08	$ 59.81	46.63%	$ 173.98	$ 45.71	35.64%	9
10	134	$ 170.54	$ 250.02	$ 79.47	46.60%	$ 231.45	$ 60.91	35.72%	10
	Summer Comparison								
11	12	$ 19.80	$ 26.92	$ 7.12	35.97%	$ 25.21	$ 5.42	27.37%	11
12	18	$ 26.82	$ 37.50	$ 10.68	39.82%	$ 34.94	$ 8.13	30.30%	12
13	24 [3]	$ 34.07	$ 48.53	$ 14.46	42.44%	$ 45.15	$ 11.08	32.52%	13
14	36	$ 49.44	$ 71.06	$ 21.61	43.71%	$ 66.05	$ 16.61	33.59%	14
15	48	$ 64.82	$ 93.58	$ 28.76	44.38%	$ 86.95	$ 22.13	34.15%	15

Present Rates [1]	
Basic Service Charge	$ 5.75
Charge per Therm	
Baseline Quantities	$ 1.17043
Tier II	$ 1.28097

Proposed Rates [2]	
Basic Service Charge	$ 5.75
Charge per Therm	
Baseline Quantities	$ 1.62187
Tier II	$ 1.74146

Winter Baseline Allowances		
	Present	Proposed
SLT	94	92

Winter Off-Peak Baseline Allowances		
	Present	Proposed
SLT	62	64

Summer Baseline Allowances		
	Present	Proposed
SLT	22	20

[1] Volume II-C, Sheets 12-14.
[2] Exhibit No._(ABC-4), Sheets 2-4.
[3] Average Summer, Winter and Winter Off-Peak Use for South Lake Tahoe.

SOUTHWEST GAS CORPORATION
NORTHERN CALIFORNIA RATE JURISDICTION
TYPICAL MONTHLY BILL COMPARISON - SECONDARY RESIDENTIAL GAS SERVICE
TEST YEAR TWELVE MONTHS ENDED DECEMBER 31, 2026

Line No.	Monthly Therms		Present Rates [1]	Proposed Rates [2]	Increase / (Decrease) Dollars	Percent	Line No.
	(a)		(b)	(c)	(d)	(e)	
1	10		$ 24.45	$ 25.47	$ 1.02	4.17%	1
2	15		$ 33.67	$ 35.21	$ 1.54	4.57%	2
3	35		$ 70.57	$ 74.16	$ 3.59	5.09%	3
4	62	[3]	$ 120.38	$ 126.73	$ 6.35	5.27%	4
5	100		$ 190.49	$ 200.73	$ 10.24	5.38%	5
6	150		$ 282.73	$ 298.09	$ 15.36	5.43%	6

Present Rates [1]	
Basic Service Charge	$ 6.00
Charge per Therm	
All Usage	$ 1.84485

Proposed Rates [2]	
Basic Service Charge	$ 6.00
Charge per Therm	
All Usage	$ 1.94729

[1] Volume II-B, Sheets 12-14.
[2] Exhibit No._(ABC-4), Sheets 2-4.
[3] Annual average usage.

SOUTHWEST GAS CORPORATION
SOUTH LAKE TAHOE RATE JURISDICTION
TYPICAL MONTHLY BILL COMPARISON - SECONDARY RESIDENTIAL GAS SERVICE
TEST YEAR TWELVE MONTHS ENDED DECEMBER 31, 2026

Line No.	Monthly Therms		Present Rates [1]	Proposed Rates [2]	Increase / (Decrease) Dollars	Percent	Line No.
	(a)		(b)	(c)	(d)	(e)	
1	10		$ 24.45	$ 25.47	$ 1.02	4.17%	1
2	15		$ 33.67	$ 35.21	$ 1.54	4.57%	2
3	40		$ 79.79	$ 83.89	$ 4.10	5.14%	3
4	57	[3]	$ 110.94	$ 116.76	$ 5.82	5.25%	4
5	100		$ 190.49	$ 200.73	$ 10.24	5.38%	5
6	150		$ 282.73	$ 298.09	$ 15.36	5.43%	6

Present Rates [1]	
Basic Service Charge	$ 6.00
Charge per Therm	
All Usage	$ 1.84485

Proposed Rates [2]	
Basic Service Charge	$ 6.00
Charge per Therm	
All Usage	$ 1.94729

[1] Volume II-C, Sheets 12-14.
[2] Exhibit No._(ABC-4), Sheets 2-4.
[3] Annual average usage.

SOUTHWEST GAS CORPORATION
NORTHERN CALIFORNIA RATE JURISDICTION
TYPICAL MONTHLY BILL COMPARISON - CORE GENERAL GAS SERVICE
TEST YEAR TWELVE MONTHS ENDED DECEMBER 31, 2026

Line No.	Monthly Therms		Present Rates [1]	Proposed Rates [2]	Increase/(Decrease) Dollars	Increase/(Decrease) Percent	Line No.
	(a)		(b)	(c)	(d)	(e)	
1	218	[3]	$ 289.00	$ 328.52	$ 39.53	13.68%	1
2	349	[4]	$ 441.40	$ 498.91	$ 57.51	13.03%	2
3	530	[5]	$ 652.33	$ 734.72	$ 82.39	12.63%	3
4	600		$ 733.46	$ 825.42	$ 91.96	12.54%	4
5	1500		$ 1,595.63	$ 1,723.04	$ 127.41	7.99%	5
6	3000		$ 3,032.57	$ 3,219.07	$ 186.50	6.15%	6
7	4000		$ 3,683.57	$ 3,868.38	$ 184.82	5.02%	7

Present Rates [1]		
Basic Service Charge		$ 11.00
Charge per Therm		
First	100	$ 1.40596
Next	500	$ 1.16372
Next	2400	$ 0.95797
Over	3000	$ 0.65099

Proposed Rates [2]		
Basic Service Charge		$ 11.00
Charge per Therm		
First	100	$ 1.63912
Next	500	$ 1.30101
Next	2400	$ 0.99735
Over	3000	$ 0.64931

[1] Volume II-B, Sheets 12-14.
[2] Exhibit No._(ABC-4), Sheets 2-4.
[3] Average summer usage.
[4] Average winter Off-Peak usage.
[5] Average winter usage.

SOUTHWEST GAS CORPORATION
SOUTH LAKE TAHOE RATE JURISDICTION
TYPICAL MONTHLY BILL COMPARISON - CORE GENERAL GAS SERVICE
TEST YEAR TWELVE MONTHS ENDED DECEMBER 31, 2026

Line No.	Monthly Therms		Present Rates [1]	Proposed Rates [2]	Increase/(Decrease) Dollars	Increase/(Decrease) Percent	Line No.
	(a)		(b)	(c)	(d)	(e)	
1	214	[3]	$ 284.66	$ 323.67	$ 39.01	13.71%	1
2	394	[4]	$ 494.22	$ 557.96	$ 63.74	12.90%	2
3	616	[5]	$ 748.70	$ 841.29	$ 92.59	12.37%	3
4	500		$ 617.08	$ 695.32	$ 78.23	12.68%	4
5	1000		$ 1,116.64	$ 1,224.36	$ 107.72	9.65%	5
6	2000		$ 2,074.61	$ 2,221.72	$ 147.11	7.09%	6
7	4000		$ 3,683.57	$ 3,868.38	$ 184.82	5.02%	7

Present Rates [1]

Basic Service Charge		$ 11.00
Charge per Therm		
First	100	$ 1.40596
Next	500	$ 1.16372
Next	2400	$ 0.95797
Over	3000	$ 0.65099

Proposed Rates [2]

Basic Service Charge		$ 11.00
Charge per Therm		
First	100	$ 1.63912
Next	500	$ 1.30101
Next	2400	$ 0.99735
Over	3000	$ 0.64931

[1] Volume II-C, Sheets 12-14.
[2] Exhibit No._(ABC-4), Sheets 2-4.
[3] Average summer usage.
[4] Average winter Off-Peak usage.
[5] Average winter usage.

SOUTHWEST GAS CORPORATION
PROPOSED NORTHERN CALIFORNIA AND SOUTH LAKE TAHOE RATE JURISDICTION
CALCULATION OF MASTER METER WITH SUBMETER DISCOUNT PER SPACE
TEST YEAR TWELVE MONTHS ENDED DECEMBER 31, 2026

Line No.	Description	Account Number	Totals	Line No.
	(a)	(b)	(c)	
	Capital Investment			
1	Distribution Services	380	$ 2,710,359	1
2	Distribution Metering Equipment	381	$ 1,035,362	2
3	Total Capital Investment		$ 3,745,721	3
	Operation and Maintenance Expenses			
4	Meter and House Regulator Expense	878	$ 523,264	4
5	Customer Installation Expenses	879	$ 1,669,913	5
6	Maintenance of Services	892	$ 275,762	6
7	Maintenance of Meters & House Regulators	893	$ 164,056	7
8	Total Operation and Maintenance Expenses		$ 2,632,995	8
	Customer Account Expenses			
9	Supervision of Customer Accounts	901	$ 71,054	9
10	Meter Reading Expense	902	$ 132,225	10
11	Customer Records and Collection Expenses	903	$ 866,465	11
12	Uncollectible Expenses	904	$ 5,169	12
13	Miscellaneous Customer Expenses	905	$ 0	13
14	Total Supervision of Customer Accounts		$ 1,074,912	14
15	Total		$ 7,453,628	15
16	Total Number of Residential Bills		419,627	16
17	Cost-Based Submetered Discount per Month		$ 17.76	17
18	Total Submetered Spaces		426	18
19	Total Cost-Based Submetered Discount		$ 90,802	19

SOUTHWEST GAS CORPORATION
PROPOSED NORTHERN CALIFORNIA AND SOUTH LAKE TAHOE RATE JURISDICTION
CALCULATION OF FRANCHISE AND UNCOLLECTIBLES FACTOR
TEST YEAR TWELVE MONTHS ENDED DECEMBER 31, 2026

Line No.	Description	Percentage	Line No.
	(a)	(b)	
	Percentage Rates		
1	Franchise	1.990%	1
2	Uncollectible	0.213%	2
	Gross Up Factors		
3	Franchises (Line 1 / (1 - Line 2) / (1 - Line 1))	2.035%	3
4	Uncollectibles (Line 2 / (1 - Line 2))	0.213%	4
5	Franchise and Uncollectible	2.248%	5

SOUTHWEST GAS CORPORATION
PROPOSED NORTHERN CALIFORNIA AND SOUTH LAKE TAHOE RATE JURISDICTION
CALCULATION OF POST TEST YEAR MARGIN ADJUSTMENTS
TEST YEAR TWELVE MONTHS ENDED DECEMBER 31, 2026

Line No.	Description	Attrition Percent	Attrition Year 2026	2027	2028	2029	2030	Line No.
	(a)	(b)	(c)	(d)	(e)	(e)	(f)	
1	Prior Year Margin After Rate Relief		$ 57,065,595	$ 57,065,595	$ 58,634,899	$ 60,247,359	$ 61,904,161	1
2	Add: Attrition Adjustment @ 2.75%	2.75%	-	1,569,304	1,612,460	1,656,802	1,702,364	2
3	Margin before Infrstructure Adjustment		$ 57,065,595	$ 58,634,899	$ 60,247,359	$ 61,904,161	$ 63,606,526	3
4	Infrastructure Adjustment			N/A	N/A	N/A	N/A	4
5	Revenue After Infrastructure Adjustment		57,065,595	58,634,899	60,247,359	61,904,161	63,606,526	5

SOUTHWEST GAS CORPORATION
PROPOSED NORTHERN CALIFORNIA AND SOUTH LAKE TAHOE RATE JURISDICTION
SUMMARY OF PROPOSED MARGIN RATES BY CLASS
TEST YEAR TWELVE MONTHS ENDED DECEMBER 31, 2026

Line No.	Description	Schedule	Proposed Margin Rates 2026	2027	2028	2029	2030	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
	Primary Residential Gas Service	GN-10/						
1	Basic Service Charge	GN-12	$ 5.75	$ 5.75	$ 5.75	$ 5.75	$ 5.75	1
	Commodity Charge							
2	Baseline Quantities		$ 1.12097	$ 1.15508	$ 1.19014	$ 1.22615	$ 1.26316	2
3	Tier II		$ 1.24056	$ 1.27467	$ 1.30973	$ 1.34574	$ 1.38275	3
	Secondary Residential Gas Service	GN-15						
4	Basic Service Charge		$ 6.00	$ 6.00	$ 6.00	$ 6.00	$ 6.00	4
	Commodity Charge							
5	All Usage		$ 1.44639	$ 1.48889	$ 1.53257	$ 1.57744	$ 1.62355	5
	Multi-Family Master Metered Gas Service	GN-20						
6	Basic Service Charge		$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	6
	Commodity Charge							
7	Baseline Quantities		$ 1.12097	$ 1.15508	$ 1.19014	$ 1.22615	$ 1.26316	7
8	Tier II		$ 1.24056	$ 1.27467	$ 1.30973	$ 1.34574	$ 1.38275	8
	Multi-Family Master Metered Gas Service - Submetered	GN-25						
9	Basic Service Charge		$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	9
10	Submeter Discount		$ (17.76)	$ (17.76)	$ (17.76)	$ (17.76)	$ (17.76)	10
	Commodity Charge							
11	Baseline Quantities		$ 1.12097	$ 1.15508	$ 1.19014	$ 1.22615	$ 1.26316	11
12	Tier II		$ 1.24056	$ 1.27467	$ 1.30973	$ 1.34574	$ 1.38275	12
	Core General Gas Service	GN-35/						
13	Basic Service Charge	GN-40	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	13
14	Transportation Service Charge		$ 780.00	$ 780.00	$ 780.00	$ 780.00	$ 780.00	14
	Commodity Charge							
15	First 100		$ 1.13822	$ 0.97236	$ 1.00042	$ 1.02925	$ 1.05888	15
16	Next 500		$ 0.80012	$ 0.75317	$ 0.77491	$ 0.79724	$ 0.82019	16
17	Next 2400		$ 0.49646	$ 0.56542	$ 0.58173	$ 0.59850	$ 0.61573	17
18	Over 3000		$ 0.14842	$ 0.26656	$ 0.27425	$ 0.28216	$ 0.29028	18
	Core Natural Gas Service for Motor Vehicles	GN-50						
19	Basic Service Charge		$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	19
	Commodity Charge							
20	All Usage		$ 0.03910	$ 0.04036	$ 0.04166	$ 0.04300	$ 0.04437	20
	Core Internal Combustion Engine Gas Service	GN-60						
21	Basic Service Charge		$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	21
	Commodity Charge							
22	All Usage		$ 0.47087	$ 0.00000	$ 0.00000	$ 0.00000	$ 0.00000	22
	Core Small Electric Power Generation Gas Service	GN-66						
23	Basic Service Charge		$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	23
	Commodity Charge							
24	All Usage		$ 0.47087	$ 0.00000	$ 0.00000	$ 0.00000	$ 0.00000	24
	Noncore General Gas Transportation Service	GN-70						
25	Basic Service Charge		$ 100.00	$ 100.00	$ 100.00	$ 100.00	$ 100.00	25
26	Transportation Service Charge		$ 780.00	$ 780.00	$ 780.00	$ 780.00	$ 780.00	26
	Commodity Charge							
27	All Usage		$ 0.14842	$ 0.00000	$ 0.00000	$ 0.00000	$ 0.00000	27

SOUTHWEST GAS CORPORATION
PROPOSED NORTHERN CALIFORNIA AND SOUTH LAKE TAHOE RATE JURISDICTION
CALCULATION OF PROPOSED MARGIN AND RATES BY CLASS POST TEST YEAR TWELVE MONTHS ENDED DECEMBER 31, 2027

			Test Year Billing Units					
			Number of	Volumes		Proposed Margin		
Line No.	Description	Schedule No.	Bills	Transport	Sales	Rates	Revenues	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
	Primary Residential Gas Service	GN-10/						
1	Basic Service Charge	GN-12	419,627			$ 5.75	$ 2,412,855	1
	Commodity Charge							
2	Baseline Quantities			19,106,610	19,106,610	$ 1.15508	$ 22,069,719	2
3	Tier II			8,509,052	8,509,052	$ 1.27467	$ 10,846,258	3
4	Total Primary Residential Gas Service		419,627	27,615,662	27,615,662		$ 35,328,832	4
	Secondary Residential Gas Service	GN-15						
5	Basic Service Charge		143,298			$ 6.00	$ 859,788	5
	Commodity Charge							
6	All Usage			8,666,032	8,666,032	$ 1.48889	$ 12,902,789	6
7	Total Secondary Residential Gas Service		143,298	8,666,032	8,666,032		$ 13,762,577	7
8	Total Residential Gas Service		562,925	36,281,694	36,281,694		$ 49,091,409	8
	Multi-Family Master Metered Gas Service	GN-20						
9	Basic Service Charge		1,104			$ 25.00	$ 27,600	9
	Commodity Charge							
10	Baseline Quantities			320,132	320,132	$ 1.15508	$ 369,779	10
11	Tier II			35,955	35,955	$ 1.27467	$ 45,831	11
12	Total Multi-Family Master Metered Gas Service		1,104	356,087	356,087		$ 443,210	12
	Multi-Family Master Metered Gas Service - Submetered	GN-25						
13	Basic Service Charge		84			$ 25.00	$ 2,100	13
14	Submeter Discount		5,112			$ (17.76)	$ (90,802)	14
	Commodity Charge							
15	Baseline Quantities			238,569	238,569	$ 1.15508	$ 275,567	15
16	Tier II			5,433	5,433	$ 1.27467	$ 6,925	16
17	Total Muti- Fam Sub		84	244,002	244,002		$ 193,790	17
18	Total Multi-Family Master Metered Gas Service		1,188	600,089	600,089		$ 637,000	18
	Core General Gas Service	GN-35/						
19	Basic Service Charge	GN-40	35,006			$ 11.00	$ 385,066	19
20	Transportation Service Charge		24			$ 780.00	$ 18,720	20
	Commodity Charge							
21	First 100			2,081,795	2,079,395	$ 0.97236	$ 2,024,252	21
22	Next 500			3,883,821	3,871,821	$ 0.75317	$ 2,925,186	22
23	Next 2400			3,682,606	3,625,006	$ 0.56542	$ 2,082,208	23
24	Over 3000			4,257,795	3,283,926	$ 0.26656	$ 1,134,955	24
25	Total Core General Gas Service		35,006	13,906,017	12,860,148		$ 8,570,387	25

SOUTHWEST GAS CORPORATION
PROPOSED NORTHERN CALIFORNIA AND SOUTH LAKE TAHOE RATE JURISDICTION
CALCULATION OF PROPOSED MARGIN AND RATES BY CLASS POST TEST YEAR TWELVE MONTHS ENDED DECEMBER 31, 2027

Line No.	Description	Schedule No.	Test Year Billing Units: Number of Bills	Volumes: Transport	Volumes: Sales	Proposed Margin: Rates	Proposed Margin: Revenues	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
	Core Natural Gas Service for Motor Vehicles	GN-50						
26	Basic Service Charge		36			$ 25.00	$ 900	26
	Commodity Charge							
27	All Usage			130,778	130,778	$ 0.04036	$ 5,278	27
28	Total Core Natural Gas Service for Motor Vehicles		36	130,778	130,778		$ 6,178	28
	Core Internal Combustion Engine Gas Service	GN-60						
29	Basic Service Charge		0			$ 25.00	$ 0	29
	Commodity Charge							
30	All Usage			0	0	$ 0.00000	$ 0	30
31	Total Core Internal Combustion Engine Gas Service		0	0	0		$ 0	31
	Core Small Electric Power Generation Gas Service	GN-66						
32	Basic Service Charge		0			$ 25.00	$ 0	32
	Commodity Charge							
33	All Usage			0	0	$ 0.00000	$ 0	33
34	Total Core Small Electric Power Generation Gas Service		0	0	0		$ 0	34
	Noncore General Gas Transportation Service	GN-70						
35	Basic Service Charge		0			$ 100.00	$ 0	35
36	Transportation Service Charge		0			$ 780.00	$ 0	36
	Commodity Charge							
37	All Usage			0	0	$ 0.00000	$ 0	37
38	Total Noncore General Gas Transportation Service		0	0	0		$ 0	38
39	Total All Schedules		599,155	50,918,578	49,872,709		$ 58,304,974	39
40	Special Contract Gas Service	G-T					$ 0	40
40	Other Operating Revenues						$ 329,925	40
41	Total Operating Revenue						$ 58,634,899	41
42	Total Revenue Requirement						$ 58,634,899	42
43	Over/Under Recovery						$ (0)	43

SOUTHWEST GAS CORPORATION
PROPOSED NORTHERN CALIFORNIA AND SOUTH LAKE TAHOE RATE JURISDICTION
CALCULATION OF PROPOSED MARGIN AND RATES BY CLASS POST TEST YEAR TWELVE MONTHS ENDED DECEMBER 31, 2028

Line No.	Description	Schedule No.	Test Year Billing Units: Number of Bills	Volumes: Transport	Volumes: Sales	Proposed Margin: Rates	Proposed Margin: Revenues	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
	Primary Residential Gas Service	GN-10/						
1	Basic Service Charge	GN-12	419,627			$ 5.75	$ 2,412,855	1
	Commodity Charge							
2	Baseline Quantities			19,106,610	19,106,610	$ 1.19014	$ 22,739,472	2
3	Tier II			8,509,052	8,509,052	$ 1.30973	$ 11,144,530	3
4	Total Primary Residential Gas Service		419,627	27,615,662	27,615,662		$ 36,296,857	4
	Secondary Residential Gas Service	GN-15						
5	Basic Service Charge		143,298			$ 6.00	$ 859,788	5
	Commodity Charge							
6	All Usage			8,666,032	8,666,032	$ 1.53257	$ 13,281,259	6
7	Total Secondary Residential Gas Service		143,298	8,666,032	8,666,032		$ 14,141,047	7
8	Total Residential Gas Service		562,925	36,281,694	36,281,694		$ 50,437,904	8
	Multi-Family Master Metered Gas Service	GN-20						
9	Basic Service Charge		1,104			$ 25.00	$ 27,600	9
	Commodity Charge							
10	Baseline Quantities			320,132	320,132	$ 1.19014	$ 381,001	10
11	Tier II			35,955	35,955	$ 1.30973	$ 47,091	11
12	Total Multi-Family Master Metered Gas Service		1,104	356,087	356,087		$ 455,692	12
	Multi-Family Master Metered Gas Service - Submetered	GN-25						
13	Basic Service Charge		84			$ 25.00	$ 2,100	13
14	Submeter Discount		5,112			$ (17.76)	$ (90,802)	14
	Commodity Charge							
15	Baseline Quantities			238,569	238,569	$ 1.19014	$ 283,930	15
16	Tier II			5,433	5,433	$ 1.30973	$ 7,115	16
17	Total Muti- Fam Sub		84	244,002	244,002		$ 202,343	17
18	Total Multi-Family Master Metered Gas Service		1,188	600,089	600,089		$ 658,035	18
	Core General Gas Service	GN-35/						
19	Basic Service Charge	GN-40	35,006			$ 11.00	$ 385,066	19
20	Transportation Service Charge		24			$ 780.00	$ 18,720	20
	Commodity Charge							
21	First 100			2,081,795	2,079,395	$ 1.00042	$ 2,082,672	21
22	Next 500			3,883,821	3,871,821	$ 0.77491	$ 3,009,606	22
23	Next 2400			3,682,606	3,625,006	$ 0.58173	$ 2,142,300	23
24	Over 3000			4,257,795	3,283,926	$ 0.27425	$ 1,167,709	24
25	Total Core General Gas Service		35,006	13,906,017	12,860,148		$ 8,806,073	25

SOUTHWEST GAS CORPORATION
PROPOSED NORTHERN CALIFORNIA AND SOUTH LAKE TAHOE RATE JURISDICTION
CALCULATION OF PROPOSED MARGIN AND RATES BY CLASS POST TEST YEAR TWELVE MONTHS ENDED DECEMBER 31, 2028

Line No.	Description	Schedule No.	Test Year Billing Units: Number of Bills	Volumes: Transport	Volumes: Sales	Proposed Margin: Rates	Proposed Margin: Revenues	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
	Core Natural Gas Service for Motor Vehicles	GN-50						
26	Basic Service Charge		36			$ 25.00	$ 900	26
	Commodity Charge							
27	All Usage			130,778	130,778	$ 0.04166	$ 5,448	27
28	Total Core Natural Gas Service for Motor Vehicles		36	130,778	130,778		$ 6,348	28
	Core Internal Combustion Engine Gas Service	GN-60						
29	Basic Service Charge		0			$ 25.00	$ 0	29
	Commodity Charge							
30	All Usage			0	0	$ 0.00000	$ 0	30
31	Total Core Internal Combustion Engine Gas Service		0	0	0		$ 0	31
	Core Small Electric Power Generation Gas Service	GN-66						
32	Basic Service Charge		0			$ 25.00	$ 0	32
	Commodity Charge							
33	All Usage			0	0	$ 0.00000	$ 0	33
34	Total Core Small Electric Power Generation Gas Service		0	0	0		$ 0	34
	Noncore General Gas Transportation Service	GN-70						
35	Basic Service Charge		0			$ 100.00	$ 0	35
36	Transportation Service Charge		0			$ 780.00	$ 0	36
	Commodity Charge							
37	All Usage			0	0	$ 0.00000	$ 0	37
38	Total Noncore General Gas Transportation Service		0	0	0		$ 0	38
39	Total All Schedules		599,155	50,918,578	49,872,709		$ 59,908,360	39
40	Special Contract Gas Service	G-T					$ 0	40
40	Other Operating Revenues						$ 338,998	40
41	Total Operating Revenue						$ 60,247,358	41
42	Total Revenue Requirement						$ 60,247,359	42
43	Over/Under Recovery						$ (1)	43

SOUTHWEST GAS CORPORATION
PROPOSED NORTHERN CALIFORNIA AND SOUTH LAKE TAHOE RATE JURISDICTION
CALCULATION OF PROPOSED MARGIN AND RATES BY CLASS POST TEST YEAR TWELVE MONTHS ENDED DECEMBER 31, 2029

Line No.	Description	Schedule No.	Test Year Billing Units: Number of Bills	Volumes: Transport	Volumes: Sales	Proposed Margin: Rates	Proposed Margin: Revenues	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
	Primary Residential Gas Service	GN-10/						
1	Basic Service Charge	GN-12	419,627			$ 5.75	$ 2,412,855	1
	Commodity Charge							
2	Baseline Quantities			19,106,610	19,106,610	$ 1.22615	$ 23,427,644	2
3	Tier II			8,509,052	8,509,052	$ 1.34574	$ 11,451,004	3
4	Total Primary Residential Gas Service		419,627	27,615,662	27,615,662		$ 37,291,503	4
	Secondary Residential Gas Service	GN-15						
5	Basic Service Charge		143,298			$ 6.00	$ 859,788	5
	Commodity Charge							
6	All Usage			8,666,032	8,666,032	$ 1.57744	$ 13,670,138	6
7	Total Secondary Residential Gas Service		143,298	8,666,032	8,666,032		$ 14,529,926	7
8	Total Residential Gas Service		562,925	36,281,694	36,281,694		$ 51,821,429	8
	Multi-Family Master Metered Gas Service	GN-20						
9	Basic Service Charge		1,104			$ 25.00	$ 27,600	9
	Commodity Charge							
10	Baseline Quantities			320,132	320,132	$ 1.22615	$ 392,531	10
11	Tier II			35,955	35,955	$ 1.34574	$ 48,386	11
12	Total Multi-Family Master Metered Gas Service		1,104	356,087	356,087		$ 468,517	12
	Multi-Family Master Metered Gas Service - Submetered	GN-25						
13	Basic Service Charge		84			$ 25.00	$ 2,100	13
14	Submeter Discount		5,112			$ (17.76)	$ (90,802)	14
	Commodity Charge							
15	Baseline Quantities			238,569	238,569	$ 1.22615	$ 292,523	15
16	Tier II			5,433	5,433	$ 1.34574	$ 7,311	16
17	Total Muti- Fam Sub		84	244,002	244,002		$ 211,132	17
18	Total Multi-Family Master Metered Gas Service		1,188	600,089	600,089		$ 679,649	18
	Core General Gas Service	GN-35/						
19	Basic Service Charge	GN-40	35,006			$ 11.00	$ 385,066	19
20	Transportation Service Charge		24			$ 780.00	$ 18,720	20
	Commodity Charge							
21	First 100			2,081,795	2,079,395	$ 1.02925	$ 2,142,697	21
22	Next 500			3,883,821	3,871,821	$ 0.79724	$ 3,096,348	22
23	Next 2400			3,682,606	3,625,006	$ 0.59850	$ 2,204,045	23
24	Over 3000			4,257,795	3,283,926	$ 0.28216	$ 1,201,364	24
25	Total Core General Gas Service		35,006	13,906,017	12,860,148		$ 9,048,240	25

SOUTHWEST GAS CORPORATION
PROPOSED NORTHERN CALIFORNIA AND SOUTH LAKE TAHOE RATE JURISDICTION
CALCULATION OF PROPOSED MARGIN AND RATES BY CLASS POST TEST YEAR TWELVE MONTHS ENDED DECEMBER 31, 2029

Line No.	Description	Schedule No.	Test Year Billing Units: Number of Bills	Volumes: Transport	Volumes: Sales	Proposed Margin: Rates	Proposed Margin: Revenues	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
	Core Natural Gas Service for Motor Vehicles	GN-50						
26	Basic Service Charge		36			$ 25.00	$ 900	26
	Commodity Charge							
27	All Usage			130,778	130,778	$ 0.04300	$ 5,623	27
28	Total Core Natural Gas Service for Motor Vehicles		36	130,778	130,778		$ 6,523	28
	Core Internal Combustion Engine Gas Service	GN-60						
29	Basic Service Charge		0			$ 25.00	$ 0	29
	Commodity Charge							
30	All Usage			0	0	$ 0.00000	$ 0	30
31	Total Core Internal Combustion Engine Gas Service		0	0	0		$ 0	31
	Core Small Electric Power Generation Gas Service	GN-66						
32	Basic Service Charge		0			$ 25.00	$ 0	32
	Commodity Charge							
33	All Usage			0	0	$ 0.00000	$ 0	33
34	Total Core Small Electric Power Generation Gas Service		0	0	0		$ 0	34
	Noncore General Gas Transportation Service	GN-70						
35	Basic Service Charge		0			$ 100.00	$ 0	35
36	Transportation Service Charge		0			$ 780.00	$ 0	36
	Commodity Charge							
37	All Usage			0	0	$ 0.00000	$ 0	37
38	Total Noncore General Gas Transportation Service		0	0	0		$ 0	38
39	Total All Schedules		599,155	50,918,578	49,872,709		$ 61,555,841	39
40	Other Operating Revenues						$ 348,320	40
41	Total Operating Revenue						$ 61,904,161	41
42	Total Revenue Requirement						$ 61,904,161	42
43	Over/Under Recovery						$ 0	43

SOUTHWEST GAS CORPORATION
PROPOSED NORTHERN CALIFORNIA AND SOUTH LAKE TAHOE RATE JURISDICTION
CALCULATION OF PROPOSED MARGIN AND RATES BY CLASS POST TEST YEAR TWELVE MONTHS ENDED DECEMBER 31, 2030

Line No.	Description	Schedule No.	Test Year Billing Units: Number of Bills	Volumes: Transport	Volumes: Sales	Proposed Margin: Rates	Proposed Margin: Revenues	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
	Primary Residential Gas Service	GN-10/						
1	Basic Service Charge	GN-12	419,627			$ 5.75	$ 2,412,855	1
	Commodity Charge							
2	Baseline Quantities			19,106,610	19,106,610	$ 1.26316	$ 24,134,740	2
3	Tier II			8,509,052	8,509,052	$ 1.38275	$ 11,765,907	3
4	Total Primary Residential Gas Service		419,627	27,615,662	27,615,662		$ 38,313,502	4
	Secondary Residential Gas Service	GN-15						
5	Basic Service Charge		143,298			$ 6.00	$ 859,788	5
	Commodity Charge							
6	All Usage			8,666,032	8,666,032	$ 1.62355	$ 14,069,711	6
7	Total Secondary Residential Gas Service		143,298	8,666,032	8,666,032		$ 14,929,499	7
8	Total Residential Gas Service		562,925	36,281,694	36,281,694		$ 53,243,001	8
	Multi-Family Master Metered Gas Service	GN-20						
9	Basic Service Charge		1,104			$ 25.00	$ 27,600	9
	Commodity Charge							
10	Baseline Quantities			320,132	320,132	$ 1.26316	$ 404,378	10
11	Tier II			35,955	35,955	$ 1.38275	$ 49,717	11
12	Total Multi-Family Master Metered Gas Service		1,104	356,087	356,087		$ 481,695	12
	Multi-Family Master Metered Gas Service - Submetered	GN-25						
13	Basic Service Charge		84			$ 25.00	$ 2,100	13
14	Submeter Discount		5,112			$ (17.76)	$ (90,802)	14
	Commodity Charge							
15	Baseline Quantities			238,569	238,569	$ 1.26316	$ 301,352	15
16	Tier II			5,433	5,433	$ 1.38275	$ 7,512	16
17	Total Muti- Fam Sub		84	244,002	244,002		$ 220,162	17
18	Total Multi-Family Master Metered Gas Service		1,188	600,089	600,089		$ 701,857	18
	Core General Gas Service	GN-35/						
19	Basic Service Charge	GN-40	35,006			$ 11.00	$ 385,066	19
20	Transportation Service Charge		24			$ 780.00	$ 18,720	20
	Commodity Charge							
21	First 100			2,081,795	2,079,395	$ 1.05888	$ 2,204,374	21
22	Next 500			3,883,821	3,871,821	$ 0.82019	$ 3,185,475	22
23	Next 2400			3,682,606	3,625,006	$ 0.61573	$ 2,267,487	23
24	Over 3000			4,257,795	3,283,926	$ 0.29028	$ 1,235,945	24
25	Total Core General Gas Service		35,006	13,906,017	12,860,148		$ 9,297,067	25

SOUTHWEST GAS CORPORATION
PROPOSED NORTHERN CALIFORNIA AND SOUTH LAKE TAHOE RATE JURISDICTION
CALCULATION OF PROPOSED MARGIN AND RATES BY CLASS POST TEST YEAR TWELVE MONTHS ENDED DECEMBER 31, 2030

			Test Year Billing Units					
				Volumes		Proposed Margin		
Line No.	Description	Schedule No.	Number of Bills	Transport	Sales	Rates	Revenues	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
	Core Natural Gas Service for Motor Vehicles	GN-50						
26	Basic Service Charge		36			$ 25.00	$ 900	26
	Commodity Charge							
27	All Usage			130,778	130,778	$ 0.04437	$ 5,802	27
28	Total Core Natural Gas Service for Motor Vehicles		36	130,778	130,778		$ 6,702	28
	Core Internal Combustion Engine Gas Service	GN-60						
29	Basic Service Charge		0			$ 25.00	$ 0	29
	Commodity Charge							
30	All Usage			0	0	$ 0.00000	$ 0	30
31	Total Core Internal Combustion Engine Gas Service		0	0	0		$ 0	31
	Core Small Electric Power Generation Gas Service	GN-66						
32	Basic Service Charge		0			$ 25.00	$ 0	32
	Commodity Charge							
33	All Usage			0	0	$ 0.00000	$ 0	33
34	Total Core Small Electric Power Generation Gas Service		0	0	0		$ 0	34
	Noncore General Gas Transportation Service	GN-70						
35	Basic Service Charge		0			$ 100.00	$ 0	35
36	Transportation Service Charge		0			$ 780.00	$ 0	36
	Commodity Charge							
37	All Usage			0	0	$ 0.00000	$ 0	37
38	Total Noncore General Gas Transportation Service		0	0	0		$ 0	38
39	Total All Schedules		599,155	50,918,578	49,872,709		$ 63,248,627	39
40	Other Operating Revenues						$ 357,899	40
41	Total Operating Revenue						$ 63,606,526	41
42	Total Revenue Requirement						$ 63,606,526	42
43	Over/Under Recovery						$ 1	43

PROPOSED TARIFF SHEETS

PRELIMINARY STATEMENT
(Continued)

9. FIXED COST ADJUSTMENT MECHANISM (FCAM) *(Continued)*

9F. ACCOUNTING PROCEDURE *(Continued)*

ANNUAL 2024 MARGIN

	Southern California	Northern California
January	$ 16,560,450	$ 7,649,908
February	$ 14,749,206	$ 6,981,192
March	$ 13,811,835	$ 6,831,369
April	$ 11,191,758	$ 5,577,926
May	$ 9,545,044	$ 4,266,242
June	$ 8,990,262	$ 3,431,583
July	$ 8,399,711	$ 2,919,377
August	$ 5,718,286	$ 1,713,129
September	$ 8,342,261	$ 2,773,369
October	$ 8,711,539	$ 3,399,418
November	$ 10,186,122	$ 4,865,361
December	$ 13,905,497	$ 6,656,719
Total	$ 130,111,973	$ 57,065,596

2. An entry to record interest on the Fixed Cost Balancing Account balance after entry (1) above, calculated as set forth in Section 12B of this Preliminary Statement.

PROPOSED TARIFF SHEETS

SOUTHWEST GAS CORPORATION
P.O. Box 98510
Las Vegas, Nevada 89193-8510 ______________________ Cal. P.U.C. Sheet No. 68
California Gas Tariff Canceling ______________________ Cal. P.U.C. Sheet No. 68

STATEMENT OF RATES

RATES APPLICABLE TO NORTHERN CALIFORNIA SERVICE AREA [1] [2]

Schedule No. and Type of Charge	Margin	Charges [3] and Adjustments	Subtotal Gas Usage Rate	Other Surcharges CPUC	Other Surcharges PPP	Gas Cost	Effective Sales Rate	
GN-10-Residential Gas Service								
Basic Service Charge	$ 5.75						$ 5.75	
Cost per Therm								
Baseline Quantities	$ 1.12097	$ .24098	$ 1.36195	$ .00100	$ .05887	$ .20005	$ 1.62187	I
Tier II	1.24056	.24098	1.48154	.00100	.05887	.20005	1.74146	I
GN-12-CARE Residential Gas Service								
Basic Service Charge	$ 4.00						$ 4.00	
Cost per Therm								
Baseline Quantities	$ .80857	$ .24098	$ 1.04955	$ .00100	$ .04255	$ .20005	$ 1.29315	I
Tier II	.90424	.24098	1.14522	.00100	.04255	.20005	1.38882	I
GN-15-Secondary Residential Gas Service								
Basic Service Charge	$ 6.00						$ 6.00	
Cost per Therm	$ 1.44639	$ .24098	$ 1.68737	$ .00100	$ .05887	$ .20005	$ 1.94729	I
GN-20-Multi-Family Master-Metered Gas Service								
Basic Service Charge	$25.00						$25.00	
Cost per Therm								
Baseline Quantities	$ 1.12097	$ .24098	$ 1.36195	$ .00100	$ .05887	$ .20005	$ 1.62187	I
Tier II	1.24056	.24098	1.48154	.00100	.05887	.20005	1.74146	I
GN-25-Multi-Family Master-Metered Gas Service-Submetered								
Basic Service Charge	$25.00						$25.00	
Cost per Therm								
Baseline Quantities	$ 1.12097	$ .24098	$ 1.36195	$ .00100	$ .05887	$ .20005	$ 1.62187	I
Tier II	1.24056	.24098	1.48154	.00100	.05887	.20005	1.74146	I
Submetered Discount per Occupied Space	($17.76)						($17.76)	
GN-35-Agriculture Employee Housing & Nonprofit Group Living Facility Gas Service								
Basic Service Charge	$ 8.80						$ 8.80	
Cost per Therm								
First 100	$ .82237	$ .24098	$ 1.06335	$ .00100	$ .04255	$ .20005	$ 1.30695	I
Next 500	.55189	.24098	.79287	.00100	.04255	.20005	1.03647	I
Next 2,400	.30896	.24098	.54994	.00100	.04255	.20005	.79354	I
Over 3,000	.03053	.24098	.27151	.00100	.04255	.20005	.51511	I
GN-40-Core General Gas Service (non-Covered Entities)								
Basic Service Charge	$11.00						$11.00	
Transportation Service Charge	$780.00						$780.00	
Cost per Therm								
First 100	$ 1.13822	$ .24098	$ 1.37920	$ .00100	$ .05887	$ .20005	$ 1.63912	I
Next 500	.80012	.24098	1.04110	.00100	.05887	.20005	1.30102	I
Next 2,400	.49646	.24098	.73744	.00100	.05887	.20005	.99736	I
Over 3,000	.14842	.24098	.38940	.00100	.05887	.20005	.64932	I

Advice Letter No.____________________ Issued by Date Filed ______________________
Decision No.________________________ Amy L. Timperley Effective ______________________
Chief Regulatory Officer Resolution No. ____________________

PROPOSED TARIFF SHEETS

SOUTHWEST GAS CORPORATION
P.O. Box 98510
Las Vegas, Nevada 89193-8510 ______________________ Cal. P.U.C. Sheet No. 69
California Gas Tariff Canceling ______________________ Cal. P.U.C. Sheet No. 69

STATEMENT OF RATES

RATES APPLICABLE TO NORTHERN CALIFORNIA SERVICE AREA [1] [2]

	Margin	Charges [3] and Adjustments	Subtotal Gas Usage Rate	Other Surcharges CPUC	Other Surcharges PPP	Gas Cost	Effective Sales Rate	
GN-40-Core General Gas Service (Covered Entities)								
Basic Service Charge	$ 11.00						$ 11.00	
Transportation Service Charge	$780.00						$780.00	
Cost per Therm								
First 100	$ 1.13822	$ .04012	$ 1.17834	$ .00100	$ .05887	$ .20005	$ 1.43826	I
Next 500	.80012	.04012	.84024	.00100	.05887	.20005	1.10016	I
Next 2,400	.49646	.04012	.53658	.00100	.05887	.20005	.79650	I
Over 3,000	.14842	.04012	.18854	.00100	.05887	.20005	.44846	I
GN-50-Core Natural Gas Service for Motor Vehicles								
Basic Service Charge	$ 25.00						$ 25.00	
Cost per Therm	$ .03910	$ .24098	$ .28008	$ .00100	$ .05887	$ .20005	$ .54000	I
GN-60-Core Internal Combustion Engine Gas Service								
Basic Service Charge	$ 25.00						$ 25.00	
Cost per Therm	$ .47087	$ .24098	$ .71185	$ .00100	$ .05887	$ .20005	$ .97177	I
GN-66-Core Small Electric Power Generation Gas Service								
Basic Service Charge	$ 25.00						$ 25.00	
Cost per Therm	$ .47087	$ .24098	$ .71185	$ .00100		$ .20005	$ .91290	I
GN-70-Noncore General Gas Transportation Service								
Basic Service Charge	$ 100.00						$ 100.00	
Transportation Service Charge	$ 780.00						$ 780.00	
Cost per Therm	$ .14842	$ .11366	$ .26208	$ .00100	$ .05887		$ .32195	
TFF-Transportation Franchise Fee Surcharge Provision								
TFF Surcharge per Therm							$ .00533	I
TDS – Transportation Distribution System Shrinkage Charge								
TDS Charge per Therm							$ .00100	I
MHPS-Master-Metered Mobile Home Park Safety Inspection Provision								
MHPS Surcharge per Space per Month							$ .21000	

Advice Letter No.______________________ Issued by Date Filed ________________________
Decision No.__________________________ Amy L. Timperley Effective __________________________
Chief Regulatory Officer Resolution No. _____________________

PROPOSED TARIFF SHEETS

SOUTHWEST GAS CORPORATION
P.O. Box 98510
Las Vegas, Nevada 89193-8510 ______________________ Cal. P.U.C. Sheet No. 70
California Gas Tariff Canceling ______________________ Cal. P.U.C. Sheet No. 70

STATEMENT OF RATES

RATES APPLICABLE TO NORTHERN CALIFORNIA SERVICE AREA [1] [2]

[1] Customers taking only transportation service will pay the Effective Sales Rate less the Interstate Reservation and Gas Cost components of the Effective Sales Rate, plus a Transportation Service Charge of $780 per month and an amount for distribution shrinkage calculated by multiplying the currently effective Gas Cost rate per therm by the Lost and Unaccounted For Gas percentage of 0.56%. The PGA Balancing Account Adjustment is applicable to customers converting from sales service to transportation service for a period of 12 months. The volume charge for customer-secured natural gas transportation will also be subject to the TFF Surcharge. R

[2] A Franchise Fee differential of 2.5% will be applied to monthly billings calculated for all rate schedules for all customers within the limits of the Town of Truckee.

[3] The Charges and Adjustments applicable to each tariff rate schedule includes the following components:

Charges and Adjustments Description	GN-10, GN-12, GN-15, GN-20, GN-25, GN-35, GN-40 (non-Covered Entities), GN-50, GN-60, GN-66	GN-40, (Covered Entities)	GN-70	
Upstream Interstate Charges				
Storage	$ .03539	$ .03539		
Reservation	.16671	.16671		
IRRAM Surcharge	.01432	.01432	$ .01432	I
Balancing Account Adjustments				
FCAM*	(.16198)	(.16198)	(.08720)	I/R
GHGBA**				
Non-Covered Entities [a]	.16760		.16760	
Covered Entities [a]		.00109		
NERBA	.00031	.00031	.00031	
NGLAPBA	.00106	.00106	.00106	I
MHPCBA	.00503	.00503	.00503	R
CDMIBA	.01000	.01000	.01000	I
RUBA	.00253	.00253	.00253	I
Total Charges and Adjustments	$ .24097	$ .07446	$ .11365	I

* The FCAM surcharge includes an amount of ($.10493) per therm related to the difference between Southwest Gas' authorized margin and recorded revenues intended to recover these costs. I

** Pursuant to D.15-10-032, Company costs incurred to comply with the California Air Resources Board (ARB) natural gas supplier Cap-and-Trade Program are to be included in transportation rates and recovered from Non-Covered Entities. Covered Entities, who are directly regulated by the ARB, are only responsible for paying for emission costs related to lost and unaccounted for gas (LUAF).

Advice Letter No.____________________ Issued by Date Filed ______________________
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Chief Regulatory Officer Resolution No. ____________________

Residential Essential Bill

	Baseline Monthly Usage (Therms)	Proposed BSC	Proposed Baseline Rate	Essential Bill at Proposed Rates
Winter				
Barstow	64	$5.75	$2.30693	$153.73
Victorville	62	$5.75	$2.30693	$148.82
Big Bear	86	$5.75	$2.30693	$204.22
Needles	28	$5.75	$2.30693	$70.27
North Lake Tahoe [1]	98	$5.75	$1.61914	$164.43
Truckee [1]	110	$5.75	$1.61914	$183.86
South Lake Tahoe [1]	92	$5.75	$1.61914	$154.71
Winter Off-Peak				
Barstow	34	$5.75	$2.30693	$84.30
Victorville	38	$5.75	$2.30693	$93.41
Big Bear	44	$5.75	$2.30693	$107.44
Needles	16	$5.75	$2.30693	$42.92
North Lake Tahoe [1]	66	$5.75	$1.61914	$112.61
Truckee [1]	70	$5.75	$1.61914	$119.09
South Lake Tahoe [1]	64	$5.75	$1.61914	$109.37
Summer				
Barstow	12	$5.75	$2.30693	$33.10
Victorville	12	$5.75	$2.30693	$33.10
Big Bear	14	$5.75	$2.30693	$38.01
Needles	7	$5.75	$2.30693	$21.88
North Lake Tahoe [1]	20	$5.75	$1.61914	$38.13
Truckee [1]	24	$5.75	$1.61914	$44.61
South Lake Tahoe [1]	20	$5.75	$1.61914	$38.13

[1] Proposed rates reflect the consolidation of Northern California and South Lake Tahoe rates.

NON CARE

WINTER	By Puma			2026		2027		2028		2029		
PUMA	County/City	Gas Climate Zone	PUMA/Gas Climate Zone	Gas AR_{20}	Gas AR_{50}	Gas AR_{20}	Gas AR_{50}	Gas AR_{20}	Gas AR_{50}	Gas AR_{20}	Gas AR_{50}	Estimated # of Housing Units
01700	El Dorado County--El Dorado Hills PUMA	SWG_NLT	01700, SWG_NLT	7.56%	2.47%	7.63%	2.48%	7.71%	2.49%	7.78%	2.50%	316
01700	El Dorado County--El Dorado Hills PUMA	SWG_SLT	01700, SWG_SLT	6.87%	2.30%	6.93%	2.31%	6.99%	2.31%	7.06%	2.32%	21,707
05700	Nevada & Sierra Counties PUMA	SWG_Truckee	05700, SWG_Truckee	14.55%	3.05%	14.75%	3.06%	14.97%	3.07%	15.18%	3.08%	13,739
06103	Placer County (East/High Country Region)--Auburn & Colfax Cities PUMA	SWG_NLT	06103, SWG_NLT	10.51%	2.19%	10.64%	2.20%	10.78%	2.21%	10.92%	2.21%	9,808
06103	Placer County (East/High Country Region)--Auburn & Colfax Cities PUMA	SWG_Truckee	06103, SWG_Truckee	11.71%	2.45%	11.86%	2.46%	12.02%	2.46%	12.18%	2.47%	2,739
07101	San Bernardino County (Northeast)--Twentynine Palms & Barstow Cities PUMA	SWG_Barstow	07101, SWG_Barstow	15.60%	3.95%	15.70%	3.93%	15.81%	3.90%	15.93%	3.87%	13,015
07101	San Bernardino County (Northeast)--Twentynine Palms & Barstow Cities PUMA	SWG_Needles	07101, SWG_Needles	7.61%	1.84%	7.66%	1.82%	7.72%	1.81%	7.78%	1.80%	655
07101	San Bernardino County (Northeast)--Twentynine Palms & Barstow Cities PUMA	SWG_Victorville	07101, SWG_Victorville	14.92%	3.81%	15.01%	3.79%	15.12%	3.76%	15.23%	3.73%	1,958
07102	San Bernardino County (West Central)--Victorville & Adelanto Cities PUMA	SWG_Victorville	07102, SWG_Victorville	7.44%	2.69%	7.46%	2.67%	7.47%	2.65%	7.49%	2.63%	46,451
07103	San Bernardino County (West Central)--Hesperia City & Apple Valley Town PUMA	SWG_Victorville	07103, SWG_Victorville	8.43%	2.87%	8.46%	2.84%	8.49%	2.83%	8.53%	2.81%	56,197
07104	San Bernardino County (Southwest)--Phelan, Lake Arrowhead & Big Bear City PUMA	SWG_Big_Bear	07104, SWG_Big_Bear	13.01%	3.38%	13.11%	3.35%	13.22%	3.33%	13.34%	3.31%	23,079
07104	San Bernardino County (Southwest)--Phelan, Lake Arrowhead & Big Bear City PUMA	SWG_Victorville	07104, SWG_Victorville	9.63%	2.47%	9.71%	2.45%	9.79%	2.44%	9.88%	2.42%	8,246

WINTER OFF PEAK	By Puma			2026		2027		2028		2029		
PUMA	County/City	Gas Climate Zone	PUMA/Gas Climate Zone	Gas AR_{20}	Gas AR_{50}	Gas AR_{20}	Gas AR_{50}	Gas AR_{20}	Gas AR_{50}	Gas AR_{20}	Gas AR_{50}	Estimated # of Housing Units
01700	El Dorado County--El Dorado Hills PUMA	SWG_NLT	01700, SWG_NLT	5.18%	1.69%	5.23%	1.70%	5.28%	1.70%	5.33%	1.71%	316
01700	El Dorado County--El Dorado Hills PUMA	SWG_SLT	01700, SWG_SLT	4.85%	1.63%	4.90%	1.63%	4.94%	1.64%	4.99%	1.64%	21,707
05700	Nevada & Sierra Counties PUMA	SWG_Truckee	05700, SWG_Truckee	9.42%	1.98%	9.56%	1.98%	9.69%	1.99%	9.84%	2.00%	13,739
06103	Placer County (East/High Country Region)--Auburn & Colfax Cities PUMA	SWG_NLT	06103, SWG_NLT	7.19%	1.50%	7.29%	1.51%	7.38%	1.51%	7.48%	1.51%	9,808
06103	Placer County (East/High Country Region)--Auburn & Colfax Cities PUMA	SWG_Truckee	06103, SWG_Truckee	7.59%	1.59%	7.68%	1.59%	7.78%	1.60%	7.89%	1.60%	2,739
07101	San Bernardino County (Northeast)--Twentynine Palms & Barstow Cities PUMA	SWG_Barstow	07101, SWG_Barstow	8.55%	2.17%	8.61%	2.15%	8.67%	2.14%	8.74%	2.12%	13,015
07101	San Bernardino County (Northeast)--Twentynine Palms & Barstow Cities PUMA	SWG_Needles	07101, SWG_Needles	4.65%	1.12%	4.68%	1.11%	4.72%	1.11%	4.75%	1.10%	655
07101	San Bernardino County (Northeast)--Twentynine Palms & Barstow Cities PUMA	SWG_Victorville	07101, SWG_Victorville	9.36%	2.39%	9.42%	2.38%	9.49%	2.36%	9.56%	2.34%	1,958
07102	San Bernardino County (West Central)--Victorville & Adelanto Cities PUMA	SWG_Victorville	07102, SWG_Victorville	4.67%	1.69%	4.68%	1.68%	4.69%	1.66%	4.70%	1.65%	46,451
07103	San Bernardino County (West Central)--Hesperia City & Apple Valley Town PUMA	SWG_Victorville	07103, SWG_Victorville	5.29%	1.80%	5.31%	1.79%	5.33%	1.77%	5.35%	1.76%	56,197
07104	San Bernardino County (Southwest)--Phelan, Lake Arrowhead & Big Bear City PUMA	SWG_Big_Bear	07104, SWG_Big_Bear	6.84%	1.78%	6.90%	1.76%	6.96%	1.75%	7.02%	1.74%	23,079
07104	San Bernardino County (Southwest)--Phelan, Lake Arrowhead & Big Bear City PUMA	SWG_Victorville	07104, SWG_Victorville	6.05%	1.55%	6.09%	1.54%	6.15%	1.53%	6.20%	1.52%	8,246

SUMMER	By Puma			2026		2027		2028		2029		
PUMA	County/City	Gas Climate Zone	PUMA/Gas Climate Zone	Gas AR_{20}	Gas AR_{50}	Gas AR_{20}	Gas AR_{50}	Gas AR_{20}	Gas AR_{50}	Gas AR_{20}	Gas AR_{50}	Estimated # of Housing Units
01700	El Dorado County--El Dorado Hills PUMA	SWG_NLT	01700, SWG_NLT	1.75%	0.57%	1.77%	0.58%	1.79%	0.58%	1.80%	0.58%	316
01700	El Dorado County--El Dorado Hills PUMA	SWG_SLT	01700, SWG_SLT	1.69%	0.57%	1.71%	0.57%	1.72%	0.57%	1.74%	0.57%	21,707
05700	Nevada & Sierra Counties PUMA	SWG_Truckee	05700, SWG_Truckee	3.53%	0.74%	3.58%	0.74%	3.63%	0.75%	3.68%	0.75%	13,739
06103	Placer County (East/High Country Region)--Auburn & Colfax Cities PUMA	SWG_NLT	06103, SWG_NLT	2.44%	0.51%	2.47%	0.51%	2.50%	0.51%	2.53%	0.51%	9,808
06103	Placer County (East/High Country Region)--Auburn & Colfax Cities PUMA	SWG_Truckee	06103, SWG_Truckee	2.84%	0.59%	2.88%	0.60%	2.92%	0.60%	2.95%	0.60%	2,739
07101	San Bernardino County (Northeast)--Twentynine Palms & Barstow Cities PUMA	SWG_Barstow	07101, SWG_Barstow	3.36%	0.85%	3.38%	0.85%	3.41%	0.84%	3.43%	0.83%	13,015
07101	San Bernardino County (Northeast)--Twentynine Palms & Barstow Cities PUMA	SWG_Needles	07101, SWG_Needles	2.37%	0.57%	2.39%	0.57%	2.40%	0.56%	2.42%	0.56%	655
07101	San Bernardino County (Northeast)--Twentynine Palms & Barstow Cities PUMA	SWG_Victorville	07101, SWG_Victorville	3.32%	0.85%	3.34%	0.84%	3.36%	0.84%	3.39%	0.83%	1,958
07102	San Bernardino County (West Central)--Victorville & Adelanto Cities PUMA	SWG_Victorville	07102, SWG_Victorville	1.66%	0.60%	1.66%	0.59%	1.66%	0.59%	1.67%	0.59%	46,451
07103	San Bernardino County (West Central)--Hesperia City & Apple Valley Town PUMA	SWG_Victorville	07103, SWG_Victorville	1.88%	0.64%	1.88%	0.63%	1.89%	0.63%	1.90%	0.62%	56,197
07104	San Bernardino County (Southwest)--Phelan, Lake Arrowhead & Big Bear City PUMA	SWG_Big_Bear	07104, SWG_Big_Bear	2.42%	0.63%	2.44%	0.62%	2.46%	0.62%	2.48%	0.62%	23,079
07104	San Bernardino County (Southwest)--Phelan, Lake Arrowhead & Big Bear City PUMA	SWG_Victorville	07104, SWG_Victorville	2.14%	0.55%	2.16%	0.55%	2.18%	0.54%	2.20%	0.54%	8,246

CARE

WINTER	By Puma			2026		2027		2028		2029		
PUMA	County/City	Gas Climate Zone	PUMA/Gas Climate Zone	Gas AR_{20}	Gas AR_{50}	Gas AR_{20}	Gas AR_{50}	Gas AR_{20}	Gas AR_{50}	Gas AR_{20}	Gas AR_{50}	Estimated # of Housing Units
01700	El Dorado County--El Dorado Hills PUMA	SWG_NLT	01700, SWG_NLT	6.02%	1.97%	6.08%	1.98%	6.14%	1.98%	6.20%	1.99%	316
01700	El Dorado County--El Dorado Hills PUMA	SWG_SLT	01700, SWG_SLT	5.47%	1.83%	5.52%	1.84%	5.57%	1.84%	5.62%	1.85%	21,707
05700	Nevada & Sierra Counties PUMA	SWG_Truckee	05700, SWG_Truckee	11.59%	2.43%	11.76%	2.44%	11.92%	2.45%	12.10%	2.46%	13,739
06103	Placer County (East/High Country Region)--Auburn & Colfax Cities PUMA	SWG_NLT	06103, SWG_NLT	8.37%	1.75%	8.47%	1.75%	8.58%	1.76%	8.70%	1.76%	9,808
06103	Placer County (East/High Country Region)--Auburn & Colfax Cities PUMA	SWG_Truckee	06103, SWG_Truckee	9.33%	1.95%	9.45%	1.96%	9.57%	1.96%	9.70%	1.97%	2,739
07101	San Bernardino County (Northeast)--Twentynine Palms & Barstow Cities PUMA	SWG_Barstow	07101, SWG_Barstow	12.42%	3.15%	12.50%	3.12%	12.59%	3.10%	12.68%	3.08%	13,015
07101	San Bernardino County (Northeast)--Twentynine Palms & Barstow Cities PUMA	SWG_Needles	07101, SWG_Needles	6.02%	1.45%	6.06%	1.44%	6.11%	1.43%	6.16%	1.42%	655
07101	San Bernardino County (Northeast)--Twentynine Palms & Barstow Cities PUMA	SWG_Victorville	07101, SWG_Victorville	11.87%	3.04%	11.95%	3.01%	12.03%	2.99%	12.12%	2.97%	1,958
07102	San Bernardino County (West Central)--Victorville & Adelanto Cities PUMA	SWG_Victorville	07102, SWG_Victorville	5.92%	2.14%	5.93%	2.13%	5.95%	2.11%	5.96%	2.09%	46,451
07103	San Bernardino County (West Central)--Hesperia City & Apple Valley Town PUMA	SWG_Victorville	07103, SWG_Victorville	6.71%	2.28%	6.73%	2.26%	6.76%	2.25%	6.79%	2.23%	56,197
07104	San Bernardino County (Southwest)--Phelan, Lake Arrowhead & Big Bear City PUMA	SWG_Big_Bear	07104, SWG_Big_Bear	10.37%	2.69%	10.45%	2.67%	10.54%	2.65%	10.63%	2.64%	23,079
07104	San Bernardino County (Southwest)--Phelan, Lake Arrowhead & Big Bear City PUMA	SWG_Victorville	07104, SWG_Victorville	7.67%	1.97%	7.73%	1.95%	7.79%	1.94%	7.86%	1.93%	8,246

WINTER OFF PEAK	By Puma			2026		2027		2028		2029		
PUMA	County/City	Gas Climate Zone	PUMA/Gas Climate Zone	Gas AR_{20}	Gas AR_{50}	Gas AR_{20}	Gas AR_{50}	Gas AR_{20}	Gas AR_{50}	Gas AR_{20}	Gas AR_{50}	Estimated # of Housing Units
01700	El Dorado County--El Dorado Hills PUMA	SWG_NLT	01700, SWG_NLT	4.12%	1.35%	4.15%	1.35%	4.19%	1.35%	4.23%	1.36%	316
01700	El Dorado County--El Dorado Hills PUMA	SWG_SLT	01700, SWG_SLT	3.86%	1.29%	3.89%	1.30%	3.93%	1.30%	3.96%	1.30%	21,707
05700	Nevada & Sierra Counties PUMA	SWG_Truckee	05700, SWG_Truckee	7.49%	1.57%	7.60%	1.58%	7.71%	1.58%	7.82%	1.59%	13,739
06103	Placer County (East/High Country Region)--Auburn & Colfax Cities PUMA	SWG_NLT	06103, SWG_NLT	5.72%	1.19%	5.79%	1.20%	5.87%	1.20%	5.95%	1.20%	9,808
06103	Placer County (East/High Country Region)--Auburn & Colfax Cities PUMA	SWG_Truckee	06103, SWG_Truckee	6.03%	1.26%	6.11%	1.27%	6.19%	1.27%	6.27%	1.27%	2,739
07101	San Bernardino County (Northeast)--Twentynine Palms & Barstow Cities PUMA	SWG_Barstow	07101, SWG_Barstow	6.78%	1.72%	6.83%	1.71%	6.88%	1.69%	6.93%	1.68%	13,015
07101	San Bernardino County (Northeast)--Twentynine Palms & Barstow Cities PUMA	SWG_Needles	07101, SWG_Needles	3.65%	0.88%	3.68%	0.88%	3.71%	0.87%	3.74%	0.86%	655
07101	San Bernardino County (Northeast)--Twentynine Palms & Barstow Cities PUMA	SWG_Victorville	07101, SWG_Victorville	7.43%	1.90%	7.48%	1.89%	7.53%	1.87%	7.59%	1.86%	1,958
07102	San Bernardino County (West Central)--Victorville & Adelanto Cities PUMA	SWG_Victorville	07102, SWG_Victorville	3.71%	1.34%	3.71%	1.33%	3.72%	1.32%	3.73%	1.31%	46,451
07103	San Bernardino County (West Central)--Hesperia City & Apple Valley Town PUMA	SWG_Victorville	07103, SWG_Victorville	4.20%	1.43%	4.21%	1.42%	4.23%	1.41%	4.25%	1.40%	56,197
07104	San Bernardino County (Southwest)--Phelan, Lake Arrowhead & Big Bear City PUMA	SWG_Big_Bear	07104, SWG_Big_Bear	5.44%	1.41%	5.48%	1.40%	5.53%	1.39%	5.57%	1.38%	23,079
07104	San Bernardino County (Southwest)--Phelan, Lake Arrowhead & Big Bear City PUMA	SWG_Victorville	07104, SWG_Victorville	4.80%	1.23%	4.84%	1.22%	4.88%	1.21%	4.92%	1.21%	8,246

SUMMER	By Puma			2026		2027		2028		2029		
PUMA	County/City	Gas Climate Zone	PUMA/Gas Climate Zone	Gas AR_{20}	Gas AR_{50}	Gas AR_{20}	Gas AR_{50}	Gas AR_{20}	Gas AR_{50}	Gas AR_{20}	Gas AR_{50}	Estimated # of Housing Units
01700	El Dorado County--El Dorado Hills PUMA	SWG_NLT	01700, SWG_NLT	1.38%	0.45%	1.39%	0.45%	1.40%	0.45%	1.42%	0.45%	316
01700	El Dorado County--El Dorado Hills PUMA	SWG_SLT	01700, SWG_SLT	1.33%	0.44%	1.34%	0.45%	1.35%	0.45%	1.36%	0.45%	21,707
05700	Nevada & Sierra Counties PUMA	SWG_Truckee	05700, SWG_Truckee	2.78%	0.58%	2.82%	0.58%	2.86%	0.59%	2.90%	0.59%	13,739
06103	Placer County (East/High Country Region)--Auburn & Colfax Cities PUMA	SWG_NLT	06103, SWG_NLT	1.91%	0.40%	1.94%	0.40%	1.96%	0.40%	1.99%	0.40%	9,808
06103	Placer County (East/High Country Region)--Auburn & Colfax Cities PUMA	SWG_Truckee	06103, SWG_Truckee	2.24%	0.47%	2.26%	0.47%	2.29%	0.47%	2.32%	0.47%	2,739
07101	San Bernardino County (Northeast)--Twentynine Palms & Barstow Cities PUMA	SWG_Barstow	07101, SWG_Barstow	2.63%	0.67%	2.64%	0.66%	2.66%	0.66%	2.68%	0.65%	13,015
07101	San Bernardino County (Northeast)--Twentynine Palms & Barstow Cities PUMA	SWG_Needles	07101, SWG_Needles	1.83%	0.44%	1.84%	0.44%	1.86%	0.44%	1.87%	0.43%	655
07101	San Bernardino County (Northeast)--Twentynine Palms & Barstow Cities PUMA	SWG_Victorville	07101, SWG_Victorville	2.59%	0.66%	2.61%	0.66%	2.63%	0.65%	2.65%	0.65%	1,958
07102	San Bernardino County (West Central)--Victorville & Adelanto Cities PUMA	SWG_Victorville	07102, SWG_Victorville	1.29%	0.47%	1.30%	0.46%	1.30%	0.46%	1.30%	0.46%	46,451
07103	San Bernardino County (West Central)--Hesperia City & Apple Valley Town PUMA	SWG_Victorville	07103, SWG_Victorville	1.47%	0.50%	1.47%	0.49%	1.48%	0.49%	1.48%	0.49%	56,197
07104	San Bernardino County (Southwest)--Phelan, Lake Arrowhead & Big Bear City PUMA	SWG_Big_Bear	07104, SWG_Big_Bear	1.90%	0.49%	1.91%	0.49%	1.93%	0.49%	1.95%	0.48%	23,079
07104	San Bernardino County (Southwest)--Phelan, Lake Arrowhead & Big Bear City PUMA	SWG_Victorville	07104, SWG_Victorville	1.68%	0.43%	1.69%	0.43%	1.70%	0.42%	1.72%	0.42%	8,246

Company Witness:
Bradley C. Anderson

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
APPLICATION 24-09-___

PREPARED DIRECT TESTIMONY
OF
BRADLEY C. ANDERSON

ON BEHALF OF
SOUTHWEST GAS CORPORATION

SEPTEMBER 5, 2024

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of
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Southwest Gas Corporation
Application 24-09-___

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Prepared Direct Testimony
of
Bradley C. Anderson

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Bradley C. Anderson. My business address is 8360 S. Durango Drive, Las Vegas, Nevada 89113.

Q. 2 By whom and in what capacity are you employed?

A. 2 I am employed by Southwest Gas Corporation (Southwest Gas or Company) in the Risk Management department. My title is Director/Enterprise Risk Management & Corporate Compliance.

Q. 3 Please summarize your educational background and relevant business experience.

A. 3 My educational background and relevant business experience are summarized in Appendix A to this testimony.

Q. 4 Have you previously testified before any regulatory commission?

A. 4 Yes. I have previously provided written testimony before the California Public Utilities Commission (CPUC or Commission).

Q. 5 What is the purpose of your prepared direct testimony in this proceeding?

A. 5 My testimony supports Southwest Gas' risk-based decision-making framework,[1] developed in compliance with Decision (D.) 14-12-025 and the *Voluntary Agreement on a Risk-Based Decision-Making Framework between the Safety and Enforcement Division and the Small Multi-Jurisdictional Utilities* (Voluntary Agreement), approved by the Commission in D.19-04-020 and issued May 6, 2019.[2] Subsequently, in D.22-10-002, the Commission kept the Voluntary Agreement in place.[3]

Q. 6 Please summarize your prepared direct testimony.

A. 6 My prepared direct testimony consists of the following key issues:

- *An overview of Southwest Gas' existing Risk Management program*
- *The Company's approach to risk-informed decision-making*
- *The requested funding for the Company's mitigation measures*

II. SOUTHWEST GAS' EXISTING RISK MANAGEMENT PROGRAM

Q. 7 Does Southwest Gas have a Risk Management Program?

A. 7 Yes. Southwest Gas has an enterprise risk management (ERM) program. The program is focused on integrating ERM practices to improve the decision-making process and ensure that strategic objectives and goals are met. Identifying and understanding how risk can impact the Company is a critical step

[1] The terms 'risk-based' and 'risk-informed' are used interchangeably throughout this testimony.

[2] Application 15-05-002. The Voluntary Agreement was between the Small Multi-Jurisdiction Utilities (SMJU) and the Risk Assessment Group of the Safety and Enforcement Division.

[3] In D.22-10-002 at pg. 48, the Commission states, "We concur with Staff that formal adoption or modification of the Voluntary Agreement is not necessary at this time. The current process of implementation of the Voluntary Agreement by the SMJUs appears to be working well."

in achieving desired outcomes. Southwest Gas' ERM program is company-wide and encompasses all three states (California, Arizona and Nevada) in which the Company operates.

Southwest Gas' ERM approach is based on the guiding principles of International Standards Organization (ISO) 31000 and the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") ERM frameworks as the building blocks for its program.

Q. 8 Please provide an overview of the Company's ERM framework.

A. 8 ERM focuses on "the culture, capabilities, and practices, integrated with strategy-setting and performance, that organizations rely on to manage risk in creating, preserving, and realizing value."[4] As part of its ERM program, Southwest Gas focuses on identifying and mitigating risks in an effort to achieve desired strategies and business objectives. This is done by focusing on the key attributes of oversight, risk identification, risk assessment, risk response, and communication and monitoring. These attributes are the foundation of the Company's program.

III. THE RISK-BASED DECISION-MAKING PROCESS

Q. 9 Please provide an overview of the Commission's risk-based decision-making process.

A. 9 On November 14, 2013, the Commission opened Rulemaking (R.) 13-11-006 through its Order Instituting Rulemaking to Develop a Risk-Based Decision-Making Framework to Evaluate Safety and Reliability Improvements and Revise

[4] Enterprise Risk Management – Integrating with Strategy and Performance p. 10

the Rate Case Plan for Energy Utilities (Rulemaking). The Rulemaking was the genesis of the risk-based decision-making framework. The purpose was to "…integrate a risk-based decision-making framework into the Rate Case Plan (RCP) for energy utilities' General Rate Cases (GRCs) in which the utilities request funding for safety related actives."[5]

On December 4, 2014, the Commission issued D.14-12-025 and ordered that Southwest Gas, along with other small and multi-jurisdictional utilities (SMJU), transition to including a risk-based decision-making framework in their respective GRCs.[6] The goal of Risk-Informed Ratemaking is to make California safer by identifying the risk mitigations that can optimize safety. Overall, the utility should show how it will use its expertise and budget to manage, mitigate, and minimize safety-related risks, along with subsequent reporting.[7,8] The Voluntary Agreement directs the SMJU, as part of their risk-based decision-making framework, to:

1. Identify its top risks.
2. Describe the controls or mitigations currently in place.
3. Present its plan for improving the mitigation of each risk.
4. Present two alternative mitigation plans that it considered.[9]

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[5] D.19-04-020, at p.3.
[6] Specifically, D.19-04-020 required applications starting three years from the order issuance date. For Southwest Gas, that coincided with the Company's Test Year 2021 General Rate Case (A.19-08-015).
[7] Voluntary Agreement at pg. 6.
[8] D.19-04-020 deferred reporting requirements for the SMJUs. Commission's D.22-10-002 further refined the reporting requirements and specified due dates. Southwest Gas completed and filed its reporting requirements for calendar years 2021, 2022, and 2023 in A.19-08-015.
[9] The alternatives analysis may include a proposal to continue the current level of controls or mitigations as one of the possible alternatives.

5. Present an estimate of "risk mitigated to cost ratio" or related "risk reduction per dollar spent."
6. Identify lessons learned to apply in future filings.
7. Move toward probabilistic calculations as much as possible.
8. For those business areas with less data, improve the collection of data and provide a timeframe for improvement.
9. Describe the company's safety culture, executive engagement, and compensation policies.
10. Respond to immediate or short-term crises outside of the Risk Assessment and Mitigation Phase (RAMP) and GRC process.[10]

Q. 10 Describe Southwest Gas' risk-informed decision-making process.

A. 10 Southwest Gas' risk-informed decision-making process consists of six high-level processes: risk identification, risk analysis, risk evaluation and scoring, risk mitigation, risk informed investment decision, and risk monitoring. The following summarizes what must be accomplished in each step:

Risk Identification

- Gather an initial list of risk events in a brainstorming session (leverage the Company's existing ERM material)
- Select priority risk events for initial analysis
- Document work involved in Risk Identification

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[10] Voluntary Agreement at pgs. 6-7. Note that the SMJU do not have a RAMP as adopted for the large investor utilities (Southern California Gas Company, San Diego Gas & Electric Company, Pacific Gas and Electric Company and Southern California Edison Company) in D.14-12-025. Southwest Gas interprets this as the SMJU's own respective risk assessment in their individual risk assessment processes.

Risk Analysis

- Perform full analysis on selected risk events (e.g., assess frequency and impact)
    - Define worst reasonable scenario and likely scenario
    - Assign frequency rating
    - Assign an impact rating for the three impact categories (Safety, Operational, Financial)
- Develop basis document to capture assumptions and rationale behind scoring
- Communicate analysis results to affected parties
- Document work in Risk Register

Risk Evaluation & Scoring

- Conduct calibration session to review total score for each fully analyzed risk
- Examine outliers and prepare for mitigation
- Communicate results to affected parties
- Document work in Risk Register

Risk Mitigation

- Review existing mitigations and controls for adequacy
- Develop new mitigations and controls as necessary
- Document work in Risk Mitigations and Controls portion of Risk Register

Risk Informed Investment Decisions

- Consolidate portfolio of proposed controls and risk mitigations

- Examine alternative mitigations or controls
- Define scope of proposed controls and risk mitigations
- Produce budgetary estimates for controls and risk mitigation
- Provide impact summary of any budget adjustments (if necessary)
- Calculate risk reduction per cost of mitigation or control to attain risk-spend-efficiencies (RSEs)

Risk Monitoring

- Review risk register on a periodic basis
- Consider new and emerging risk events
- Direct new and emerging risk events to Risk Analysis and Risk Evaluation and Scoring process.

The Company's risk management framework is consistent with major international standards and leading practices within the utility industry. The Company's goal is that all employees become "risk managers" who are encouraged to identify and ultimately help mitigate risks.

Q. 11 Please describe Southwest Gas' approach to developing a risk-informed decision-making process for this GRC.

A. 11 The Company retained the services of Accenture Consulting (Accenture) to further develop and integrate the risk-based decision-making framework for the Company's California operations in compliance with the Voluntary Agreement. Accenture also worked with Southwest Gas' Risk Project Team (Risk Project

Team)[11] to brainstorm additional risks including those specific to the Company's California operations. Each risk was then assessed utilizing a bowtie analysis, scored, and documented with existing controls and proposed mitigation plans. Risks were scored according to a risk framework typical to California risk assessments comprised of safety, operational, and financial risk. Proposed mitigations were scored according to the same rubric in terms of their reduction of risk as well as their cost, rendering RSEs to quantifiably represent mitigation value.

Q. 12 Does Southwest Gas have a lexicon?

A. 12 Yes. The following table provides the Company's risk management lexicon that will be utilized throughout this testimony.

Term	Definition
Alternative Analysis	Evaluation of different alternatives available to mitigate risk
Control	Currently established measure that is modifying risk
Event	An occurrence or change of a particular set of circumstances that may have potentially adverse consequences and may require action to address.
Frequency	Number of events generally defined per unit of time. (Frequency is often incorrectly treated as synonymous with probability or likelihood).
Impact (or Consequence)	The effect or outcome of an event affecting objectives, which may be expressed, by terms including, although not limited to health, safety, reliability, economic and/or environmental damage.
Inherent Risk	The level of risk that exists without risk controls or mitigations.

[11] Southwest Gas' Risk Project Team consisted of subject matter experts from Risk Management, Engineering Staff, System Integrity, Gas Operations Support Staff, Information/Cybersecurity Services, Business Continuity, Infrastructure Protection, Security Operations, and Division Operations (Engineering). A second team comprised of management-level employees, including but not limited to Director-level employees and Vice Presidents over the functional areas represented on the project team, was also assembled to review the initial scoring and proposed mitigations and offer feedback.

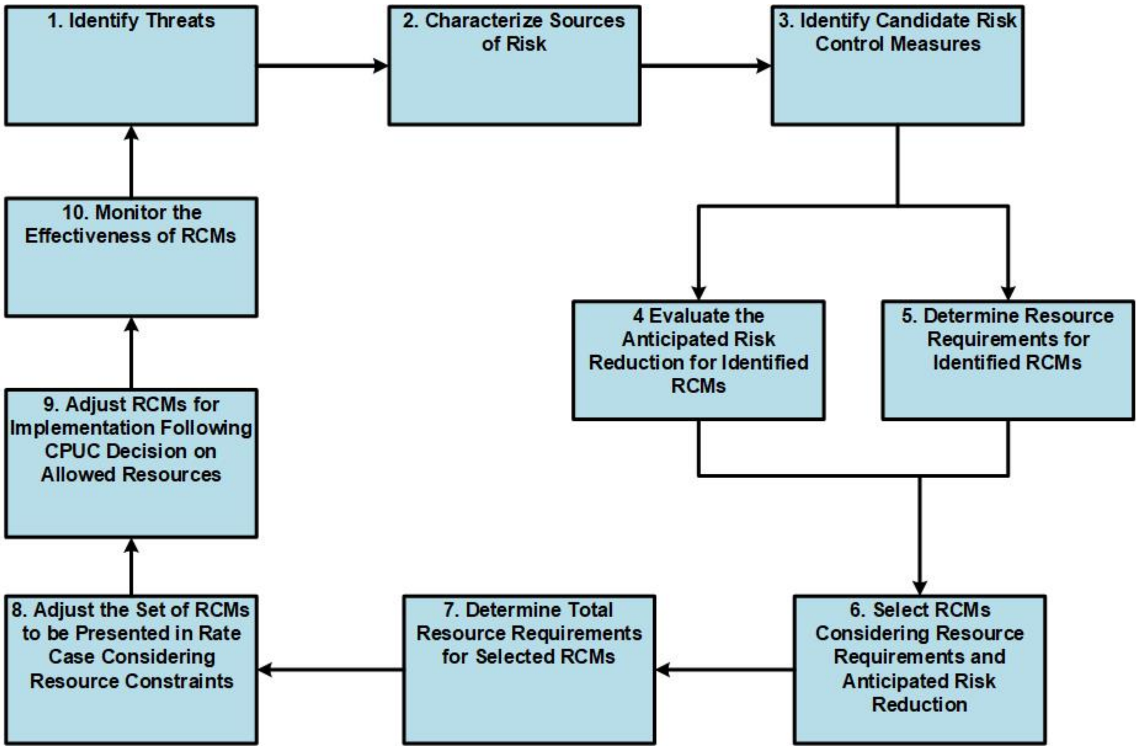
Term	Definition
Mitigation	Measure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event.
Outcome	The final resolution or end result.
Probability	The relative possibility that an event will occur, probability is quantified as a number between 0% and 100% (where 0% indicates impossibility and 100% indicates certainty). The higher the probability of an event, the more certain an event will occur. (Often informally referred to as likelihood or chance).
Planned or Forecasted Residual Risk	Risk remaining after implementation of proposed mitigations.
Residual Risk	Risk remaining after current controls.
Risk	The potential for the occurrence of an event that would be desirable to avoid, often expressed in terms of a combination of various outcomes of an adverse event and their associated probabilities. Different stakeholders may have varied perspectives on risk.
Risk Driver	Factor(s) that could cause one or more risks to occur (Risk driver may also be commonly referred to as "threat").
Risk Response Plan	Collection of mitigations
Risk Score	Numerical representation of qualitative and/or quantitative risk assessment that is typically used to relatively rank risks and may change over time.
Risk Tolerance	Maximum amount of residual risk that an entity or its stakeholders are willing to accept after application of risk control or mitigation. Risk tolerance can be influenced by legal or regulatory requirements.
Worst Case Scenario	Severe hypothetical rendering of the risk event which is still within the realm of possibility.

Q. 13 How does the Southwest Gas' approach align with the Cycla 10 model as prescribed by the Commission?

A. 13 The Company's approach to the risk-informed decision-making process is grounded in the basic tenets of COSO and ISO. The Company leveraged both of these frameworks in the development of its ERM methodology. The California-specific risk-management process (RMP) leveraged the prior COSO base ERM framework and also utilized the principles in ISO 31000. Following ISO 31000 helps organizations achieve objectives, improves the identification of risks, and more effectively allocates resources for risk reduction. ISO 31000 has been applied across many different industries including utilities. As such, Southwest Gas has designed a framework for the California-specific RMP that is consistent with the guidance in ISO 31000. In particular, Southwest Gas' risk management process incorporates the following six risk-related steps:

1. Risk identification;
2. Risk analysis;
3. Risk evaluation and scoring;
4. Risk mitigation determination;
5. Risk informed project decision making; and
6. Risk monitoring.

This risk-informed process is based upon the 10 steps of the Cycla risk management process. The following flow chart illustrates the Cycla process:



The table below maps Southwest Gas' six risk-related steps used for the California-specific RMP to the Cycla steps.

Southwest Gas	Cycla
1. Risk Identification	Steps 1 and 2
2. Risk Analysis	
3. Risk evaluation and scoring	
4. Risk Mitigation determination	Steps 3, 4, and 5
5. Risk informed project decision making	Steps 6, 7, 8, and 9
6. Risk monitoring	Step 10

Q. 14 Describe the Company's risk identification process?

A. 14 Risk identification sets out to identify an organization's exposure to uncertainty.[12] Risk identification is the "process of finding, recognizing, and describing risks."[13]

[12] ISO 31000 "A Risk Management Standard" p.5.
[13] ISO 31000: "Risk management – principles and guidelines" p.4.

This includes not only the identification of risks, but also the characterization of the sources of risk. To support the step, Accenture facilitated a brainstorming session with the Risk Project Team to create an initial list of risk events from the prior General Rate Case and identified additional operational risks through various group exercises. The Risk Project Team reviewed the list of risk events developed in the brainstorming session(s). The review eliminated any duplications and combined similar risk events.

Next, risk events were categorized. An example of categorization is to align risks with asset classes. Categorization helps to identify risk events that more directly affect Southwest Gas objectives and allow for risk events to be aligned with risk functional ownership by assigning a risk owner for each group of risk events. Risk owners were responsible for: characterizing the worst reasonable case for each risk event, identifying the existing controls, scoring the risk event, identifying the proposed mitigations, and scoring the planned risk following the implementation of the mitigations. While risk owners were responsible for final say on these efforts, they were done in collaboration with the broader project team as facilitated by Accenture. This augmented the breadth of considerations and refined results throughout the effort. Risk reductions were determined based on a combination of internal and external data (when available) as well as expert judgement of the risk owners and subject matter experts.

Q. 15 Please describe Southwest Gas' risk analysis process.

A. 15 A key step to the risk analysis process is a risk assessment. A risk assessment consists of rating each risk based on the likelihood (the frequency it will occur) and impact (the severity of the risk event's consequences if it occurs). Risk analysis is performed to allow a company to better understand identified risks, assess the likelihood and consequence of an occurrence, and determine the magnitude. During this step, subject matter experts and the Risk Project Team populated the risk registry. The risk registry is the data file which contains the risk event, the magnitude of likelihood and consequences for each risk event, the risk mitigations that affect the risk events and the risk reduction information resulting from the mitigations. The Risk Project Team compiles and enters the following data about each risk into the risk registry:

- Title
- Owner
- Description
- Worst Reasonable Scenario

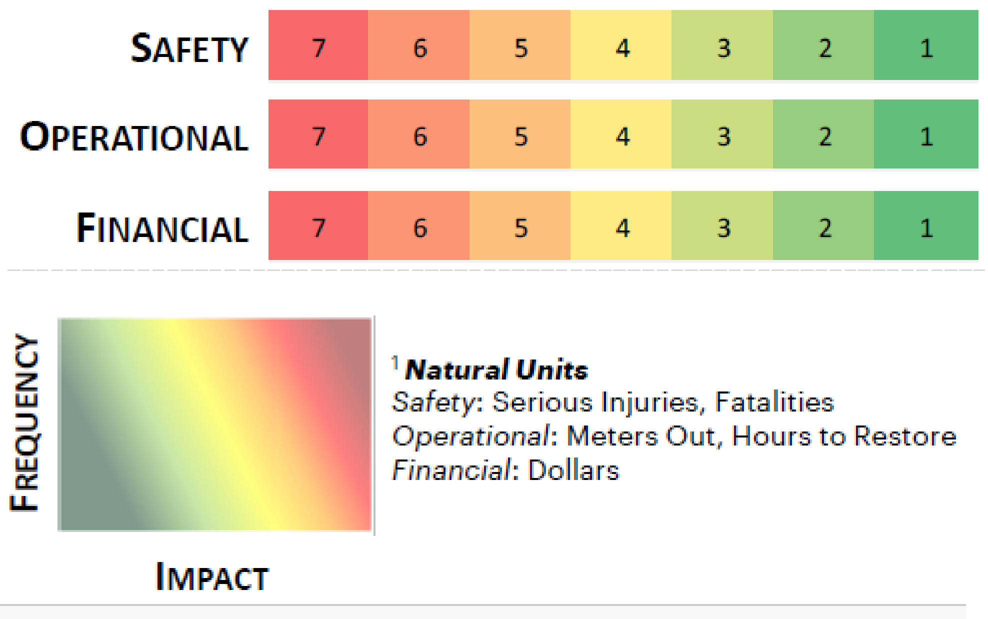
Like many utilities, Southwest Gas' current ability to accurately extract data from the various sources in order to provide reliable probabilistic analyses is limited. As such, the Company adhered to single-point analyses throughout the risk analysis process with information from historical incidents, industry experience and other subject matter expert incident experience to identify a worst reasonable scenario. Given the Risk Project Team's experience from the previous risk analysis efforts, the team was able to rely less on estimates from subject matter experts and leverage data such as Distribution Integrity Management Program (DIMP) records. The Project Risk Team and subject matter experts then assigned incident frequencies to define likelihood, which are reflected in the table below, using expertise, experience, and data. The quantified risk event frequency figures in 'event per year' were interpolated onto the 1-to-7 scale in accordance with the Voluntary Agreement 7 x 7 for risk calculation.

Level	Value	Occurrence
	7	>10 times per year
	6	1-10 times per year
	5	Once every 1-3 years
	4	Once every 3-10 years
	3	Once every 10-30 years
	2	Once every 30-100 years
	1	Once every 100+ years

To assess consequence, Southwest Gas relied on subject matter expert knowledge to define the Company's valuation of risk according to three Impact Categories: Safety; Operational; and Financial. The Company used a pairwise comparison to determine the weights to be attributed to each of the categories. A pairwise comparison is a facilitated exercise where the Risk Project Team compares the relative values of examples for each attribute through every possible permutation and the results of the comparisons are used in a mathematical computation to determine the relative weighting for each attribute. Based on the pairwise comparison, the Risk Project Team considered the weights used by other California utilities and assigned the final weights for each of the impact categories. The final Impact Category weights are:

Safety	Operational	Financial
65%	20%	15%

Southwest Gas then adopted a scale from 1 to 7, with level 1 defined as negligible and level 7 as catastrophic for each Impact Category. Quantified risk event impact figures were interpolated onto the 1-to-7 scale for 7 x 7 risk calculation.



Q. 16 Please describe Southwest Gas' risk evaluation and scoring process.

A. 16 Risk evaluation is the "process of comparing the results of risk analysis with risk criteria to determine whether the risk and/or its magnitude is acceptable or tolerable."[14] The risk register calculates a total risk score from the data collected in risk analysis. The risk scores establish a relative ranking of risk events for discussion purposes. The score is a calculation based on available data and

[14] ISO 31000, p.6.

subject matter expert-informed quantitative input of the impact and frequency associated with the risk event's worst reasonable scenario. The potential impacts of the worst reasonable scenario across the three impact categories are then scored in real units of the respective impact category which are then interpolated into the 1-to-7 scale (7 being the greatest severity). Once the impact is articulated, a frequency based on data and subject matter expertise is assigned to each worst reasonable case scenario and interpolated into the 1-to-7 scale (7 being the most frequent). The risk register then applies a formula to create a score.

$$Risk\ Score = Frequency \times \sum_{i=1}^{3} Weight_i \times 10^{Impact_i}$$

The scores of risk events can be plotted on a heat map matrix. Southwest Gas has chosen to use a 7 x 7 heat map matrix. The 7 x 7 matrix is consistent with modern practice in the utility industry. It provides a better differentiation of risk events than a 3 x 3 map matrix or a 5 x 5 map matrix. The 3 x 3 and 5 x 5 matrix maps produce a less distinct differentiation of risks. That is, many risks are high impact, low frequency and occupy the same space on the heat map, thereby limiting its usefulness in identifying areas of focus.

A 7 x 7 matrix map provides a better view of relative priority of risk events. The scale places a greater value on mitigating risks in the top right quadrant of the matrix map rather than the bottom left. Risks in the top right quadrant have higher risk scores than those on the bottom left.

Q. 17 Please describe Southwest Gas' risk mitigation/determination approach.

A. 17 Risk mitigation moderates or alleviates a risk to lessen its likelihood or consequence in some way. The first step in the mitigation process is to determine whether any existing controls are already established and in place. Each risk event will have a mitigation plan that provides an overview of the risk. Based on the results of the risk evaluation, risk mitigations should be developed and documented for those risks identified as needing mitigation.

For those that need additional mitigation, the risk-informed investment decision process allows Southwest Gas to review investment opportunities and adjust its portfolio of projects based on the result of the first four risk processes in terms of the resource requirements and anticipated risk reduction. In order to quantitatively compare mitigations, the Company calculates RSEs for each selected mitigation according to the formula below. The RSE depicts the amount of risk that is reduced per dollar spent on a mitigation.

$$RSE = \frac{Risk\ Reduction}{Cost}$$

The portfolio of controls and mitigations is consolidated for review. Budget constraints are considered. Constraints include, for instance, resource constraints such as availability of trained and qualified personnel, execution constraints such as the time necessary to obtain required permits, and system constraints such as the ability to deliver service to customers while performing the total portfolio of work. Resource and other constraints may drive adjustments to the proposed work portfolio. Selection of mitigations plans are then selected based on RSEs and limitation of constraints.

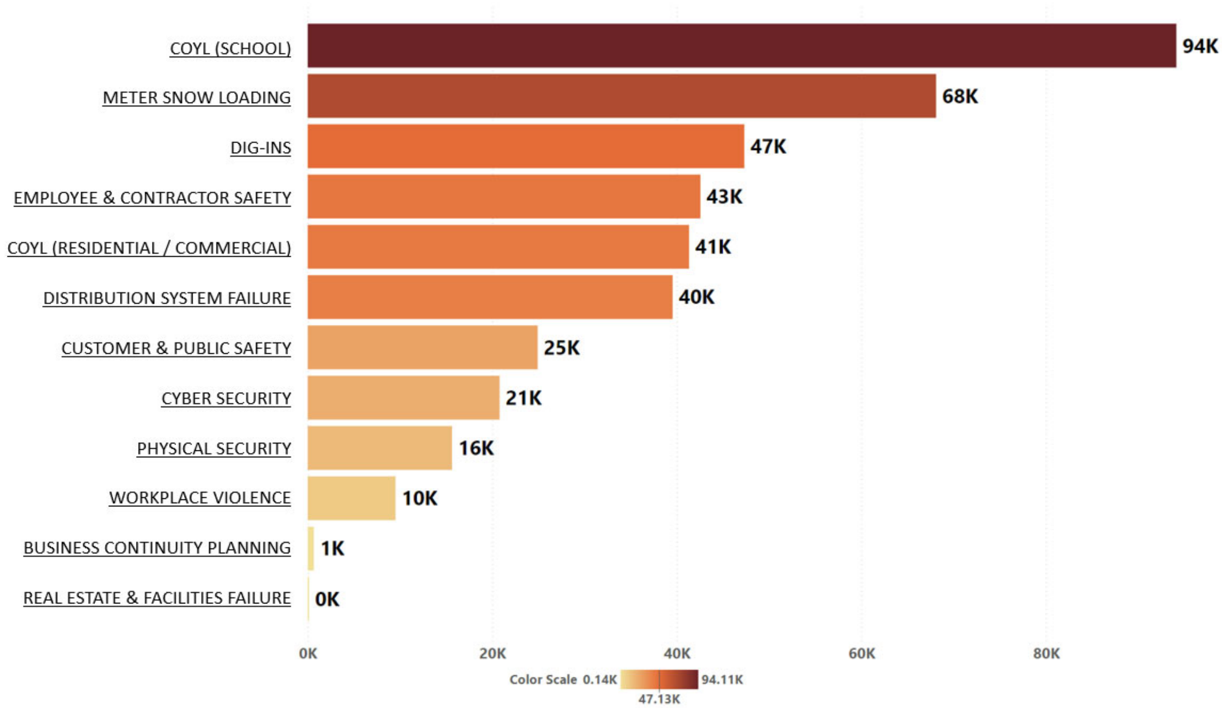
Q. 18 Please describe Southwest Gas' risk monitoring approach.

A. 18 Monitoring is initiated once Southwest Gas has completed the first five processes of risk management. This step includes a review of all aspects of risk management and supports the Company's efforts at continuous improvement its framework.

Continuous monitoring and review of risk events ensures that risk owners understand the residual risk appropriately and evaluate the effectiveness of controls. New risks can appear while other risks may no longer exist (i.e., discontinued operations). Changes in business conditions may also change the risk frequency or velocity. The dynamic nature of risks required the Risk Project Team to develop measures for monitoring risks and identifying such changes.

Q. 19 What were the top risks identified?

A. 19 The objective of the six-step risk process is to identify risks to the organization. The table below identifies Southwest Gas' top risks based on risk scores and judgement of the Risk Project Team.



Q. 20 What lessons did Southwest Gas learn that it can incorporate into future filings?

A. 20 This is now the second time that Southwest Gas undertook the risk-informed decision-making process. The process improved from the prior process; however, the Company identified opportunities for improvement in future GRCs. Probabilistic modeling is one such area the CPUC continues to encourage the utilities to mature. Southwest Gas will continue to look for opportunities to improve and incorporate probabilistic modeling. Also, the Company will consider periodic updates to leadership throughout the risk workshop series. This would allow leaders the opportunity to provide preliminary inputs and guidance.

Q. 21 How does the Company plan on increasing its use of probabilistic calculations and improving data collection?

A. 21 Southwest Gas continues to work toward refining the risk-based decision-making process, which includes, when appropriate, gradual movement toward more probabilistic calculations that are quantifiable. The Company will continue to improve data collections methods and will continue to endeavor to evaluate and document various data points in the future including more detailed data that would allow for the development of probabilistic distributions of frequency and consequence.

Q. 22 Please describe Southwest Gas' safety culture, executive engagement, and compensation policies.

A. 22 The safety culture at Southwest Gas is one of ownership and leadership. It begins with the following mission statement:

> Safety is our number one priority at Southwest Gas. The Company will continually foster a culture where employees are empowered to embrace personal responsibility for the safety of themselves, their colleagues, and the communities they serve.

Southwest Gas' commitment to safety is established and modeled through its executive management engagement. This "tone at the top" is demonstrated by including safety metrics into Southwest Gas management incentive compensation plan.[15] It is also reflected in Southwest Gas' Pipeline Safety

[15] See Southwest Gas' responses to Master Data Requests 84 and 85.

Committee, a group of Vice Presidents and Senior Vice Presidents, that meet regularly to discuss emerging issues within the industry, as well as best practices and lessons learned from the Company's own operations.

Southwest Gas' commitment to safety is also evidenced in internal and external messaging from its leadership. At the beginning of each calendar year, Southwest Gas hosts a Safety Kick Off meeting for the entire Company. This highlights the Company's safety message, goals, and commitment to safety throughout the year. In addition to the Safety Kick Off meeting, the Company participates in the National Safety Month, an initiative started by the National Safety Council.

Additionally, there is a bi-weekly safety call that is facilitated by the Officers of the Company. These calls highlight safety messaging, relevant safety topics, near misses, and lessons learned among other items. Similarly, Southwest Gas executives express the Company's commitment to safety in external communications such as the Company's California Safety Plan and the Southwest Gas Holdings, Inc. Sustainability Report.

Southwest Gas also recognizes the importance of educating its customers and the general public about natural gas safety. The Company consistently provides safety messaging in its customer bills and on its website, as well as through broader outreach mediums such as radio spots and social media.

Q. 23 Please describe how Southwest Gas will respond to immediate or short-term crises outside of the RAMP and GRC process?

A. 23 As mentioned in this testimony and described in further detail in the Prepared Direct Testimony of Company witness Kevin M. Lang, the proposed mitigations (three of which are carryovers from the Company's prior rate case) stemming from Southwest Gas' risk-informed decision-making framework focus on proactive measures that are incremental to the Company's day-to-day operations. Southwest Gas did not propose mitigations that are mandated by pipeline safety codes or other requirements, and that are embedded in the Company's current cost of service. Accordingly, Southwest Gas intends to respond to immediate or short-term safety-related crises in the manner prescribed by both regulation and its internal policies and procedures, which will ensure that customers continue to receive safe and reliable natural gas service.

IV. REQUESTED FUNDING OF MITIGATION MEASURES

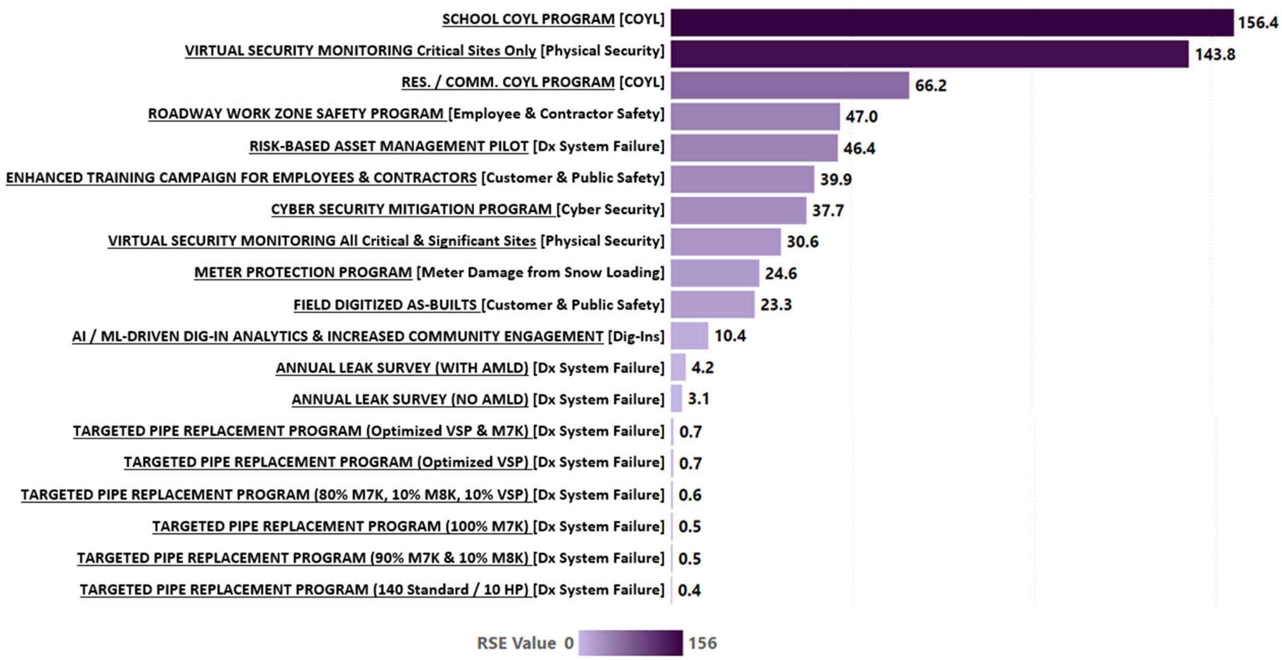
Q. 24 What mitigations does the Company propose as a result of its risk-informed decision-making process?

A. 24 Southwest Gas is proposing several mitigations that address various risks identified through the risk-informed decision-making process. Three of the proposed mitigations are continuations of prior rate case proposals along with one new mitigation proposal. Southwest Gas also evaluated certain controls that it has in place (for example, controls related to dig-ins), which are extremely effective. In most cases, Southwest Gas believes that the funding included in its requested revenue requirement increase[16] is sufficient to continue the identified controls and implement the majority of the scored mitigations. However, the Company is requesting specific cost recovery for four (4) of its mitigations – continuation of its the Targeted Pipe Preplacement Program (TPR),

[16] For additional discussion of the Company's requested revenue requirement increase, please refer to the Prepared Direct Testimony of Company witness Randi L. Cunningham.

Meter Protection Program, School Customer Owned Yardline (COYL) program, and a new Annual Leak Survey Program with conventional and Advanced Mobile Leak Detection.

Southwest Gas has determined RSEs of the proposed mitigations.



General Principle 4 required Southwest Gas to present two alternative mitigation plans that the Company considered for the selected risks. The alternatives analysis may include a proposal to continue the current level of controls or mitigations as one of the possible alternatives. For further details regarding the methodology and process for scoring risks and determining RSEs please refer to Exhibit No. __(BCA-1). The following table shows the results of that exercise.

Alternate Mitigation and RSEs		
Risk	**Alternate Mitigation(s) Considered and RSE(s)**	**Selected Mitigation and RSE**
System Failure	• Targeted Pipe Replacement (TPR) Program – Optimized VSP & M7000 (RSE 0.7) • TPR - Optimized VSP (RSE 0.7) • TPR - 80% M7000, 10% M8000, 10% VSP (RSE 0.6) • TPR - 100% M7000 (RSE 0.5) • TPR - 90% M7000, & 10% M8000 (RSE 0.5) • TPR - 140 Standard/10 HP (RSE 0.4)	Targeted Pipe Replacement Program (RSE 0.7)
COYL	• School COYL Program (RSE 156.4) • Residential/Commercial COYL Program (RSE 66.2)	School COYL Program (RSE 156.4)
Customer Safety	• Meter Protection Program (RSE 24.6) • Enhanced Training Campaign for Employees and Contractors (RSE 39.9) • Field Digitized As-Builts (RSE 23.3)	Meter Protection Program (RSE 24.6)[17]
System Failure	• Annual Leak Survey with AMLD (RSE 4.2) • Annual Leak Survey No AMLD (RSE 3.1) • Continue with Current Leak Survey Program (RSE - N/A)	Annual Leak Survey with AMLD (RSE 4.2)

[17] The Meter Protection Program includes a suite of safety options (Meter Sheds, EFVs, and ERTs) in which Southwest Gas determines which to utilize based on individual customer need. See the Prepared Direct Testimony of Company witness Kevin M. Lang for the operational implementation of this program.

These four mitigations are supported from an operations perspective by Company witness Kevin M. Lang. Further detail concerning the proposed ratemaking treatment for these programs is provided in the Prepared Direct Testimony of Company witness Randi L. Cunningham.

Q. 25 Does this conclude your prepared direct testimony?

A. 25 Yes.

SUMMARY OF QUALIFICATIONS
BRADLEY C. ANDERSON

I have a Bachelor of Science in Business Administration from Utah Valley University (formerly Utah Valley State College) and Master of Science in Accounting (Masters) from University of Nevada Las Vegas. Shortly after earning my Masters, I began my professional career with Deloitte as an Auditor. At Deloitte, I worked on several engagements providing auditing services to publicly-traded companies for nearly four years.

I transitioned from Deloitte to Southwest Gas as an Auditor in May of 2011. As an Auditor, I was responsible for planning, developing, and executing complex financial and operational reviews/audits. All audits were done using a risk-based audit program. As such, risk assessments were a critical part of the audit planning process.

In April of 2014 I moved from Internal Audit to the Risk Management. During my tenure in Risk Management, I have been a Supervisor, Administrator, Manager, and am currently Director of Enterprise Risk Management and Corporate Compliance. As a Director, I am responsible for: the day-to-day oversight of the Company’s commercial insurance program; Enterprise Risk Management, Business Continuity, Claims and Investigations, and Infrastructure Protection.

2026 CA GRC Risk Workshop Series

Final Results

June 2024

SOUTHWEST GAS

accenture

Contents

Background and Methodology

Methodology

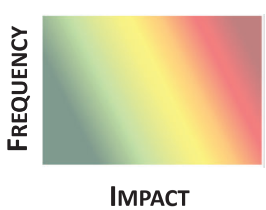
1 Brainstorm list of enterprise **risks**

Risk $_A$ | Risk $_B$ | Risk $_C$ | …

2 Score each risk in "natural units"[1] for each of the three **impact categories** and **frequency** to infer a 1-to-7 score and render a quantitative **risk score**

SAFETY	7	6	5	4	3	2	1
OPERATIONAL	7	6	5	4	3	2	1
FINANCIAL	7	6	5	4	3	2	1
FREQUENCY	7	6	5	4	3	2	1

$$Risk\ Score = Frequency \times \sum_{i=1}^{3} Weight_i \times 10^{Impact_i}$$



[1] ***Natural Units***
Safety: Serious Injuries, Fatalities
Operational: Meters Out, Hours to Restore
Financial: Dollars

3 List **mitigations** for each risk

Risk $_A$ | Risk $_B$ | Risk $_C$ | …

Mitigation	Description
Mitigation$_1$	~~~~~~~~~~~~~~~~~~
Mitigation$_2$	~~~~~~~~~~~~~~~~~~
Mitigation$_3$	~~~~~~~~~~~~~~~~~~
…	~~~~~~~~~~~~~~~~~~

4 For each mitigation, quantify how much risk is reduced using the method in Step 1, and combine with cost figures to attain **Risk-Spend-Efficiency (RSE)**

$$RSE = \frac{\Delta Risk}{Cost}$$

Risk $_A$

Mitigation	Description	RSE
Mitigation$_1$	~~~~~~~~~~~~~~~~~~	xxx
Mitigation$_2$	~~~~~~~~~~~~~~~~~~	xxx
Mitigation$_3$	~~~~~~~~~~~~~~~~~~	xxx
…	~~~~~~~~~~~~~~~~~~	xxx

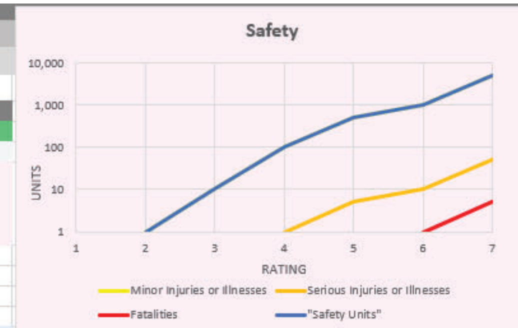
7x7 Rubric

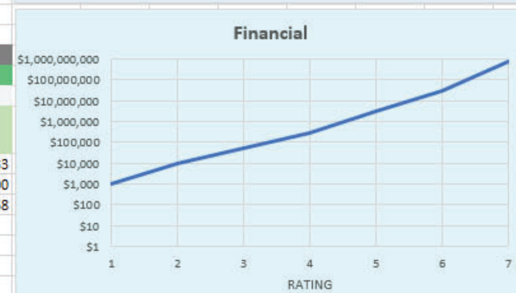
7x7 Inputs

NOTE: Values represent lower limit of rating

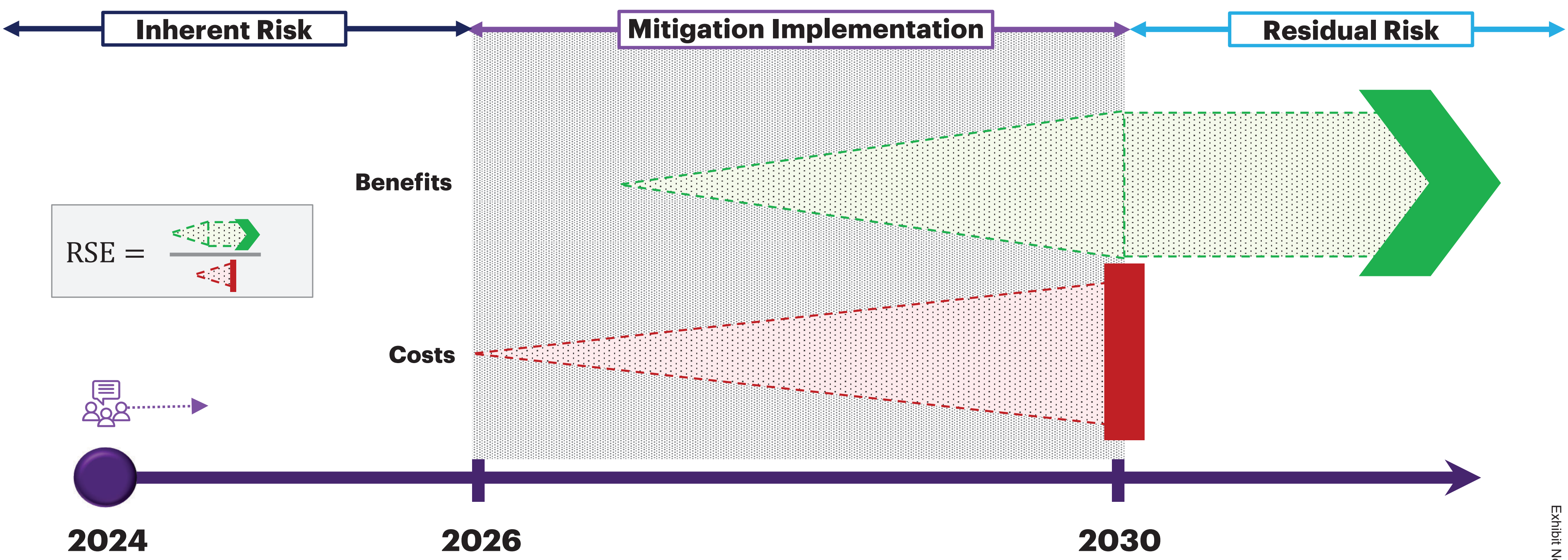
CATEGORY DESCRIPTION	WEIGHT	RATING 7	6	5	4	3	2	1
		Catastrophic	Severe	Extensive	Major	Moderate	Minor	Negligible
Safety: Danger to employees or the public	65%	Many fatalities and life threatening injuries	Few fatalities and life threatening injuries	Many serious injuries / illnesses	Few serious injuries / illnesses	Many minor injuries / illnesses	Few minor injuries / illnesses	No reportable injuries / illnesses
Minor Injuries or Illnesses		5,000	1,000	500	100	10	1	0
Serious Injuries or Illnesses		50	10	5	1	0	0	0
Fatalities		5	1	0	0	0	0	0
"Safety Units"		5,000	1,000	500	100	10	1	0
Operational: Disruption to company operations that could impact customers; may be measured in quantity of impacted customers, critical locations, &/or duration	20%	Customers affected: >200k Time to restore: 60 days	Customers affected: 50k - 200k Time to restore: 30 days	Customers affected: 5k - 50k Time to restore: 1 week	Customers affected: 1k - 5k Time to restore: 2 days	Customers affected: 100 - 1k Time to restore: 12 hours	Customers affected: 10 - 100 Time to restore: 3 hours	Customers affected: <10 Time to restore: <1 hour
Customers Affected		200,000	50,000	5,000	1,000	100	10	1
Hours to Restore		1,440	720	168	48	12	3	1
Financial: Potential financial loss, including disallowance, legal actions, replacement energy, remediation, damage to 3rd party,	15%	>$750M loss	$30M - $750M loss	$3M - $30M loss	$300k - $3M loss	$50k - $300k loss	$10k - $50k loss	<$10k
Financial loss		$750,000,000	$30,000,000	$3,000,000	$300,000	$50,000	$10,000	$1,000

Frequency	RATING 7	6	5	4	3	2	1
	Common	Regular	Frequent	Occasional	Infrequent	Rare	Remote
Frequency: Likelihood of an occurrence	> 10 times per year	1 to 10 times per year	Once every 1 to 3 years	Once every 3 to 10 years	Once every 10 to 30 years	Once every 30 to 100 years	Once every 100+ years
Min Rate	10.0000	1.0000	0.3333	0.1000	0.0333	0.0100	0.0033
Max Rate	30.0000	10.0000	1.0000	0.3333	0.1000	0.0333	0.0100
Value (Not used)	17.3205	3.1623	0.5774	0.1826	0.0577	0.0183	0.0058





2026 California GRC Method

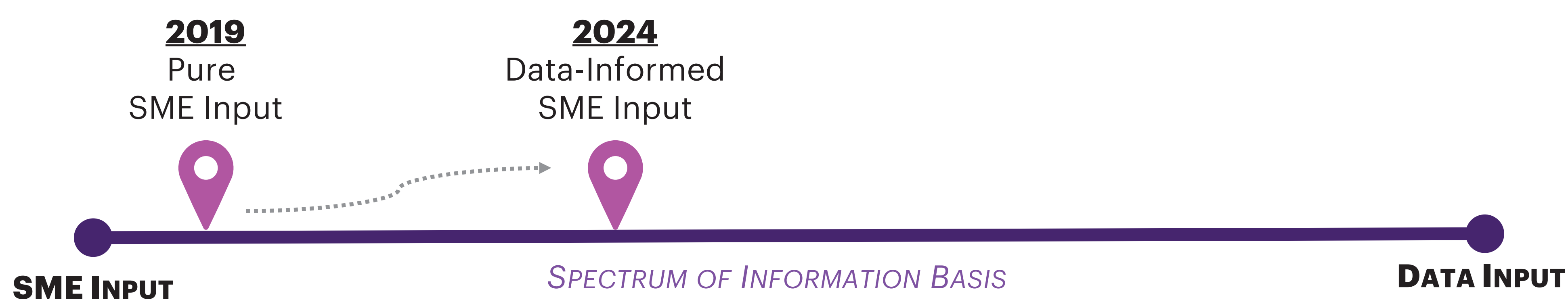


KEY IMPROVEMENTS: 2019 VS. 2024

Key Improvements

- **Data-informed** risk scoring and mitigation frequencies (pre- and post-)
- **Cost allocation** from O&M vs capital
- **Ramp-up period** for mitigations
- **Refreshed value framework** which further emphasizes safety

Note: These improvements advance SWG maturity and quality of results yet hamper comparability to 2019 results



Risk scoring results

PROPOSED CA RISK REGISTRY FOR '26 CA GRC

Category	Risk	Risk Owner	Definition	Worst Reasonable Scenario
Pipeline Operational Risks	**Dig-Ins**	Gas Operations Support Staff	1st, 2nd or 3rd party damage to SWG underground assets	Dig-in causes building to fill with gas, resulting in explosion, causing injuries / fatalities, property damage, financial loss, regulatory impact, and reputational damage
	Distribution System Failure	System Integrity	Damage to or failure of the gas distribution pipeline	Distribution pipe at household leaks and explodes, causing injuries / fatalities and loss of property
	Meter Damage from Snow Loading	District Operations NNV	Inclement winter weather damages meters on side of customer's property	Ice or snow falls off the roof line, breaks the meter off at house and gas migrates into the house resulting in an explosion
Customer Risks	**Customer & Public Safety**	Gas Operations Support Staff	Event causing health or financial damage to a member of SWG's customer base	Errors in covered tasks and/or emergency response for a customer call result in an unintended catastrophic event (home explosion) causing a loss of life
	COYL (Residential, Commercial)	System Integrity	Leak on residential / commercial customer-owned pipelines that are neglected by customers	Catastrophic leak in COYL with migration into residential structure with ignition, resulting in injuries / fatalities, property damage, and reputational damage
	COYL (School)	System Integrity	Leak on school customer-owned pipelines that are neglected by customers	Catastrophic leak in COYL with migration into portable classroom at a school with ignition, resulting in injuries / fatalities, property damage, and reputational damage
Personnel Risks	**Employee & Contractor Safety**	Operations Risk Management & Safety	Employee- or contractor-related event resulting in an Occupational Safety and Health Administration (OSHA)-recordable injury or fatality	Incident in work zone adjacent to roadway involving a negligent driver resulting in significant loss of life of employees; SWG created & controlled work with a 3-man crew
	Workplace Violence	Infrastructure Protection	Violent incident in a SWG workplace	Targeted shooter event at Victorville resulting in major loss of life
Infrastructure Risks	**Business Continuity Planning**	Business Continuity	Disruption of business operations arising from infraction on business continuity	Data center outage rendering server for FOMS (field order management system) unavailable, requiring infrastructure rebuild and alternative business structure accommodation
	Cyber Security	Information Security	Cybersecurity breach that results in the exposure and/or destruction of critical data	Cybersecurity compromise of employee or retiree data via privileged insider error and/or malicious intent, resulting in a loss of confidentiality event
	Physical Security	Infrastructure Protection	Facilities-related events arising from lack of physical security over significant gas or corporate infrastructure	A malicious syndicate vandalize regulator station causing unwarranted overpressure and pipe explosion causing injuries / fatalities and reputation damage
	Real Estate & Facilities Failure	Enterprise Facilities Management	Real estate incident prohibiting facilities from occupancy on normal use	A long-term power utility failure renders Victorville facilities unoccupiable for four days as backup generation does not support sustained independent operation in excess of 96 hours

FINAL RISK SCORING RESULTS

Click Below Links to View Associated Risk Slide

COYL (SCHOOL)

METER SNOW LOADING

DIG-INS

EMPLOYEE & CONTRACTOR SAFETY

COYL (RESIDENTIAL / COMMERCIAL)

DISTRIBUTION SYSTEM FAILURE

CUSTOMER & PUBLIC SAFETY

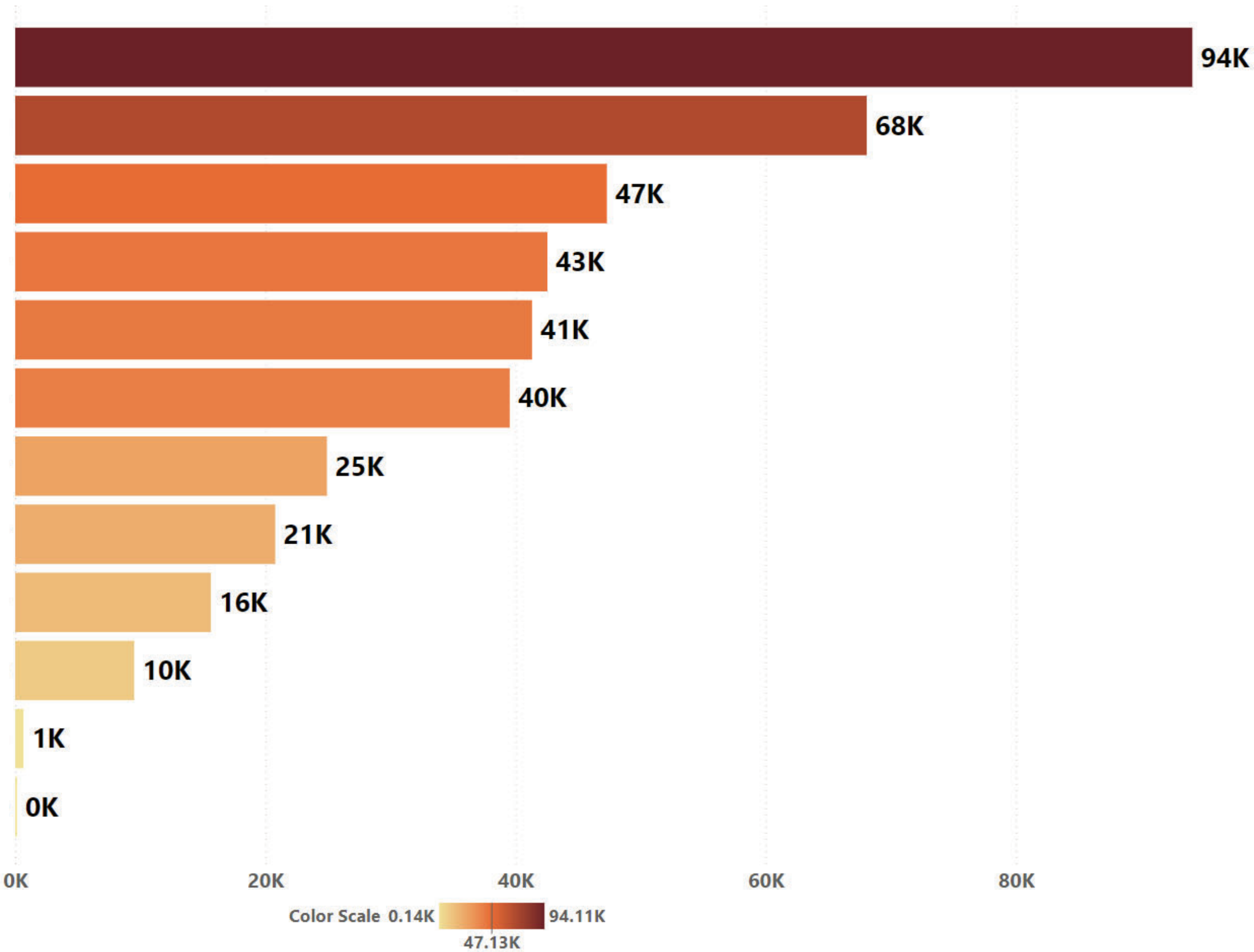
CYBER SECURITY

PHYSICAL SECURITY

WORKPLACE VIOLENCE

BUSINESS CONTINUITY PLANNING

REAL ESTATE & FACILITIES FAILURE



Shortcuts:
•RISK SCORING RESULTS
•MITIGATION SCORING RESULTS

COYL (SCHOOL) Scoring Summary

DEFINITION

Leak on school customer-owned pipelines that are neglected by customers

WORST REASONABLE SCENARIO

Catastrophic leak in COYL with migration into portable classroom at a school with ignition, resulting in injuries / fatalities, property damage, and reputational damage

SAFETY IMPACT PER INCIDENT

5 *Fatalities*

10 *Serious Injuries*

Assumes an average classroom size of ~25 with up to one classroom within radius of explosion. Class size is consistent with the self-contained average classroom sizes for K-5 per CA Dept. of Education. Average serious injuries of top 10 highest fatality count PHMSA distribution incidents w/ explosions since 2010: 9.9; Average of top 10 highest fatality count PHMSA distribution incidents w/ explosions since 2010: 4.4

OPERATIONAL IMPACT PER INCIDENT

1 *Meters Out*

120 *Hours to Restore*

Single customer (the school); likely multiple days necessary for system restoration.

FINANCIAL IMPACT PER INCIDENT

$60M

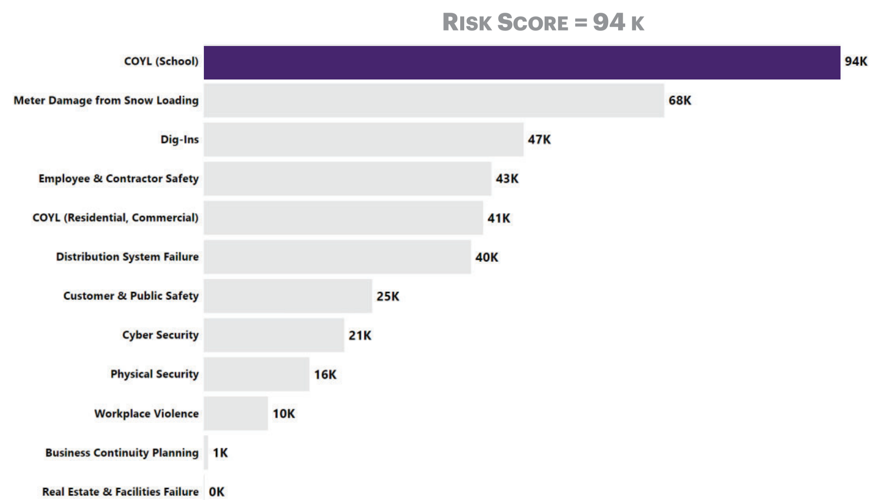
The most applicable recent incident (Hennipen MN in 2018) had an estimated $48M in property damage.

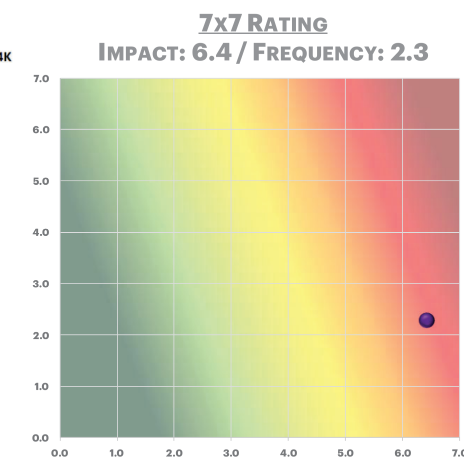
FREQUENCY

1 incident every…

71.8 *Years*

Frequency is based on last ten years (2014 - 2023) of school COYL incidents reported to SWG, which had come from a SWG-CA total school count of 136. By end of 2025, 34 of those 136 schools are anticipated to have been addressed via the 2021 GRC cycle school COYL program. This frequency calculation applies to the remaining 102 schools with COYLs in the service territory by end of 2025.





COYL (SCHOOL) Supporting Info: Frequency Calculation

Definition

Leak on school customer-owned pipelines that are neglected by customers

Worst Reasonable Scenario

Catastrophic leak in COYL with migration into portable classroom at a school with ignition, resulting in injuries / fatalities, property damage, and reputational damage

#	Parameter	Value	Rationale / Data Source
1	Projected Annual Incidents / Year based on End of Year School Count	**1.65**	Based on a projected end of 2025 School COYL count of 102, which assumes that 34 of the original 136 schools in the CA service territory were addressed between 2021 – 2025 (see program background slide for more info on projection)
		✖	
2	Reporting Inflator ☆	**2**	Assumption that for every 1 incident reported to SWG, one additional incident is addressed by the school w/o contacting SWG
		✖	
3	% of Incidents which are "Major" ☆	**10%**	Assumption that 1 in 10 school COYL incidents are significant (Note: SWG-CA identified 22 school incidents over past 10 years [2014-2023]; 2 had a known closure)
		✖	
4	% of Major Leaks which Ignite / Explode	**15.4%**	Enercon Safety Study – Sept. 2015 – Table 8-1
		✖	
5	School in session rate ☆	**27.4%**	Accounts for the % of time during a calendar year that a school is in session and occupied (see school occupancy rate slide)
		=	
	Calculated Fatal Explosion School COYL Incidents Per Year	***0.0139***	
	Equivalent to an event occurring every 'n' years	***71.8***	

☆ = **SME Estimate**

COYL (SCHOOL) Supporting Info: Data Review

Historical Incident Data Overview:

Count of Schools assumed to be in-scope by Operating Area	
NCA & SLT	31
SCA	105
Total	136

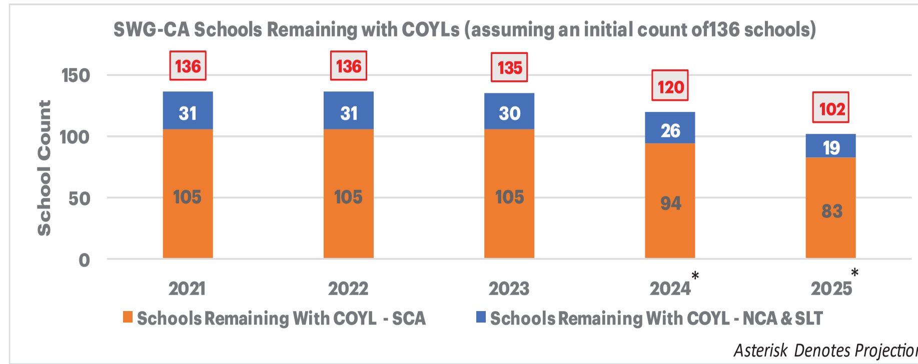
Total Reported Incidents to SWG (2014 – 2023)	
NCA & SLT	11
SCA	11
Total	22

Average Reported Incidents per year (based on last 10 yrs)	
NCA & SLT	1.1
SCA	1.1
Total	2.2

At this rate, and an assumed count of 136 schools, a given school reports an incident to SWG once per ~62 years

"Major" Incidents Rationale	
Total documented incidents across last 10 years (2014 – 2023)	22
Incidents in which a school closure was documented	2

Program Progress to-date, and projections for '24 & '25:



Progress					
Year	2021	2022	2023	2024*	2025*
NCA/SLT	0	0	1	4	7
SCA	0	0	0	11	11
Schools Completed (Total)	**0**	**0**	**1**	**15**	**18**

By end of 2025, a total of 34 schools are projected to be completed, leaving 102 schools still to be addressed

1. *Asterisk denotes projections from SWG-CA team*

COYL (SCHOOL) Supporting Info: Occupancy Rate Assumption

Overview of the methodology applied for arriving at the “School in Session Rate” percentage assumption:

Value	Parameter	Rationale
52	Weeks per year	*Weeks per calendar year*
×		
5	Days per week	*Monday through Friday weekly*
-		
60	Weekdays per year where school is closed	*Accounting for holidays and summer break when facilities are not customarily occupied in large numbers*
=		
200	Assumed school days per year	*180 school days per calendar year as required by CA state law + 20 days of summer school*
×		
12	Hours per school day	*Actual school day is shorter, but this accounts for occupancy time before and after school*
=		
2,400	Hours of school in session per year	
÷		
8,760	Total hours per year	*[24 hours / day] × [365 days / year]*
=		
27.4%	% of a given year that school is in session	*This is the assumption that directly feeds into the incident frequency calculation*

Shortcuts:
•RISK SCORING RESULTS
•MITIGATION SCORING RESULTS

METER SNOW LOADING Scoring Summary

DEFINITION

Inclement winter weather damages meters on side of customer's property

WORST REASONABLE SCENARIO

Ice or snow falls off the roof line, breaks the meter off at house and gas migrates into the house resulting in an explosion

SAFETY IMPACT PER INCIDENT

1 *Fatality* 2 *Serious Injuries*	-US Census estimate for California household size (2.89) -PHMSA 2010 - present distribution incident data shows more serious injuries occur than fatalities for explosion incidents in which safety-related consequences resulted (serious injury and/or fatality).

OPERATIONAL IMPACT PER INCIDENT

3 *Meters Out* 72 *Hours to Restore*	Assume customer of primary residence and 2 adjacent customers for a 3-day period (same assumption applied as the customer & public safety risk)

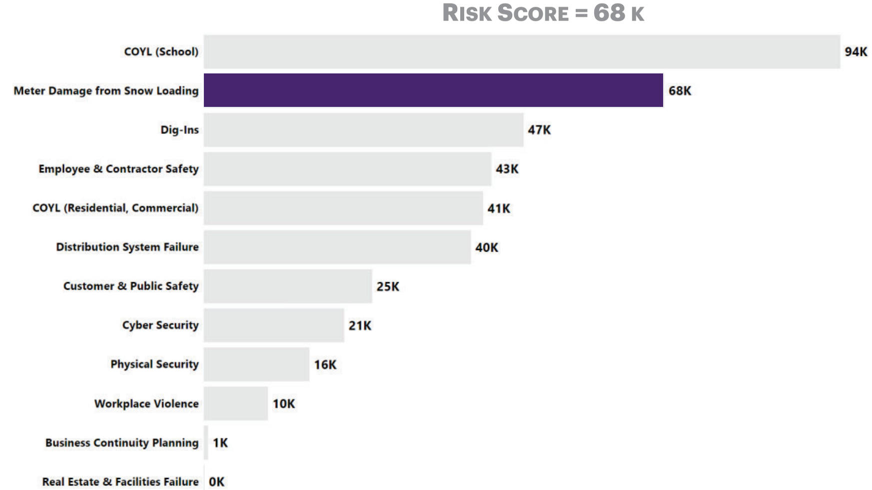
FINANCIAL IMPACT PER INCIDENT

$13M	$3M in fines, and $10M for property damage

FREQUENCY

1 incident every… 13.4 *Years*	This event frequency is based on projected average meter incident counts per winter season by the end of 2025. It was derived using available historical meter incident data and anticipated progress from the 2021 GRC's meter protection program. There have been multiple explosion incidents in recent years (twice past 7 years), including the 2008 incident at a restaurant.

RISK SCORE = 68 K



7x7 RATING
IMPACT: 5.7 / FREQUENCY: 3.7

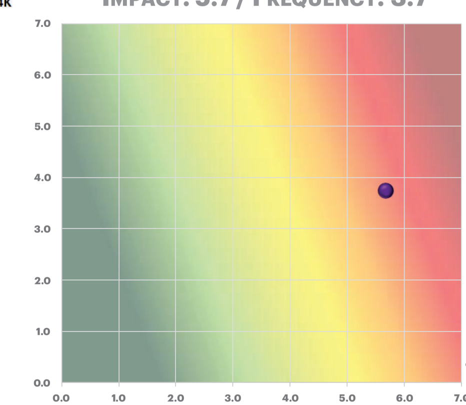


Exhibit No.___ (BCA-1)
Sheet 15 of 96

Shortcuts:
•RISK SCORING RESULTS
•MITIGATION SCORING RESULTS

METER SNOW LOADING Supporting Info: Frequency Calculation

Definition

Inclement winter weather damages meters on side of customer's property

Worst Reasonable Scenario

Ice or snow falls off the roof line, breaks the meter off at house and gas migrates into the house resulting in an explosion

#	Parameter	Value	Rationale / Data Source
1	Estimated snow-related meter incidents per year (2026 proj.)	86	• Continuation from the in-flight mitigation RSE calculation assumptions; accounts for the anticipated incident reduction progress achieved via the 2021 GRC cycle meter protection program
		✖	
2	% of meter incidents resulting in an explosion	0.44%	• SWG Incident Records: Over the 2022 – 2023 winter season, 1 of the 229 documented meter incidents resulted in an explosion (0.44%)
		✖	
3	% of Gas Explosion Incidents from natural forces causes resulting in safety consequences	39.4%	• 2010 – 2023 PHMSA Incidents: Of the 33 distribution incidents in which natural forces was the cause AND an explosion occurred, 13 resulted in some kind of safety consequences (serious injuries and/or fatalities)
		✖	
4	Home Occupancy % ☆	50%	• Assumption that many of the SWG-supplied homes in heavy-snow areas are either part-time residences or vacation rentals, thus a lower occupancy rate than a typical home (Supporting Article)
		=	
	Calculated Fatal Explosion Incidents Per Year from Meter Snow Loading	0.07	
	Equivalent to an event occurring every 'n' years	13.4	

☆ = SME Estimate

DIG-INS Scoring Summary

DEFINITION

1st, 2nd or 3rd party damage to SWG underground assets

WORST REASONABLE SCENARIO

Dig-in causes building to fill with gas, resulting in explosion, causing injuries / fatalities, property damage, financial loss, regulatory impact, and reputational damage

SAFETY IMPACT PER INCIDENT

1 *Fatality*

2 *Serious Injuries*

In the past 25 years, SWG has had one incident resulting in 2 serious injuries (employees), and another resulting in a fatality. Approximately 20% of the past 5 years' dig-in events have occurred in a home setting (avg. household is 3 people in CA per US Census)

OPERATIONAL IMPACT PER INCIDENT

1.5K *Meters Out*

72 *Hours to Restore*

One of the past incidents resulted in shutting off 1,500 customer residences that were restored within 72 hours

FINANCIAL IMPACT PER INCIDENT

$13M

$3M in fines, and $10M for property damage

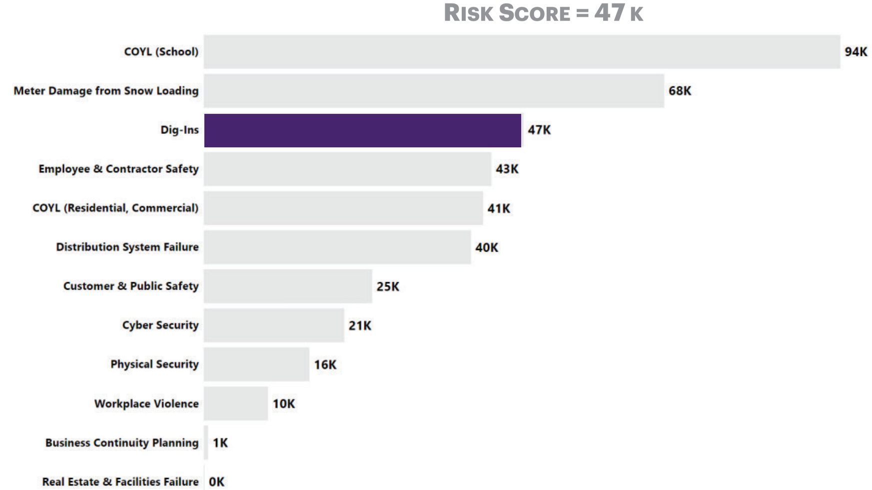
FREQUENCY

1 incident every…

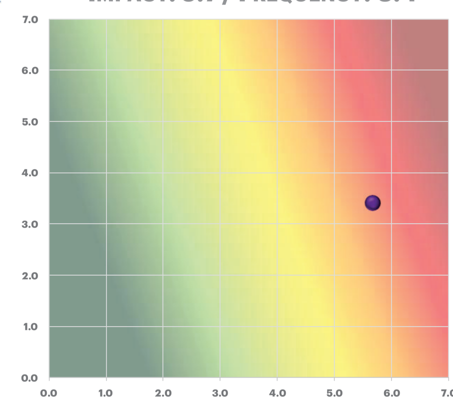
19.3 *Years*

This estimate is based on the historical 5-year average (2018 - 2022) of 132 excavation-triggered leaks per year for SWG-CA with a series of assumptions applied.

RISK SCORE = 47 K



7X7 RATING
IMPACT: 5.7 / FREQUENCY: 3.4



DIG-INS Supporting Info: Frequency Calculation

Definition

1st, 2nd or 3rd party damage to SWG underground assets

TRIGGERS

- Equipment Failure
- Weld/Pipe Material Failure
- Corrosion Failure
- Excavation Damage
- Incorrect Operations
- Natural Force Damage
- Other Outside Force

RISK EVENT: DIG-INS

Worst Reasonable Scenario

Dig-in causes building to fill with gas, resulting in explosion, causing injuries / fatalities, property damage, financial loss, regulatory impact, and reputational damage

#	Parameter	Value	Rationale / Data Source
1	Excavation Leaks / Year (SWG-CA)	125	• 2018 – 2022 average dig-ins per year (SWG-CA Mains & Services annual leak records)
		✖	
2	% of dig-ins resulting in an ignition OR explosion	0.09%	• Based on 5,573 line breaks from 2018 - 2022, there were a total of 5 which resulted in an ignition event (SWG enterprise-wide data)
		✖	
3	% of Gas Explosion Incidents resulting in a fatality	46.3%	• 2010-2023 PHMSA Incidents: Of the 95 excavation damage incidents where an explosion occurred, 44 (46.3%) resulted in serious injury and/or fatality
		=	
	Calculated Fatal Explosion Incidents Per Year from Dig-Ins	0.05	
	Equivalent to an event occurring every 'n' years	**19.3**	

★ = SME Estimate

Shortcuts:
•RISK SCORING RESULTS
•MITIGATION SCORING RESULTS

EMPLOYEE & CONTRACTOR SAFETY Scoring Summary

DEFINITION

Employee- or contractor-related event resulting in an Occupational Safety and Health Administration (OSHA)-recordable injury or fatality

WORST REASONABLE SCENARIO

Incident in work zone adjacent to roadway involving a negligent driver resulting in significant loss of life of employees; SWG created & controlled work with a 3-man crew.

SAFETY IMPACT PER INCIDENT

1
Fatality

0
Serious Injuries

Assumes a 3-man crew, with 1 of the personnel working in vicinity of accident

OPERATIONAL IMPACT PER INCIDENT

0
Meters Out

0
Hours to Restore

Such an incident is not anticipated to trigger any impact to customers

FINANCIAL IMPACT PER INCIDENT

$450K

$450K for loss of work truck and associated equipment loadout

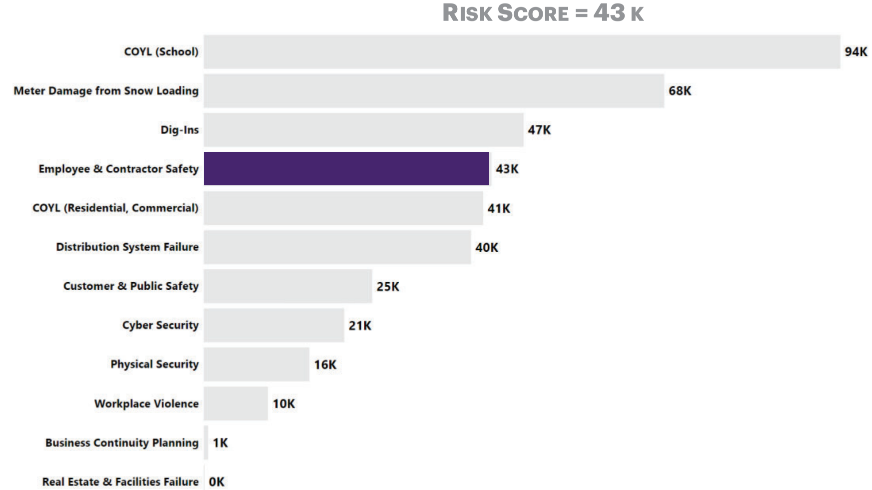
FREQUENCY

1 incident every…

15.3
Years

2 similar incidents (1 each in NV and AZ) in past 10 years. Based on 2019-2023 SWG-CA roadway adjacent capital & O&M spend of $73M per year on avg., 10% of which is assumed to occur in high-risk roadside areas ($7.3M). The $7.3M is then multiplied by the NHWA statistic of 1 roadway work zone fatality for every $112M in spend.

RISK SCORE = 43 K



7x7 RATING
IMPACT: 4.5 / FREQUENCY: 3.6

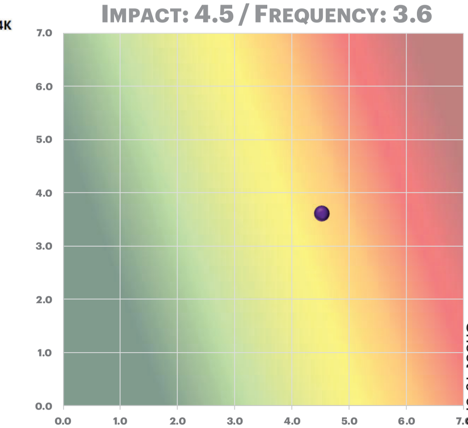


Exhibit No.___ (BCA-1)
Sheet 19 of 96

EMPL. & CONT. SAFETY Supporting Info: Frequency Calculation

Definition

Employee- or contractor-related event resulting in an Occupational Safety and Health Administration (OSHA)-recordable injury or fatality

Worst Reasonable Scenario

Incident in work zone adjacent to roadway involving a negligent driver resulting in significant loss of life of employees; SWG created & controlled work with a 3-man crew

#	Parameter	Value	Rationale / Data Source
1	SWG-CA Avg. Annual Spend on work adjacent to roadways	**$73M**	• 2019-2023 avg. capital & O&M spend for roadway-related work
		✖	
2	Assumed Percentage of above spend adjacent to high-risk roadside areas (e.g., highways) ☆	**10%**	• Assumption – this is an estimate of the mileage of mains for SWG-CA which are within 50 feet of streets with posted speed limits of 50 mph or greater
		=	
3	Assume high-risk area spend	**$7.3M**	• Result of [item 1] x [item 2]
		✖	
4	Federal Highway Administration roadside work zone fatality assumption	$\frac{1\ fatality}{\$112M}$	• Source - Federal Highway Administration
		=	
	Calculated Fatal Explosion Incidents Per Year	**0.07**	
	Equivalent to an event occurring every 'n' years	**15.3**	

☆ = SME Estimate

COYL (RESIDENTIAL / COMMERCIAL) Scoring Summary

DEFINITION

Leak on residential / commercial customer-owned pipelines that are neglected by customers

WORST REASONABLE SCENARIO

Catastrophic leak in COYL with migration into residential structure with ignition, resulting in injuries / fatalities, property damage, and reputational damage

SAFETY IMPACT PER INCIDENT

1 *Fatality*

2 *Serious Injuries*

-Most of the COYLs in the CA service territory are residential, so residential assumptions are applied.
-US Census estimate for California household size (2.89)
-PHMSA 2010 - present distribution incident data shows more serious injuries occur than fatalities for explosion incidents in which safety-related consequences resulted (serious injury and/or fatality).

OPERATIONAL IMPACT PER INCIDENT

3 *Meters Out*

120 *Hours to Restore*

Assume customer of primary residence and 2 adjacent customers. Likely multiple days to restore service (same hours assumption as School COYL)

FINANCIAL IMPACT PER INCIDENT

$10M

Assumes $10M in property damages. No fines are assessed since it is the responsibility of the customer to maintain.

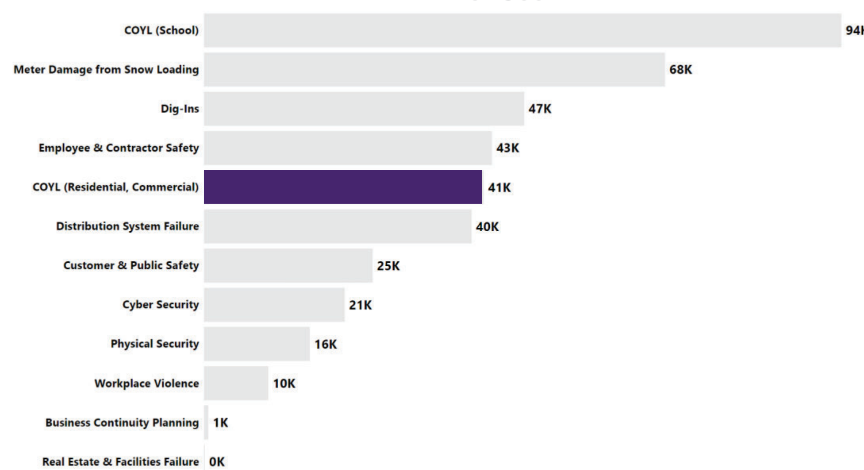
FREQUENCY

1 incident every…

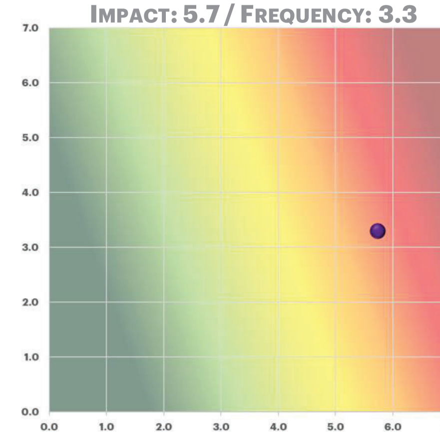
21.9 *Years*

Based on an estimated 4,591 non-school customers with a COYL in the CA service territory, and a series of assumptions applied to estimate an incident rate and ultimately a frequency for a worst reasonable scenario event.

RISK SCORE = 41 K



7x7 RATING
IMPACT: 5.7 / FREQUENCY: 3.3



COYL (RES./COMM.) Supporting Info: Frequency Calculation

Definition

Leak on residential / commercial customer-owned pipelines that are neglected by customers

Worst Reasonable Scenario

Catastrophic leak in COYL with migration into commercial structure with ignition, resulting in injuries / fatalities, property damage, and reputational damage

#	Parameter	Value	Rationale / Data Source
1	Approx. Count of Residential / Commercial COYLs in SWG-CA service territory	**4,591**	• SWG-CA GIS records for all COYL customers (excludes schools)
		✖	
2	Estimated Incidents per COYL per Year: SWG-CA	**0.0162**	• Ratio using school COYL data for SWG-CA: 2.2 incidents/yr. divided across the 136 schools with COYLs → 0.0162 incidents per COYL per year
		✖	
3	% of Residential / Commercial COYL incidents resulting in ignition or explosion event ☆	**0.15%**	• Assumption that for every 2,000 residential / commercial COYL incidents, 3 would result in an ignition and/or explosion event (as a reference point for comparison, 0.09% of SWG dig-ins resulted in an ignition/explosion)
		✖	
4	% of Gas Ignition / Explosion Incidents resulting in a fatality	**41%**	• PHMSA Incidents: Of the 147 non-excavation distribution incidents since 2010 in which an explosion occurred, 61 (41%) resulted in some kind of safety consequences; same assumption applied to dist. sys. failure
		=	
	Calculated Fatal Explosion Res./Comm. COYL Incidents Per Year	**0.05**	
	Equivalent to an event occurring every ‘n’ years	**21.9**	

☆ = SME Estimate

DISTRIBUTION SYSTEM FAILURE Scoring Summary

DEFINITION

Damage to or failure of the gas distribution pipeline

WORST REASONABLE SCENARIO

Distribution pipe adjacent to household leaks and explodes, causing injuries / fatalities and loss of property

SAFETY IMPACT PER INCIDENT

1 *Fatality*

2 *Serious Injuries*

-US Census estimate for California household size (2.89)
-PHMSA 2010 - present distribution incident data shows more serious injuries occur than fatalities for explosion incidents in which safety-related consequences resulted (serious injury and/or fatality).

OPERATIONAL IMPACT PER INCIDENT

2.5k *Meters Out*

120 *Hours to Restore*

Based on isolation zones consisting of around 2,500 customers (for a typical HP distribution line). Extensive restoration time is likely.

FINANCIAL IMPACT PER INCIDENT

$50M

Considering the potential impact of failure of the HP system (>60psi). More customers affected, supply distribution, and potentially higher regulatory compliance fines.

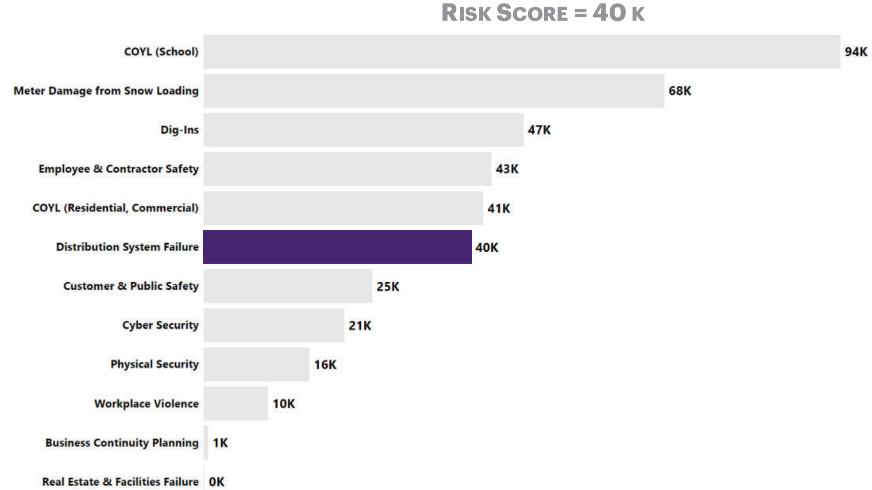
FREQUENCY

1 incident every…

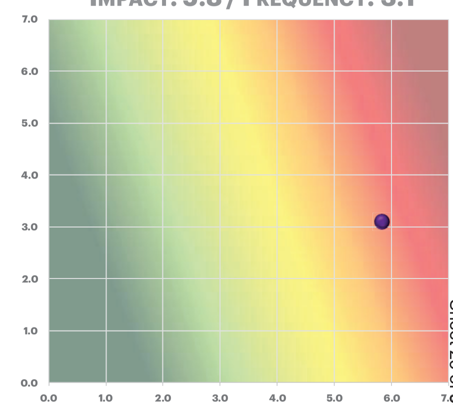
27.1 *Years*

Based on 2018-2022 avg. of 85 non-excavation leaks per year. Also accounts for the anticipated TPRP progress for '23 - '25, which is estimated to reduce a cumulative 2.61 leaks per year based on mileage replaced by end of '25.

RISK SCORE = 40 K



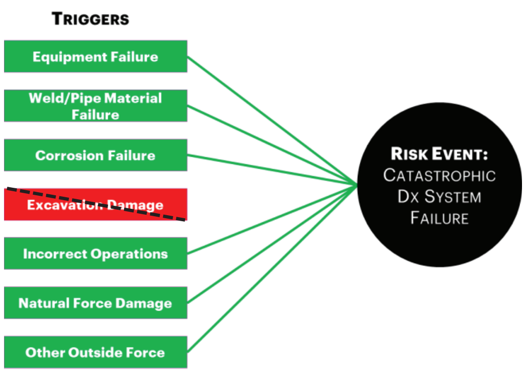
7x7 RATING
IMPACT: 5.8 / FREQUENCY: 3.1



DISTRIBUTION SYSTEM FAILURE Supporting Info: Frequency Calculation

Definition

Damage to or failure of the gas distribution pipeline



Worst Reasonable Scenario

Distribution supply line leaks and explodes, causing injuries / fatalities, property damage and reputational damage

#	Parameter	Value	Rationale / Data Source
1	Leaks / Year (SWG-CA)	82.9	• Average non-excavation leaks per year (2018 – 2022) = 84.6. Source: DIMP CA mains & services leak worksheets; Subtracts anticipated leaks avoided as result of ongoing '23 – '25 TPRP replacements (2.61).
		✖	
2	% of Non-Excavation Leaks which are Grade 1	36.2%	• % of non-excavation leaks which were Grade 1 (2018 – 2022) – Source: DIMP CA mains & services leak worksheets
		✖	
3	% of Non-Excavation Grade 1 Leaks resulting in ignition or explosion ☆	0.3%	• Assumption that 3 per 1,000 Grade 1 non-excavation leaks will result in an ignition or explosion event
		✖	
4	% of Gas Explosion Incidents resulting in a fatality	41%	• 2010-2023 PHMSA Incidents: Of the 147 non-excavation distribution incidents since 2010 in which an explosion occurred, 61 (41%) resulted in some kind of safety consequences
		=	
	Calculated Fatal Explosion Incidents Per Year from Dist. Sys. Failure	0.037	
	Equivalent to an event occurring every 'n' years	**27.1**	

☆ = SME Estimate

Shortcuts:
•RISK SCORING RESULTS
•MITIGATION SCORING RESULTS

CUSTOMER & PUBLIC SAFETY Scoring Summary

DEFINITION

Event causing health or financial damage to a member of SWG's customer base

WORST REASONABLE SCENARIO

Errors in covered tasks and/or emergency response for a customer call result in an unintended catastrophic event (home explosion) causing a loss of life.

SAFETY IMPACT PER INCIDENT

1 *Fatality*

2 *Serious Injuries*

-US Census estimate for California household size (2.89)
-PHMSA 2010 - present distribution incident data shows more serious injuries occur than fatalities for explosion incidents in which safety-related consequences resulted (serious injury and/or fatality).

OPERATIONAL IMPACT PER INCIDENT

3 *Meters Out*

72 *Hours to Restore*

Assume customer of primary residence and 2 adjacent customers for a 3-day period (same assumption applied as meter snow loading)

FINANCIAL IMPACT PER INCIDENT

$13M

$10M property losses and $3M in fines

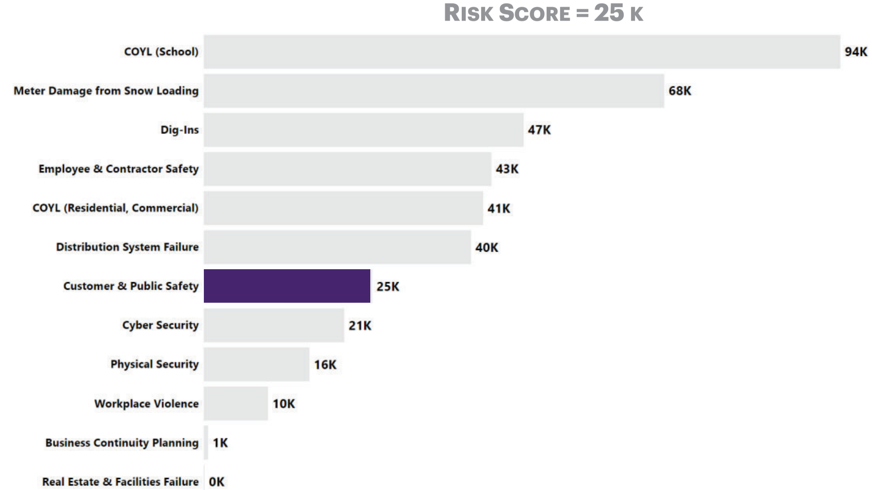
FREQUENCY

1 incident every…

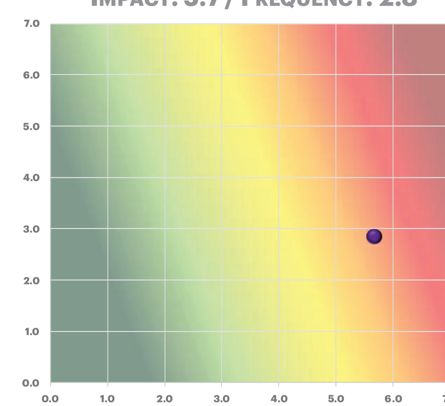
36.6 *Years*

Based on a '20 - '22 average annual work order count of 29,352 for SWG-CA (customer & construction), and a 3.1% suspension and/or disqualification rate on contractor & employee QC/TEP checks over '20 - '22. With a series of additional SME assumptions applied, the rate of one catastrophic event every 36.6 years was derived.

RISK SCORE = 25 K



7x7 RATING
IMPACT: 5.7 / FREQUENCY: 2.8



CUST. & PUB. SAFETY Supporting Info: Frequency Calculation

Definition

Event causing health or financial damage to a member of SWG's customer base

Worst Reasonable Scenario

Errors in covered tasks and/or emergency response for a customer call result in an unintended catastrophic event (home explosion) causing a loss of life.

#	Parameter	Value	Rationale / Data Source
1	# of work orders per year (SWG-CA)	**29,352**	• '20 – '22 Avg. work orders per year across customer & construction
		✖	
2	Technician Error Rate	**3.1%**	• Based on 14,069 QC checks performed across SWG-CA from 2020 – 2022, there were a total of 430 DQs and suspensions (3.1%)
		=	
3	Estimated Work Orders per Year in SWG-CA in which a technician error occurs	**910**	• [Item 1] x [Item 2] = this is the estimated number of work orders per year across construction & customer in which an error occurs
		✖	
4	Assumed Percentage of ☆ Technician Errors which may have serious safety consequences	**10%**	• Assumption that for every 10 work order errors by technicians, 1 has major safety implications
		✖	
5	Assumed % of errors in which the ☆ customer doesn't notify SWG-CA	**20%**	• Assumes that for every 5 major unresolved safety errors, 1 goes unnoticed by the customer and is not reported to SWG
		✖	
6	Assumed % of major safety ☆ related misses which result in worst reasonable scenario event	**0.15%**	• Assumes that 3 in every 2,000 instances where a non-customer reported major safety error leads to an ignition or explosion event
		=	
	Calculated Fatal Explosion Incidents Per Year from Technician Error	**0.03**	
		⬇	
	Equivalent to an event occurring every 'n' years	**36.6**	

☆ = **SME Estimate**

CYBER SECURITY Scoring Summary

DEFINITION

Cybersecurity breach that results in the exposure and/or destruction of critical data

WORST REASONABLE SCENARIO

Cybersecurity compromise of employee or retiree data via privileged insider error and/or malicious intent, resulting in a loss of confidentiality event.

SAFETY IMPACT PER INCIDENT

0 *Fatalities*

0 *Serious Injuries*

No direct safety consequences are deemed to be applicable for a PII breach.

OPERATIONAL IMPACT PER INCIDENT

0 *Meters Out*

0 *Hours to Restore*

No customer interruptions are assessed to result directly from a PII breach.

FINANCIAL IMPACT PER INCIDENT

$27.4M

The 90th percentile loss value from the RiskLens estimate is $27.4M

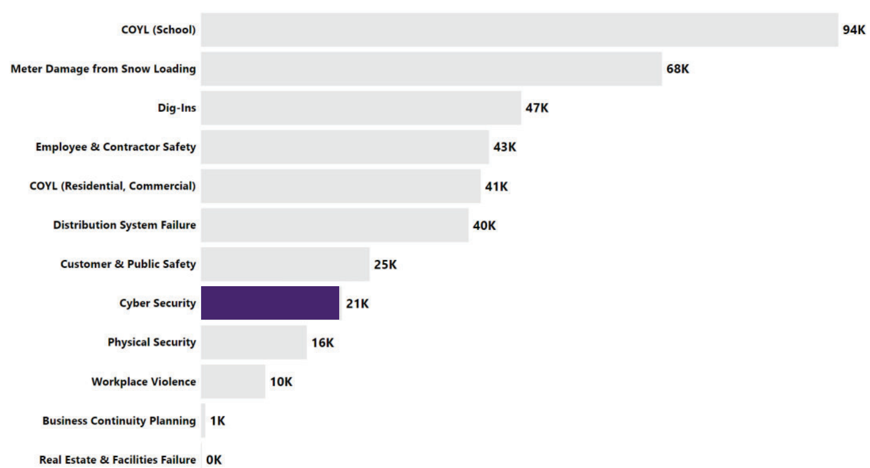
FREQUENCY

1 incident every…

6.59 *Years*

Using the average event frequency value from the RiskLens data

RISK SCORE = 21 K



7x7 RATING

IMPACT: 1.5 / FREQUENCY: 4.3

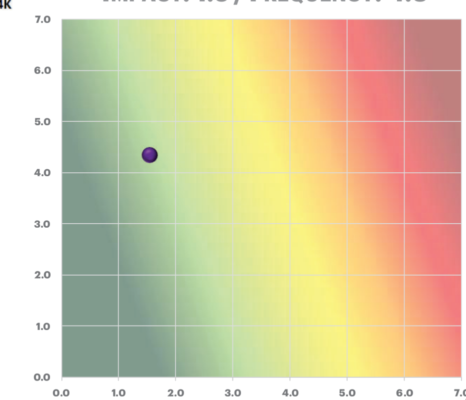


Exhibit No.___ (BCA-1)
Sheet 27 of 96

Shortcuts:
•RISK SCORING RESULTS
•MITIGATION SCORING RESULTS

PHYSICAL SECURITY Scoring Summary

DEFINITION

Facilities-related events arising from lack of physical security over significant gas or corporate infrastructure

WORST REASONABLE SCENARIO

A malicious syndicate vandalize regulator station causing unwarranted overpressure and pipe explosion causing injuries / fatalities and reputation damage

SAFETY IMPACT PER INCIDENT

2 *Fatalities*

1 *Serious Injuries*

There are regulators installed at every customer meter set. To over pressurize a houseline, one of those regulators must fail open. This assumes that one customer's houseline is subsequently over pressurized, or a pipe leak results with gas migrating into the house, and an explosion occurs. Same estimates used for the household explosion incidents used to characterize other risks (e.g., distribution system failure)

OPERATIONAL IMPACT PER INCIDENT

10K *Meters Out*

240 *Hours to Restore*

Assumes 10K customers impacted due to necessary leak surveys following the over pressurization event, which could take up to 10 days to address.

FINANCIAL IMPACT PER INCIDENT

$75M

Assumes $10M for customer property damage, $3M for fines, and follow-on work needed: service restoration, replacement of regulators, mains & services ($62M)

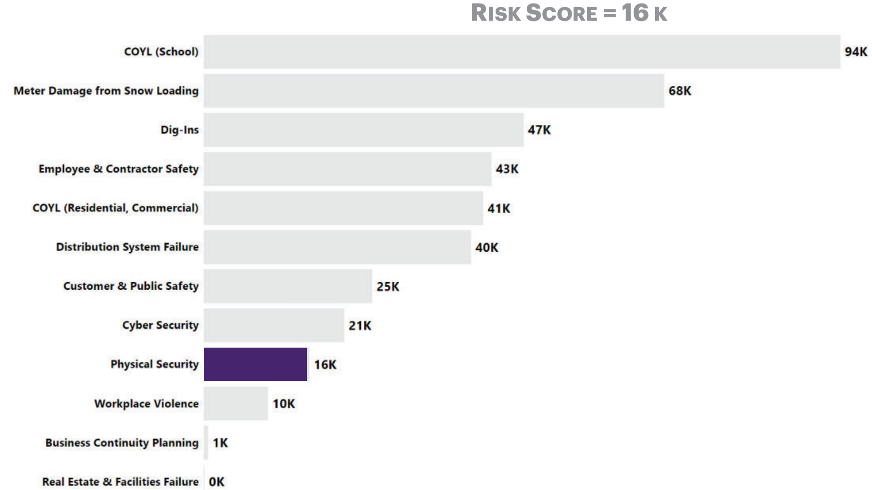
FREQUENCY

1 incident every...

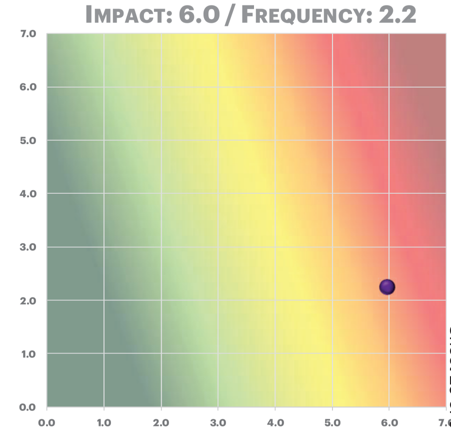
75 *Years*

Based on historical 0.4 incidents per year on avg. based on 2019 - 2023 data, 1/33 of which are assumed to be serious, which equates to 1 serious intentional damage incident every 75 years.

RISK SCORE = 16 K



7X7 RATING
IMPACT: 6.0 / FREQUENCY: 2.2



Shortcuts:
•RISK SCORING RESULTS
•MITIGATION SCORING RESULTS

PHYSICAL SECURITY Supporting Info: Frequency Calculation

Definition

Facilities-related events arising from lack of physical security over significant gas or corporate infrastructure

Worst Reasonable Scenario

A malicious syndicate vandalize regulator station causing unwarranted overpressure and pipe explosion causing injuries / fatalities and reputation damage

#	Parameter	Value	Rationale / Data Source
1	Avg. Intentional Damage Incidents per year of unprotected / unmonitored SWG-CA pipeline infrastructure	0.4	• Based on 2 documented incidents of intentional damage of non-customer gas infrastructure in SWG-CA over past 5 years (2019 – 2023)
		✖	
2	"Major" damage assumption ☆	3.33%	• Assumption that for every 33 incidents of intentional damage to pipeline infrastructure, 1 has the potential to inflict significant damage
		=	
	Calculated Fatal Explosion Incidents Per Year from Intentional Damage of Unprotected / Unmonitored SWG-CA pipeline infrastructure	0.01	
	Equivalent to an event occurring every 'n' years	**75**	

☆ = **SME Estimate**

Shortcuts:
•RISK SCORING RESULTS
•MITIGATION SCORING RESULTS

WORKPLACE VIOLENCE Scoring Summary

DEFINITION

Violence in the workplace resulting in safety consequences

WORST REASONABLE SCENARIO

Targeted shooter event at Victorville resulting in major loss of life

SAFETY IMPACT PER INCIDENT

1 *Fatality*

3 *Serious Injuries*

Nationwide, the 20-yr average event resulted in 5 serious injuries and 3 fatalities. There are an estimated 75 - 100 employees & contractors present in the office on a normal working day. With current mitigations / controls in place, we assess that the consequences associated with an incident at Victorville are likely to be less than the FBI report averages. (FBI: Active Shooter Incidents 20 Year Review)

OPERATIONAL IMPACT PER INCIDENT

0 *Meters Out*

0 *Hours to Restore*

Such an incident at Victorville would not impact the continuation of gas service to our customers.

FINANCIAL IMPACT PER INCIDENT

$1M

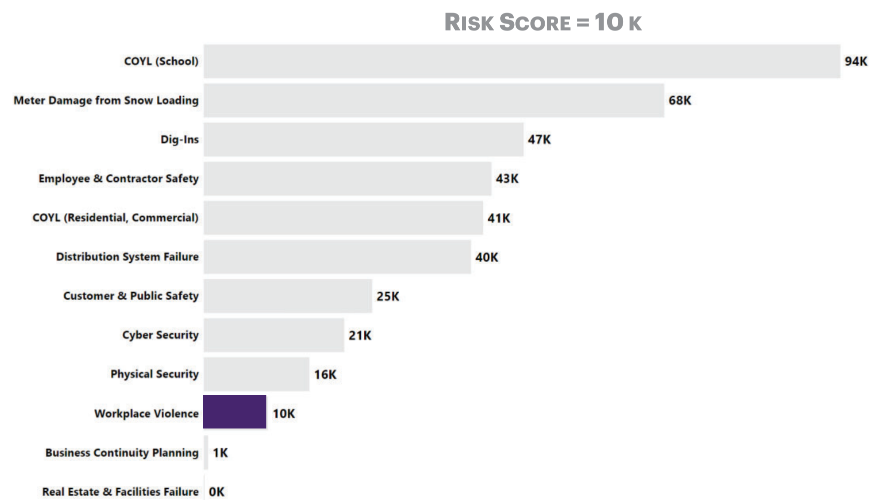
Estimate includes property damage and any applicable fines.

FREQUENCY

1 incident every…

100 *Years*

Any probabilistic method for determining the likelihood of such an event would suggest a very low event occurrence. However, the increase in recent mass shooting occurrences in the US is cause for concern, so a nominal incident frequency of once per 100 years was chosen.



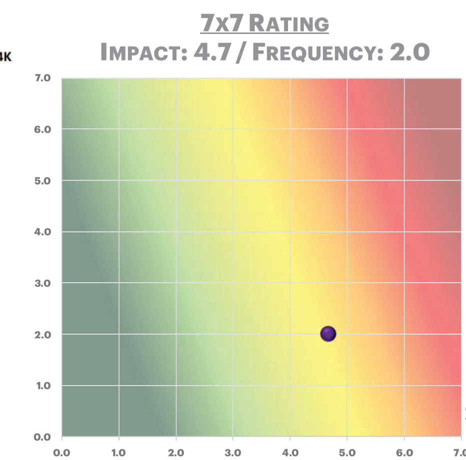


Exhibit No.___ (BCA-1)
Sheet 31 of 96

Shortcuts:
•RISK SCORING RESULTS
•MITIGATION SCORING RESULTS

BUSINESS CONTINUITY PLANNING Scoring Summary

DEFINITION

Disruption of business operations arising from infraction on business continuity

WORST REASONABLE SCENARIO

Data center outage rendering server for FOMS (field order management system) unavailable, requiring infrastructure rebuild and alternative business structure accommodation.

SAFETY IMPACT PER INCIDENT

0 *Fatalities*

0 *Serious Injuries*

No anticipated safety consequences directly related to a FOMS crash

OPERATIONAL IMPACT PER INCIDENT

0 *Meters Out*

0 *Hours to Restore*

While delays to existing outages may be plausible, no customer outages created as a direct result of FOMS crash

FINANCIAL IMPACT PER INCIDENT

$2M

Added labor costs for 7 days of service calls while FOMS is down, and labor costs dedicated to restoration of normal operations upon return of FOMS. (avg. time to address a call, # of calls, cost of overtime to address a call, cost of system recovery and data entry of backlog). Assumes $1M for added labor for business adapting, $1M for backlog

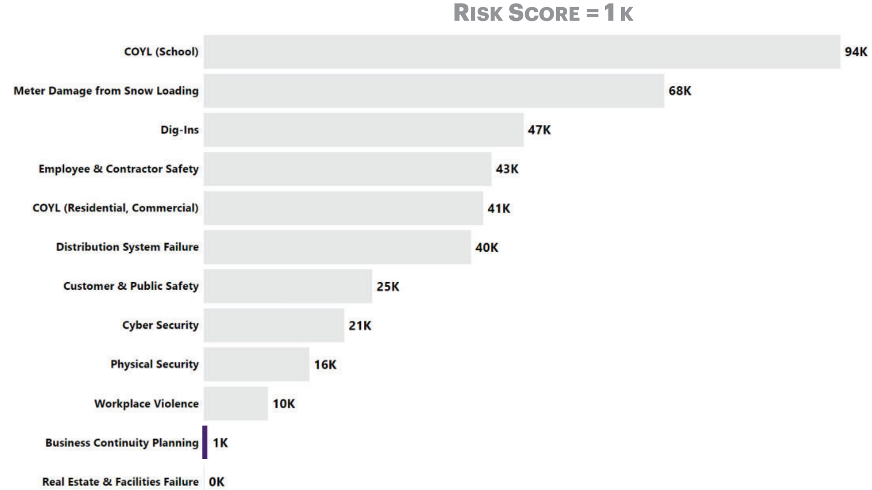
FREQUENCY

1 incident every…

15 *Years*

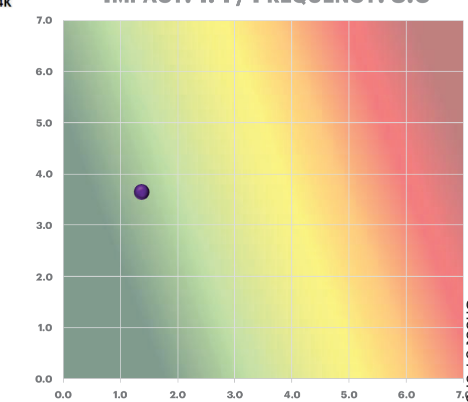
Industry data point from RiskLens given the amount of redundancy in the system

RISK SCORE = 1K



7X7 RATING

IMPACT: 1.4 / FREQUENCY: 3.6



Shortcuts:
•RISK SCORING RESULTS
•MITIGATION SCORING RESULTS

REAL ESTATE & FACILITIES FAILURE Scoring Summary

DEFINITION

Real estate incident prohibiting facilities from occupancy for normal use

WORST REASONABLE SCENARIO

A long-term power utility failure renders Victorville facilities unoccupiable for four days as backup generation does not support sustained independent operation more than 96 hours.

SAFETY IMPACT PER INCIDENT

0 *Fatalities*

0 *Serious Injuries*

No direct safety consequences are anticipated from a power failure event.

OPERATIONAL IMPACT PER INCIDENT

0 *Meters Out*

0 *Hours to Restore*

No customer outages would directly result from a sustained loss of power at the Victorville facilities. Looking ahead into future years however, an increasingly electrified vehicle fleet could be severely impacted via a facility power failure if redundant backup power supplies (e.g., battery backups) are not in place, which would ultimately delay incident response time.

FINANCIAL IMPACT PER INCIDENT

$1M

Cost is related to transitioning to manual-based mitigating factors until automated systems return.

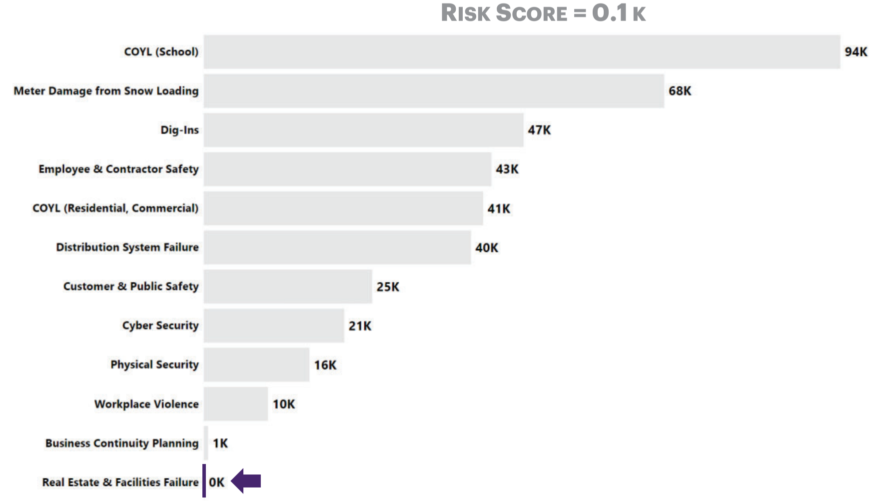
FREQUENCY

1 incident every…

35 *Years*

A sustained power interruption is assessed to be highly unlikely. Emergency power system is tested regularly, and fuel storage allows for up to 96 hours of sustained operation.

RISK SCORE = 0.1K



7x7 RATING

IMPACT: 1.3 / FREQUENCY: 2.9

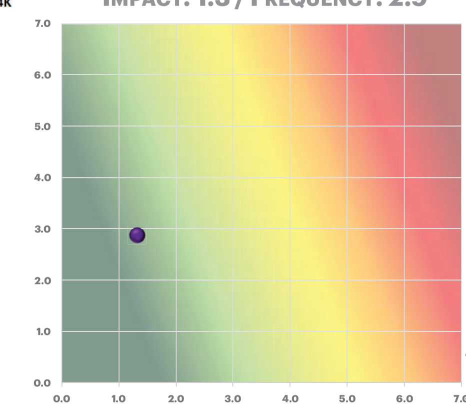


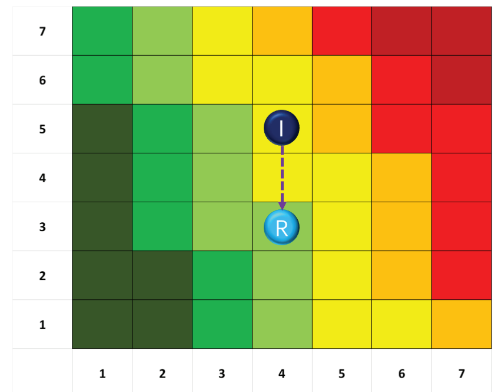
Exhibit No.___ (BCA-1)
Sheet 32 of 96

Mitigation scoring results

Risk Spend Efficiency (RSE)

$$\boxed{RSE} = \frac{Risk\ Reduction}{Cost}$$

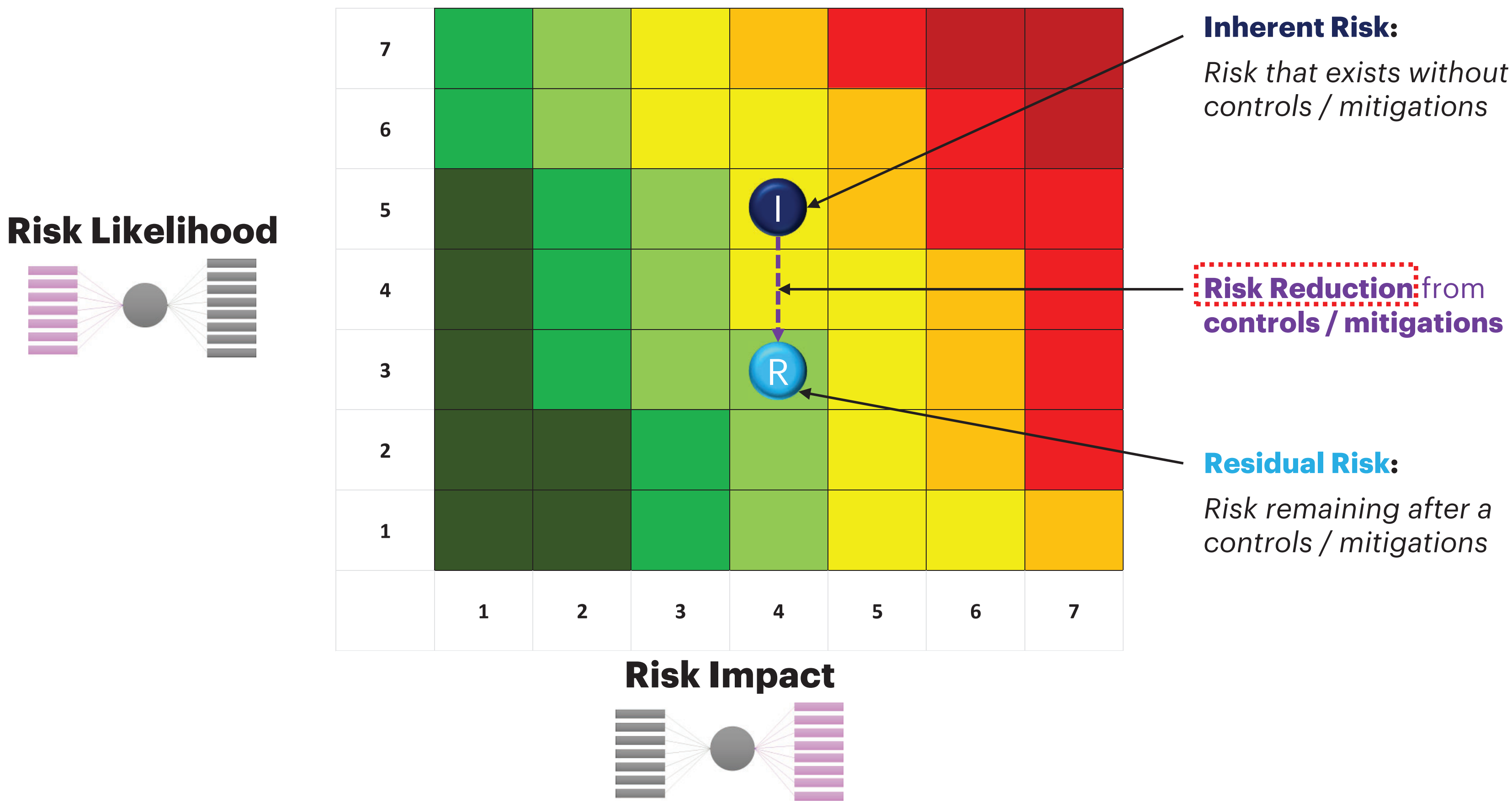
Risk Reduction:
Reduction in likelihood and consequence



Cost:
Capital and O&M costs throughout the life of the mitigation

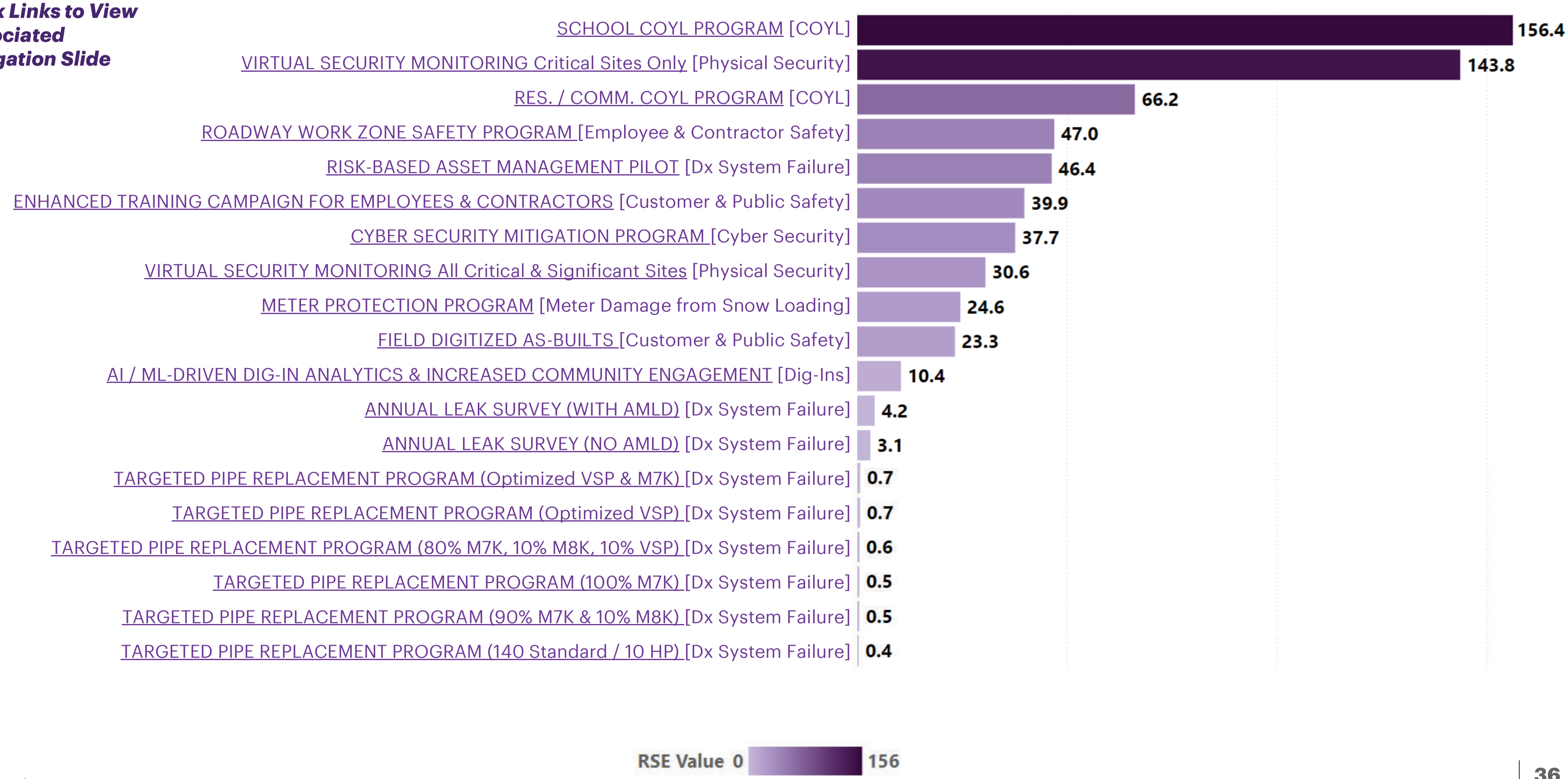
			2026-2030	
Mitigation	Description	Budget Code	Capital Forecast	O&M Forecast

Risk Reduction Definition



MITIGATION SCORING RESULTS

Click Links to View Associated Mitigation Slide



Shortcuts:
•RISK SCORING RESULTS
•MITIGATION SCORING RESULTS

SCHOOL COYL PROGRAM Scoring Summary

RISK MITIGATED

COYL (School)

MITIGATION ACTIVITIES

Re-configuration of COYL where meter is placed closer to adjacent structure(s), thereby removing the COYL

INVESTMENT AMOUNT

$24.4M
(estimate across GRC cycle)

$325k per school with 75 schools to be addressed over the 5-year period (15 annually). Projecting 15 schools per year (11 for SCA, 4 for NCA/SLT) is an attainable target based on anticipated rate of progress for '24 and '25. 15 schools per year over the 5-year cycle equates to $24.375M at the estimate of $325K per project.

BENEFITS LIFETIME

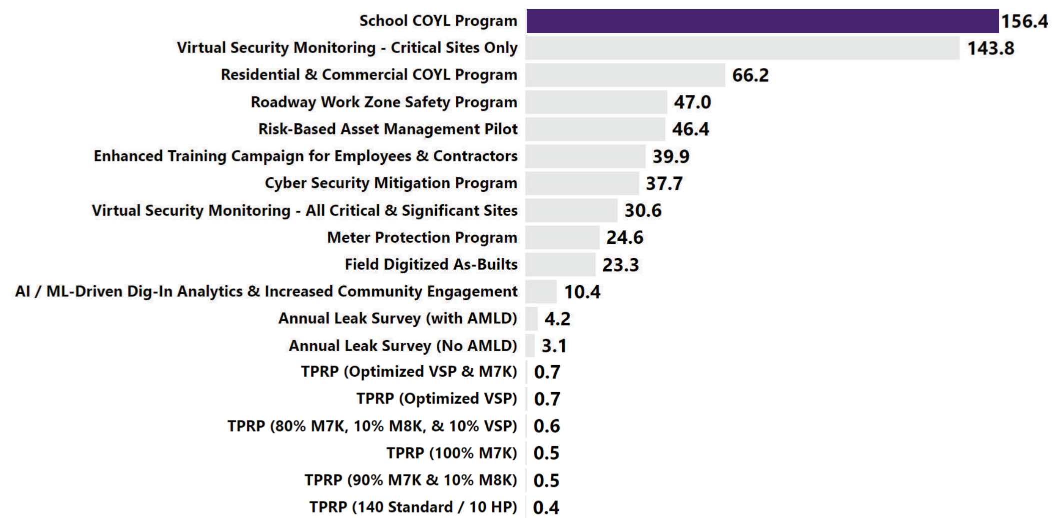
50
Years

Based on the assumed useful lifetime of the new pipe infrastructure that will be installed in the reconfigured system

FREQUENCY MITIGATION

INHERENT (BEFORE)	RESIDUAL (AFTER)	
1 incident every… 71.8 *Years*	*1 incident every…* 271.3 *Years*	At the beginning of '26, SWG-CA anticipates 102 schools with COYLs remaining in the service territory, based on an anticipated 34 schools being addressed across 2023 – 2025. 102 schools remaining equates to an incident frequency of once every 72 years. With an anticipated 75 of those 102 schools getting addressed during the '26 GRC cycle, the worst reasonable scenario frequency will decrease from once per ~72 years to once per ~271 years.

RISK SPEND EFFICIENCY (RSE) = 156.4



Note: Impact (safety, operational, financial) remain unchanged by mitigation

Shortcuts:
•RISK SCORING RESULTS
•MITIGATION SCORING RESULTS

SCHOOL COYL PROGRAM Cost Summary

RISK MITIGATED

COYL (School)

MITIGATION ACTIVITIES

Re-configuration of COYL where meter is placed closer to adjacent structure(s), thereby removing the COYL

TOTAL INVESTMENT AMOUNT

$24.4M ***Future Value***

$21.2M ***Net Present Value***

100% ***CAPITAL***

0% ***O&M***

Annual Cost Breakdown	2026	2027	2028	2029	2030
• SCA (11 schools per year @ $325k each) [CAPITAL]	$3,575,000	$3,575,000	$3,575,000	$3,575,000	$3,575,000
• NCA (4 schools per year @ $325k each) [CAPITAL]	$1,300,000	$1,300,000	$1,300,000	$1,300,000	$1,300,000
• Annual Total (SWG-CA)	**$4,875,000**	**$4,875,000**	**$4,875,000**	**$4,875,000**	**$4,875,000**

COYL (SCHOOL) Supporting Info: Residual Frequency Calculation

Anticipated impact from: SCHOOL COYL PROGRAM

#	Parameter	INHERENT (BEFORE)	RESIDUAL (AFTER)	Rationale / Data Source
1	Projected Annual Incidents / Year based on End of Year School Count	1.65	0.44	At an anticipated 15 schools per year across 2026 – 2030, SWG-CA anticipates completing 75 schools over the next GRC cycle, reducing the number of school COYLs remaining in the service territory to 27 by end of 2030
		✖	✖	
2	Reporting Inflator ☆	2	2	Assumption that for every 1 incident reported to SWG, one additional incident is addressed by the school w/o contacting SWG
		✖	✖	
3	% of Incidents which are "Major" ☆	10%	10%	Assumption that 1 in 10 school COYL incidents are significant (Note: SWG-CA identified 22 school incidents over past 10 years [2014-2023]; 2 had a known closure)
		✖	✖	
4	% of Major Leaks which Ignite / Explode	15.4%	15.4%	Enercon Safety Study – Sept. 2015 – Table 8-1
		✖	✖	
5	School in session rate ☆	27.4%	27.4%	Accounts for the % of time during a calendar year that a school is in session and occupied
		=	=	
	Calculated Fatal Explosion School COYL Incidents Per Year	0.0139	0.004	
	Equivalent to an event occurring every 'n' years	71.8	271.3	

GREEN = Updated Input
☆ = SME Estimate

VIRTUAL SECURITY MONITORING

Critical Sites Only - Scoring Summary

Risk Mitigated

Physical Security

Mitigation Activities

Addition of virtual security monitoring from PSOC site at the 2 critical pipeline infrastructure sites in SWG-CA service territory.

Investment Amount

$110k
(estimate across GRC cycle)

$50K per site in capital investment, and $1K per site in annual O&M costs. SWG-CA has identified 1 critical site and 1 future critical site requiring such measures in accordance with TSA Pipeline Security Guidelines.

Benefits Lifetime

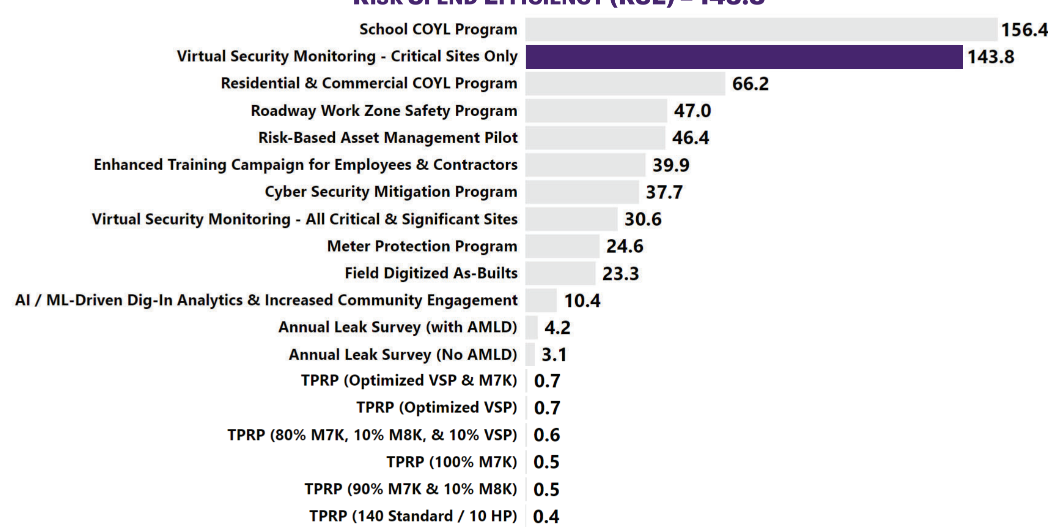
5
Years

Based on expected lifecycle replacement for equipment

Frequency Mitigation

Inherent (Before)	Residual (After)	
1 incident every... 75 *Years*	*1 incident every...* 93.8 *Years*	Based on the original incident frequency of once every 75 years, adding remote monitoring protection to the critical sites only is assessed to reduce incident frequency by 20%

Risk Spend Efficiency (RSE) = 143.8



Note: Impact (safety, operational, financial) remain unchanged by mitigation

Shortcuts:
•RISK SCORING RESULTS
•MITIGATION SCORING RESULTS

VIRTUAL SECURITY MONITORING

Critical Sites Only - Cost Summary

RISK MITIGATED

Physical Security

MITIGATION ACTIVITIES

Addition of virtual security monitoring from PSOC site at the 2 critical pipeline infrastructure sites in SWG-CA service territory.

TOTAL INVESTMENT AMOUNT

$110k ***Future Value***	$109k ***Net Present Value***	91% ***CAPITAL*** / 9% ***O&M***

Annual Cost Breakdown	2026	2027	2028	2029	2030
• Capital Investment (2 sites @ $50K each)	$100,000	-	-	-	-
• Recurring O&M ($1K per site)	$2,000	$2,000	$2,000	$2,000	$2,000
• Annual Total (SWG-CA)	**$102,000**	**$2,000**	**$2,000**	**$2,000**	**$2,000**

RES. / COMM. COYL PROGRAM Scoring Summary

Risk Mitigated

COYL (Residential / Commercial)

Mitigation Activities

Re-configuration of COYL where meter is placed closer to adjacent structure(s), thereby removing the COYL

Investment Amount

$9.4M

(estimate across GRC cycle)

$7.5k per site on avg. and 250 addressed per year across the 5-year GRC cycle (nominally assuming 100 per year for NCA/SLT and 150 per year for SCA)

Benefits Lifetime

50

Years

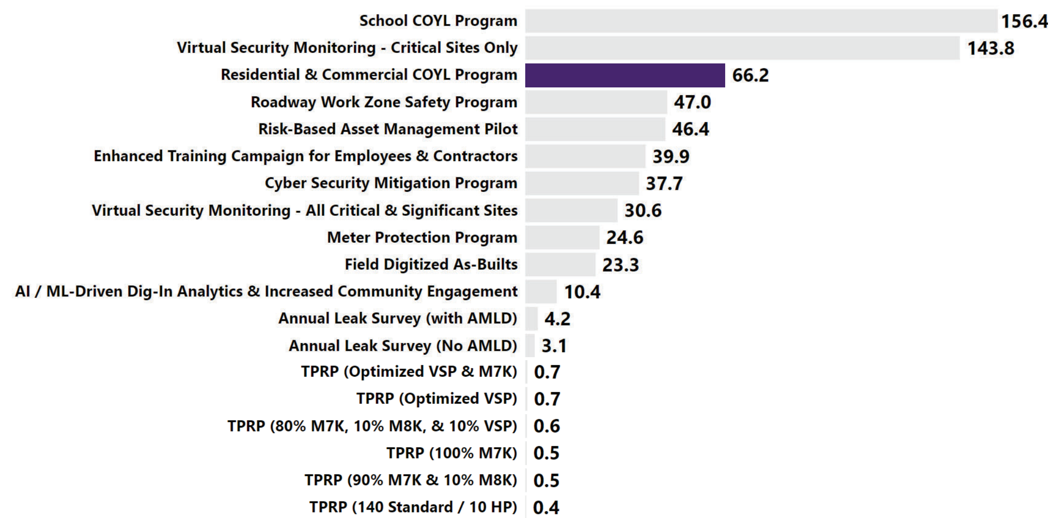
Based on the assumed useful lifetime of the new pipe infrastructure that will be installed in the reconfigured system

Frequency Mitigation

Inherent (Before)	Residual (After)
1 incident every… 21.9 *Years*	*1 incident every…* 30.1 *Years*

At an anticipated 250 COYLs per year addressed over the 5-year period, a total of 1.25K properties are expected to be addressed over the life of the cycle. The assumed pre-mitigated incident frequency is 21.89 years, which is based on 4,591 combined residential and commercial properties that have been identified in the SWG-CA service territory. Resulting frequency with 3,341 properties left to address is once every 30.1 years.

Risk Spend Efficiency (RSE) = 66.2



Note: Impact (safety, operational, financial) remain unchanged by mitigation

Shortcuts:
•RISK SCORING RESULTS
•MITIGATION SCORING RESULTS

RES. / COMM. COYL PROGRAM Cost Summary

RISK MITIGATED

COYL (Residential / Commercial)

MITIGATION ACTIVITIES

Re-configuration of COYL where meter is placed closer to adjacent structure(s), thereby removing the COYL

TOTAL INVESTMENT AMOUNT

$9.4M *Future Value*	$8.2M *Net Present Value*	100% *CAPITAL* / 0% *O&M*

Annual Cost Breakdown	2026	2027	2028	2029	2030
• SCA (150 properties per year @ $7.5k each) [CAPITAL]	$1,125,000	$1,125,000	$1,125,000	$1,125,000	$1,125,000
• NCA/SLT (100 properties per year @ $7.5k each) [CAPITAL]	$750,000	$750,000	$750,000	$750,000	$750,000
• Annual Total (SWG-CA)	**$1,875,000**	**$1,875,000**	**$1,875,000**	**$1,875,000**	**$1,875,000**

COYL (RES./COMM.) Supporting Info: Residual Frequency Calculation

Anticipated impact from: RESIDENTIAL & COMMERCIAL COYL PROGRAM

#	Parameter	INHERENT (BEFORE)	RESIDUAL (AFTER)	Rationale / Data Source
1	Approx. Count of Residential / Commercial COYLs in SWG-CA service territory	4,591	3,341	• At an anticipated 250 properties per year across 2026 – 2030, SWG-CA would address a total of 1,250 properties over the next GRC cycle, reducing the number of res./comm. COYLs remaining in the service territory to 3,341 by end of 2030
		✖	✖	
2	Estimated Incidents per COYL per Year: SWG-CA	0.0162	0.0162	• Ratio using school COYL data for SWG-CA: 2.2 incidents/yr divided across the 136 schools with COYLs → 0.0162 incidents per COYL per year
		✖	✖	
3	% of Residential / Commercial COYL incidents resulting in ignition or explosion event ☆	0.15%	0.15%	• Assumption that for every 2,000 residential / commercial COYL incidents, 3 would result in an ignition and/or explosion event (as a reference point for comparison, 0.09% of SWG dig-ins resulted in an ignition/explosion)
		✖	✖	
4	% of Gas Ignition / Explosion Incidents resulting in a fatality	41%	41%	• PHMSA Incidents: Of the 147 non-excavation distribution incidents since 2010 in which an explosion occurred, 61 (41%) resulted in some kind of safety consequences; same assumption applied to dist. sys. failure
		=	=	
	Calculated Fatal Explosion Res./Comm. COYL Incidents Per Year	0.05	0.03	
	Equivalent to an event occurring every 'n' years	**21.9**	**30.1**	

GREEN = Updated Input
☆ = SME Estimate

ROADWAY WORK ZONE SAFETY PROGRAM Scoring Summary

Risk Mitigated

Employee & Contractor Safety

Mitigation Activities

Development of effective roadway/work zone safety controls to prevent vehicle incursions. This may include a change in practices, procedures, or implementation of barriers or devices to prevent incursions.

Investment Amount

$1.8M

(estimate across GRC cycle)

1. **TRAINING:** $150k initial investment, and $25k per year for annual refreshers
2. **SCORPION TRUCKS:** (2) for SCA and (2) for NCA/SLT ($200k each)
3. **FTE Addition:** Hiring of a Traffic Safety Analyst ($145k avg. annual loaded rate)

Benefits Lifetime

8

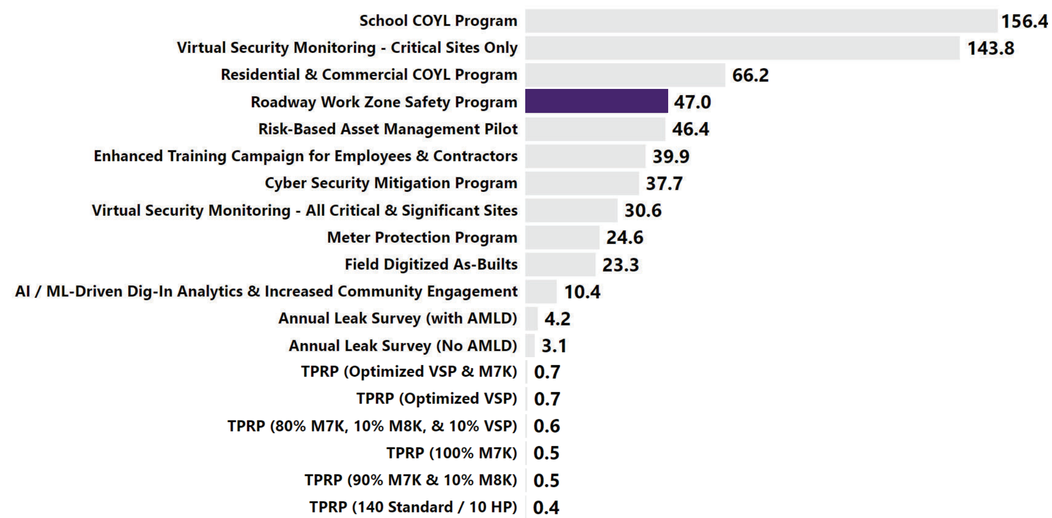
Years

Based on current life cycle replacements for vehicles. It is also assumed that if recurring training were to not continue beyond year 5 of the next GRC cycle, that the organizational impact of enhanced training would last up to 3 additional years.

Frequency Mitigation

Inherent (Before)	Residual (After)	
1 incident every... 15.3 *Years*	*1 incident every...* 20 *Years*	This risk involves several factors that are outside of the control of the enterprise. As a goal, the above mitigations should reduce the worst reasonable scenario frequency from once per 15.3 years to once per 20 years

Risk Spend Efficiency (RSE) = 47.0



Note: Impact (safety, operational, financial) remain unchanged by mitigation

Shortcuts:
•RISK SCORING RESULTS
•MITIGATION SCORING RESULTS

ROADWAY WORK ZONE SAFETY PROGRAM Cost Summary

RISK MITIGATED

Employee & Contractor Safety

MITIGATION ACTIVITIES

Development of effective roadway/work zone safety controls to prevent vehicle incursions. This may include a change in practices, procedures, or implementation of barriers or devices to prevent incursions.

TOTAL INVESTMENT AMOUNT

$1.8M	$1.7M	77%	23%
Future Value	***Net Present Value***	***CAPITAL***	***O&M***

Annual Cost Breakdown	2026	2027	2028	2029	2030
• **Training Program Implementation [O&M]**	$150,000	-	-	-	-
• **Recurring Training Costs [O&M]**	$25,000	$25,000	$25,000	$25,000	$25,000
• **Capital Investment: Scorpion Trucks [CAPITAL]** *4 @ $200k each*	$800,000	-	-	-	-
• **FTE: (1) 100% MP Analyst II Operations (EX) [CAPITAL]** *$145k avg. Annual Loaded Rate*	$135,822	$140,643	$145,636	$150,806	$156,160
• **Annual Total (SWG-CA)**	**$1,110,822**	**$165,643**	**$170,636**	**$175,806**	**$181,160**

EMPLOYEE & CONTRACTOR SAFETY

Supporting Info: Residual Frequency Calculation

Anticipated impact from: ROADWAY WORKZONE SAFETY PROGRAM

#	Parameter	INHERENT (BEFORE)	RESIDUAL (AFTER)	Rationale / Data Source
1	SWG-CA Avg. Annual Spend on work adjacent to roadways	$73M	$73M	• 2019-2023 avg. capital & O&M spend for roadway-related work
		✖	✖	
2	Assumed Percentage of above spend adjacent to high-risk roadside areas (e.g., highways) ☆	10%	10%	• Assumption – this is an estimate of the mileage of mains for SWG-CA which are within 50 feet of streets with posted speed limits of 50 mph or greater
		=	=	
3	Assume high-risk area spend	$7.3M	$7.3M	• Result of [item 1] x [item 2]
		✖	✖	
4	Federal Highway Administration roadside work zone fatality assumption	$\frac{1\ fatality}{\$112M}$	$\frac{1\ fatality}{\$112M}$	• Source - Federal Highway Administration
			✖	
		=	77%	• Reducing incident frequency to once every 20 years from the original 15.3 years equates to an approximate 23% reduction in incidents (100% - 23% = 77%)
			=	
	Calculated Fatal Explosion Incidents Per Year	0.065	0.05	
		⬇	⬇	
	Equivalent to an event occurring every 'n' years	15.3	20	

GREEN = Updated Input
☆ = SME Estimate

RISK-BASED ASSET MGMT PILOT Scoring Summary

RISK MITIGATED

Distribution System Failure

MITIGATION ACTIVITIES

Activities to develop a risk-based asset management system for a single asset family. Activities include organization structure, underlying business processes, connections to ERM, data orientation, analytics and reporting, division-level data collection & reporting, and work plan development

INVESTMENT AMOUNT

$589k

(estimate across GRC cycle)

$100k annually across the 5-year period to cover the CA service territory, and the addition of 1 senior level FTE at the enterprise level ($162k average annual loaded rate, 10.95% of cost-share assumed to apply to CA)

BENEFITS LIFETIME

1

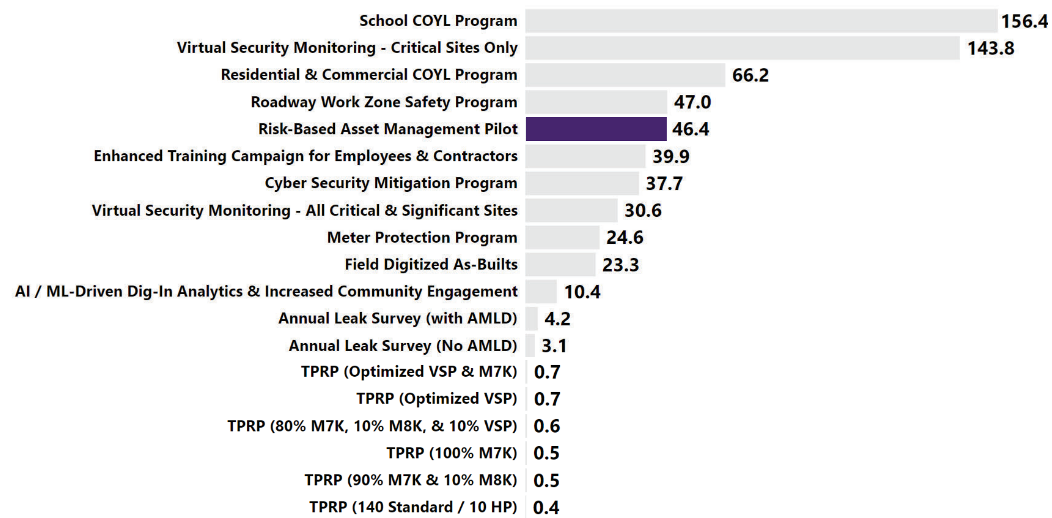
Year

The benefits from the program would be realized for only as long as the program remains funded and in effect. If approved, the benefits will be realized over the duration of the next GRC cycle

FREQUENCY MITIGATION

INHERENT (BEFORE)	RESIDUAL (AFTER)	
1 incident every… 27.1 *Years*	*1 incident every…* 33.9 *Years*	When compared against a beginning of '26 average of 82.99 non-excavation leaks per year, SWG-CA assesses that this program could achieve a year-over-year non-excavation leak reduction of 5%, starting by year 3. By year 5 with this assumption applied, that would yield a 2030 non-excavation leaks per year average of 71.15. The resulting frequency also considers a mild reduction in the assumed percentage of grade 1 leaks resulting in an ignition or explosion event (before: 0.3%, after: 0.28%)

RISK SPEND EFFICIENCY (RSE) = 46.4



Note: Impact (safety, operational, financial) remain unchanged by mitigation

Shortcuts:
•RISK SCORING RESULTS
•MITIGATION SCORING RESULTS

RISK-BASED ASSET MGMT PILOT Cost Summary

RISK MITIGATED

Distribution System Failure

MITIGATION ACTIVITIES

Activities to develop a risk-based asset management system for a single asset family. Activities include organization structure, underlying business processes, connections to ERM, data orientation, analytics and reporting, division-level data collection & reporting, and work plan development

TOTAL INVESTMENT AMOUNT

$589k	$513k	0%
Future Value	***Net Present Value***	***CAPITAL***
		100%
		O&M

Annual Cost Breakdown	2026	2027	2028	2029	2030
• **FTE: (1) 100% MP Specialist / Laboratory Services (EX) ($162k avg. annual loaded rate → 10.95% cost share for CA-focused workshare) [O&M]**	$16,539	$17,127	$17,735	$18,364	$19,016
• **Recurring Program Costs [O&M]**	$100,000	$100,000	$100,000	$100,000	$100,000
• **Annual Total (SWG-CA)**	**$116,539**	**$117,127**	**$117,735**	**$118,364**	**$119,016**

DIST. SYS. FAILURE Supporting Info: Residual Freq. Calculation

Anticipated impact from: Risk-Based Asset Management Pilot

#	Parameter	INHERENT (BEFORE)	RESIDUAL (AFTER)	Rationale / Data Source
1	Leaks / Year (SWG-CA)	82.9	71.1	• When compared against a beginning of '26 avg. of 82.99 leaks per year, team assesses that this program could achieve an annual non-excavation leak reduction of 5%, starting by year 3. By year 5 with this assumption applied, that would yield a 2030 leaks per year average of 71.1
		✖	✖	
2	% of Non-Excavation Leaks which are Grade 1	36.2%	36.2%	• % of non-excavation leaks which were Grade 1 (2018 – 2022) – Source: DIMP CA mains & services leak worksheets
		✖	✖	
3	☆ % of Non-Excavation Grade 1 Leaks resulting in ignition or explosion	0.3%	0.28%	• Assumes that this program could lead to a minor reduction in the number of grade 1 leaks resulting in an ignition or explosion, due to the program's enablement of more proactive identification
		✖	✖	
4	% of Gas Explosion Incidents resulting in a fatality	41%	41%	• 2010-2023 PHMSA Incidents: Of the 147 non-excavation distribution incidents since 2010 in which an explosion occurred, 61 (41%) resulted in some kind of safety consequences
		=	=	
	Calculated Fatal Explosion Incidents Per Year from Dist. Sys. Failure	0.037	0.030	
	Equivalent to an event occurring every 'n' years	27.1	33.9	

GREEN = Updated Input
☆ = SME Estimate

Shortcuts:
•RISK SCORING RESULTS
•MITIGATION SCORING RESULTS

ENHANCED TRAINING CAMPAIGN FOR EMPLOYEES & CONTRACTORS

Scoring Summary

RISK MITIGATED

Customer & Public Safety

MITIGATION ACTIVITIES

Virtual / hands-on scenario-based training program for employees & contractors

INVESTMENT AMOUNT

$1.5M

(estimate across GRC cycle)

- $500K initial capital investment
- $200K annual O&M

BENEFITS LIFETIME

8

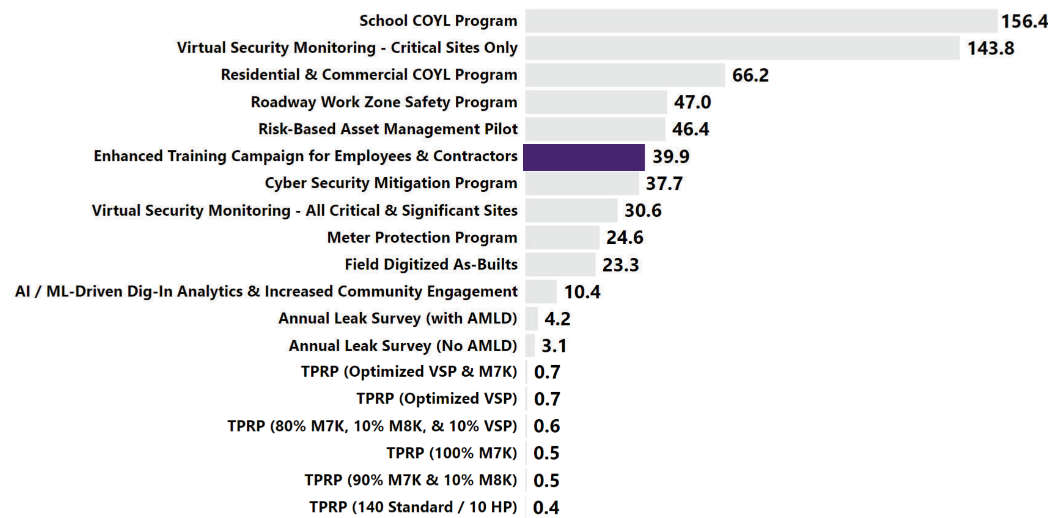
Years

Assess that training impact will be realized for at least 3 years beyond the life of the program

FREQUENCY MITIGATION

INHERENT (BEFORE)	RESIDUAL (AFTER)	
1 incident every… 36.6 Years	*1 incident every…* 50.5 Years	Program goal would be to reduce employee and contractor QC check DQ/Suspension rate from 3.1% to 2.5% across contractors and SWG technicians. Also accounts for a slight reduction in the % of technician errors in the field with serious safety implications

RISK SPEND EFFICIENCY (RSE) = 39.9



Note: Impact (safety, operational, financial) remain unchanged by mitigation

Shortcuts:
•RISK SCORING RESULTS
•MITIGATION SCORING RESULTS

ENHANCED TRAINING CAMPAIGN FOR EMPLOYEES & CONTRACTORS

Cost Summary

RISK MITIGATED

Customer & Public Safety

MITIGATION ACTIVITIES

Virtual / hands-on scenario-based training program for employees & contractors

TOTAL INVESTMENT AMOUNT

$1.5M ***Future Value***

$1.37M ***Net Present Value***

33% ***CAPITAL***

67% ***O&M***

Annual Cost Breakdown	2026	2027	2028	2029	2030
• **Capital Investment**	$500,000	-	-	-	-
• **Recurring O&M**	$200,000	$200,000	$200,000	$200,000	$200,000
• **Annual Total (SWG-CA)**	**$700,000**	**$200,000**	**$200,000**	**$200,000**	**$200,000**

CUST. & PUB. SAFETY Supporting Info: Residual Frequency Calculation

Anticipated impact from: Enhanced Training for Employees & Contractors

#	Parameter	INHERENT (BEFORE)	RESIDUAL (AFTER)	Rationale / Data Source
1	# of work orders per year (SWG-CA)	29,352	29,352	• '20 – '22 Avg. work orders per year across customer & construction
		×	×	
2	Technician Error Rate	3.1%	2.5%	• SWG-CA estimates that the enhanced training program could reduce the suspension / disqualification rate on technician quality checks from 3.1% to 2.5%
		=	=	
3	Estimated Work Orders per Year in SWG-CA in which a technician error occurs	910	734	• [Item 1] x [Item 2] = this is the estimated number of work orders per year across construction & customer in which an error occurs
		×	×	
4	Assumed Percentage of Technician Errors which may have serious safety consequences ☆	10%	9%	• SWG-CA estimates that the enhanced training program could slightly reduce the proportion of technician errors with serious safety consequences (a 10% reduction)
		×	×	
5	Assumed % of errors in which the customer doesn't notify SWG-CA ☆	20%	20%	• Assumes that for every 5 major unresolved safety errors, 1 goes unnoticed by the customer and is not reported to SWG
		×	×	
6	Assumed % of major safety related misses which result in worst reasonable scenario event ☆	0.15%	0.15%	• Assumes that 3 in every 2,000 instances where a non-customer reported major safety error leads to an ignition or explosion event
		=	=	
	Calculated Fatal Explosion Incidents Per Year from Technician Error	0.03	0.02	
		⇩	⬇	
	Equivalent to an event occurring every 'n' years	36.6	50.5	

GREEN = Updated Input
☆ = SME Estimate

CYBER SECURITY MITIGATION PROGRAM Scoring Summary

RISK MITIGATED

Cyber Security

MITIGATION ACTIVITIES

Consists of a suite of initiatives including company-wide privilege management, additional logging and segmentation, and security enhancements

INVESTMENT AMOUNT

$2.5M

(estimate across GRC cycle)

1. Company-wide Privilege Access Management, Additional Logging, and Segmentation: $20k initial investment, $105k annually ($545k)
2. Cloud / Application / System Security Enhancements: (~$1.3M over 2026 - 2030)
3. Data Loss Prevention: $30k annually ($150k)
4. Regulatory Cybersecurity Compliance: $50k annually ($250k)
5. SCADA Architecture & Security Enhancements: $50k annually ($250k)

BENEFITS LIFETIME

1 *Year*

Benefits would continue only as long as the funding exists for necessary system updates and hardware refreshes. Once the program ends, there are no residual benefits in later years.

FREQUENCY MITIGATION

INHERENT (BEFORE)	RESIDUAL (AFTER)
1 incident every... 6.59 *Years*	*1 incident every...* 6.67 *Years*

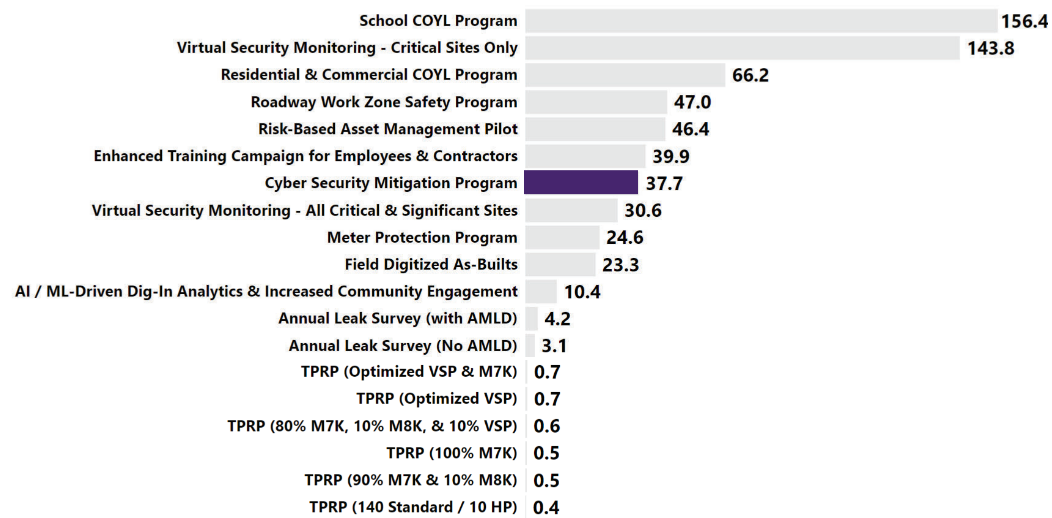
Though the incident frequency is not expected to change substantially, **the primary value comes from the significantly reduced financial impact of a worst reasonable scenario incident (see below)**

FINANCIAL MITIGATION

INHERENT (BEFORE)	RESIDUAL (AFTER)
$27.4M	$323K

Pre-mitigated, the 90th percentile financial impact for SWG-CA is $27.4M. This suite of enhancements is assessed to reduce the 90th percentile financial impact to $323k.

RISK SPEND EFFICIENCY (RSE) = 37.7



Shortcuts:
•RISK SCORING RESULTS
•MITIGATION SCORING RESULTS

CYBER SECURITY MITIGATION PROGRAM Cost Summary

RISK MITIGATED

Cyber Security

MITIGATION ACTIVITIES

Consists of a suite of initiatives including company-wide privilege management, additional logging and segmentation, and security enhancements

TOTAL INVESTMENT AMOUNT

$2.5M *Future Value*	$2.2M *Net Present Value*	2% *CAPITAL* / 98% *O&M*

Annual Cost Breakdown

	Year 1	Year 2	Year 3	Year 4	Year 5
•Company Wide Privilege Management – Implementation [CAPITAL]	$10,000	-	-	-	-
•Company Wide Privilege Management – Recurring [O&M]	$50,000	$50,000	$50,000	$50,000	$50,000
•Segmentation – Implementation [CAPITAL]	$10,000	-	-	-	-
•Segmentation - Annual Cost [O&M]	$50,000	$50,000	$50,000	$50,000	$50,000
•Additional Logging [O&M]	$5,000	$5,000	$5,000	$5,000	$5,000
•Cloud Security Enhancements [O&M] *($160k recurring)*	$160,000	$160,000	$160,000	$160,000	$160,000
•Application Security Enhancements [CAPITAL] *($18k initial, start in year 3)*	-	-	$18,000	-	-
•Application Security Enhancements [O&M] *($60 recurring, start in year 3)*	-	-	$60,000	$60,000	$60,000
•System Security Enhancements [CAPITAL] *($18k initial)*	$18,000	-	-	-	-
•System Security Enhancements [O&M] *($60k recurring)*	$60,000	$60,000	$60,000	$60,000	$60,000
•Data Loss Prevention [O&M] *($30k recurring)*	$30,000	$30,000	$30,000	$30,000	$30,000
•Regulatory Cybersecurity Compliance [O&M] *($50k recurring)*	$50,000	$50,000	$50,000	$50,000	$50,000
•SCADA Architecture & Security [O&M] *($50k recurring)*	$50,000	$50,000	$50,000	$50,000	$50,000
Annual Totals	**$493,000**	**$455,000**	**$533,000**	**$515,000**	**$515,000**

VIRTUAL SECURITY MONITORING

All Critical & Significant Sites - Scoring Summary

RISK MITIGATED

Physical Security

MITIGATION ACTIVITIES

Addition of virtual security monitoring from PSOC site at the 2 critical and 14 significant pipeline infrastructure sites in SWG-CA service territory.

INVESTMENT AMOUNT

$880k
(estimate across GRC cycle)

$50K per site in capital investment, and $1K per site in annual O&M costs. SWG-CA has identified 1 critical site and 1 future critical site requiring such measures IAW TSA Pipeline Security Guidelines, and 14 significant sites. Assume that an average of 3 sites could be addressed annually across the 5 years, with the 16th site completed at some time over the 5 year cycle.

BENEFITS LIFETIME

5
Years

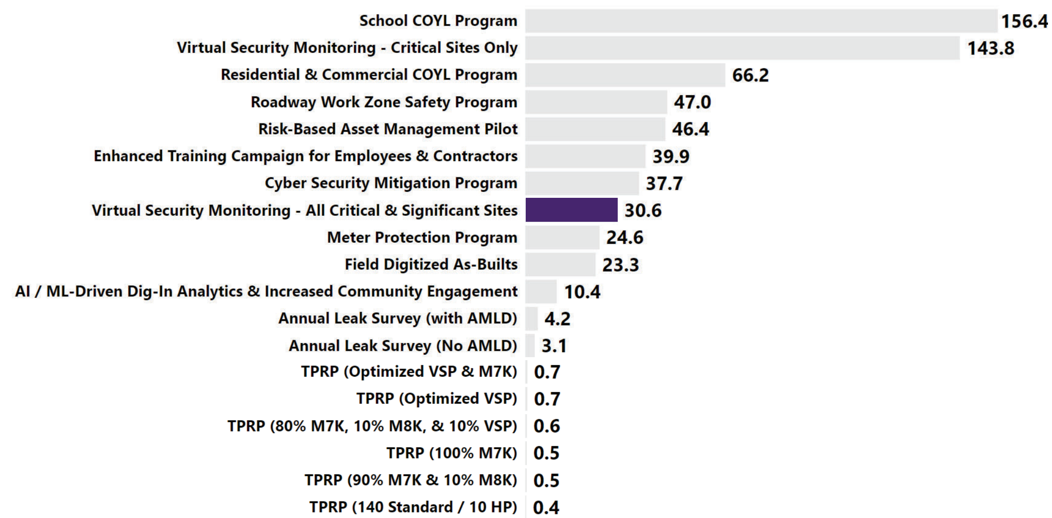
Based on expected lifecycle replacement for equipment

FREQUENCY MITIGATION

INHERENT (BEFORE)	RESIDUAL (AFTER)
1 incident every... 75 *Years*	*1 incident every...* 150 *Years*

Based on the original incident frequency of once every 75 years, adding remote monitoring protection is assessed to reduce incident frequency by half

RISK SPEND EFFICIENCY (RSE) = 30.6



Note: Impact (safety, operational, financial) remain unchanged by mitigation

Shortcuts:
•RISK SCORING RESULTS
•MITIGATION SCORING RESULTS

VIRTUAL SECURITY MONITORING

All Critical & Significant Sites - Cost Summary

RISK MITIGATED

Physical Security

MITIGATION ACTIVITIES

Addition of virtual security monitoring from PSOC site at the 2 critical and 14 significant pipeline infrastructure sites in SWG-CA service territory.

TOTAL INVESTMENT AMOUNT

$880k ***Future Value***

$767k ***Net Present Value***

91% ***CAPITAL***

9% ***O&M***

Annual Cost Breakdown	2026	2027	2028	2029	2030
• Capital Investment (16 sites @ $50K each)	$160,000	$160,000	$160,000	$160,000	$160,000
• Recurring O&M ($1K per site)	$16,000	$16,000	$16,000	$16,000	$16,000
• Annual Total (SWG-CA)	$176,000	$176,000	$176,000	$176,000	$176,000

METER PROTECTION PROGRAM Scoring Summary

RISK MITIGATED

Meter Damage from Snow Loading

MITIGATION ACTIVITIES

Combined meter hardening program consisting of meter sheds, EFVs, and ERTs

INVESTMENT AMOUNT

$36.6M
(estimate across GRC cycle)

1. Cost per Meter Shed= $1250; anticipating installing 3k Meter Sheds per year
2. Cost per EFV=$1250; anticipating installing 2.5k EFVs per year
3. Cost per ERT=$300; anticipating installing 1.5k ERTs per year

BENEFITS LIFETIME

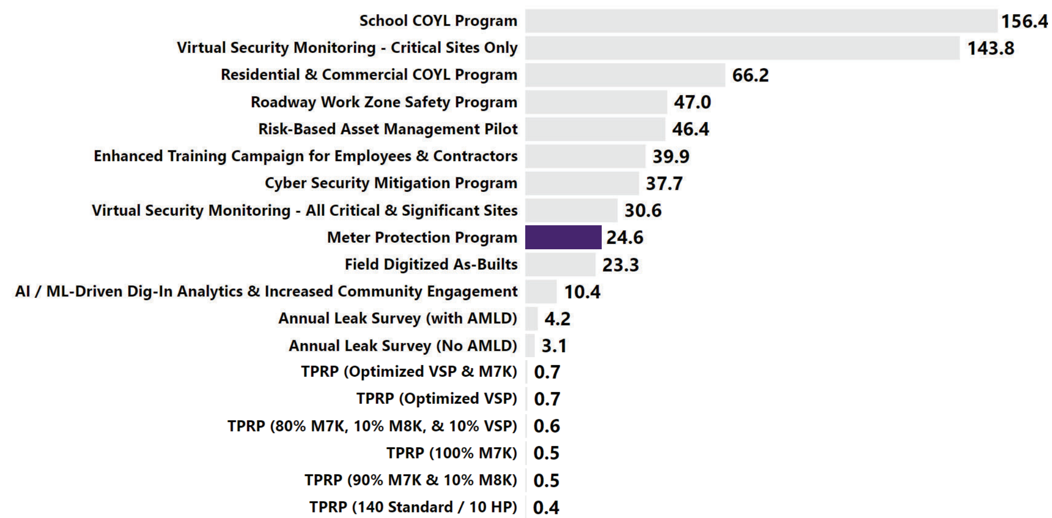
28.3
Years

Weighted average based on the following nominal lifetimes per device: 20-year lifetime for meter sheds, 20-year lifetime for ERTs, and 45-year lifetime for EFVs.

FREQUENCY MITIGATION

INHERENT (BEFORE)	RESIDUAL (AFTER)	
1 incident every… 13.4 *Years*	*1 incident every…* 24.1 *Years*	Based on anticipated progress (installing 15k meter sheds, 12.5k EFVs, and 7.5k ERTs), and the assumed end of '25 frequency value of once every 13.4 years.

RISK SPEND EFFICIENCY (RSE) = 24.6



Note: Impact (safety, operational, financial) remain unchanged by mitigation

METER PROTECTION PROGRAM Cost Summary

RISK MITIGATED

Meter Damage from Snow Loading

MITIGATION ACTIVITIES

Combined meter hardening program consisting of meter sheds, EFVs, and ERTs

TOTAL INVESTMENT AMOUNT

$36.6M ***Future Value***	$31.9M ***Net Present Value***	100% ***CAPITAL*** 0% ***O&M***

Annual Cost Breakdown	**2026**	**2027**	**2028**	**2029**	**2030**
• **Meter Sheds (3K per year @ $1,250 each) [CAPITAL]**	$3,750,000	$3,750,000	$3,750,000	$3,750,000	$3,750,000
• **EFVs (2.5K per year @ $1,250 each) [CAPITAL]**	$3,125,000	$3,125,000	$3,125,000	$3,125,000	$3,125,000
• **ERTs (1.5K per year @ $300 each) [CAPITAL]**	$450,000	$450,000	$450,000	$450,000	$450,000
• **Annual Total (SWG-CA)**	**$7,325,000**	**$7,325,000**	**$7,325,000**	**$7,325,000**	**$7,325,000**

Shortcuts:
•RISK SCORING RESULTS
•MITIGATION SCORING RESULTS

METER SNOW LOADING Supporting Info: Residual Freq. Calculation

#	Parameter	INHERENT (BEFORE)	RESIDUAL (AFTER)	Rationale / Data Source
1	Estimated snow-related meter incidents per year (2026 projection)	86	48	Based on anticipated progress for '26 – '30 (installing 15k meter sheds, 12.5k EFVs, and 7.5k ERTs), and the assumed end of '25 frequency value of once every 13.4 years.
		✖	✖	
2	% of meter incidents resulting in an explosion	0.44%	0.44%	• SWG Incident Records: Over the 2022 – 2023 winter season, 1 of the 229 documented meter incidents resulted in an explosion (0.44%)
		✖	✖	
3	% of Gas Explosion Incidents from natural forces causes resulting in safety consequences	39.4%	39.4%	• 2010 – 2023 PHMSA Incidents: Of the 33 distribution incidents in which natural forces was the cause AND an explosion occurred, 13 resulted in some kind of safety consequences (serious injuries and/or fatalities)
		✖	✖	
4	Home Occupancy % ★	50%	50%	• Assumption that many of the SWG-supplied homes in heavy-snow areas are either part-time residences or vacation rentals, thus a lower occupancy rate than a typical home (Supporting Article)
		=	=	
	Calculated Fatal Explosion Incidents Per Year from Meter Snow Loading	0.075	0.041	
	Equivalent to an event occurring every 'n' years	13.4	24.1	

GREEN = Updated Input
★ = SME Estimate

FIELD DIGITIZED AS-BUILTS Scoring Summary

Risk Mitigated

Customer & Public Safety

Mitigation Activities

Digitization of records for pipe replacement & construction

Investment Amount

$2.0M

(estimate across GRC cycle)

1. **(1) Field FTE** (~$161k avg. annual loaded rate), 2. **(1) Back Office GIS Specialist** (~$135k avg. annual loaded rate), 3. **CartoPac Field Devices** ($500K for the procurement of an estimated 30 devices needed to fully implement this mitigation; 20 for SCA and 10 for NCA/SLT)

Benefits Lifetime

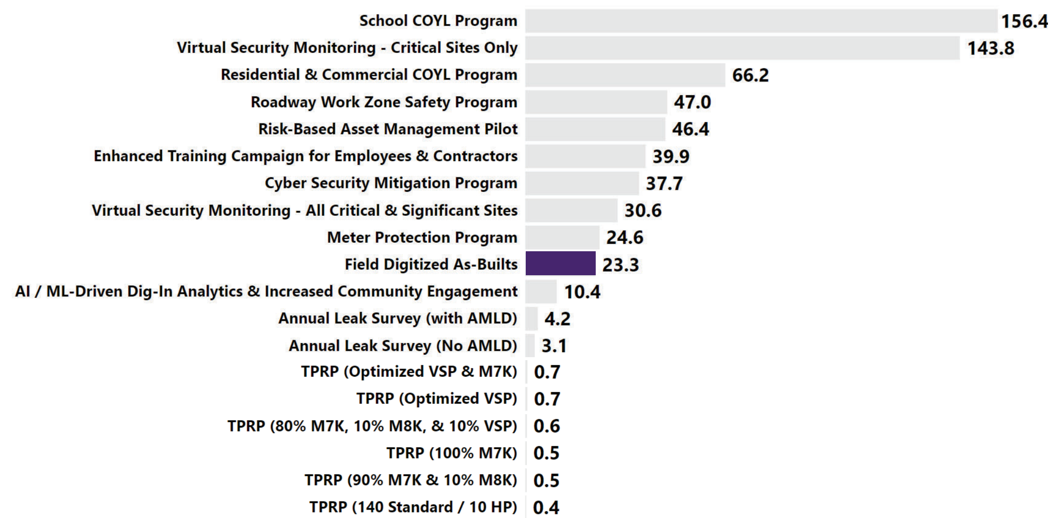
5 *Years*

Basing on the useful lifetime of the field devices before they need to be refreshed

Frequency Mitigation

Inherent (Before)	Residual (After)	
1 incident every… 36.6 *Years*	*1 incident every…* 54.9 *Years*	This mitigation would not be expected to reduce unsatisfactory technician performance, but instead provide a means of more expedient trouble response actions by the company, which would reduce the rate of catastrophic events. With mitigation, it assumes that 1 in every 1,000 instances where a non-customer reported major safety error leads to an ignition or explosion event, down from 1.5 in every 1,000.

Risk Spend Efficiency (RSE) = 23.3



Note: Impact (safety, operational, financial) remain unchanged by mitigation

Shortcuts:
•RISK SCORING RESULTS
•MITIGATION SCORING RESULTS

FIELD DIGITIZED AS-BUILTS Cost Summary

RISK MITIGATED

Customer & Public Safety

MITIGATION ACTIVITIES

Digitization of records for pipe replacement & construction

TOTAL INVESTMENT AMOUNT

$2.0M ***Future Value***

$1.8M ***Net Present Value***

100% ***CAPITAL***

0% ***O&M***

Annual Cost Breakdown	2026	2027	2028	2029	2030
• **FTE: (1) Step 9 GIS Specialist (Non-GF) [Capital]** *$135k avg. annual loaded rate*	$125,484	$129,938	$134,551	$139,328	$144,274
• **FTE: (1) Step 9 Construction Technician (Non-GF) [Capital]** *$161k avg. annual loaded rate*	$149,991	$155,315	$160,829	$166,538	$172,450
• **CartoPac Field Devices [CAPITAL]**	$500,000	-	-	-	-
• **Annual Total (SWG-CA)**	**$775,475**	**$285,253**	**$295,380**	**$305,866**	**$316,724**

CUST. & PUB. SAFETY Supporting Info: Residual Frequency Calculation

Anticipated impact from: Field Digitized As-Builts

#	Parameter	INHERENT (BEFORE)	RESIDUAL (AFTER)	Rationale / Data Source
1	# of work orders per year (SWG-CA)	29,352	29,352	• '20 – '22 Avg. work orders per year across customer & construction
		×	×	
2	Technician Error Rate	3.1%	3.1%	• Based on 14,069 QC checks performed across SWG-CA from 2020 – 2022, there were a total of 430 disqualifications and suspensions (3.1%)
		=	=	
3	Estimated Work Orders per Year in SWG-CA in which a technician error occurs	910	910	• [Item 1] x [Item 2] = this is the estimated number of work orders per year across construction & customer in which an error occurs
		×	×	
4	Assumed Percentage of Technician Errors which may have serious safety consequences ☆	10%	10%	• SWG-CA estimates that the enhanced training program could slightly reduce the proportion of technician errors with serious safety consequences (a 10% reduction)
		×	×	
5	Assumed % of errors in which the customer doesn't notify SWG-CA ☆	20%	20%	• Assumes that for every 5 major unresolved safety errors, 1 goes unnoticed by the customer and is not reported to SWG
		×	×	
6	Assumed % of major safety related misses which result in worst reasonable scenario event ☆	0.15%	0.10%	• With field data collection in effect, assumes that 1 in every 1,000 instances where a non-customer reported major safety error leads to an ignition or explosion event
		=	=	
	Calculated Fatal Explosion Incidents Per Year from Technician Error	0.03	0.02	
	Equivalent to an event occurring every 'n' years	**36.6**	**54.9**	

GREEN = Updated Input
☆ = SME Estimate

AI / ML-DRIVEN DIG-IN ANALYTICS & INCREASED COMMUNITY ENGAGEMENT

Scoring Summary

RISK MITIGATED

Dig-ins

MITIGATION ACTIVITIES

Team of analysts responsible for tracing back each dig-in to the responsible party, thereby enhancing customer & public outreach efforts to target the most likely violators.

INVESTMENT AMOUNT

$3.9M
(estimate across GRC cycle)

- **4 FTE additions to data & analytics team** in support of an AI (artificial intelligence) and ML (machine learning) leveraged program to identify the parties responsible for each dig-in incident, enabling better targeted customer & public outreach efforts to address the most prominent violators. Team will also engage local communities to spread public awareness. 3 FTEs for SCA and 1 FTE for NCA/SLT at an avg. annual loaded rate of $170k per FTE.
- **$100k annual budget for increased community engagement** campaigns.

BENEFITS LIFETIME

1
Year

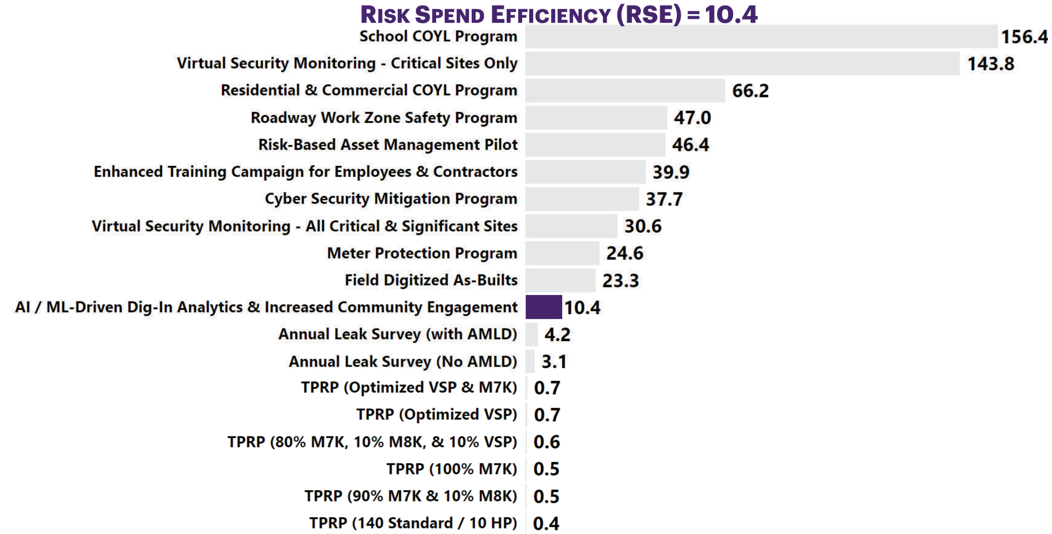
The benefits from the program would be realized for only as long as the program remains funded and in effect. If approved, the benefits will be realized over the duration of the next GRC cycle.

FREQUENCY MITIGATION

INHERENT (BEFORE)	RESIDUAL (AFTER)
1 incident every… 19.3 *Years*	*1 incident every…* 25.7 *Years*

Based on a pre-mitigated frequency of once every 19.3 years, SWG-CA anticipates that the program will reduce the number of excavation damage incidents by 25%, resulting in a mitigated frequency of once per 25.68 years. If the program were to continue beyond just the next 5-year cycle, the resulting benefits are likely to increase.

RISK SPEND EFFICIENCY (RSE) = 10.4



Note: Impact (safety, operational, financial) remain unchanged by mitigation

AI / ML-DRIVEN DIG-IN ANALYTICS & INCREASED COMMUNITY ENGAGEMENT
Cost Summary

RISK MITIGATED

Dig-ins

MITIGATION ACTIVITIES

Team of analysts responsible for tracing back each dig-in to the responsible party, thereby catering customer & public outreach efforts to target the most likely violators.

TOTAL INVESTMENT AMOUNT

$3.9M ***Future Value***	$3.4M ***Net Present Value***	9% ***CAPITAL*** / 91% ***O&M***

Annual Cost Breakdown	2026	2027	2028	2029	2030
• FTE: (3) 100% MP Data Scientists (EX) for SCA ($170k avg. annual loaded rate each) [90% O&M / 10% CAPITAL]	$474,607	$491,455	$508,902	$526,968	$545,676
• FTE: (1) 100% MP Data Scientists (EX) for NCA/SLT ($170k avg. annual loaded rate) [90% O&M / 10% CAPITAL]	$158,202	$163,818	$169,634	$175,656	$181,892
• Increased Public Awareness Campaign Budget [O&M]	$100,000	$100,000	$100,000	$100,000	$100,000
• Annual Total (SWG-CA)	**$732,809**	**$755,274**	**$778,536**	**$802,624**	**$827,567**

DIG-INS Supporting Info: Residual Frequency Calculation

Anticipated impact from: AI / ML-DRIVEN DIG-IN ANALYTICS & INCREASED COMMUNITY ENGAGEMENT

#	Parameter	INHERENT (BEFORE)	RESIDUAL (AFTER)	Rationale / Data Source
1	Excavation Leaks / Year (SWG-CA)	125	93.75	• With the AI / ML-Driven Dig-In Analytics & Increased Community Outreach program in place, SWG-CA anticipates to reduce excavation damage incidents by 25%
		×	×	
2	% of dig-ins resulting in an ignition OR explosion	0.09%	0.09%	• Based on 5,573 line breaks from 2018 - 2022, there were a total of 5 which resulted in an ignition event (SWG enterprise-wide data)
		×	×	
3	% of Gas Explosion Incidents resulting in a fatality	46.3%	46.3%	• 2010-2023 PHMSA Incidents: Of the 95 excavation damage incidents where an explosion occurred, 44 (46.3%) resulted in serious injury and/or fatality
		=	=	
	Calculated Fatal Explosion Incidents Per Year from Dig-Ins	0.05	0.04	
	Equivalent to an event occurring every 'n' years	19.3	25.7	

GREEN = Updated Input
☆ = SME Estimate

Shortcuts:
•RISK SCORING RESULTS
•MITIGATION SCORING RESULTS

ANNUAL LEAK SURVEY (WITH AMLD) Scoring Summary

RISK MITIGATED

Distribution System Failure

MITIGATION ACTIVITIES

Increases leak survey inspection frequency from once every 3 years to yearly for all the California service territory, and subsequent repair of discovered leaks, which also facilitates: 1) Fugitive emission reduction on SWG system (subsurface and above ground facilities) as well as customer house lines (COYLs) for entire SWG-CA service territory. 2) Optimizes employee safety via remote means of leak detection (Advanced Mobile Leak Detection eliminates the need for access to customer property for leak surveying)

INVESTMENT AMOUNT

$10.2M
(estimate across GRC cycle)

The following costs assume 1 year LS / 3 year ACS periodicities: **A. Walking Patrols:** SCA is expected to cost $525k annually, and NCA/SLT is expected to cost $262.5k annually (both 75% of the current costs for the once every 3 year program due to the addition of AMLD), **B. Initial Capital Investment:** $3.25M for AMLD with ~2/3 of cost allotted to SCA, and add'l crew trucks- $400k for SCA, $250k for NCA/SLT, **C. Additional SWG Recurring O&M:** additional FTEs for SCA (x2) and NCA/SLT (x1) ($175k loaded rate per FTE), **D. Leak Identification & Repair:** Boosting the leak survey periodicity to annual is likely to result in the identification of additional leaks during the early years of the program. Assumes an additional 80 leaks ID'd per year at an avg. cost to address of $5K, $400k annually (accounting for the first 3 years of the program), **E. Advanced Mobile Leak Detection:** $750k annually with ~2/3 of the cost allocated to SCA, which covers the cost of vehicle operation and the addition of 3 FTEs as the drivers

BENEFITS LIFETIME

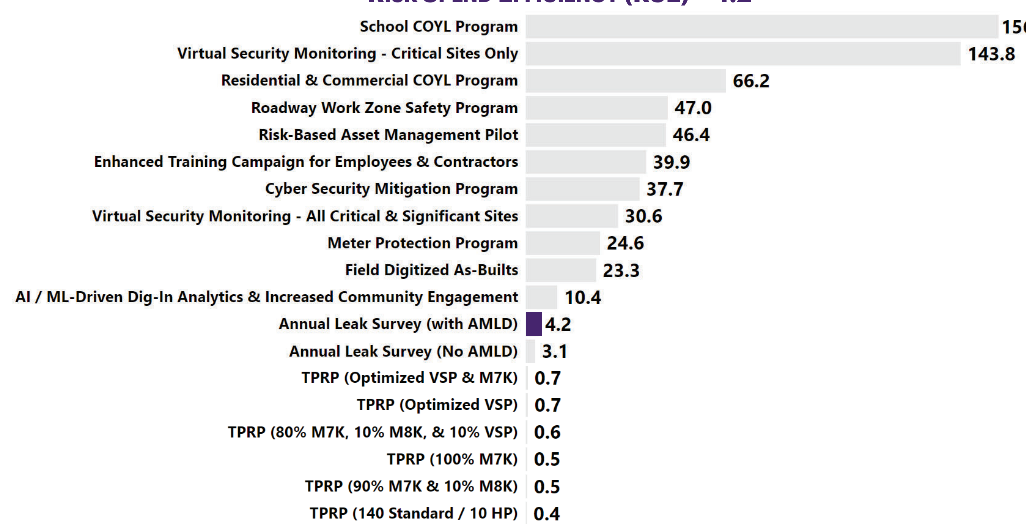
1
Year

The benefits from the program would be realized for only as long as the program remains funded and in effect. If approved, the benefits will be realized over the duration of the next GRC cycle.

FREQUENCY MITIGATION

INHERENT (BEFORE)	RESIDUAL (AFTER)	
1 incident every... 27.1 *Years*	*1 incident every...* 40.6 *Years*	The driver behind the frequency reduction is the assumption that 2 in 1,000 Grade 1 non-excavation leaks will result in an ignition or explosion event, down from 3 in 1,000 pre-mitigation. Rationale is that SWG-CA will discover a greater % of G1 leaks proactively and address them via the annual leak surveys, as opposed to the leak remaining undiscovered and ultimately unaddressed by the company. Beyond the first few years of the program, it would be expected to see a reduction in non-excavation leaks per year, but an increase in documented leaks is anticipated in the early years due to boosting the survey periodicity.

RISK SPEND EFFICIENCY (RSE) = 4.2



Note: Impact (safety, operational, financial) remain unchanged by mitigation

ANNUAL LEAK SURVEY (WITH AMLD) Cost Summary

RISK MITIGATED

Distribution System Failure

MITIGATION ACTIVITIES

Increases leak survey inspection frequency from once every 3 years to yearly for all the California service territory, and subsequent repair of discovered leaks, which also facilitates: 1) Fugitive emission reduction on SWG system (subsurface and above ground facilities) as well as customer house lines (COYLs) for entire SWG-CA service territory. 2) Optimizes employee safety via remote means of leak detection (Advanced Mobile Leak Detection eliminates the need for access to customer property for leak surveying)

TOTAL INVESTMENT AMOUNT

$10.2M *Future Value*	$9.5M *Net Present Value*	42% *CAPITAL* / 58% *O&M*

Annual Cost Breakdown *(Accounts for incremental costs of existing programs, increase or decrease)*	2026	2027	2028	2029	2030
• **Recurring Walking Costs (SCA) [O&M]** *Assumes a 25% reduction from the existing $700k annual (-$175k) [O&M]*	-$175,000	-$175,000	-$175,000	-$175,000	-$175,000
• **Recurring Walking Costs (NCA/SLT) [O&M]** *Assumes a 25% reduction from the existing $285k annual (-$71.25k)*	-$71,250	-$71,250	-$71,250	-$71,250	-$71,250
• **AMLD: Investment [CAPITAL]** *Cost split allocated 71% to SCA / 29% to NCA/SLT*	$3,250,000	-	-	-	-
• **AMLD: Recurring Costs [O&M]** *Cost split allocated 71% to SCA / 29% to NCA/SLT*	$750,000	$750,000	$750,000	$750,000	$750,000
• **Additional Work Trucks [CAPITAL]** *$400k for SCA & $250k for NCA/SLT*	$650,000	-	-	-	-
• **FTE: (2) for SCA & (1) for NCA / SLT ($175k avg. annual loaded rate) [O&M]** *SCA: (1) Step 9 Crew Leader/Construction, (1) Step 9 Construction Technician & NCA/SLT: (1) Step 9 District Technician*	$489,709	$507,094	$525,096	$543,737	$563,039
• **Additional Leak Repair Cost [30% CAPITAL / 70% O&M]** *Accounts for identification & repair of up to 80 additional leaks per year ($5k avg. repair cost)*	$400,000	$400,000	$400,000	-	-
• **Annual Total (SWG-CA)**	**$5,293,459**	**$1,410,844**	**$1,428,846**	**$1,047,487**	**$1,066,789**

Shortcuts:
•RISK SCORING RESULTS
•MITIGATION SCORING RESULTS

ANNUAL LEAK SURVEY (NO AMLD) Scoring Summary

RISK MITIGATED

Distribution System Failure

MITIGATION ACTIVITIES

Increases leak survey inspection frequency from once every 3 years to yearly for all the California service territory, and subsequent repair of discovered leaks, which also facilitates fugitive emission reduction on SWG system (subsurface and above ground facilities) as well as customer house lines (COYLs) for entire SWG-CA service territory.

INVESTMENT AMOUNT

$14.3M

(estimate across GRC cycle)

The following costs assume 1 year LS / 1 year ACS periodicities: **A. Walking Patrols:** SCA is expected to cost $2.1M annually, and NCA/SLT is expected to cost $855k annually (both 3x the current costs for the once every 3 year program), **B. Initial Capital Investment:** Add'l crew trucks- $400k for SCA, $250k for NCA/SLT, **C. Additional SWG Recurring O&M:** additional FTEs for SCA (x2) and NCA/SLT (x1) ($175k avg. annual loaded rate per FTE), **D. Leak Identification & Repair:** Boosting the leak survey periodicity to annual is likely to result in the identification of additional leaks during the early years of the program. Assumes an additional 80 leaks ID'd per year at an avg. cost to address of $5k, $400k annually (accounting for the first 3 years of the program)

BENEFITS LIFETIME

1

Year

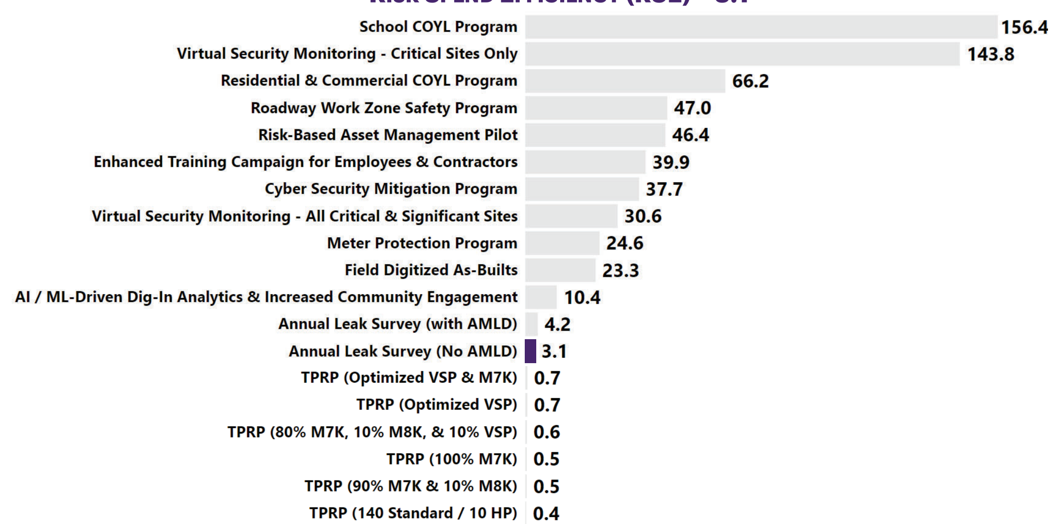
The benefits from the program would be realized for only as long as the program remains funded and in effect. If approved, the benefits will be realized over the duration of the next GRC cycle.

FREQUENCY MITIGATION

INHERENT (BEFORE)	RESIDUAL (AFTER)
1 incident every... 27.1 *Years*	*1 incident every...* 40.6 *Years*

The driver behind the frequency reduction is the assumption that 2 in 1,000 Grade 1 non-excavation leaks will result in an ignition or explosion event, down from 3 in 1,000 pre-mitigation. Rationale is that SWG-CA will discover a greater % of G1 leaks proactively and address them via the annual leak surveys, as opposed to the leak remaining undiscovered and ultimately unaddressed by the company. Beyond the first few years of the program, it would be expected to see a reduction in non-excavation leaks per year, but an increase in documented leaks is anticipated in the early years due to boosting the survey periodicity.

RISK SPEND EFFICIENCY (RSE) = 3.1



Note: Impact (safety, operational, financial) remain unchanged by mitigation

Shortcuts:
•RISK SCORING RESULTS
•MITIGATION SCORING RESULTS

ANNUAL LEAK SURVEY (NO AMLD) Cost Summary

RISK MITIGATED

Distribution System Failure

MITIGATION ACTIVITIES

Increases leak survey inspection frequency from once every 3 years to yearly for all the California service territory, and subsequent repair of discovered leaks, which also facilitates fugitive emission reduction on SWG system (subsurface and above ground facilities) as well as customer house lines (COYLs) for entire SWG-CA service territory.

TOTAL INVESTMENT AMOUNT

$14.3M	$12.6M	7%
Future Value	***Net Present Value***	***CAPITAL***
		93% ***O&M***

Annual Cost Breakdown *(Accounts for incremental costs of existing programs, increase or decrease)*	2026	2027	2028	2029	2030
• **Additional Work Trucks [CAPITAL]** - *$400k for SCA & $250k for NCA/SLT*	$650,000	-	-	-	-
• **Recurring Walking Costs (SCA) [O&M] –** *Assumes annual costs triple from the existing $700k annual (+$1.4M)*	+$1,400,000	+$1,400,000	+$1,400,000	+$1,400,000	+$1,400,000
• **Recurring Walking Costs (NCA/SLT) [O&M]** – *Assumes annual costs triple from the existing $285k annual (+$570k)*	+$570,000	+$570,000	+$570,000	+$570,000	+$570,000
• **FTE: (2) for SCA & (1) for NCA / SLT ($175k avg. annual loaded rate) [O&M]** *SCA: (1) Step 9 Crew Leader/Construction, (1) Step 9 Construction Technician & NCA/SLT: (1) Step 9 District Technician*	$489,709	$507,094	$525,096	$543,737	$563,039
• **Additional Leak Repair Cost [30% CAPITAL / 70% O&M]**	$400,000	$400,000	$400,000	-	-
• **Annual Total (SWG-CA)**	**$3,509,709**	**$2,877,094**	**$2,895,096**	**$2,513,737**	**$2,533,039**

Shortcuts:
•RISK SCORING RESULTS
•MITIGATION SCORING RESULTS

DIST. SYS. FAILURE Supporting Info: Residual Freq. Calculation

Anticipated impact from: Annual Leak Survey (No AMLD) OR Annual Leak Survey (With AMLD)

#	Parameter	INHERENT (BEFORE)	RESIDUAL (AFTER)	Rationale / Data Source
1	Leaks / Year (SWG-CA)	82.9	82.9	• Unchanged: Shifting to an annual leak survey periodicity is likely to result in a higher documented number of leaks during the initial years before leveling out to a lower count long-term
		✖	✖	
2	% of Non-Excavation Leaks which are Grade 1	36.2%	36.2%	• % of non-excavation leaks which were Grade 1 (2018 – 2022) – Source: DIMP CA mains & services leak worksheets
		✖	✖	
3	% of Non-Excavation Grade 1 Leaks resulting in ignition or explosion ☆	0.3%	0.2%	• The driver behind the frequency reduction is the assumption that 2 per 1,000 Grade 1 non-excavation leaks will result in an ignition or explosion event, down from 3 per 1,000 pre-mitigated
		✖	✖	
4	% of Gas Explosion Incidents resulting in a fatality	41%	41%	• 2010-2023 PHMSA Incidents: Of the 147 non-excavation distribution incidents since 2010 in which an explosion occurred, 61 (41%) resulted in some kind of safety consequences
		=	=	
	Calculated Fatal Explosion Incidents Per Year from Dist. Sys. Failure	0.037	0.025	
	Equivalent to an event occurring every 'n' years	27.1	40.6	

GREEN = Updated Input
☆ = SME Estimate

TARGETED PIPE REPLACEMENT PROGRAM

Program Evaluation Overview

Risk Mitigated

Distribution System Failure

Mitigation Overview

Six unique approaches, each consisting of varying combinations of the 4 highest risk pipe types in the CA service territory, were evaluated to identify the most optimum program in terms of risk reduction per $ spent

Investment Amount

$96.4M To measure relative cost-effectiveness in terms of material-related leak reduction per dollar invested, each scenario considers an equal dollar amount (this was the $ value of the first scenario discussed from workshop #3 (140 Standard / 10 HP)

Cost Estimates

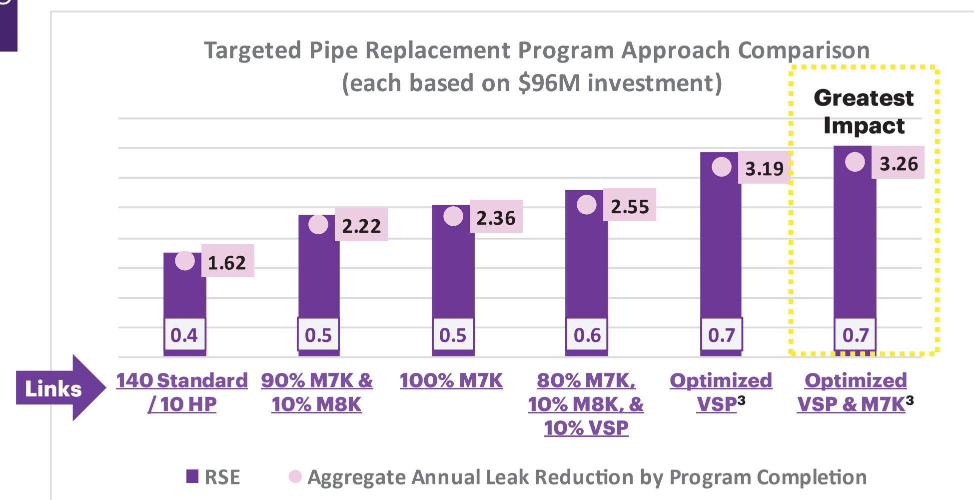
$425 *Per foot*	**High Pressure** Pipe Replacement (SCA territory)	**$100** *Per foot*	**Standard Pressure** Pipe Replacement (SCA territory)

Pipe Performance
(2018 – 2022 Avg. Leaks Per Mile[1])

"Bang-For-Buck" & Ranking
(Leak Reduction Per Dollar Spent[2])

Pipe Type	Pipe Performance	÷ Cost	Bang-For-Buck	Ranking
Pre-1961 Vintage High-Pressure Steel	**0.053** *Leaks/mi*		**2.34E-8**	**3rd**
Pre-1961 Vintage Standard Steel	**0.031** *Leaks/mi*		**5.88E-8**	**1st**
Driscopipe M7000	**0.013** *Leaks/mi*		**2.45E-8**	**2nd**
Driscopipe M8000	**0.005** *Leaks/mi*		**9.91E-9**	**4th**

Scenario Comparison



1. Leak rates are comprised of 2018 – 2022 history of material failure-related leaks (corrosion, pipe weld / joint failure, or equipment failure)
2. *Calculated figures are is the Leak Rate (Leaks / Mile) divided by the equivalent cost per Mile replaced (Cost per Foot × 5,280)*
3. The above estimates are based on ~50 miles of Pre-1961 Vintage Standard Steel remaining in SWG-CA by beginning of 2026, which accounts for continued progress from current TPRP.

Shortcuts:
•RISK SCORING RESULTS
•MITIGATION SCORING RESULTS

TARGETED PIPE REPLACEMENT PROGRAM

Demonstrating the Value of Optimization

APPROACH OVERVIEW

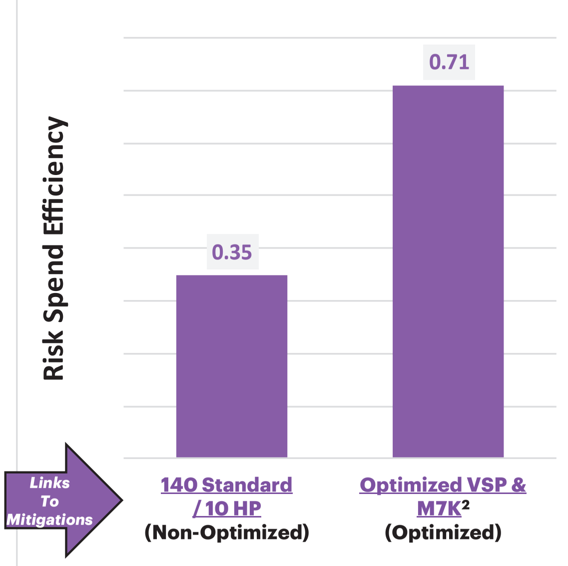
Six unique approaches, each consisting of various combinations of the 4 highest risk pipe types in the CA service territory, were evaluated to **identify the most optimum program in terms of risk reduction per dollar invested**

HOW OPTIMIZATION WAS DONE

- 2018 – 2022 Average Leaks Per Mile[1] were compared across 4 pipe categories of interest:
  - **Pre-1961 Vintage HP Steel***
  - **Pre-1961 Vintage Standard Steel***
  - **Driscopipe M7000***
  - **Driscopipe M8000**
- **Leak rate** was **measured against** estimated **replacement cost** to derive a "bang-for-buck" rating for each pipe type, enabling the path for optimization

*Part of 2021 GRC TPRP

RSE COMPARISON



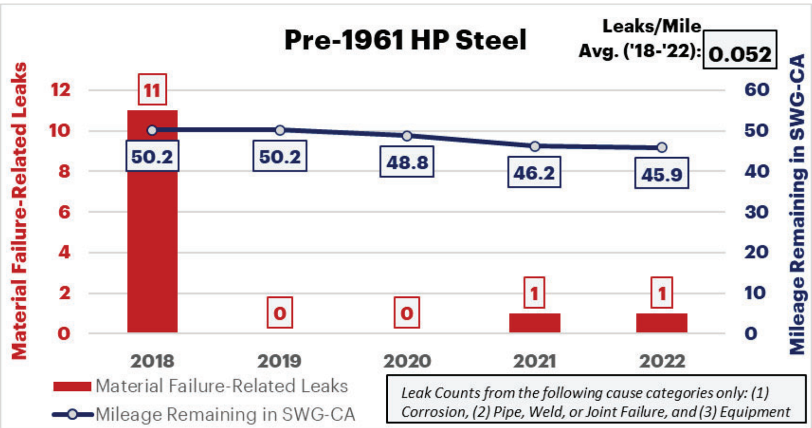
2X risk reduction achieved per dollar invested via optimization

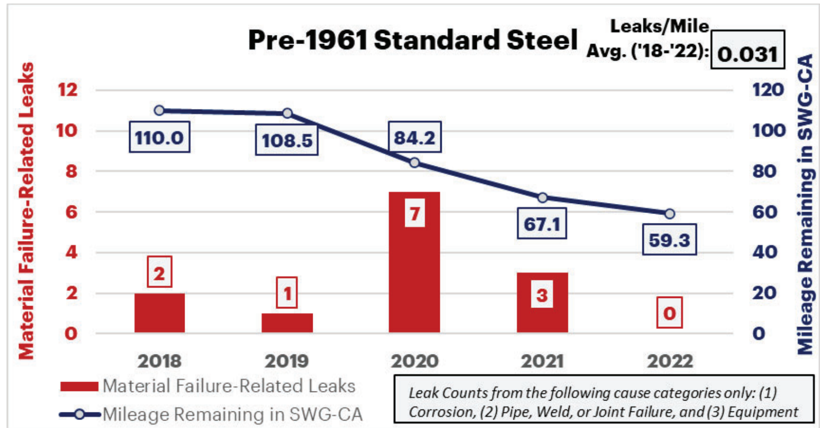
1. Leak rates are comprised of 2018 – 2022 history of material failure-related leaks (corrosion, pipe weld / joint failure, or equipment failure)
2. The above estimates are based on ~50 miles of Pre-1961 Vintage Standard Steel remaining in SWG-CA by beginning of 2026, which accounts for continued progress from current TPRP.

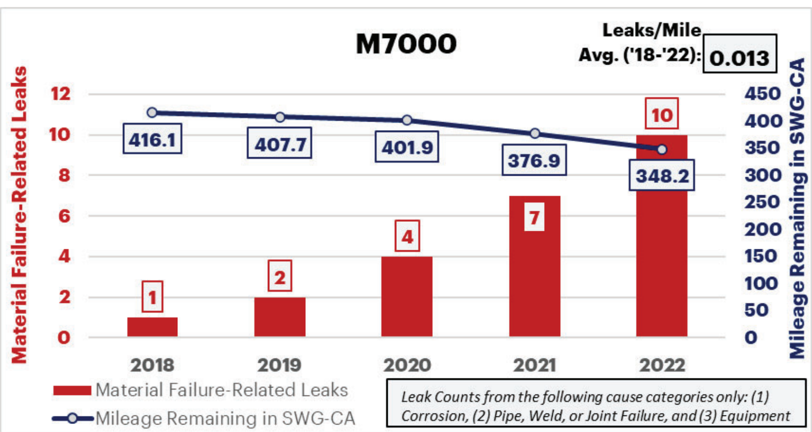
Shortcuts:
•RISK SCORING RESULTS
•MITIGATION SCORING RESULTS

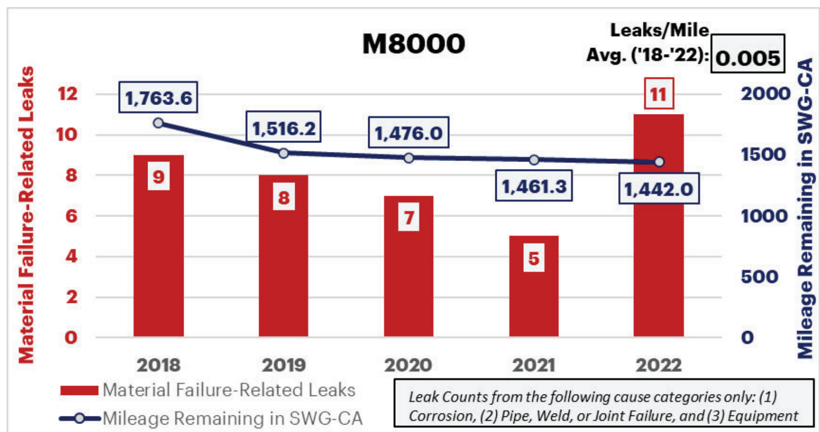
TARGETED PIPE REPLACEMENT PROGRAM

2018 – 2022 Performance Summary for Target Pipes









WHY THIS MATTERS

Since the foundation of risk reduction for this risk is “estimated leaks avoided”, the following leak rates are referenced for estimating the risk reduction for each scenario

DATA SOURCES

(1) ***Pre-1961 Steel miles & leaks:*** *Query results provided by Brooke Bachmann on 10/25/23*

(2) ***M7000 and M8000 miles & leaks:*** *SWG-CA Mains and Services leak records*

Sources: (1) For M7000 and M8000: SWG-CA Mains and Services leak records, (2) For Pre-1961 Steel: Query results provided by Brooke Bachmann on 10/25/23

TARGETED PIPE REPLACEMENT PROGRAM (OPTIMIZED VSP & M7K)

Scoring Summary

Risk Mitigated

Distribution System Failure

Mitigation Activities

Optimized approach of replacing high risk pipe in the SCA service territory, specifically Pre-1961 Vintage Steel (non-HP) and Driscopipe M7000, prioritizing highest leak reduction per $ spent.

Investment Amount

$96.4M
(estimate across GRC cycle)

At a cost of $100 per foot of standard pressure pipe replaced, the budget prioritizes replacement of all remaining Pre-1961 vintage standard steel, with remaining funds allocated to replacement of Driscopipe M7000.

Benefits Lifetime

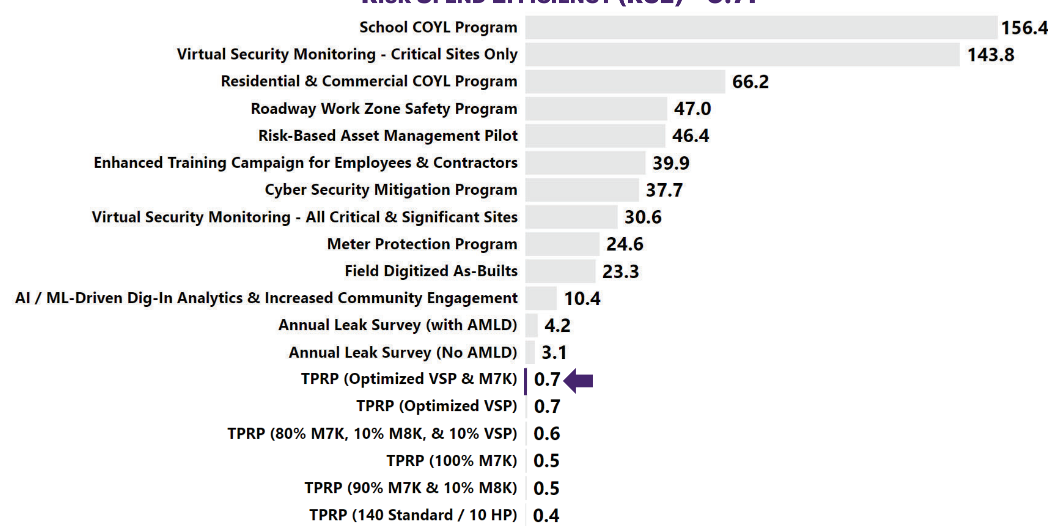
50
Years

Based on nominal life expectancy of asset

Frequency Mitigation

Inherent (Before)	Residual[1] (After)	
1 incident every… 27.1 *Years*	*1 incident every…* 28.2 *Years*	When compared against a beginning of '26 avg. of 82.99 leaks per year, this program could achieve an annual non-excavation leak reduction 3.26 leaks per year by end of the '26 GRC cycle, which is based on multiplying the anticipated miles per pipe type to be replaced by their corresponding average '18 – '22 leak rates.

Risk Spend Efficiency (RSE) = 0.71



Note: Impact (safety, operational, financial) remain unchanged by mitigation
(1) The above estimate is based on ~50 miles of Pre-1961 Vintage Standard Steel remaining in SWG-CA by beginning of 2026, which accounts for continued progress from current TPRP.

TARGETED PIPE REPLACEMENT PROGRAM (OPTIMIZED VSP & M7K)
Cost Summary

RISK MITIGATED	MITIGATION ACTIVITIES	TOTAL INVESTMENT AMOUNT		
Distribution System Failure	Optimized approach of replacing high risk pipe in the SCA service territory, specifically Pre-1961 Vintage Steel (non-HP) and Driscopipe M7000.	$96.4M ***Future Value***	$83.9M ***Net Present Value***	100% ***CAPITAL*** / 0% ***O&M***

Annual Cost Breakdown	2026	2027	2028	2029	2030
• Driscopipe M7000 [CAPITAL]	$13,992,000	$13,992,000	$13,992,000	$13,992,000	$13,992,000
• Pre-1961 Standard Steel [CAPITAL][1]	$5,280,000	$5,280,000	$5,280,000	$5,280,000	$5,280,000
• **Annual Total (SWG-CA)**	**$19,272,000**	**$19,272,000**	**$19,272,000**	**$19,272,000**	**$19,272,000**

(1) The above estimate is based on ~50 miles of Pre-1961 Vintage Standard Steel remaining in SWG-CA by beginning of 2026, which accounts for continued progress from current TPRP.

Shortcuts:
•RISK SCORING RESULTS
•MITIGATION SCORING RESULTS

DIST. SYS. FAILURE Supporting Info: Residual Freq. Calculation

Anticipated impact from: Targeted Pipe Replacement Program (Optimized VSP & M7K)

#	Parameter	INHERENT (BEFORE)	RESIDUAL (AFTER)	Rationale / Data Source
1	Leaks / Year (SWG-CA)	82.99	79.73	• Accounts for '26 – '30 replacement a combined 182.5 miles replaced across M7000 and standard VSP pipe categories. Multiplying miles replaced for each pipe type by its corresponding '18 – '22 material failure leak rates, it equates to an assumed annual leak reduction of 3.26 leaks/year by the end of the program. (82.99 – 3.26 = 79.73)
		✖	✖	
2	% of Non-Excavation Leaks which are Grade 1	36.2%	36.2%	• % of non-excavation leaks which were Grade 1 (2018 – 2022) – Source: DIMP CA mains & services leak worksheets
		✖	✖	
3	% of Non-Excavation Grade 1 Leaks resulting in ignition or explosion ☆	0.3%	0.3%	• Assumption that 3 per 1,000 Grade 1 non-excavation leaks will result in an ignition or explosion event
		✖	✖	
4	% of Gas Explosion Incidents resulting in a fatality	41%	41%	• 2010-2023 PHMSA Incidents: Of the 147 non-excavation distribution incidents since 2010 in which an explosion occurred, 61 (41%) resulted in some kind of safety consequences
		=	=	
	Calculated Fatal Explosion Incidents Per Year from Dist. Sys. Failure	0.037	0.035	
		⬇	⬇	
	Equivalent to an event occurring every 'n' years	27.1	28.2	

GREEN = Updated Input
☆ = SME Estimate

TARGETED PIPE REPLACEMENT PROGRAM (OPTIMIZED VSP)

Scoring Summary

RISK MITIGATED

Distribution System Failure

MITIGATION ACTIVITIES

Optimized approach of replacement of high risk pipe in the SCA service territory, specifically Pre-1961 Vintage Steel (both the standard and HP categories), prioritizing highest leak reduction per $ spent.

INVESTMENT AMOUNT

$96.4M

(estimate across GRC cycle)

At a cost of $100 per foot, this investment amount could replace the remaining 100% of the remaining miles of Pre-1961 Vintage standard steel, at a cost of ~$30M. The remaining funds would then be used to replace Pre-1961 Vintage HP steel at a cost of $425 per foot.

BENEFITS LIFETIME

50

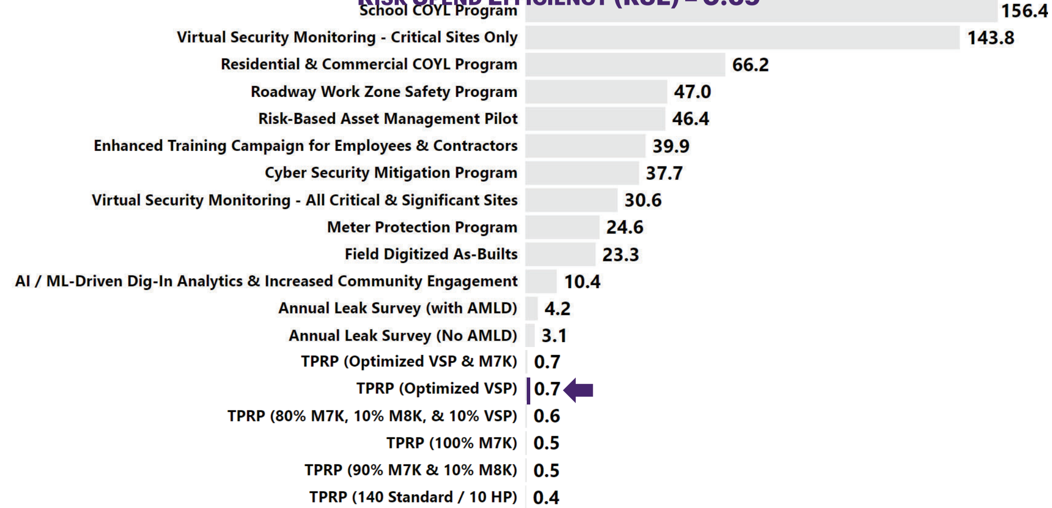
Years

Based on nominal life expectancy of asset

FREQUENCY MITIGATION

INHERENT (BEFORE)	RESIDUAL (AFTER)	
1 incident every… 27.1 *Years*	*1 incident every…* 28.2 *Years*	When compared against a beginning of '26 avg. of 82.99 leaks per year, this program could achieve an annual non-excavation leak reduction 3.19 leaks per year by end of the '26 GRC cycle, which is based on multiplying the anticipated miles of Pre-1961 vintage steel (HP and standard) to be replaced by their corresponding average '18 – '22 leak rates.

RISK SPEND EFFICIENCY (RSE) = 0.69



Note: Impact (safety, operational, financial) remain unchanged by mitigation
(1) The above estimate is based on ~50 miles of Pre-1961 Vintage Standard Steel remaining in SWG-CA by beginning of 2026, which accounts for continued progress from current TPRP.

Shortcuts:
•RISK SCORING RESULTS
•MITIGATION SCORING RESULTS

TARGETED PIPE REPLACEMENT PROGRAM (OPTIMIZED VSP)

Cost Summary

RISK MITIGATED	MITIGATION ACTIVITIES	TOTAL INVESTMENT AMOUNT		
Distribution System Failure	Collection of replacement initiatives including high risk pipe in the SCA service territory (Pre-1961 Vintage Standard Steel, & Pre-1961 Vintage HP Steel)	$96.4M ***Future Value***	$83.9M ***Net Present Value***	100% ***CAPITAL*** 0% ***O&M***

Annual Cost Breakdown	2026	2027	2028	2029	2030
• **Pre-1961 Vintage Standard Steel [CAPITAL][1]**	$5,280,000	$5,280,000	$5,280,000	$5,280,000	$5,280,000
• **Pre-1961 Vintage HP Steel [CAPITAL]**	$13,992,000	$13,992,000	$13,992,000	$13,992,000	$13,992,000
• **Annual Total (SWG-CA)**	**$19,272,000**	**$19,272,000**	**$19,272,000**	**$19,272,000**	**$19,272,000**

(1) The above estimate is based on ~50 miles of Pre-1961 Vintage Standard Steel remaining in SWG-CA by beginning of 2026, which accounts for continued progress from current TPRP.

Shortcuts:
•RISK SCORING RESULTS
•MITIGATION SCORING RESULTS

DIST. SYS. FAILURE Supporting Info: Residual Freq. Calculation

Anticipated impact from: Targeted Pipe Replacement Program (Optimized VSP)

#	Parameter	INHERENT (BEFORE)	RESIDUAL (AFTER)	Rationale / Data Source
1	Leaks / Year (SWG-CA)	82.99	79.80	• Accounts for '26 – '30 replacement totals of 59 miles of Pre-1961 Standard Steel and 29 miles of Pre-1961 HP Steel. Multiplying miles replaced for each pipe type by its corresponding '18 – '22 material failure leak rates, it equates to an assumed annual leak reduction of 3.19 leaks/year by the end of the program. (82.99 – 3.19 = 79.80)
		✖	✖	
2	% of Non-Excavation Leaks which are Grade 1	36.2%	36.2%	• % of non-excavation leaks which were Grade 1 (2018 – 2022) – Source: DIMP CA mains & services leak worksheets
		✖	✖	
3	% of Non-Excavation Grade 1 Leaks resulting in ignition or explosion ☆	0.3%	0.3%	• Assumption that 3 per 1,000 Grade 1 non-excavation leaks will result in an ignition or explosion event
		✖	✖	
4	% of Gas Explosion Incidents resulting in a fatality	41%	41%	• 2010-2023 PHMSA Incidents: Of the 147 non-excavation distribution incidents since 2010 in which an explosion occurred, 61 (41%) resulted in some kind of safety consequences
		=	=	
	Calculated Fatal Explosion Incidents Per Year from Dist. Sys. Failure	0.037	0.036	
		⬇	⬇	
	Equivalent to an event occurring every 'n' years	27.1	28.2	

GREEN = Updated Input
☆ = SME Estimate

TARGETED PIPE REPLACEMENT PROGRAM (80% M7K, 10% M8K, & 10% VSP)

Scoring Summary

RISK MITIGATED

Distribution System Failure

MITIGATION ACTIVITIES

Collection of replacement initiatives including high risk pipe in the SCA service territory, specifically Pre-1961 Vintage Steel (non-HP), Driscopipe M7000, and Driscopipe M8000

INVESTMENT AMOUNT

$96.4M
(estimate across GRC cycle)

At a cost of $100 per foot of standard pressure pipe replaced, the investment would be split 80% to Driscopipe M7000, 10% to Pre-1961 Vintage Steel, and 10% to Driscopipe M8000.

BENEFITS LIFETIME

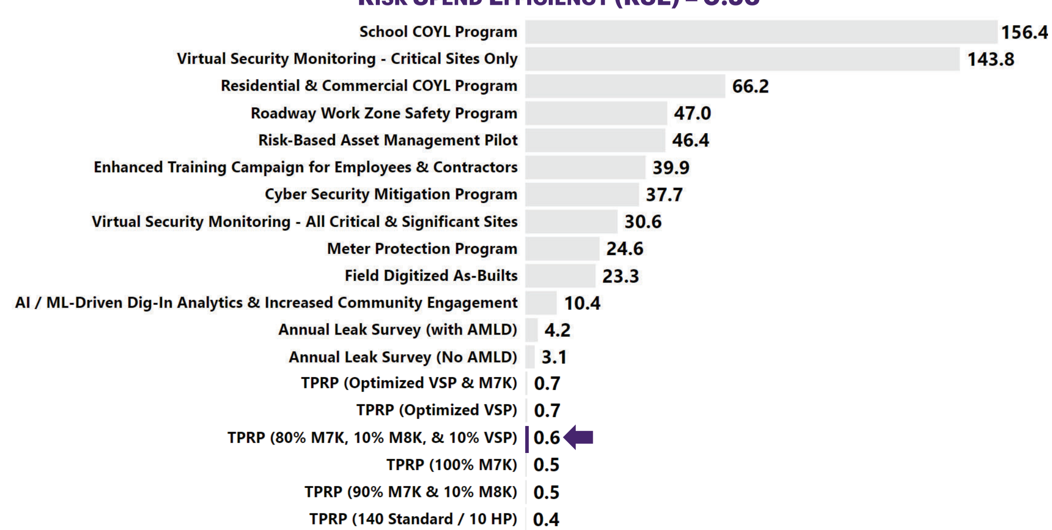
50
Years

Based on nominal life expectancy of asset

FREQUENCY MITIGATION

INHERENT (BEFORE)	RESIDUAL (AFTER)	
1 incident every… 27.1 *Years*	*1 incident every…* 27.9 *Years*	When compared against a beginning of '26 avg. of 82.99 leaks per year, this program could achieve an annual non-excavation leak reduction 2.55 leaks per year by end of the '26 GRC cycle, which is based on multiplying the anticipated miles per pipe type to be replaced by their corresponding average '18 – '22 leak rates.

RISK SPEND EFFICIENCY (RSE) = 0.56



Note: Impact (safety, operational, financial) remain unchanged by mitigation

TARGETED PIPE REPLACEMENT PROGRAM (80% M7K, 10% M8K, & 10% VSP)
Cost Summary

RISK MITIGATED

Distribution System Failure

MITIGATION ACTIVITIES

Collection of replacement initiatives including high risk pipe in the SCA service territory (Driscopipe M7000, Driscopipe M8000, and Pre-1961 Vintage Standard Steel)

TOTAL INVESTMENT AMOUNT

$96.4M *Future Value*	$83.9M *Net Present Value*	100% *CAPITAL* / 0% *O&M*

Annual Cost Breakdown	2026	2027	2028	2029	2030
• Driscopipe M7000 (80% of portfolio) [CAPITAL]	$15,417,600	$15,417,600	$15,417,600	$15,417,600	$15,417,600
• Driscopipe M8000 (10% of portfolio) [CAPITAL]	$1,927,000	$1,927,000	$1,927,000	$1,927,000	$1,927,000
• Pre-1961 Standard Steel (10% of portfolio) [CAPITAL]	$1,927,000	$1,927,000	$1,927,000	$1,927,000	$1,927,000
• **Annual Total (SWG-CA)**	**$19,272,000**	**$19,272,000**	**$19,272,000**	**$19,272,000**	**$19,272,000**

Shortcuts:
•RISK SCORING RESULTS
•MITIGATION SCORING RESULTS

DIST. SYS. FAILURE Supporting Info: Residual Freq. Calculation

Anticipated impact from: Targeted Pipe Replacement Program (80% M7K, 10% M8K, & 10% VSP)

#	Parameter	INHERENT (BEFORE)	RESIDUAL (AFTER)	Rationale / Data Source
1	Leaks / Year (SWG-CA)	82.99	80.44	• Accounts for '26 – '30 replacement a combined 182.5 miles replaced across M7000, M8000, and standard VSP pipe categories. Multiplying miles replaced for each pipe type by its corresponding '18 – '22 material failure leak rates, it equates to an assumed annual leak reduction of 2.55 leaks/year by the end of the program. (82.99 – 2.55 = 80.44)
		✖	✖	
2	% of Non-Excavation Leaks which are Grade 1	36.2%	36.2%	• % of non-excavation leaks which were Grade 1 (2018 – 2022) – Source: DIMP CA mains & services leak worksheets
		✖	✖	
3	% of Non-Excavation Grade 1 Leaks resulting in ignition or explosion ☆	0.3%	0.3%	• Assumption that 3 per 1,000 Grade 1 non-excavation leaks will result in an ignition or explosion event
		✖	✖	
4	% of Gas Explosion Incidents resulting in a fatality	41%	41%	• 2010-2023 PHMSA Incidents: Of the 147 non-excavation distribution incidents since 2010 in which an explosion occurred, 61 (41%) resulted in some kind of safety consequences
		=	=	
	Calculated Fatal Explosion Incidents Per Year from Dist. Sys. Failure	0.037	0.036	
		⬇	⬇	
	Equivalent to an event occurring every 'n' years	27.1	27.9	

GREEN = Updated Input
☆ = SME Estimate

TARGETED PIPE REPLACEMENT PROGRAM (100% M7K)

Scoring Summary

Risk Mitigated

Distribution System Failure

Mitigation Activities

Collection of replacement initiatives including high risk pipe in the SCA service territory, specifically Driscopipe M7000

Investment Amount

$96.4M
(estimate across GRC cycle)

At a cost of $100 per foot, this investment amount could replace 182.5 miles of Driscopipe M7000.

Benefits Lifetime

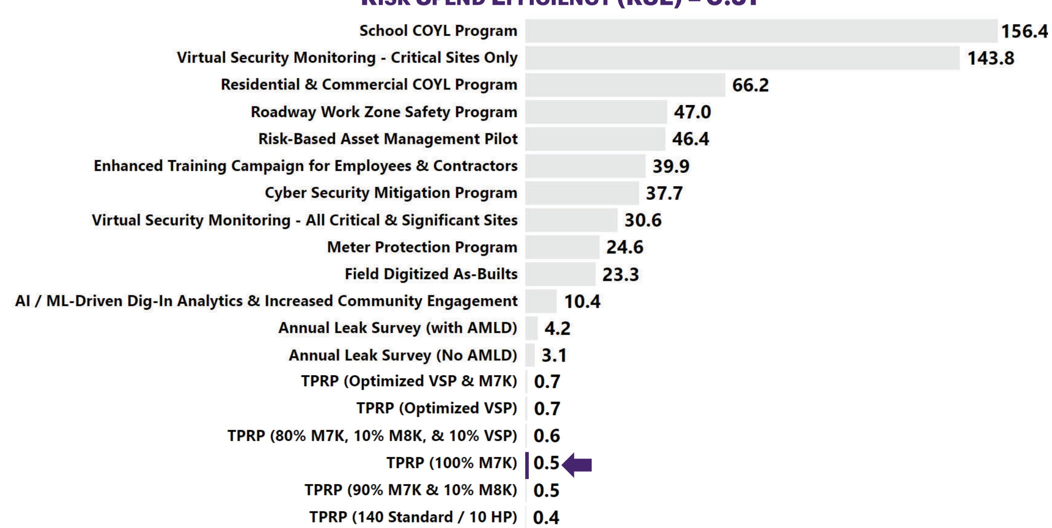
50
Years

Based on nominal life expectancy of asset

Frequency Mitigation

Inherent (Before)	Residual (After)	
1 incident every... 27.1 *Years*	*1 incident every...* 27.9 *Years*	When compared against a beginning of '26 avg. of 82.99 leaks per year, this program could achieve an annual non-excavation leak reduction 2.36 leaks per year by end of the '26 GRC cycle, which is based on multiplying the anticipated 182.5 miles of Driscopipe M7000 to be replaced by its corresponding average '18 – '22 leak rate.

Risk Spend Efficiency (RSE) = 0.51



Note: Impact (safety, operational, financial) remain unchanged by mitigation

Shortcuts:
•RISK SCORING RESULTS
•MITIGATION SCORING RESULTS

TARGETED PIPE REPLACEMENT PROGRAM (100% M7K)

Cost Summary

RISK MITIGATED

Distribution System Failure

MITIGATION ACTIVITIES

Collection of replacement initiatives including high risk pipe in the SCA service territory, specifically Driscopipe M7000

TOTAL INVESTMENT AMOUNT

$96.4M ***Future Value***	$83.9M ***Net Present Value***	100% ***CAPITAL*** / 0% ***O&M***

Annual Cost Breakdown	2026	2027	2028	2029	2030
• Driscopipe M7000 [CAPITAL]	$19,272,000	$19,272,000	$19,272,000	$19,272,000	$19,272,000
• Annual Total (SWG-CA)	**$19,272,000**	**$19,272,000**	**$19,272,000**	**$19,272,000**	**$19,272,000**

DIST. SYS. FAILURE Supporting Info: Residual Freq. Calculation

Anticipated impact from: Targeted Pipe Replacement Program (100% M7K)

#	Parameter	INHERENT (BEFORE)	RESIDUAL (AFTER)	Rationale / Data Source
1	Leaks / Year (SWG-CA)	82.99	80.63	• Accounts for '26 – '30 replacement totals of 182.5 miles of M7000. Multiplying miles replaced by its corresponding '18 – '22 material failure leak rate, it equates to an assumed annual leak reduction of 2.36 leaks/year by the end of the program. (82.99 – 2.36 = 80.63)
		×	×	
2	% of Non-Excavation Leaks which are Grade 1	36.2%	36.2%	• % of non-excavation leaks which were Grade 1 (2018 – 2022) – Source: DIMP CA mains & services leak worksheets
		×	×	
3	% of Non-Excavation Grade 1 Leaks ☆ resulting in ignition or explosion	0.3%	0.3%	• Assumption that 3 per 1,000 Grade 1 non-excavation leaks will result in an ignition or explosion event
		×	×	
4	% of Gas Explosion Incidents resulting in a fatality	41%	41%	• 2010-2023 PHMSA Incidents: Of the 147 non-excavation distribution incidents since 2010 in which an explosion occurred, 61 (41%) resulted in some kind of safety consequences
		=	=	
	Calculated Fatal Explosion Incidents Per Year from Dist. Sys. Failure	0.037	0.036	
	Equivalent to an event occurring every 'n' years	27.1	27.9	

GREEN = Updated Input
☆ = SME Estimate

TARGETED PIPE REPLACEMENT PROGRAM (90% M7K & 10% M8K)

Scoring Summary

RISK MITIGATED

Distribution System Failure

MITIGATION ACTIVITIES

Collection of replacement initiatives including high risk pipe in the SCA service territory, specifically Driscopipe M7000 and Driscopipe M8000

INVESTMENT AMOUNT

$96.4M
(estimate across GRC cycle)

At a cost of $100 per foot of standard pressure pipe replaced, the investment would be split 90% to Driscopipe M7000 and 10% to Driscopipe M8000.

BENEFITS LIFETIME

50
Years

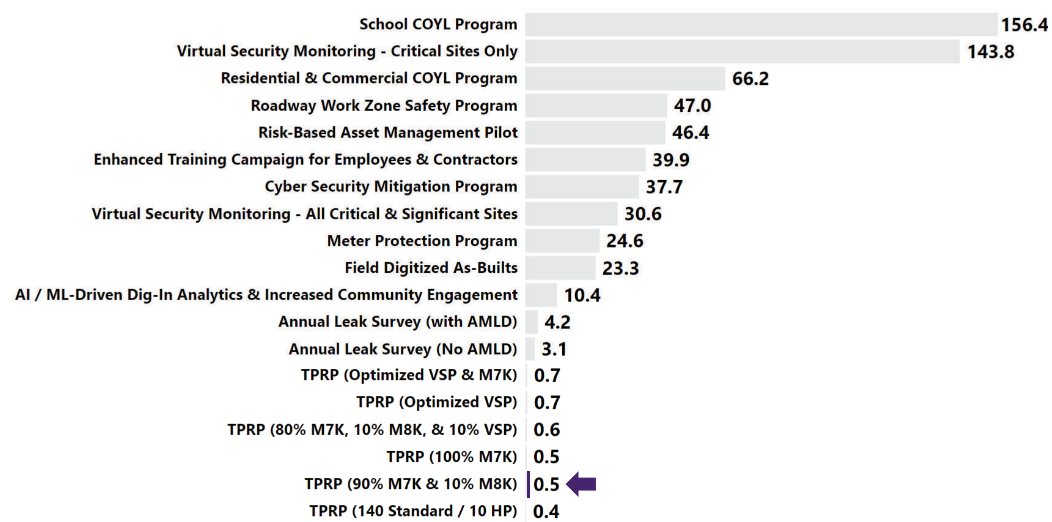
Based on nominal life expectancy of asset

FREQUENCY MITIGATION

INHERENT (BEFORE)	RESIDUAL (AFTER)
1 incident every… 27.1 *Years*	*1 incident every…* 27.8 *Years*

When compared against a beginning of '26 avg. of 82.99 leaks per year, this program could achieve an annual non-excavation leak reduction 2.22 leaks per year by end of the '26 GRC cycle, which is based on multiplying the anticipated miles per pipe type to be replaced by their corresponding average '18 – '22 leak rates.

RISK SPEND EFFICIENCY (RSE) = 0.48



Note: Impact (safety, operational, financial) remain unchanged by mitigation

TARGETED PIPE REPLACEMENT PROGRAM (90% M7K & 10% M8K)
Cost Summary

RISK MITIGATED
Distribution System Failure

MITIGATION ACTIVITIES
Collection of replacement initiatives including high risk pipe in the SCA service territory, specifically Driscopipe M7000 and Driscopipe M8000

TOTAL INVESTMENT AMOUNT
$96.4M	$83.9M	100%	0%
Future Value	***Net Present Value***	***CAPITAL***	***O&M***

Annual Cost Breakdown	2026	2027	2028	2029	2030
• Driscopipe M7000 (90% of portfolio) [CAPITAL]	$17,345,000	$17,345,000	$17,345,000	$17,345,000	$17,345,000
• Driscopipe M8000 (10% of portfolio) [CAPITAL]	$1,927,000	$1,927,000	$1,927,000	$1,927,000	$1,927,000
• **Annual Total (SWG-CA)**	**$19,272,000**	**$19,272,000**	**$19,272,000**	**$19,272,000**	**$19,272,000**

Shortcuts:
•RISK SCORING RESULTS
•MITIGATION SCORING RESULTS

DIST. SYS. FAILURE Supporting Info: Residual Freq. Calculation

Anticipated impact from: Targeted Pipe Replacement Program (90% M7K & 10% M8K)

#	Parameter	INHERENT (BEFORE)	RESIDUAL (AFTER)	Rationale / Data Source
1	Leaks / Year (SWG-CA)	82.99	80.77	• Accounts for '26 – '30 replacement a combined 182.5 miles replaced across M7000 and M8000. Multiplying miles replaced for each pipe type by its corresponding '18 – '22 material failure leak rates, it equates to an assumed annual leak reduction of 2.22 leaks/year by the end of the program. (82.99 – 2.22 = 80.77)
		×	×	
2	% of Non-Excavation Leaks which are Grade 1	36.2%	36.2%	• % of non-excavation leaks which were Grade 1 (2018 – 2022) – Source: DIMP CA mains & services leak worksheets
		×	×	
3	% of Non-Excavation Grade 1 Leaks resulting in ignition or explosion ☆	0.3%	0.3%	• Assumption that 3 per 1,000 Grade 1 non-excavation leaks will result in an ignition or explosion event
		×	×	
4	% of Gas Explosion Incidents resulting in a fatality	41%	41%	• 2010-2023 PHMSA Incidents: Of the 147 non-excavation distribution incidents since 2010 in which an explosion occurred, 61 (41%) resulted in some kind of safety consequences
		=	=	
	Calculated Fatal Explosion Incidents Per Year from Dist. Sys. Failure	0.037	0.036	
	Equivalent to an event occurring every 'n' years	27.1	27.8	

GREEN = Updated Input
☆ = SME Estimate

TARGETED PIPE REPLACEMENT PROGRAM (140 STANDARD / 10 HP)

Scoring Summary

RISK MITIGATED

Distribution System Failure

MITIGATION ACTIVITIES

Collection of replacement initiatives including high risk pipe in the SCA service territory (140 miles combined of Driscopipe M7000, Driscopipe M8000, & Pre-1961 Vintage Standard Steel, and 10 miles of Pre-1961 Vintage HP Steel)

INVESTMENT AMOUNT

$96.4M
(estimate across GRC cycle)

Estimated replacement costs per foot of pipe are $100 for standard and $425 for high pressure (HP). This scenario projects SCA replacing a combined 30 miles per year (28 of standard and 2 HP). Across the 5-year period the total mileage replaced throughout the '26 GRC cycle would be 150 miles, 140 of standard pipe and 10 of HP pipe.

BENEFITS LIFETIME

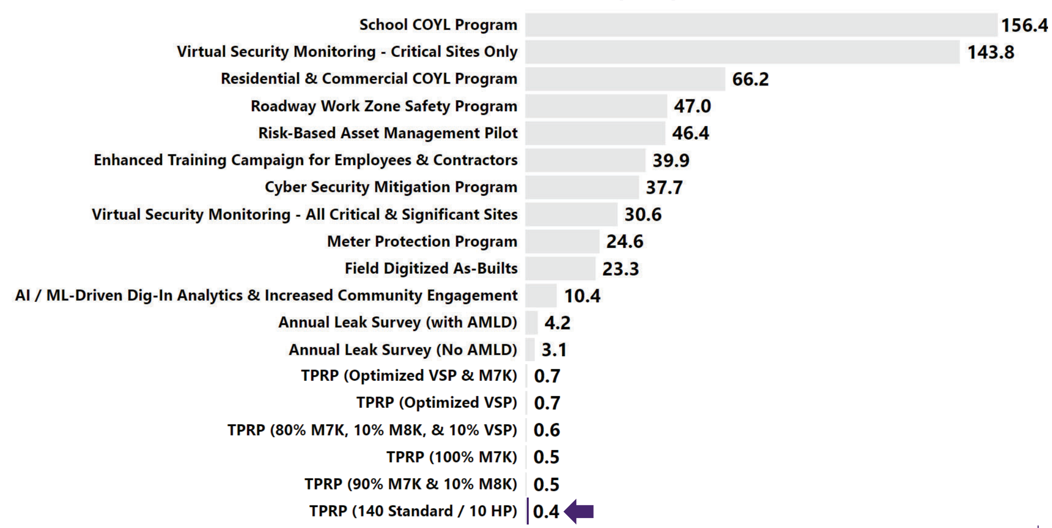
50
Years

Based on nominal life expectancy of asset

FREQUENCY MITIGATION

INHERENT (BEFORE)	RESIDUAL (AFTER)	
1 incident every... 27.1 *Years*	*1 incident every...* 27.6 *Years*	When compared against a beginning of '26 avg. of 82.99 leaks per year, this program could achieve an annual non-excavation leak reduction 1.62 leaks per year by end of the '26 GRC cycle, which is based on multiplying the anticipated 140 miles of standard pressure pipe to be replaced by the combined average '18 – '22 leak rate across the 3 standard pressure pipe categories, and applying the same methodology for the 10 miles of HP pipe

RISK SPEND EFFICIENCY (RSE) = 0.35



Note: Impact (safety, operational, financial) remain unchanged by mitigation

TARGETED PIPE REPLACEMENT PROGRAM (140 STANDARD / 10 HP)
Cost Summary

RISK MITIGATED	MITIGATION ACTIVITIES
Distribution System Failure	Collection of replacement initiatives including high risk pipe in the SCA service territory (140 miles combined of Driscopipe M7000, Driscopipe M8000, & Pre-1961 Vintage Standard Steel, and 10 miles of Pre-1961 Vintage HP Steel)

TOTAL INVESTMENT AMOUNT		
$96.4M ***Future Value***	$83.9M ***Net Present Value***	100% ***CAPITAL*** / 0% ***O&M***

Annual Cost Breakdown	2026	2027	2028	2029	2030
• **Standard Pipe Replacement – Includes M7000, M8000, and Vintage Standard Steel (28 miles annual @ $100 per ft.)**	$14,784,000	$14,784,000	$14,784,000	$14,784,000	$14,784,000
• **HP Vintage Steel Pipe Replacement (2 miles annual @ $425 per ft.)**	$4,488,000	$4,488,000	$4,488,000	$4,488,000	$4,488,000
• **Annual Total (SWG-CA)**	**$19,272,000**	**$19,272,000**	**$19,272,000**	**$19,272,000**	**$19,272,000**

DIST. SYS. FAILURE Supporting Info: Residual Freq. Calculation

Anticipated impact from: Targeted Pipe Replacement Program (140 Standard / 10 HP)

#	Parameter	INHERENT (BEFORE)	RESIDUAL (AFTER)	Rationale / Data Source
1	Leaks / Year (SWG-CA)	82.99	81.37	• Accounts for '26 – '30 replacement totals of 10 miles of Pre-1961 HP Steel, and 140 miles combined of Pre-1961 Standard Steel, M7000, and M8000. Multiplying miles replaced for each pipe type by its corresponding '18 – '22 material failure leak rates, it equates to an assumed annual leak reduction of 1.62 leaks/year by the end of the program. (82.99 – 1.62 = 81.37)
		✖	✖	
2	% of Non-Excavation Leaks which are Grade 1	36.2%	36.2%	• % of non-excavation leaks which were Grade 1 (2018 – 2022) – Source: DIMP CA mains & services leak worksheets
		✖	✖	
3	% of Non-Excavation Grade 1 Leaks resulting in ignition or explosion ☆	0.3%	0.3%	• Assumption that 3 per 1,000 Grade 1 non-excavation leaks will result in an ignition or explosion event
		✖	✖	
4	% of Gas Explosion Incidents resulting in a fatality	41%	41%	• 2010-2023 PHMSA Incidents: Of the 147 non-excavation distribution incidents since 2010 in which an explosion occurred, 61 (41%) resulted in some kind of safety consequences
		=	=	
	Calculated Fatal Explosion Incidents Per Year from Dist. Sys. Failure	0.037	0.036	
	Equivalent to an event occurring every 'n' years	27.1	27.62	

GREEN = Updated Input
☆ = SME Estimate

Conclusion

Thank you!

For questions, please contact:

- **Brian Fletcher – brian.fletcher@accenture.com**

SOUTHWEST GAS

accenture

Appendix

Pairwise Exercise Results

1 Select **criteria** to represent company values, accompanied by **metrics** with **baseline values**

Pairwise Criteria Inputs

Criteria	Units	Baseline Values
Safety	Fatality	1
Operational	Gas Meters Interrupted	50,000
Financial	$	30,000,000

2 Compare **criteria** in pairs to express their importance

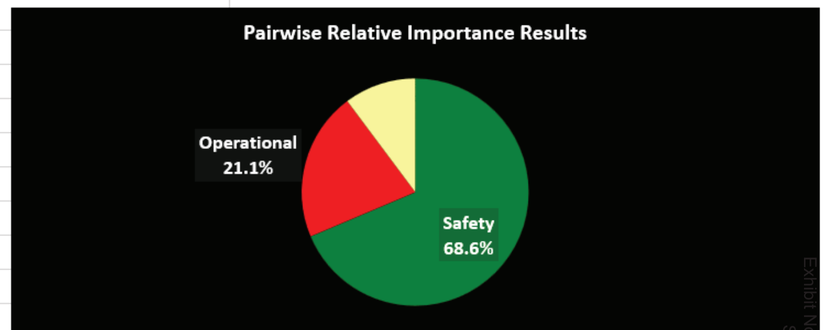
↓Choose Comparators from Dropdowns

1 Fatality	is	More Important Than	50,000 Gas Meters Interrupted
1 Fatality	is	More Important Than	30,000,000 $
50,000 Gas Meters Interrupted	is	Marginally More Important Than	30,000,000 $

Results reflect **relative importance** of criteria to express their **%-weightings** used in risk calculations. Dialogue with SMEs, refine and determine final %-weightings

Derived Relative Importance Weights

	Safety	Operational	Financial
Weights from Pairwise ○	69%	21%	10%
Weights from SME ◉	65%	20%	15%



Company Witness:
Kevin M. Lang

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
APPLICATION 24-09-___

PREPARED DIRECT TESTIMONY
OF
KEVIN M. LANG

ON BEHALF OF
SOUTHWEST GAS CORPORATION

SEPTEMBER 5, 2024

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Prepared Direct Testimony
of
Kevin M. Lang

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Prepared Direct Testimony
of
Kevin M. Lang

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Kevin M. Lang. My business address is 8360 South Durango Drive, Las Vegas, Nevada 89113.

Q. 2 By whom and in what capacity are you employed?

A. 2 I am employed by Southwest Gas Corporation (Southwest Gas or the Company) in the Engineering Staff department. My title is Vice President of Engineering Staff.

Q. 3 Please summarize your educational background and relevant business experience.

A. 3 My educational background and relevant business experience are summarized in Appendix A to this testimony.

Q. 4 Have you previously testified before any regulatory commission?

A. 4 Yes. I have previously testified before California Public Utilities Commission (Commission), the Arizona Corporation Commission, and the Public Utilities Commission of Nevada (PUCN).

Q. 5 What is the purpose of your prepared direct testimony in this proceeding?

A. 5 I sponsor, from an operations perspective, the Company's proposal to continue its risk-informed program for the Targeted Pipe Replacement Program; the Meter Protection Program, and the School Customer-Owned Yard Line (COYL) Program. Additionally, I provide testimony to support the proposed implementation of an Annual Leak Detection Program using Advanced Mobile Leak Detection (AMLD) equipment.

Q. 6 Please summarize your prepared direct testimony.

A. 6 My prepared direct testimony consists of the following key issues:

- The continuation of the Targeted Pipe Replacement Program of select distribution steel and Driscopipe 7000 plastic pipes.
- The continuation of the Meter Protection Program that includes a suite of protection options for heavy snow load areas within the Company's Big Bear and Lake Tahoe areas.
- The continuation of a School COYL Replacement Program that targets risky and unmaintained COYLs in schools and the replacement of these customer-owned facilities with Company owned and maintained facilities.
- The implementation of an Annual Leak Survey Program utilizing conventional and Advanced Mobile Leak Detection (AMLD) equipment.

II. RISK-INFORMED DECISION-MAKING PROCESS

Q. 7 What is the Risk-Informed Decision-making Process?

A. 7 As discussed more fully and supported in the Prepared Direct Testimony of Company witness Bradley C. Anderson, Southwest Gas, along with the other small and multi-jurisdictional utilities in California were directed to transition to a risk-informed decision-making process in their general rate case applications beginning in 2017.[1] Through this process, Southwest Gas identified and evaluated several risks and controls and mitigations to address the identified risks.

[1] Decision (D.) 14-12-025, Ordering Paragraph 4, at pg. 55.

Q. 8 Are the programs proposed in your prepared direct testimony a direct result of the risk-informed decision-making process?

A. 8 Yes. Southwest Gas' proposals for continuation of the Targeted Pipe Replacement Program, the Meter Protection Program, and the School COYL Program were all the direct result of the Company's risk-informed decision-making process. Additionally, the Company has identified and is proposing one new program item in a systemwide, annual leak survey utilizing AMLD equipment in addition to conventional leak detection equipment. The Prepared Direct Testimony of Bradley C. Anderson provides specific details on the scoring and ranking of these identified programs.

III. TARGETED PIPE REPLACEMENT PROGRAM

Q. 9 Please describe the Company's continuation of its Targeted Pipe Replacement Program.

A. 9 Southwest Gas is proposing to continue its Targeted Pipe Replacement Program that focuses on two primary classifications of vintage pipelines:

- Pre-1961 vintage distribution steel pipelines
- Driscopipe 7000 distribution plastic pipelines

Q. 10 Why is it important to proactively replace pipe before it leaks?

A. 10 Although no immediate safety concern exists on vintage pipelines such as those the Company has identified for its Targeted Pipe Replacement Program, Southwest Gas realizes it has aging infrastructure. It is prudent to proactively replace aging infrastructure before it leaks, to avoid a safety concern. Safety and reliability are top priorities at Southwest Gas and the Company consistently strives to be a leader in the natural gas industry by being a proactive and prudent operator.

Q. 11 What is the Company proposing with regards to select distribution and steel pipe replacement?

A. 11 Southwest Gas is proposing to accelerate the replacement of approximately 9 miles per year of pre-1961 distribution pipeline. For the purposes of this proposal, distribution pipelines are all pipelines that are not classified as transmission under Part 192.13 and the current California General Order 112-F.

California has had some form of state pipeline safety code as early as 1961.[2] In contrast, the federal pipeline safety code requirements were not formally established until 1970. Prior to 1961, there was no formal state pipeline safety code for pipeline construction practices, material selection, material and pipeline testing, cathodic protection requirement, recordkeeping requirements, and other key elements of modern pipeline construction requirements.

Older pipelines do not have all the safety features associated with modern pipelines such as improved coatings, enhancements to steel pipe quality and performance standards, more comprehensive welding procedures, and enhanced testing requirements. Prior to the promulgation of state and federal pipeline safety regulations, operators utilized industry consensus standards and other industry practices of the time to govern pipeline construction practices, material selection, and material and pipeline testing. These consensus standards were voluntary and not as comprehensive as the mandatory pipeline safety standards in place today.

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[2] Decision No. 61269 adopted California General Order 112 on December 28, 1960, with a July 1, 1961, effective date.

Steel pipe is prone to corrosion which can lead to leaks in a piping system. Corrosion can be mitigated through the adequate application of cathodic protection on steel pipe. Cathodic protection is achieved through the combination of a protective coating system and the application of an electric current in order to modify the electric potential of the metal surface to prevent corrosion. Federal and State pipeline safety rules mandated the cathodic protection of all steel pipe after 1970. The possible lack of cathodic protection on pre-1961 vintage steel pipe therefore presents a potential corrosion risk to the pipe. In addition, before the implementation of state and federal pipeline safety codes, pipeline installation records were not as complete and were not always retained for the same length of time as they are today.

The accelerated replacement of pre-1961 vintage steel pipe will address all of these factors by allowing Southwest Gas to bring the entirety its steel system up to modern construction and recordkeeping standards.

Q. 12 Did the Company previously propose a Targeted Pipe Replacement Program?

A. 12 Yes. In D.21-03-052, the Commission approved Southwest Gas' proposed program to replace certain vintage steel and Driscopipe 7000 pipelines within its Southern California service territory.

Q. 13 Is Southwest Gas' proposal in the instant docket a continuation of that previous scope of replacement for the Targeted Pipe Replacement Program?

A. 13 No. In D.21-03-052, Southwest Gas was authorized to replace pre-1961 vintage steel distribution pipe, a small amount of vintage steel high pressure pipe, and Driscopipe 7000 pipe based upon an authorized amount of spend per year.

Q. 14 What is Southwest Gas proposing within this Application for its Targeted Pipe Replacement Program?

A. 14 The Company proposes to continue the replacement of Driscopipe 7000 as well as the replacement of pre-1961 vintage steel pipe that operates at 60 psig or lower pressures. While not part of Southwest Gas' currently proposed Targeted Pipe Replacement Program, Southwest Gas will continue to replace pre-1961 high-pressure[3] steel pipe through other normal course of business work processes such as franchise pipe replacement, system reinforcements, and the Company's Distribution Integrity Management Program (DIMP) risk assessments.

Q. 15 What is Driscopipe 7000 pipe?

A. 15 Driscopipe is the brand name for Phillips Driscopipe, Inc. and its predecessor company Phillips Products Company. The brand name Driscopipe is still in use today. Driscopipe is a polyethylene (PE) plastic pipe type that has been installed in natural gas systems since the 1960s. Driscopipe model 7000 pipe was installed for use for distribution pressure mains and services, typically between one-half inch and four inches in diameter and was installed between 1974 and

[3] The Company defines "high-pressure" as any pipeline that operates above 60 psig pressure.

1980. The Company has approximately 359 miles of 7000 pipe in its Southern California territory (Districts 11 (Victorville) and 12 (Barstow)) as of January 30th, 2024.

Q. 16 What is the Company proposing with regard to its Driscopipe 7000 pipe replacement?

A. 16 Southwest Gas is proposing to proactively replace approximately 27 miles per year of 7000 pipe in its Southern California service territory. This plastic distribution pipe is at least 40 years old and is showing signs that it is no longer performing as expected. Southwest Gas replaced all known early vintage plastic pipe types (PVC, Aldyl-A, Aldyl-HD, and Tenite) in its California distribution system—7000 pipe is the next oldest plastic pipe type. The Company approach to proactively replacing aging infrastructure before it becomes a safety concern has yielded a distribution system with very low leak rates.

Q. 17 Is Southwest Gas proposing to accelerate the replacement of pre-1961 vintage steel and 7000 distribution plastic pipes because they are unsafe to operate?

A. 17 No. The pre-1961 vintage steel and 7000 distribution plastic pipes in the Company's distribution system do not present an immediate safety concern. Southwest Gas maintains vigorous programs to ensure the distribution system is operated in a safe and reliable manner. Instead, the Company's proposal seeks to continue to proactively replace this aging infrastructure before it becomes unsafe, and to enhance the safety and reliability of the existing system through a systematic and measured program.

Q 18 What does Southwest Gas do to address the unsafe pipe in its system?

A. 18 Unsafe pipe, regardless of age or pipe type, is replaced immediately in accordance with the Company's Operations Manual. Southwest Gas' distribution integrity management programs work to identify those pipelines that may represent a safety concern and address those concerns through additional or accelerated actions, and preventative and mitigative measures. Furthermore, Southwest Gas' integrity management programs and Operations Manual are designed to meet or exceed current Federal and State pipeline safety requirements.

Q. 19 Please describe the Company's DIMP.

A. 19 Southwest Gas' DIMP involves a risk-based process to gather and evaluate information about the Company's distribution system and to prioritize and implement actions based upon that information to maintain the safety and integrity of those systems. Southwest Gas conducts an annual evaluation and assessment that assists in the determination of whether to schedule a particular pipe segment for replacement or whether to implement other risk control practices such as additional leak surveys.

Q. 20 Does the proposed Targeted Pipe Replacement Program override the processes established through the Company's DIMP?

A. 20 No, the Targeted Pipe Replacement Program would continue to complement these processes. Southwest Gas' DIMP will continue to identify and address potential safety concerns through normal operations. Southwest Gas' proposed Targeted Pipe Replacement Program will complement and build upon the success of the Company's DIMP by combining the risk-based approach of integrity management with a proactive approach to modernize the Company's infrastructure.

Q. 21 Why is Southwest Gas proposing to continue the Targeted Pipe Replacement Program if no safety concern exists and the Company has a functional DIMP that addresses potential safety concerns in its system?

A. 21 As mentioned previously, Southwest Gas has approximately 62 miles of pre-1961 steel pipe operating at 60 psig or lower pressure and approximately 359 miles of 7000 pipe in its Southern California service territory. Given these inventory amounts, Southwest Gas recommends continuing working towards modernizing these facilities through a systematic and methodical approach that does not unduly burden Southwest Gas or its customers. In addition, the continuation of the Company's Targeted Pipe Replacement Program will serve to modernize Southwest Gas' distribution pipe facilities to current industry safety standards. Further, this modernization program will also provide enhanced safety and reliability of Southwest Gas' distribution systems through enhanced record keeping and documentation regarding pipeline construction practices, material selection, material, and pipeline testing, as well as improved pipe quality and performance standards of newer facilities.

Q. 22 Why is Southwest Gas not proposing a similar Targeted Pipe Replacement Program for its Northern California service territories?

A. 22 As discussed in D.21-03-052, the Company is focusing its Targeted Pipe Replacement Program in Southern California where it has the largest percentage of these two vintage pipe types. In addition, the Southern California service territories are located in semi-arid desert areas. While Southwest Gas anticipates that it will eventually have to target replacement of 7000 plastic pipe in its Northern California and South Lake Tahoe service territories, the Company continues to experience a higher leakage rate in its desert regions.

Q. 23 What is the breakdown of the Targeted Pipe Replacement Program costs by rate jurisdiction?

A. 23 Exhibit No.__(KML-1) provides a breakdown of the estimated pipe replacement mileage and incremental costs for Southwest Gas' Targeted Pipe Replacement Program for the Southern California rate jurisdiction. The Company is not proposing any work under the Targeted Pipe Replacement Program for its Northern California or Needles service territories.

<u>IV. METER PROTECTION PROGRAM</u>

Q. 24 Please describe the Company's continuation of its Meter Protection Program.

A. 24 Due to Southwest Gas having service territories containing heavy snow load areas, the Company identified the need to continue its comprehensive and proactive program to protect Southwest Gas meter sets from the threat of snow and ice loading damage. Originally, Southwest Gas proposed the program due to the occurrence of 52 incidents and facilities damages caused by the snow and ice loading on Company meter sets during the winter season of 2018/2019. During the winter season of 2023/2024, Southwest Gas experienced 195 incidents due to unusually high snow fall rates. These past and recent incidents highlight the need for the continued protection of existing Company facilities in heavy snow load areas.

Southwest Gas requires customers to implement extra precautions to ensure that gas piping, meters, and outdoor appliances remain safe in heavy snow load areas. This includes the requirement for customers to install a meter snow shelter (meter shed) above the gas meter to prevent snow and ice accumulation. Southwest Gas currently requires all new customer meters, and any customer who requires their existing meter or service line location to be relocated, to install a meter shed. The Company provides meter shed designs on the Southwest Gas website for customer reference.

Southwest Gas' continuation of the Meter Protection Program would continue to include a suite of safety options that are aimed at enhancing the protection of existing meters in heavy snow load areas that currently do not have an adequate form of meter protection against snow load. These options include the continued retrofitting of meter sheds for current customers without such protection; the continued evaluation and installation of an Excess Flow Valve (EFV) on certain service lines; and the continued upgrading of the meter encoder receiver transmitter (ERT) device to allow for daily meter usage monitoring following a heavy snowfall event. This suite of protection options will provide both a proactive and reactive level of protection against damage from snow and ice loading.

Q. 25 Please describe the Company's heavy snow load areas.

A. 25 Southwest Gas considers its California service territories located in Big Bear Lake, North Lake Tahoe, South Lake Tahoe and Truckee to contain heavy snow load areas. These areas commonly receive over five (5) feet of snowfall or more annually. For example, the United States Climate Data website (www.usclimatedata.com) reports average annual snowfall totals based upon data collected from 1981 through 2019. The average annual snowfall reported for the City of Big Bear Lake is approximately 67 inches; the North Lake Tahoe area including Tahoe City is approximately 184 inches; the Town of Truckee is approximately 97 inches; and the City of South Lake Tahoe is approximately 408 inches.

Q. 26 What is a meter shed?

A. 26 A meter shed is a structurally engineered shelter that is installed above the natural gas meter that protects the meter from snow and ice loading damage. Starting in approximately 2009, Southwest Gas began requiring all new customers and those customers which required a meter or service relocation to install meter shed. If a customer's meter is damaged by snow and ice loading, the customer is required to install a meter shed before service is restored to the home or business.

Q. 27 Has Southwest Gas installed meter sheds for any of its California customers previously?

A. 27 Yes. While meter sheds are required to be installed and maintained by the customer for all new services, the Commission authorized Southwest Gas to install meter sheds in D.14-03-021 as part of the California Mobile Home Park Utility Upgrade Program (MHP Program)[4] and again in D.21-03-052, Southwest Gas' Test Year 2021 general rate case.

Q. 28 Is Southwest Gas proposing the installation of meter sheds for all of its customers in heavy snow load areas?

A. 28 No. Southwest Gas' proposed continuation of the Meter Protection Program would focus on meter shed installations on those existing unprotected customer

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[4] The MHP Program is a voluntary program offered to eligible master-metered sub-metered MHPs or manufactured housing communities to convert their sub-metered spaces and common-use services from master-metered sub-metered gas distribution to direct Company gas distribution service subject to the requires and limitations set forth in the Company's tariff Rule No. 23 – Mobile Home Park Utility Upgrade Program. The Commission authorized the MHP Program for an additional 10 years in D.20-04-004.

meters where the meter is located on the eave side of the house. The eaves are the edges of the roof which overhang the face of a wall and generally project beyond the side of a building or home. The eave side of the home is generally where the highest risk of snow and ice damage occurs to a meter set assembly as it falls off the roof.

Q. 29 Is the Company continuing to educate and make its customers aware of the potential damages from snow and ice loading on its meter sets?

A. 29 Yes. Southwest Gas provides bi-annual notifications to its customers in heavy snow load areas, which inform of the potential risk of damage by snow and ice loads for gas piping, meter, and outdoor appliances. Southwest Gas also makes this same information available online and through local newspapers and other media types such as radio-based public awareness messaging. A copy of the Company's current Snow Season Safety brochure is provided as Exhibit No.__(KML-2).

Q. 30 What is an EFV?

A. 30 An EFV, or Excess Flow Valve, is a device that automatically closes and restricts the flow of natural gas if an underground service pipe is broken, completely cut, or torn apart. Such damage usually results from some type of excavation or digging activity. An EFV may also restrict the flow if the gas meter is damaged, which could result from a vehicle impact or from a large snow or ice load.

Q. 31 How will the installation of an EFV serve to protect a meter from snow and ice damage?

A. 31 An EFV can serve as a second source of defense in the event that a meter is damaged from snow or ice loading where, for example, Southwest Gas' aboveground piping leading up to the meter is completely severed resulting in a release of gas large enough to trigger the EFV. An EFV works by detecting large releases of natural gas that exceed the normal expected flow conditions for the Company's service piping and triggers a ball or plug to stop off/restrict flow through the piping. The EFV is typically installed as close to the Company's gas main piping as possible, thereby providing maximum protection to the downstream service line.

Q. 32 Does Southwest Gas currently install EFVs in its system?

A. 32 Yes, Southwest Gas currently installs EFVs on all new service lines meeting certain sizing parameters,[5] fully replaced service lines, and anytime the Company exposes the main-to-service connection for maintenance. The installation of an EFV on these types of situations is mandated by Federal regulation. Southwest Gas has installed EFVs in its distribution system over the past decade as Federal laws changed to expand their requirement in specific instances.

Southwest Gas' proposed Meter Protection Program would target those vintage service lines in its heavy snow load areas that were installed when EFVs were not required. Southwest Gas plans to further target those service lines where the homes may be unoccupied during the winter months. These homes may only be occupied as vacation homes during the summer months and would therefore likely not have an occupant available during the winter to properly clear ice and snow from around the meter set as described in Exhibit No.__(KML-2),

[5] In situations such as commercial installation or extremely large residential installations where the natural gas service load demand is larger than the rated capacity of the Company's currently available EFVs, Southwest Gas will install a service-line shut-off valve which requires manual intervention to stop off flow.

the Company's instructions and public awareness messaging to customers in heavy snow load areas.

Q. 33 What is enhanced metering or ERT?

A. 33 Enhanced metering employs the latest electronic meter reading technologies which allow the Company to obtain near-real time hourly usage data from a customer's gas meter. Southwest Gas has utilized electronic meter reading technologies since the late 1990's in parts of its service territories that are difficult to read manually. In the 2006-2008 timeframe, Southwest Gas embarked on a project to install electronic meter reading devices, or ERTs, on every gas meter.

The early versions of these ERT devices only collected composite usage data and would relay it to a hand-held device for meter reading and billing purposes. The latest technology in ERTs capture hourly data and are capable of data logging in up to 1-minute increments. The ability to remotely capture hourly or more frequent usage data in heavy snow load areas following an extreme snow fall event would provide Southwest Gas with the ability to target certain neighborhoods and evaluate the customer usage data. A targeted data analysis would look for unusual increases in natural gas usage through the meter or other anomalies that could be indicative of a damage to the Company's meter set assembly or the customer-owned piping downstream of the Company's meter.

While, at this time, Southwest Gas is not proposing to implement a full Advanced Metering Infrastructure (AMI) system where it can remotely access customer usage data in near-real time. Southwest Gas is proposing to utilize ERT devices compatible with this technology to allow the Company to employ more frequent meter reads during heavy snow load events. Southwest Gas can then use this more frequent data to run analytics to look for potential leaks or damaged meter set assemblies.

Q. 34 Please describe the Company's proposed enhanced metering under the Meter Protection Program.

A. 34 Southwest Gas is currently installing the most up-to-date technology of ERT devices for all new meter set installations and any time a meter is removed from the field and replaced. The Company's proposal, as part of its Meter Protection Program, would identify those meters in heavy snow load areas that do not have the most current type of ERT device installed and target those for replacement. This meter reading technology upgrade would work in concert with the application of a meter shed, and an EFV, to provide maximum protection from the threat of snow and ice loading.

Q. 35 How will the continuation of the three proposed safety options under the Meter Protection Program work in concert with each other?

A. 35 The installation of a meter shed serves to proactively prevent snow and ice loading from damaging Southwest Gas facilities resulting in the unexpected release of natural gas in close proximity to the structure. The installation of an EFV coupled with an ERT would serve as reactive measures to identify or limit the effect of a natural gas release should the Company's meter set assembly or customer-owned piping be damaged from excessive snow and ice loading. In some parts of the Lake Tahoe region for example, local building design codes currently require structures such as roofs to withstand a snow loading force of up to 300 pounds per square inch. These local building codes have evolved over the years and are much more stringent today than they were decades ago.

Southwest Gas' proposed Meter Protection Program would identify those meters in heavy snow load areas that are most vulnerable to damage from snow and ice loading and apply a combination of safety options to lessen the likelihood of damage.

Q. 36 What is the breakdown of the Meter Protection Program costs by rate jurisdiction?

A. 36 Exhibit No.__(KML-1) provides a breakdown of the estimated incremental costs for Southwest Gas' Meter Protection Program by rate jurisdiction.

<u>V. SCHOOL CUSTOMER-OWNED YARD LINE (COYL) PROGRAM</u>

Q. 37 What is a COYL?

A. 37 A COYL is the primary customer gas piping that begins from the service point of delivery at the outlet of Southwest Gas' meter located at the property line or public right-of-way, and extends underground from the meter to the house, building, or gas utilization equipment where gas is consumed. By definition, a COYL is pipe downstream from the Company's meter, and is not owned by Southwest Gas. The customer is solely responsible for inspecting and maintaining a COYL. Exhibit No.__(KML-3) provides a schematic of a typical COYL. For the purpose of the School COYL Program, a COYL does not include other secondary COYLs that may branch off the primary COYL or that may exist further downstream on the customer's houseline pipe facilities.

Q. 38 What is Southwest Gas' responsibility for COYLs?

A. 38 Pursuant to the Company's Tariff Rule Nos. 16 and 19, Southwest Gas has no obligation to inspect or maintain facilities beyond the point of delivery, including COYLs which are owned, operated and maintained by the customer. However, Southwest Gas is required by Federal regulation (49 C.F.R. § 192.16) to notify a customer at least once in writing of the following information:

- Southwest Gas does not maintain the customer's buried piping;
- If the customer's piping is not maintained, it may be subject to the potential hazards of corrosion and leakage;
- Buried gas piping should be:
  - Periodically inspected for leaks;
  - Periodically inspected for corrosion if the piping is metallic; and
  - Repaired if any unsafe condition is discovered.
- When excavating near buried gas piping, the piping should be located in advance, and the excavation done by hand; and
- Provide resources for locating, inspecting and repairing customer's buried piping.

Southwest Gas accomplishes this notification requirement for new customers through a brochure. In addition, Southwest Gas reminds customers about COYLs through information provided on the back of their monthly bills (or through Southwest Gas' website links for those customers receiving electronic bills).

Q. 39 Please summarize the timeline for Southwest Gas' School COYL Program proposal.

A. 39 Southwest Gas will continue its outreach to school COYL owners. Upon Commission reapproval of the COYL Program, Southwest Gas proposes to continue to prioritize school COYLs by contacting each school COYL owner and verifying interest in a school COYL Program.

Q. 40 Please describe the School COYL program.

A. 40 With the consent of the customer, all known school COYLs will be replaced over an approximate eight-year time period assuming that 100% of the customers choose to participate in the Program. If a school COYL is found to be leaking, the customer will be offered an opportunity to have the school COYL replaced with Southwest Gas-owned facilities and meter(s) relocated adjacent to the school structure(s). In essence, Southwest Gas is proposing a long-term plan for enhancing the safety and integrity of school COYLs by abandoning them and installing Company-owned and maintained facilities up to the structure thereby eliminating any customer-buried piping from the meter to the structure.

Q. 41 What is the breakdown of replacement costs by rate jurisdiction?

A. 41 Exhibit No.__(KML-1) provides a breakdown of the estimated number of COYLs and the range of incremental replacement costs for school COYL categories by rate jurisdiction.

VI. ANNUAL LEAK SURVEY PROGRAM

Q. 42 What frequency does the Company perform its leak detection survey of its California natural gas assets today?

A. 42 Southwest Gas currently leak surveys its California natural gas assets at a frequency of at least once every three years except in situations where the Federal and State pipeline safety regulations require a more frequent leak detection survey such as business districts, transmission facilities, and in situations where the Company's DIMP or its Transmission Integrity Management Program (TRIMP) requirement more frequent leak detection surveys.

Q. 43 Does the Company perform systemwide leak detection surveys on an annual basis anywhere else within its three-state service territories?

A. 43 Yes. In 2021, the PUCN adopted a first of its kind regulation making Nevada the first state in the nation to require annual leak surveys of all natural gas and liquid propane gas distribution pipeline systems.[6] Consistent with the PUCN's new requirement, Southwest Gas commenced a Commission-approved annual leak detection survey of all natural gas assets within the Company's Nevada service territory on January 1, 2023.

Q. 44 Why does the Company propose to perform its leak detection surveys on an annual basis?

A. 44 While natural gas systems are designed not to leak, leakage can occur due to integrity management concerns, aging infrastructure, excavation damages, and other leak causes. The Federal and State pipeline safety code requires an annual leak survey in areas defined as a business district and a complete leak survey of the distribution system once every five calendar years not to exceed 63 months. Nearly a decade ago, Southwest Gas voluntarily shifted this frequency to once every three calendar years to enhance data collection into its integrity management programs, optimize contractor resource utilizations, and minimize methane emissions.

Recently, starting in January 2023, Southwest Gas started an annual leak survey of all of its Nevada piping resulting from a change in the Nevada State pipeline safety regulations. As witnessed in the annual leak detection survey in Nevada, incremental leaks are discovered and repaired sooner than they

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[6] Docket No. 19-09011; see also the PUCN 2023 Biennial Report at page 29. https://www.leg.state.nv.us/Division/Research/Documents/RTTL_NRS703.180_2023.pdf

otherwise would have been. Through the first year of the annual leak survey program in Nevada, a 61% increase in underground incremental leaks were found in the areas that would not have been leak surveyed again until 2024 and 2025. Through the first two quarters of the 2024 annual leak detection survey, a 39% increase in underground incremental leaks were found.

This demonstrates that an annual leak detection survey should drive down the overall number of leaks across the system which improves safety. Additionally, the reduction of overall leakage has a secondary benefit of reducing greenhouse gas (GHG) emissions from the distribution system, consistent with the Company's Natural Gas Leakage Abatement Program as required under R.15-01-008.

Q. 45 What did the Company learn from its experience in its Nevada service territory regarding the annual leak detection survey?

A. 45 Southwest Gas recognized that with proper resource planning and support from its regulatory Commission, an annual leak survey will find more leaks, and, therefore make the Company's distribution system safer through the reduction of overall system risk while also lowering overall GHG emissions from Southwest Gas' natural gas system.

Q. 46 What is the Company proposing with regards to an Annual Leak Survey Program in California?

A. 46 Southwest Gas currently utilizes contractor leak survey companies to complete its required leak surveys. Consistent with this approach, the increased footage resulting from the annual leak surveys would also be completed by the contractors. Southwest Gas is proposing to invest in new equipment and personnel to establish and facilitate the Annual Leak Survey Program. The

Company anticipates two personnel will be needed in its Southern California Division and one will be needed in its Northern California territory to assist in the repair of the anticipated increase in incremental leaks discovered by moving to an annual leak detection survey. The investment in new equipment is needed to complete the work with a total net present value of $9.5 million over the five-year period with 42% being capital and 58% in O&M as shown in Exhibit No.__(KML-4).

Q. 47 Is the Company proposing to utilize AMLD leak detection technologies in its proposal to perform an annual leak survey?

A. 47 Safety is paramount at Southwest Gas. The Company has a long history incorporating new and innovative technologies to further the tenants of safety, quality, and excellence throughout the Company's operations. Southwest Gas routinely engages with industry peers through organizations such as the American Gas Association (AGA) and the Western Energy Institute (WEI). A key aspect of these ongoing engagements includes the sharing and benchmarking of best practices throughout the industry including other natural gas operators and industry research and development consortiums.

Through these interactions, the Company identified several industry peers that leverage the AMLD technology to improve leak detection efficiency and to assist in the quantification of methane emissions from natural gas facilities when leaks occur. CenterPoint Energy, Consumers Energy, DTE, National Grid, ONE Gas, PG&E, Atmos Energy, and Southern Company are among industry peers currently using AMLD equipment.

Additionally, in a collaborative effort to develop advanced technologies for the natural gas industry, U.S. utilities are combining interests, expertise, and resources into focused R&D projects through Operations Technology Development company (OTD) and NYSEARCH. Both OTD and NYSEARCH are research consortiums that Southwest Gas participates in. AMLD technologies are amongst some of the ongoing research needs, and member organizations are seeing significant benefits from adoption.

The benefits of the AMLD include enhanced leak detection capabilities and methane detection sensitivities down to 1 part per billion (ppb), mobile leak detection at higher speeds than conventional equipment, back-end data analytics, methane plume analysis, and methane emissions quantification. The latter aspect allows Southwest Gas to further its primary objective of maintaining and operating a safe system while also eliminating hazardous leaks and minimizing releases of natural gas from its facilities, a requirement under the Section 114 of the Pipelines and Enhancing Safety Act of 2020 (PIPES Act of 2020).

Q. 48 Are there any legislative or regulatory drivers the Company considered prior to purchasing the AMLD equipment?

A. 48 Yes. Congress placed explicit legislative focus on the elimination of leaks and minimization of natural gas releases with the enactment of a self-executing Federal mandate under Section 114 of the PIPES Act of 2020.[7] Section 114 requires operators, including Southwest Gas, to update inspection and maintenance plans required under 49 U.S.C. 60108(a) to address eliminating hazardous leaks and minimizing releases of natural gas. Subsequently, the Pipeline and Hazardous Materials Safety Administration (PHMSA) published an

[7] Pub. L 116-260, Division "R" – PIPES Act of 2020 signed into law on December 27, 2020.

Advisory Bulletin ADB-2021-01 to operators of natural gas facilities advising them of this self-executing federal mandate. The Advisory Bulletin also reminded operators of the requirement under 49 U.S.C. 60108(a)(2) to continue updating these plans to meet the requirements of any future regulations related to leak detection and repair that are promulgated under 49 U.S.C. 60102(q).

PHMSA released the Gas Pipeline Leak Detection and Repair Notice of Proposed Rulemaking (NPRM)[8] on May 18, 2023, which includes draft provisions for operators to conduct engineering tests and analyses in the development of an Advanced Leak Detection Program (ALDP) and accompanying performance standards. PHMSA proposes, among other regulatory enhancements and new programs in the NPRM, a minimum equipment sensitivity requirement of 5 parts per million (ppm) through the development of a new §192.763 ALDP section of the Federal pipeline safety code.

Q. 49 How does the proposed annual leak survey utilizing AMLD lower overall distribution system risk?

A. 49 The implementation of an annual leak detection survey utilizing AMLD in addition to conventional leak detection survey equipment is expected to have a similar result to what Southwest Gas experienced in its Nevada service territory: finding and repairing leaks more quickly than what would have been identified with the Company's current leak survey frequency.

[8] Docket No. PHMSA-2021-0039, RIN 2137-AF51.

Q. 50 What other benefits does the Company's risk-informed proposal have beyond pipeline safety benefits?

A. 50 The Company's proposal to continue its Meter Protection Program, its modified Targeted Pipe Replacement Program, and its newly proposed Annual Leak Survey Program all provide a secondary benefit of lowering overall GHG emissions from the Company's distribution system. Additionally, in the case of the continuation of the Company's School COYL Program, reduction of GHG emissions from downstream customer piping. While not the primary reasoning for proposing these efforts, all four programs allow for the Company to lower risk to its customers and communities while simultaneously lowering overall system GHG emissions. This also aligns with R.15-01-008, prompted by Senate Bill 1371, and the effort to reduce natural gas leakage from Commission regulated natural gas pipelines and facilities within the State.

Q. 51 Does this conclude your prepared direct testimony?

A. 51 Yes.

SUMMARY OF QUALIFICATIONS
KEVIN M. LANG

Kevin M. Lang is the Vice President of Engineering Services for Southwest Gas Corporation (Southwest Gas). He leads technical and engineering support to five operating divisions and Great Basin Gas Transmission Company for pipeline safety code compliance; right-of-way and land rights acquisition and maintenance, material specifications and approval; proper energy measurement; pipeline cathodic protection; technical support of the SCADA system; project design review; hydraulic modeling and project management support; the distribution and transmission integrity management programs, laboratory services, the Graphical Information System (GIS) program management, and the training and qualification of technical services and corrosion control personnel.

Mr. Lang joined Southwest Gas in 2003 as an engineer in Victorville, CA. Mr. Lang oversaw the design of new and replacement transmission and distribution natural gas facilities in progressive technical and leadership positions. He was promoted to Director of Gas Operation Support Staff in 2011, Director of Engineering Services in 2012, and Vice President of Engineering Staff in 2024.

He holds a Bachelor of Science degree in mining engineering from Virginia Tech and a master’s degree in business administration from the University of Arizona Global Campus. He is a registered Professional Engineering in the state of Arizona and Nevada with a proficiency in Civil Engineering. Mr. Lang currently serves on the American Gas Association’s Operations Safety Regulatory Action Committee.

California Customer Owned Yard Line (COYL) Program

	Southern California (Count)	Northern California (Count)	South Lake Tahoe (Count)	California Total (Count)
School	83	9	10	**102**
Total COYLs - California	**83**	**9**	**10**	**102**

	Southern California (Estimated Cost)	Northern California (Estimated Cost)	South Lake Tahoe (Estimated Cost)	California Total (Estimated Cost)
5-Year Total COYL w/20% contingency	$ 21,450,000	$ 3,666,000	$ 4,134,000	**$ 29,250,000**
Estimated annual COYL	$ 4,290,000	$ 733,200	$ 826,800	**$ 5,850,000**

California Meter Protection Program

	Southern California (Count)	Northern California (Count)	South Lake Tahoe (Count)	California Total (Count)
Meter Shed	$ 7,500,000	$ 5,400,000	$ 9,600,000	**$ 22,500,000**
EFV	$ 6,250,000	$ 4,500,000	$ 8,000,000	**$ 18,750,000**
ERTs	$ 900,000	$ 648,000	$ 1,152,000	**$ 2,700,000**
Total Meter Protection - California	**$ 14,650,000**	**$ 10,548,000**	**$ 18,752,000**	**$ 43,950,000**

Note: Estimated costs include a 20% contingency

Targeted Pipeline Replacement Program

(Southern California Rate Jurisdiction Only)

	Mains	Services	SCA Total
M7000	$ 58,766,400	$ 25,185,600	**$ 83,952,000**
Distribution Steel	$ 22,176,000	$ 9,504,000	**$ 31,680,000**
Total Estimated Pipe Replacement Cost	**$ 80,942,400**	**$ 34,689,600**	**$ 115,632,000**

Note: Estimated costs include a 20% contingency

SNOW SEASON SAFETY

SOUTHWEST GAS

Heavy snow and ice falling from roofs can damage natural gas meters, regulators, and associated natural gas piping. Special care must be taken when clearing roofs to prevent impact. Also, ice and snow accumulation, whether natural or manmade, can damage gas meters and outdoor appliances and create a hazardous leak.

Here are tips to help protect against potential damage:

- Install a shelter above your natural gas meter to prevent snow and ice accumulation. For more information on how to build a snow shelter or for a contractor referral, please visit Southwest Gas at **www.swgas.com/safety** or call **1-800-654-2765**.
- Use a broom, instead of a shovel where possible, to clear snow or ice off natural gas meters and outdoor appliances, including regulators, associated piping, and propane appliances.
- When shoveling or plowing, don't pile snow on gas meters or outdoor appliances.
- Keep all outside gutters free of leaves and debris, including those above or near the natural gas meter and outdoor appliances.
- Natural gas appliances require proper exhaust and ventilation. It's important to know the location of air supply and exhaust ducts, and keep them free of snow, ice, leaves, or other debris. Keeping vents clear can prevent operational problems for appliances and the accumulation of carbon monoxide in buildings.
- Make sure your residence has functioning carbon monoxide alarms as required by Health and Safety Code §17926.

Meter with snow shelter

Meter without snow shelter

Anyone who notices a natural gas appliance not functioning properly; a hissing noise coming from the ground or an above-ground pipeline; and/or the smell of rotten eggs, even if it's slight or momentary, should leave the area immediately and then call **911** and **Southwest Gas** at **1-800-867-9091** from a safe location.

Southwest Gas wants to remind you that it's important to maintain and protect natural gas meters and appliances because failure to do so can result in damages and injuries, and possibly the discontinuance of natural gas service.

Safety is always a priority at Southwest Gas.

SOUTHWEST GAS

Exhibit No._ (KML-2)
Sheet 1 of 2

SEGURIDAD
PARA LA TEMPORADA DE NIEVE

La nieve y el hielo pesados que caen de los techos pueden dañar los medidores, los reguladores y la tubería de gas natural relacionada. Se debe tener cuidado especial cuando se limpien los techos para evitar un impacto. También, la acumulación de nieve y hielo, ya sea natural o artificial, puede dañar los medidores de gas y los aparatos exteriores, y así crear una fuga peligrosa.

He aquí consejos para ayudar a protegerlos de un posible daño:

- Instale una protección sobre su medidor de gas natural para evitar la acumulación de nieve y hielo. Para mayor información sobre cómo construir una protección contra nieve o para obtener referencias sobre un contratista, visite Southwest Gas en **www.swgas.com/safety** o llame al **1-800-654-2765**.
- Utilice una escoba, en lugar de una pala cuando sea posible, para limpiar de nieve y hielo los medidores y aparatos exteriores, incluso los reguladores, la tubería relacionada y los dispositivos a gas propano.
- Cuando palee o se abra camino, no acumule la nieve en los medidores o aparatos exteriores.
- Mantenga todos los desagües exteriores libres de hojas y basura, incluso aquellos sobre o cerca del medidor de gas natural y de los aparatos exteriores.
- Los aparatos de gas natural requieren de una salida y ventilación adecuadas. Es importante que conozca la ubicación de sus ductos de suministro y salida de aire y que los mantenga libres de nieve, hielo, hojas u otros desechos. Mantener los conductos libres puede evitar problemas operativos de los aparatos y la acumulación de monóxido de carbono en los edificios.
- Asegúrese de que su residencia cuente con alarmas de monóxido de carbono en buen funcionamiento como lo pide el Código de Salud y Seguridad §17926.

Medidor con protección para nieve

Medidor sin protección para nieve

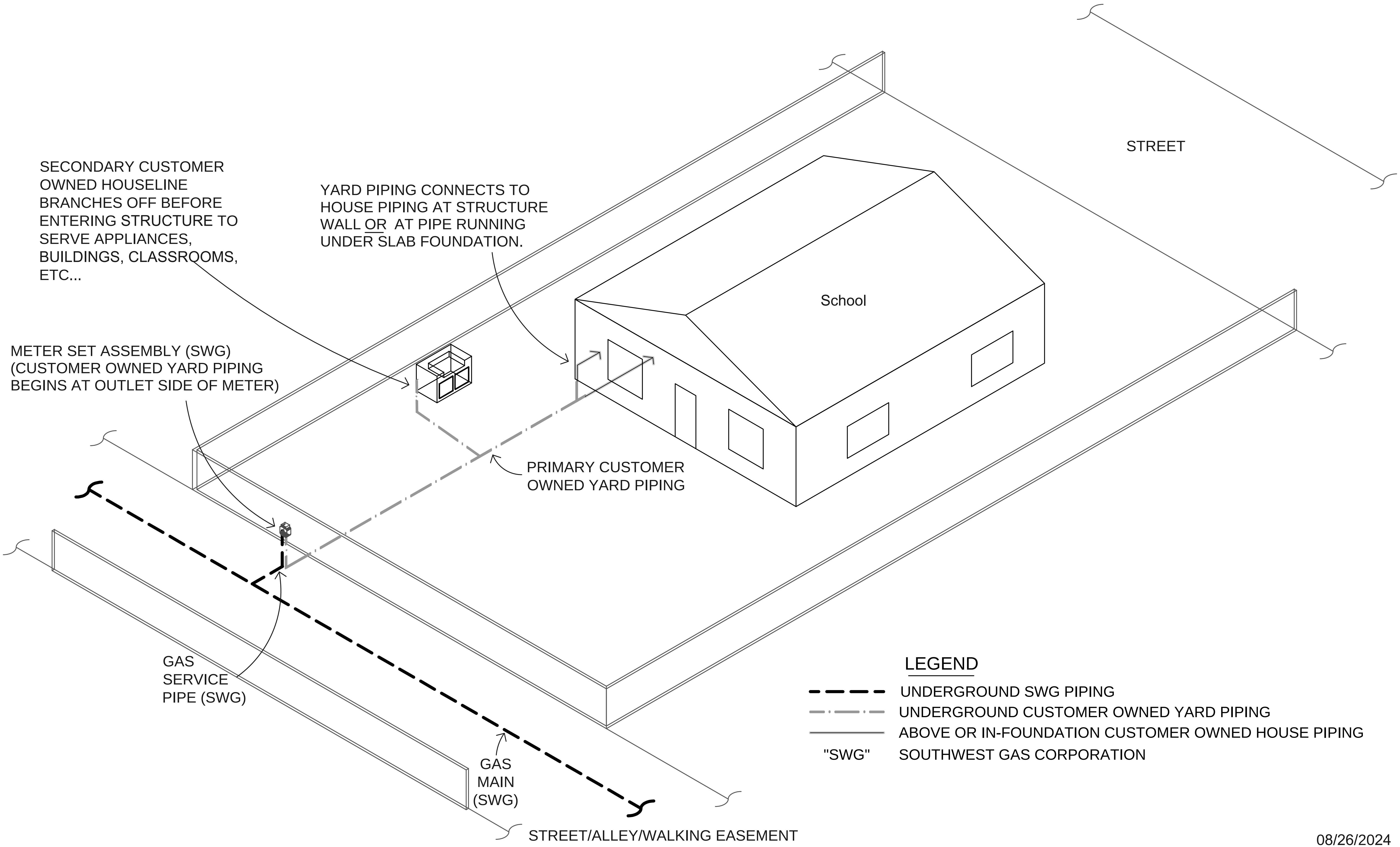
Cualquier persona que detecte un aparato de gas natural que no funcione correctamente, un ruido como silbido que proviene de la tierra o una línea expuesta, u olor a huevos podridos, aunque sea ligero o momentáneo, debe abandonar el área de inmediato y llamar al **911** y a **Southwest Gas** al **1-800-867-9091** desde una ubicación segura.

Southwest Gas desea recordarle que es importante dar mantenimiento y proteger los medidores y aparatos de gas natural porque el no hacerlo puede provocar daños y lesiones, y tal vez el corte del servicio de gas natural.

La seguridad siempre es una prioridad en Southwest Gas.

SOUTHWEST GAS

SCHOOL CUSTOMER OWNED YARD INSTALLATION (TYPICAL)



08/26/2024

Annual Leak Survey Program
Implementation Cost Worksheet

	NNV	SCA	Total
Currrent Leak Survey Annual cost (3 Years)	$ 285,000	$ 700,000	**$ 985,000**
Proposed Leak Survey Annual cost (1 year)	$ 510,755	$ 1,217,995	**$ 1,728,750**
Delta	$ 225,755	$ 517,995	**$ 743,750**
Total one-time Capital Cost	$ 1,190,355	$ 2,709,645	**$ 3,900,000**
2026 Total Delta	**$ 1,416,110**	**$ 3,227,640**	**$ 4,643,750**
2027 and Beyond Total Delta	**$ 225,755**	**$ 517,995**	**$ 743,750**

Note: Proposed Annual Survey does not include contingency

Company Witness:
Byron C. Williams

IN THE MATTER OF

SOUTHWEST GAS CORPORATION

APPLICATION 24-09-___

PREPARED DIRECT TESTIMONY

OF

BYRON C. WILLIAMS

ON BEHALF OF

SOUTHWEST GAS CORPORATION

SEPTEMBER 5, 2024

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of
Byron C. Williams

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Prepared Direct Testimony
of
Byron C. Williams

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Byron C. Williams. My business address is 8360 S. Durango Drive, Las Vegas, Nevada 89113.

Q. 2 By whom and in what capacity are you employed?

A. 2 I am employed by Southwest Gas Corporation (Southwest Gas or Company) in the Tax Department. My title is Director/Tax.

Q. 3 Please summarize your educational background and relevant business experience.

A. 3 My educational background and relevant business experience are summarized in Appendix A to this testimony.

Q. 4 Have you previously testified before any regulatory commission?

A. 4 Yes. I have previously testified before the Arizona Corporation Commission and the Public Utilities Commission of Nevada. I have also previously provided written testimony to the California Public Utilities Commission and the Federal Energy Regulatory Commission.

Q. 5 What is the purpose of your prepared direct testimony in this proceeding?

A. 5 I sponsor all areas of Southwest Gas' federal and state income tax and other state and local taxes, including schedules and supporting workpapers found in

Chapters 15 and 16 of Southwest Gas' general rate case filing, with the exception of those related to payroll taxes.

Q. 6 Please summarize your prepared direct testimony.

A. 6 My prepared direct testimony consists of the following key issues:

- An overview of the tax information and related schedules in this application.
- Southwest Gas' calculation and amortization of its Excess Accumulated Deferred Income Taxes (EADIT).
- The Company's proposed methodology for implementing the new guidance associated with Tax Repairs.
- A description of taxes, other than income taxes, that are included in this Application.

II. OVERVIEW OF TAX INFORMATION AND RELATED SCHEDULES

Q. 7 Please discuss how the tax information is presented in this Application.

A. 7 The tax information is organized into schedules for the Southern California, Northern California and South Lake Tahoe rate jurisdictions. For each rate jurisdiction, the narrative summary at the beginning of Chapters 15 and 16 provides a general description and additional details regarding the schedules that I am sponsoring.

Q. 8 Please summarize the schedules provided in Chapter 16.

A. 8 Chapter 16 (Sheets 1 and 2) provides a summary of significant tax accounting methods including (as applicable) use of full normalization accounting, contributions and advances, and the methods of projecting property taxes. Chapter 16 also provides the calculation of net federal and California income taxes on operations, as well as taxes other than income taxes. In addition, Chapter 16 provides the computations of the deferred income taxes balances projected for the end of the test period and shown elsewhere in the filing as an adjustment to rate base, as well as the amortization of EADIT.

Q. 9 Please describe the adjustments made to federal and state income taxes.

A. 9 The calculation of and adjustments to federal and California income taxes on operations is shown on Sheet 7 of Chapter 16. Southwest Gas used the statutory 21 percent federal income and 8.84 percent California corporate franchise tax rates.

Q. 10 Please discuss the calculation of federal and California deferred income tax liabilities at the end of the test year.

A. 10 Chapter 16 provides the calculation of deferred federal and state income tax balances. The calculation is performed by adding the deferred tax adjustments resulting from the projection of Schedule M differences to the December 31, 2023 deferred income tax balances in the general ledger. Chapter 16 also shows the calculation of deferred income taxes and provides the calculation and allocation of System Allocable taxes to the applicable rate jurisdiction.

III. EXCESS ACCUMULATED DEFERRED INCOME TAXES

Q. 11 What is EADIT?

A. 11 As part of the Tax Cuts and Jobs Act (TCJA), the corporate federal income tax rate was reduced from 35 percent to 21 percent, effective January 1, 2018. EADIT is the portion of the deferred tax liability that existed at the end of 2017 (calculated as the difference that resulted from a change from the 35 percent federal income tax rate) that will never be paid to the federal government because the tax rate was reduced to 21 percent. At the end of 2017, the income tax deferred liability accounts were revalued assuming a 21 percent federal tax rate, which continues to be in place. The EADIT was reclassified from the deferred income tax liability account to a regulatory liability account, to be refunded to customers.

Q. 12 What are protected and unprotected EADIT?

A. 12 Protected EADIT is the portion of the total EADIT that is associated with the cumulative book/tax differences of depreciable property (plant-related). Southwest Gas treats plant-related EADIT as protected, and therefore subject to the Internal Revenue Service (IRS) normalization rules and related penalties in the event of their violation. Unprotected EADIT is total EADIT less protected EADIT and is not subject to the IRS normalization rules and violation penalties.

Q. 13 How will Southwest Gas' EADIT be returned to customers?

A. 13 Southwest Gas proposes to continue to adjust the revenue requirement by the maximum amount of protected EADIT amortization allowed using the Average Rate Assumption Method (ARAM) as defined in the Internal Revenue Code (IRC) and associated Treasury Regulations. In addition, the Company continues to propose an annual adjustment to reflect the actual annual ARAM amounts once finalized.[1] Southwest Gas will also have fully amortized the unprotected EADIT by Test Year 2026, based on the five-year amortization period (as agreed upon in the Company's last California general rate case). These adjustments are addressed in the Prepared Direct Testimony of Company witness Randi L. Cunningham.

[1] Southwest Gas will continue to include adjustments for EADIT in its Annual Attrition Adjustments Advice Letters.

Q. 14 What is the ARAM?

A. 14 Under federal income tax law provisions, the ARAM is the methodology used to calculate the maximum amount of protected EADIT returned to customers without triggering penalties for a normalization violation. Please refer to the Prepared Direct Testimony of Company witness Randi L. Cunningham for details regarding the amortization of EADIT included in Southwest Gas' cost of service.

Q. 15 How does the ARAM calculate the amortization of EADIT?

A. 15 The ARAM calculation consists of two parts: (1) the entity calculates the ratio of aggregate deferred taxes for the property to the aggregate timing differences for the property; and (2) the resulting percentage ratio calculated is multiplied by the amount of timing differences turning around during the year.

Q. 16 Why must Southwest Gas return EADIT to customers over time, rather than immediately?

A. 16 The IRC, as amended by the TCJA, penalizes the return of protected EADIT to customers more rapidly, or to a greater extent, than the amount computed using the ARAM. A refund exceeding ARAM limitations is recognized as a normalization violation according to the IRC and Treasury Regulations. The estimated turnaround required by ARAM for the Company's protected EADIT is approximately 40 years (i.e., the book life of the underlying property).

Q. 17 What are the penalties for a normalization violation if the EADIT is returned to customers too quickly?

A. 17 The penalties for a normalization violation are severe and include the following: (1) a current tax penalty equal to the amount by which the entity returned the EADIT to customers more rapidly than permitted under ARAM; and (2) the entity will no longer be able to claim accelerated depreciation for income tax purposes. These penalties would increase cash tax payments, potentially leading to increased borrowing costs and future customer rate increases.

Q. 18 What are some of the benefits of continuing to utilize Southwest Gas' treatment of its EADIT?

A. 18 Southwest Gas' methodology to continue its treatment ensures that all eligible EADIT is returned to customers. It also ensures that the amortization of the EADIT for financial statement purposes matches the period in which the EADIT is returned to customers. The Company reduces the EADIT regulatory liability recorded in its financial statements as the EADIT is returned to customers. The approach and use of the ARAM methodology also mitigates potential normalization violations as defined by the IRC and associated Treasury Regulations.

Q. 19 Has the Commission adopted the use of ARAM for the amortization of EADIT in the past with respect to Southwest Gas?

A. 19 Yes. In Decision (D.)21-03-052, the Commission adopted the use of ARAM for the amortization of EADIT with respect to Southwest Gas.

IV. TAX REPAIRS REVENUE PROCEDURE

Q. 20 Has there been any new guidance associated with Tax Repairs?

A. 20 Yes. In April 2023, the IRS released Revenue Procedure 2023-15 (Rev. Proc. 2023-15), related to gas industry tax repairs. Rev. Proc. 2023-15 is effective for taxable years ending after May 1, 2023, and provides a safe harbor method of accounting that taxpayers may use to determine whether expenditures to repair, maintain, replace, or improve natural gas transmission or distribution property must be treated as capitalized, or deducted in the period incurred, for tax purposes.

Q. 21 Is Southwest Gas analyzing the impact of the new Rev. Proc. 2023-15?

A. 21 Yes. Southwest Gas is currently analyzing this revenue procedure to determine the potential impact and is assessing whether to elect the optional tax accounting method and the associated IRC Section 481(a) adjustment. It should be noted that Rev. Proc. 2023-15 is an optional tax accounting method change and provides a safe harbor to electing entities. Southwest Gas is currently in the process of implementing technology functionality necessary for calculating the estimated impact on their respective repair deductions under the new method.

Q. 22 Does Southwest Gas anticipate adopting Rev. Proc. 2023-15?

A. 22 Southwest Gas only plans to adopt the new natural gas industry safe harbor method if it results in higher tax repairs deductions benefitting customers.

Q. 23 When would Southwest Gas anticipate adopting Rev. Proc. 2023-15 should it benefit customers?

A. 23 It is anticipated that if Southwest Gas adopts this new natural gas safe harbor method, it would likely be in association with the 2024 federal income tax return (which is expected to be filed in October 2025). Also, if the Company decides to adopt the new method of accounting, it would also likely disclose that decision in a quarterly 10-Q or an annual 10-K filing with the Securities and Exchange Commission (SEC), which may occur before the 2024 federal income tax return is filed. However, as previously noted, Southwest Gas does not yet know the impact of such election.

Q. 24 How does Southwest Gas propose to treat Rev. Proc. 2023-15 for the instant rate case?

A. 24 The natural gas safe harbor in Rev. Proc. 2023-15, if elected, will likely be implemented before the Test Year 2026 rates become effective. Therefore, Southwest Gas proposes incorporating the impact of its tax position, inclusive of Rev. Proc. 2023-15, and the associated customer benefits in this rate case, instead of waiting until the Company's next general rate case cycle, likely Test Year 2031. This proposal provides timely assessment of the impacts overall and any ratepayer relief associated with this issue.

Should Southwest Gas elect the natural gas safe harbor, the Company will submit a Tier 2 advice letter within 30 days following the earliest of the following initial disclosures to inform the Commission of its election:

1. Quarterly 10-Q filing with the SEC;
2. Annual 10-K filing with the SEC; or
3. The filing of the federal income tax return in which the election is made.

Additionally, Southwest Gas will submit supplemental prepared direct testimony in this proceeding that will discuss the impacts of the safe harbor election.

Q. 25 Should Southwest Gas adopt the natural gas safe harbor, how would that impact the current Tax Memorandum Account?

A. 25 The Tax Memorandum Account (TMA) was established in accordance with D.17-06-006. As stated in Southwest Gas' tariff, the purpose of the TMA is to "track any revenue difference resulting from differences between the Company's authorized income tax expenses and its actually incurred income tax expenses, including repair deductions and bonus depreciation." Southwest Gas believes the natural gas safe harbor falls within the provisions of the TMA.

However, because the Company proposes incorporating the natural gas safe harbor impact (if elected) in this rate case, all revenue differences resulting from the new tax repairs will be reflected in Test Year 2026 authorized rates contemplated in this Application. As a result, no TMA tracking or entry would be required for the impact of Rev. Proc. 2023-15. However, if Southwest Gas adopts Rev. Proc. 2023-15, but does not incorporate any impacts of the natural gas safe harbor in this Application, the Company would then track the applicable differences in the TMA.

<u>V. OTHER TAXES</u>

Q. 26 Please discuss the taxes other than income taxes included in this Application.

A. 26 Sheets 3 through 6 of Chapter 16 provide a summary and supporting calculations of taxes other than income taxes, including California property tax specifically related to jurisdiction plant and payroll taxes. Payroll taxes are sponsored by Company witness Randi L. Cunningham. Local franchise taxes imposed by various counties or cities are included in Chapter 15.

Q. 27 Does this conclude your prepared direct testimony?

A. 27 Yes.

SUMMARY OF QUALIFICATIONS

BYRON C. WILLIAMS

I am a graduate of Brigham Young University having received a Bachelor of Sciences in Accounting in 2001. In 2003, I earned a Master's in Business Taxation from the University of Southern California.

In 2002, I joined the tax department of PricewaterhouseCoopers LLP in Los Angeles. In 2010, I joined the Las Vegas office, and was promoted to Director in 2011. In 2013, I joined Southwest Gas Corporation as Director/Tax. I am responsible for all phases of the Company's taxes, including preparation of all federal, state, and local tax returns and tax provisions, researching tax matters and preparation of tax-related testimony and exhibits for rate proceedings, including rate cases.

I have been licensed as a Certified Public Accountant by the State of California since 2007. In 2011, I also became licensed as a Certified Public Accountant by the State of Nevada. I am also a member of the American Institute of Public Accountants, as well as the Nevada Society of CPAs.

Company Witness:
Justin L. Forsberg

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
APPLICATION 24-09-___

PREPARED DIRECT TESTIMONY
OF
JUSTIN S. FORSBERG

ON BEHALF OF
SOUTHWEST GAS CORPORATION

SEPTEMBER 5, 2024

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of
Justin S. Forsberg

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Prepared Direct Testimony
of
Justin S. Forsberg

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Justin S. Forsberg. My business address is 8360 S. Durango Drive, Las Vegas, Nevada 89113.

Q. 2 By whom and in what capacity are you employed?

A. 2 I am employed by Southwest Gas Corporation (Southwest Gas or Company) in the Corporate Finance department. My title is Vice President of Investor Relations and Treasurer.

Q. 3 Please summarize your educational background and relevant business experience.

A. 3 My educational background and relevant business experience are summarized in Appendix A to this testimony.

Q. 4 Have you previously testified before any regulatory commission?

A. 4 No.

Q. 5 What is the purpose of your prepared direct testimony in this proceeding?

A. 5 I sponsor Southwest Gas' overall requested rates of return (RORs), also referred to as cost of capital, which are displayed in Chapter 24 of the rate case filing, for the Company's three California rate jurisdictions: Southern California; Northern California; and South Lake Tahoe. Specifically, my prepared direct testimony supports:

- the development of the requested capital structure and the embedded cost of long-term debt used for determining the appropriate cost of capital;
- the importance of the proposed overall RORs on Southwest Gas' credit ratings and financial profile; and
- the continued use of the Automatic Trigger Mechanism (ATM), used to adjust the Company's overall RORs between general rate cases.

Southwest Gas' requested cost of common equity and cost of debt used to determine the overall RORs is provided in the Prepared Direct Testimony of Company witness Dylan W. D'Ascendis.

Q. 6 Please summarize your prepared direct testimony.

A. 6 My prepared direct testimony consists of the following key issues:

- The development of the overall requested RORs for the Company's three rate jurisdictions, based on a 2026 test year. Southwest Gas is requesting overall rates of return of 7.74 percent and 7.85 percent, for its Southern California rate jurisdiction and for both the Northern California and South Lake Tahoe rate jurisdictions, respectively.
- A review of Southwest Gas' financial profile, and the need for Southwest Gas to offer a competitive rate of return to continue to attract capital. I also discuss how Southwest Gas' overall RORs are necessary to support and sustain the Company's financial profile and credit ratings.
- Southwest Gas' requested target capital structure comprised of 50.00 percent common equity and 50.00 percent long-term debt.
- The development of Southwest Gas' embedded cost of long-term debt. For the 2026 test year, the projected embedded cost of debt for the

Company's Southern California rate jurisdiction is 4.14 percent and for both the Northern California and South Lake Tahoe rate jurisdictions, the projected embedded cost of debt is 4.34 percent. The slightly lower embedded cost of debt for the Southern California rate jurisdiction is due to the inclusion of the jurisdiction-specific Big Bear Industrial Development Revenue Bonds (IDRBs).

- Southwest Gas' request to continue the ATM, as authorized in Decision D.14-06-028, and continued in D.21-03-052, for adjustments to the Company's authorized cost of capital between general rate cases given preset changes in the level of utility bond yields.

Q. 7 Are you sponsoring any schedules and exhibits in support of your prepared direct testimony?

A. 7 Yes. I am sponsoring a supporting financial exhibit, Exhibit Nos.__(JSF-1), which is attached, and the schedules set forth in Chapter 24A. The exhibit and schedules were prepared by me or under my supervision.

II. SOUTHWEST GAS' REQUESTED OVERALL RATES OF RETURN

Q. 8 Are the overall RORs necessary for Southwest Gas to have an opportunity to earn a fair and reasonable return on its California distribution properties?

A. 8 Yes. As supported by the prepared direct testimony of Company witness, Dylan W. D'Ascendis, Southwest Gas' proposed overall requested RORs for the Company's Southern California rate jurisdiction and for both the Northern California and South Lake Tahoe rate jurisdictions, are 7.74 percent and 7.85 percent, respectively. These overall requested RORs are reasonable and properly reflect the Company's level of business, financial, and regulatory risks.

Q. 9 Why are the overall requested RORs appropriate and necessary for Southwest Gas?

A. 9 These overall requested RORs are necessary to maintain Southwest Gas' financial integrity, allow the Company to attract new capital, and provide Southwest Gas' equity holders an opportunity to earn a fair and reasonable return on their investment.

The Company has, since the late 1950s, filed rate cases as a "diversified" utility. The multi-jurisdictional rate case filings are based on the fact that Southwest Gas, as a natural gas utility, serves three states with several different ratemaking jurisdictions. Southwest Gas requests only gas distribution utility required RORs in all jurisdictional filings within each state. The capital costs requested in this filing are utility-only costs. Southwest Gas' practices assure that the costs of utility operations attributable to each of its jurisdictions are properly insulated from the impact of any non-utility activities.

In summary, Southwest Gas' requested overall RORs in this proceeding are fair to both customers and shareholders and properly reflect the risks and returns appropriate for its gas distribution properties.

III. SOUTHWEST GAS' FINANCIAL PROFILE

A. Credit Ratings

Q. 10 What are the Company's current long-term unsecured debt credit ratings?

A. 10 As discussed in the prepared direct testimony of Dylan W. D'Ascendis, currently, Southwest Gas' long-term unsecured debt credit ratings are "Baa1" from Moody's, "BBB" from S&P, and "A-" from Fitch, Inc. (Fitch).

Q. 11 Please summarize the importance of Southwest Gas' credit rating.

A. 11 The importance of Southwest Gas' credit rating is due to the capital-intensive nature of the natural gas distribution business. Southwest Gas needs to make continuing and substantial investments to provide reliable and safe service to customers and to support economic growth. On a total company basis, Southwest Gas anticipates capital expenditures over the three-year period ending December 31, 2026, to be approximately $2.4 billion.

Q. 12 How do Southwest Gas' credit ratings compare to the credit ratings of the proxy group of companies that were used to estimate the cost of common equity?

A. 12 The proxy group consisting of six natural gas local distribution companies used in the Prepared Direct Testimony of Company witness Dylan W. D'Ascendis have an average Moody's rating of A2 and an average S&P rating of A-. Relative to Southwest Gas, the proxy group has an average rating from Moody's that is two notches higher (A2 versus Baa1). Compared to the Company's S&P rating, the proxy group has an average rating that is two notches higher (A- versus BBB).[1]

Q. 13 Is the regulatory environment important in the determination of a credit rating for Southwest Gas?

A. 13 Yes. For a public utility, credit rating agencies regard regulation as a significant factor in determining financial performance, as regulation defines the environment in which the utility operates. The importance of regulation in the ratings process for utilities is further evidenced by Moody's Investor Services (Moody's) assigning a total 50% weighting to the following two key factors: (1) regulatory framework;

[1] Exhibit No.__(JSF-1).

and (2) the ability to recover costs and earn returns.[2] Moody's indicated the following regarding how the regulatory environments could impact ratings specifically on Southwest Gas:

> Factors that Could Lead to an Upgrade
>
> A rating upgrade could be considered if there are significant improvements in its regulatory environments that meaningfully reduce regulatory lag and if key credit metrics increase…
>
> Factors that Could Lead to a Downgrade
>
> A rating downgrade could be considered if there is a decline in the supportiveness of Southwest Gas' regulatory environments…[3]

In a similar context, Fitch Ratings, Inc. (Fitch) designates the "Regulatory Environment" as being at the top level of its "Relative Importance" matrix assigning a "Higher Importance" designation compared to "Average Importance" or "Lower Importance".[4]

Q. 14 Do the rating agencies regularly assess and compare regulatory environments by jurisdiction?

A. 14 Yes. For example, S&P recently provided its assessment of the credit supportive nature on a state-by-state basis. Using a five-tiered scale with "Credit supportive" being the lowest ranking and "Most credit supportive" being the highest ranking.[5]

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[2] Moody's Investor Services, "Credit Opinion – Southwest Gas Corporation", December 5, 2023.

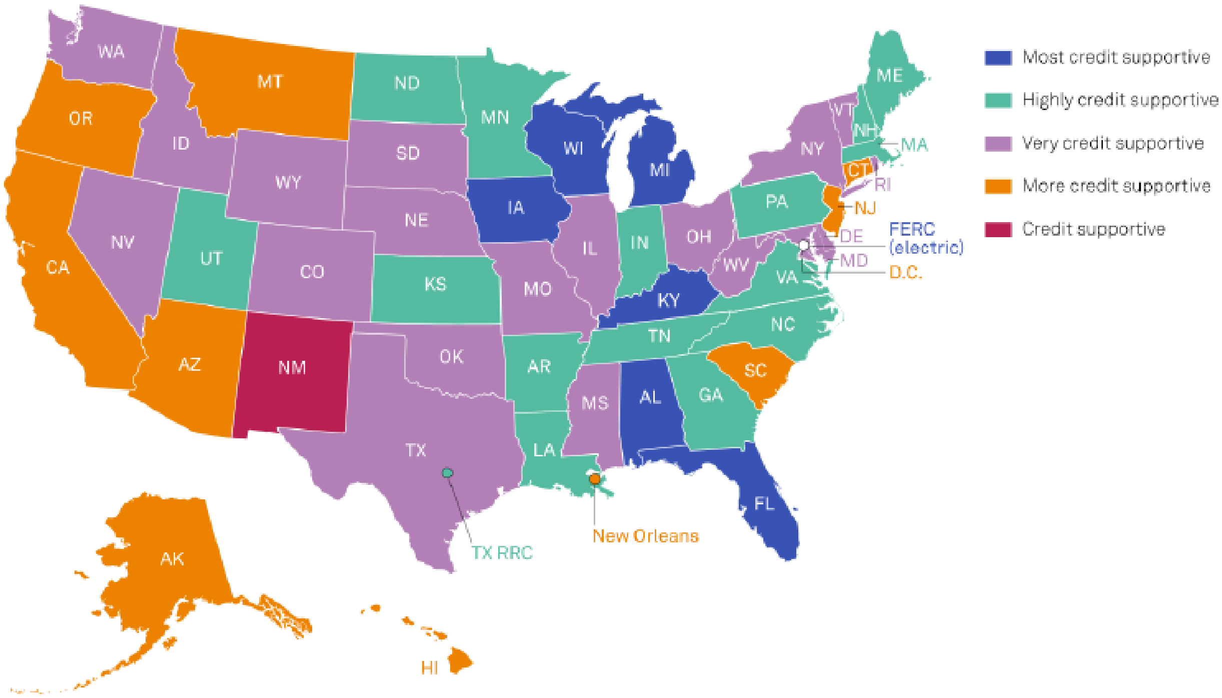
[3] *Id.*

[4] Fitch Ratings, "Southwest Gas Corporation", September 6, 2023

[5] S&P Global Ratings, "Industry Credit Outlook 2024 – North American Regulated Utilities", January 9, 2024

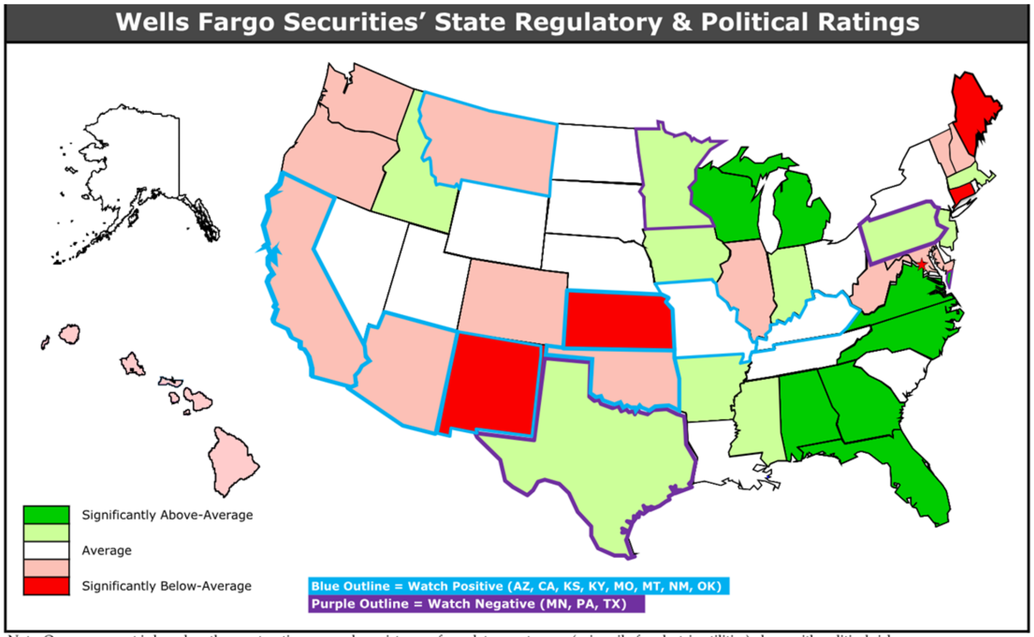
Regulatory assessment by state

As of November 2023



Source: S&P Global Ratings.

In addition, both equity and fixed income investors view the relative supportive nature of each state among their considerations when making investment decisions. An example from Wells Fargo published in early 2024 can be found in the following "heat map" analysis:



Note: Our assessment is based on the constructiveness and consistency of regulatory outcomes (primarily for electric utilities) along with political risk.
Source: Wells Fargo Securities, LLC Estimates

Q. 15 What is Southwest Gas' current credit rating outlook?

A. 15 The current credit rating outlook for Southwest Gas provided by S&P is "positive" while the ratings outlooks from Moody's and Fitch are both "stable". A credit rating outlook is an assessment of the direction of the credit rating over the intermediate to longer term.

Q. 16 What is Southwest Gas' target credit rating?

A. 16 Southwest Gas' short and long-run goals are to continue to maintain investment grade credit ratings and to further strengthen its credit profile in the view of all the ratings agencies. Southwest Gas believes that this strategy provides the Company with a greater amount of financial flexibility. Southwest Gas would be able to attract capital at reasonable prices during both normal and turbulent market conditions.

Q. 17 Has Southwest Gas' parent company, Southwest Gas Holdings, Inc. (SWX), Inc., contributed capital to Southwest Gas in the form of equity in order to support and maintain the Company's strong investment grade credit ratings?

A. 17 Yes. Southwest Gas is committed to maintaining an appropriate capital structure to support its strong investment grade credit ratings. This commitment has been demonstrated by SWX's willingness to continue to contribute capital in the form of equity to finance the Company's investment in utility plant and maintain its capital structure. The contributed capital historically has been provided primarily from at-the-market equity issuances pursuant to the parent company's equity shelf program (ESP), with $150 million at-the-market shares registered in March 2017, $300 million in May 2019, $500 million in April 2021, and $340 million in August 2024. The August 2024 at-the-market registration of $340 million represented the unissued amount from the existing S-3 registration shelf that expires in November 2026.

From January 2017 through August 2024, the parent company issued 8.334 million shares of common stock under the at-the-market programs, raising net proceeds of approximately $602.1 million. The net proceeds during this period were contributed to, and reflected in the records of, Southwest Gas as a capital contribution from SWX. At August 30, 2024, SWX had approximately $340 million of remaining capacity on the existing S-3 registration shelf and on the 2024 at-the-market.

In addition, approximately $43.3 million of capital contributions from SWX were made over the same period, using proceeds of common stock issuances from SWX's other common stock programs and a secondary common stock issuance. During 2023, SWX contributed an additional $530.0 million of capital to Southwest Gas, again demonstrating its commitment to supporting the Company's strong financial position and favorable credit ratings. The contributed capital was financed via proceeds from a term loan entered into by SWX in April 2023. Both SWX and Southwest Gas are committed to taking the future actions needed to continue to support the strong credit ratings of the Company to achieve its target capital structure.

B. <u>Infrastructure Replacement Programs</u>

Q. 18 Please briefly describe the approved infrastructure programs that run through Southwest Gas' Infrastructure Reliability and Replacement Adjustment Mechanism (IRRAM).

A. 18 In D.21-03-052, issued in the Company's last general rate case (Test Year 2021; A.19-08-015), the Commission continued the approval of the IRRAM, which is a two-way balancing account to record and recover the revenue requirement attributed to Southwest Gas' three authorized risk-based infrastructure replacement programs – the Targeted Pipe Replacement program, the School Customer Owned Yard Line (COYL) program, and the Meter Protection program. Southwest Gas initially requested and was authorized the IRRAM in the Company's Test Year 2014 general rate case (A.12-12-024; D.14-06-028) to address the Company's investment in certain non-revenue producing gas infrastructure and pipeline replacement programs. Southwest Gas is proposing the continuation of the existing three risk-based programs in addition to a new Annual Leak Survey Program with Advance Mobile Leak Detection (AMLD), with cost recovery to continue through the IRRAM. The specific details of Southwest Gas' continuation of its three programs and the proposed Annual

Leak Survey Program are described in the Prepared Direct Testimony of Company witnesses Kevin M. Lang and Bradley C. Anderson.

Q. 19 How does Southwest Gas' IRRAM help sustain the Company's improved financial profile?

A. 19 The current and proposed capital investments under the IRRAM improve Southwest Gas' ability to recover costs associated with its non-revenue producing infrastructure investments on a more timely basis and reduce regulatory lag, which would over time help maintain Southwest Gas' financial metrics, including its ability to earn its authorized RORs, and increase the opportunity for the Company to improve its credit ratings. From a capital attraction standpoint, the IRRAM would continue to make Southwest Gas more comparable to other natural gas utilities that have similar mechanisms or other mechanisms that allow for timely recovery of similar costs.

Q. 20 How do rating agencies view capital tracking mechanisms such as IRRAM as a factor for Southwest Gas' credit rating?

A. 20 Rating agencies view the Commission approval of such mechanisms as a positive regulatory support factor, and such mechanisms are in line with Southwest Gas peer utilities. Specifically, rating agencies recognize the benefit from such mechanisms, with S&P recently stating:

> We view SWG's regulatory diversity and larger scale as favorable to its risk profile and in line with its peers. In addition, the company's access to constructive regulatory mechanisms, including the decoupling and rate riders for purchased gas and accelerated infrastructure replacement, informs our view that its effective management of regulatory risk is in line with that of peers.[6]

S&P also indicated the following:

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[6] S&P Global Ratings, "Southwest Gas Corp.", September 5, 2023

> We believe SWG's gross margins will continue to benefit from its revenue decoupled rate design, customer growth will remain robust across its service footprint, and the company will continue to recover growth capital through regulatory mechanisms. In addition, we anticipate SWG will preserve its balanced capital structure over time in line with the regulatory approved capital structure.[7]

Additionally, referencing the North American investor-owned regulated electric, gas and water utilities, and the key risks to the 2024 key baseline assumptions, S&P noted:

> Timely recovery of prudently spent capital and operation and maintenance (O&M) costs is necessary for the industry to maintain credit quality.[8]

Q. 21 What is the potential credit rating impact of the requested RORs and IRRAM to Southwest Gas?

A. 21 Given the above-described need for Southwest Gas to have continued access to capital and credit capacity at reasonable costs, Commission approval of the Company's proposed spending under the IRRAM and approval of the Company's requested RORs will give Southwest Gas the opportunity to sustain, and the ability to improve, its credit ratings, which benefits both its customers and its equity investors.

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[7] *Id.*

[8] S&P Global Ratings, "Industry Credit Outlook 2024 – North American Regulated Utilities", January 9, 2024

C. Capital Attraction

Q. 22 Please describe the importance of the capital-attraction function of utility ratemaking.

A. 22 Southwest Gas participates in the competitive global capital markets to attract capital in light of other opportunities investors consider, including peer utilities and other investment opportunities.

For Southwest Gas to successfully attract debt or equity capital, it must demonstrate an ability to achieve a competitive return on that equity capital. The ongoing and repeated need to access the capital markets for debt or equity is not just an academic discussion. As previously discussed, $602.1 million of common stock has been issued through SWX's ESP since 2017 with the net proceeds being contributed as equity to Southwest Gas.

The Prepared Direct Testimony of Company witness Dylan W. D'Ascendis discusses the development of a fair and reasonable cost of common equity of 11.35 percent, considering Southwest Gas' specific risk factors and costs of common equity for proxy groups of similar natural gas utilities.

Q. 23 What are the primary types of institutions from which Southwest Gas attracts investment?

A. 23 While Southwest Gas attempts to attract capital investment from a variety of capital market participants as an issuer of debt instruments (such as bonds) and equity instruments (such as shares of stock), it currently believes the following types of institutions are most likely to be attracted to infrastructure investment opportunities that a local natural gas distribution company might provide as it invests in infrastructure to support safety and reliability as well as economic activity in its service area:

- Pension funds (such as CalPERS, CalSTRS, and the Texas Teachers Retirement System);
- Mutual funds (such as Fidelity Investments, Vanguard, BlackRock, and T. Rowe Price);
- Insurance companies (such as MetLife, Prudential Financial, and MassMutual); and
- Hedge funds (such as Citadel, Millennium Management, and Blackstone)

These types of institutions are primarily focused on investing in return-seeking assets in order to help individuals plan and prepare for retirement, fund future medical events via health savings accounts, incur the costs associated with higher education, and to financially protect loved ones in the event of one’s tragedy or death.

Q. 24 How can delivering competitive rates of return allow Southwest Gas to attract investment dollars?

A. 24 In order to attract investment dollars controlled by potential investors so they can meet their objectives and commitments to their participants and clients, Southwest Gas believes it needs to consistently deliver competitive rates of return on the investments it makes in its service area. Defining competitive rates of return is part of the rate case filing process.

Q. 25 How has Southwest Gas performed relative to its peer group when raising capital?

A. 25 The chart below summarizes how SWX has performed utilizing a total shareholder return (TSR) perspective, which contemplates share price performance and assuming reinvested dividends from January 1, 2019 – August 15, 2024.

Company	Symbol	TSR
Atmos Energy Corp.	ATO	8.62%
New Jersey Resources Corp.	NJR	3.21%
Northwest Natural Gas	NWN	-3.93%
ONE Gas Inc.	OGS	0.06%
NiSource Inc.	NI	7.74%
Spire Inc.	SR	1.31%
Southwest Gas Holdings, Inc.	SWX	2.03%

Source: Bloomberg

In addition, Southwest Gas has been successful in pricing its public bond instruments in line with similarly rated peer utilities over the same historical period.

Q. 26 In addition to the already discussed equity capital contributed by SWX since 2017, what is the amount of external capital Southwest Gas has acquired since the filing of its last rate case in 2019?

A. 26 Since August 30, 2019, Southwest Gas has accessed the capital markets primarily through senior note offerings to fund utility capital expenditures. The Company completed five note issuances totaling nearly $2 billion in gross proceeds. Additionally, during early 2021 and 2023, Southwest Gas accessed the short-term loan market, directly with its banks, to facilitate the funding of unexpected increases in the price of natural gas due to weather and other natural gas market-related events that constrained those markets throughout the Western United States. These short-term loans were paid off by proceeds from debt issuances by the Company and SWX. Southwest Gas also continues to maintain and utilize, when necessary, its revolving credit facility, primarily for the fluctuation of natural gas commodity costs and for other short-term working capital needs.

These various transactions demonstrate the Company's actual experience in the recent past and the significance of the need to have access to the capital markets.

Q. 27 How does the overall ROR balance the interests of both customers and investors of Southwest Gas?

A. 27 Southwest Gas' financial health is, over time, important in determining the rates it must charge its customers. The Company's credit ratings are significantly influenced by its financial strength. Southwest Gas' cost of debt is in large part determined by the Company's credit ratings. All other things being equal, with stronger credit ratings, Southwest Gas' cost of capital and the rates it charges its customers would be lower.

It is also important that equity investors be given the opportunity to earn a ROR commensurate with the level of risk associated with their investment. Investor confidence in Southwest Gas, which is the primary subsidiary of SWX, is important for SWX's existing shareholders and for its future ability to issue additional common equity. If the overall authorized ROR is set below Southwest Gas' actual cost of capital, it may be unable to attract sufficient financing at reasonable rates and pricing to continue to fund required capital expenditures and maintain its quality of customer service. Southwest Gas' requested overall RORs is expected to help sustain the Company's financial condition, including its credit ratings. In the long-run, this will benefit both Southwest Gas' customers and its equity investors.

With the regulatory support of the Commission in approving the Company's proposed overall RORs, Southwest Gas can maintain, with the opportunity to improve, its financial profile and credit ratings. Such improvement benefits Southwest Gas' customers by reducing the long-run average capital costs embedded in customer rates.

IV. RECOMMENDED CAPITAL STRUCTURE

Q. 28 What is Southwest Gas' current Commission-authorized ratemaking capital structure and overall RORs?

A. 28 Southwest Gas' current RORs were authorized in D.21-03-052, based on a 2021 Test Year. The capital structure and weighted cost of capital authorized D.21-03-052 for Southwest Gas' California three rate jurisdictions are as follows:

SOUTHERN CALIFORNIA RATE JURISDICTION

Component	Ratio	Cost	Weighted Cost
Long-Term Debt	48.00%	3.98%	1.91%
Common Equity	52.00%	10.00%	5.20%
Total	100.00%		7.11%

NORTHERN CALIFORNIA/SOUTH LAKE TAHOE RATE JURISDICTIONS

Component	Ratio	Cost	Weighted Cost
Long-Term Debt	48.00%	4.67%	2.24%
Common Equity	52.00%	10.00%	5.20%
Total	100.00%		7.44%

Q. 29 Please discuss the recommended capital structure used to develop the overall proposed RORs in this Application.

A. 29 The recommended capital structure used to determine the currently requested RORs consists of 50 percent long-term debt and 50 percent common equity. The recommended capital structure is the target capital structure Southwest Gas reasonably expects to achieve on average during the 2026-2030 period when new rates will be in effect as authorized through this Application.

Q. 30 What is the basis for Southwest Gas' requested target capital structure?

A. 30 Two primary factors support the Company's requested capital structure of 50 percent long-term debt and 50 percent common equity: (1) growth in retained earnings, and (2) continued equity contributions from its parent company, Southwest Gas Holdings, Inc. The Company anticipates that underlying business trends and economic growth will continue to be favorable in the jurisdictions in which it operates ultimately driving favorable Company financial performance. Additionally, and as stated elsewhere in the testimony, the parent company plans on continuing to support, as it has done historically, the Company's capital position with planned equity capital contributions in the timeframe leading up to the end of 2026.[9]

In addition, the Company's target capital structure is consistent with the range of capital structures maintained by the Utility Proxy Group used to calculate the Company's ROE in this proceeding. As shown on page 1 of Schedule DWD-2 accompanying Mr. Dylan W. D'Ascendis' prepared direct testimony, the range of equity ratios maintained by the Utility Proxy Group is from 40.23% to 62.38%. Similarly, on page 2 of Schedule DWD-2, the range of equity ratios maintained by the operating subsidiaries of the Utility Proxy Group are from 39.60% to 61.24%. Finally, the projected equity ratios of the Utility Proxy Group, as reported by Value Line range from 37.50% to 60.00%. In view of these ranges, the Company's target capital structure is reasonable and appropriate.

[9] See Application Schedules included in Chapter 24A.

Q. 31 Please summarize the supporting factors for Southwest Gas' proposed target capital structure in this proceeding.

A. 31 Southwest Gas proposed target capital structure, with a 50 percent common equity ratio, is the expected average capital structure that will be in place during the 2026-2030 period. This capital structure for ratemaking purposes is consistent in supporting the Company's strong investment grade credit ratings. In addition, the requested target capital structure, while having a lower relative common equity ratio, is reasonable in comparison to the projected capital structures for the proxy group companies used to estimate the cost of common equity in this proceeding.

V. EMBEDDED COST OF LONG-TERM DEBT

Q. 32 Have you determined the appropriate cost rate for long-term debt capital based on the 2026 test year?

A. 32 Yes. For the Southern California rate jurisdiction, the appropriate cost of long-term debt is 4.14 percent, which includes the cost of the jurisdiction-specific Big Bear IDRBs. For both the Northern California and South Lake Tahoe rate jurisdictions, the appropriate cost rate for long-term debt is 4.34 percent. The cost of long-term debt is comprised of the cost of fixed-rate debentures, fixed-rate medium-term notes, and a variable-rate term facility, with the Southern California rate jurisdiction also including the Big Bear IDRBs. For the Southern California rate jurisdiction, the components of the embedded cost of long-term debt for the 2026 test year are displayed in Tab A, Schedule 5, Sheet 2 of 4, of Chapter 24 schedules (Volumes II-A through C) in the Application. For the Northern California and South Lake Tahoe rate jurisdictions, the components of the embedded cost of long-term debt for the 2026 test year are displayed in Tab A Schedule 5, Sheet 1 of 3, of Chapter 24 schedules.

Q. 33 Please describe the development of the cost rates of the debentures and notes.

A. 33 Southwest Gas anticipates having eleven debentures and notes issues outstanding at the end of the 2026 test year, totaling approximately $3.525 billion of gross principal. The debentures and notes have a weighted average cost of 4.30 percent.

Q. 34 Please provide a listing of the debentures and notes anticipated to be outstanding at the end of the Test year.

A. 34 Please see Tab A, Schedule 5, Sheet 4 of 4, of Chapter 24 schedules (Volumes II-A through C) in the Application.

Q. 35 Please describe the cost rate of the medium-term notes.

A. 35 Southwest Gas established a $150 million medium-term note program in November 1997. Medium-term notes can be issued with maturities ranging from nine months to 30 years. The Company issued all of its medium-term note program and will have two remaining medium-term note issues outstanding for the 2026 Test Year totaling approximately $32.5 million of gross principal. For the 2026 Test Year, the medium-term notes have a weighted average cost of 7.71 percent.

Q. 36 How are the effective cost rates of debentures, notes, and medium-term notes calculated?

A. 36 The effective cost rates of debentures, notes, and medium-term notes are calculated through the use of the yield-to-maturity (YTM) or effective interest rate method.

Q. 37 Please describe and discuss the development of the cost rate for the variable-rate term facility debt.

A. 37 Southwest Gas has a $400 million revolving credit facility. In addition, the Company has a $50 million uncommitted F-2 commercial paper program, supported by the revolving credit facility. Southwest Gas continues to view $150 million of the facility as a permanent intermediate-term component of its debt portfolio, and accordingly classifies it as long-term debt. Southwest Gas uses the remaining $250 million of the facility to fund recurring, working capital needs.

For the 2026 Test Year, Southwest Gas anticipates having approximately $117.8 million outstanding on average as part of the long-term debt portion of the facility. Of this amount, all of the $117.8 million will be outstanding as Secured Overnight Financing Rate (SOFR) loans. For the SOFR loans, an average overnight SOFR rate of 2.88 percent was used for 2026, which was obtained from the S&P Global August 2024 key interest rate forecast for 2026. The all-in effective rate of the long-term debt portion of the facility for the 2026 test year is 4.22 percent. This all-in rate includes the interest on the loans, an annual fee, any unused commitment fees and amortization of debt expenses incurred to establish the facility.

Q. 38 Why are the Clark County IDRBs excluded from the Southern California, Northern California, and South Lake Tahoe rate jurisdictions, and the Big Bear IDRBs excluded from the Northern California and South Lake Tahoe rate jurisdictions in calculating the cost of debt?

A. 38 Southwest Gas issued IDRBs in two of its rate jurisdictions. The IDRB issues and applicable rate jurisdictions are as follows: (1) the Clark County, Nevada IDRBs (2003 Series A, 2008 Series A and 2009 Series A) for its Southern Nevada rate jurisdiction, and (2) the City of Big Bear IDRBs (1993 Series A) for its Southern

California rate jurisdiction. As reflected in the IDRB indentures and financing agreements, the proceeds from the issuance of this type of debt are restricted to funding qualified construction expenditures for additions and improvements in the specific distribution systems to which the IDRBs relate. In addition, there are strict Internal Revenue Service (IRS) rules which mandate that the benefits of the tax-exempt, lower cost IDRBs must accrue to customers in the specific jurisdiction to which the IDRBs apply. Deviation from the requirements of the IRS rules could result in the loss of the IDRB tax-exempt status, which would, in turn, require the Company to refinance its debt at a potentially higher cost, due to the potential loss of the tax-exempt status of the bonds, and depending on market conditions and relative interest rates at the time of the deviation.

Q. 39 How have regulatory jurisdictions treated the cost of Southwest Gas' IDRBs in past regulatory proceedings?

A. 39 Southwest Gas has historically excluded the IDRBs from the cost of debt calculation in all regulatory jurisdictions, except for the specific jurisdictions (Southern Nevada for Clark County IDRBs and Southern California for City of Big Bear IDRBs), to which the relevant IDRBs apply. This Commission, the Public Utilities Commission of Nevada, the Arizona Corporation Commission, and the Federal Energy Regulatory Commission have accepted this treatment for IDRBs in past regulatory proceedings.

Q. 40 Please describe and discuss the development of the cost of IDRBs for the Southern California rate jurisdiction.

A. 40 For the 2026 test year, the anticipated effective cost of the $50 million variable rate Big Bear IDRBs is 3.39 percent. The interest rate on the IDRBs is set weekly by a remarketing agent. The weekly rates are set close to the Securities Industry and Financial Markets Association (SIFMA) Municipal Swap Index rate[10], also known by market participants simply as the SIFMA rate. The actual Big Bear rate spread above SIFMA has been approximately 6 basis points. The projected rate for 2026 is based on a regression analysis of the historical average monthly SIFMA rates as a function of the 1-month SOFR rates, plus the 6 basis points spread. The regression equation is then used to forecast SIFMA rates for 2026, using the S&P Global forecast of the average 1-month SOFR rate for 2026. In addition, the Big Bear IDRBs are credit-enhanced with a back-up line of credit. The annual credit facility fees are included to determine the effective cost.

Q. 41 Please explain how the embedded cost of debt for the Southern California rate jurisdiction is calculated.

A. 41 Due to the $50 million in gross principal of the Big Bear IDRBs, which are specific to the Southern California rate jurisdiction, the embedded debt cost is the weighted cost of the Big Bear IDRBs, combined with Southwest Gas' other long-term debt. To determine the embedded debt cost, the implicit amount of debt required to finance the Southern California jurisdictional rate base was determined by multiplying the percent of total debt in the capital structure by the amount of rate base. The implicit amount of debt is calculated as follows:

Implicit Debt = Debt to Capital Ratio X Southern California Rate Base
= 50 Percent X $466,429,122
= $233,214,561

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[10] The Securities Industry and Financial Markets Association Municipal Swap Index is a 7-day high-grade market index comprised of tax-exempt Variable Rate Demand Obligations (VRDOs) with certain characteristics. The Index is calculated and published by Bloomberg. The Index is overseen by SIFMA's Municipal Swap Index Committee.

Next, the Big Bear IDRBs are allocated first to the total amount of implicit debt. The remaining portion of other debt is calculated as the difference between the implicit amount of debt and the jurisdiction-specific Big Bear IDRBs. The other debt is comprised of the Company's non-jurisdictional specific debt, applied on a pro rata basis. For the Southern California rate jurisdiction, the amount of other debt is calculated as follows:

Implicit Amount of Debt	$233,214,561
Less Net Proceeds Big Bear IDRBs	49,876,858
= Other Debt	$183,337,703

The embedded debt cost is then calculated using the components of debt identified in the previous calculation to calculate the weighted cost of debt for the Southern California rate jurisdiction. The allocation process and the calculation of the weighted embedded cost of debt for the Southern California rate jurisdiction are displayed in Chapter 24, Tab A, Schedule 5, Sheet 1 of 4 in Volumes II-A through C of the Application.

VI. CONTINUATION OF THE ATM

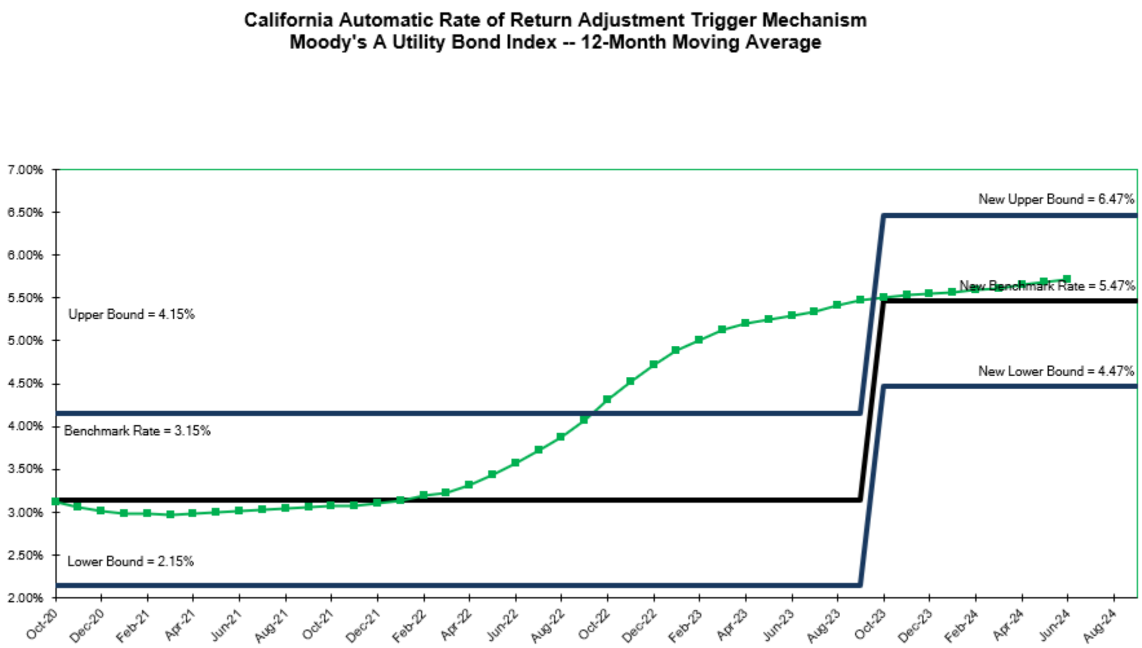
Q. 42 Is Southwest Gas making an ATM proposal in this proceeding?

A. 42 Yes. The Company is requesting the continuation of the ATM approved in D.14-06-028 and continued in D.21-03-052. The ATM adjusts the authorized ROR between general rate cases as a result of changes in utility bond yields. The need for an ROR adjustment is triggered when the average benchmark yield, measured by the Moody's A Utility Bond yield, changes by more than 100 basis points.

Q. 43 Has the ATM been triggered since the authorized RORs were established in D.21-03-052?

A. 43 Yes. For the twelve-month period ending September 2023, the average Moody's

A Utility Bond rate was 5.47 percent, 232 basis points higher than the benchmark rate of 3.15 percent. The ATM was triggered as the twelve-month average rate exceeded the benchmark rate by more than 100 basis points. The new benchmark rate is 5.47 percent. The following graph displays the twelve-month rolling average of the Moody's A Utility Bond Index.



Q. 44 Please discuss the features of Southwest Gas' requested ATM.

A. 44 The ATM would have the following features:

- The initial ATM benchmark established in the proceeding will be computed using the average monthly yields for the 12-month period ended September 30, 2025 for the Moody's Baa Utility Bond Index. The annual measurement period is the twelve-month period ended September. As of the date of this application, Southwest Gas' long-term unsecured credit ratings are Baa1 from Moody's and BBB from S&P. Should the ATM be triggered, Southwest Gas will submit an Advice Letter detailing the results of the trigger mechanism, which includes any required change in rates and revenue requirements based on the trigger mechanism.

- If, in any year, the difference between the current twelve-month average and the benchmark, exceeds 100 basis points, then an automatic adjustment in the Company's authorized ROR will result. Southwest Gas will update its cost of capital and compute a new ROR as follows:
    1. The authorized ROE in effect at the time of adjustment is adjusted by one-half of the change in the average utility bond yields that triggered the adjustment.
    2. The embedded costs of long-term debt and preferred equity are updated to reflect actual September month-end embedded costs in that year.
    3. The capital structure authorized in this application will be used to compute the updated ROR.
- In any year that the twelve-month average triggers an automatic adjustment, that average becomes the new benchmark until another automatic adjustment is triggered.
- There would be no off-ramp provision, as Southwest Gas would have the right to file a cost of capital application outside of the ATM upon an extraordinary or catastrophic event that materially impacts its cost of capital and/or capital structure.

Q. 45 What are the benefits of continuing Southwest Gas ATM for ROR adjustments?

A. 45 The continuation of the ATM would facilitate the Company's five-year rate case cycle, as it would not require separate cost of capital reviews or participation in the four major utilities' generic cost of capital proceeding outside of a general rate case. As a result, the continuation of the ATM will allow Southwest Gas and the Commission to better utilize staff resources and avoid the litigation costs of participating in a separate cost of capital proceeding. The ATM will streamline the regulatory process and adjust the Company's authorized ROR based on changes in actual observed capital market conditions. Such a mechanism is fair and reasonable to both Southwest Gas' investors and customers. In addition, the ATM would provide Southwest Gas with a comparable cost of capital mechanism approved and utilized by the other California major energy utilities.

Q. 46 Does this conclude your prepared direct testimony?

A. 46 Yes.

SUMMARY OF QUALIFICATIONS
JUSTIN S. FORSBERG

Justin S. Forsberg is the Vice President of Investor Relations and Treasurer for Southwest Gas Corporation (Southwest Gas) and Southwest Gas Holdings, Inc. In his investor relations role, he oversees the investor relations team, the development and implementation of investor communication strategies, the engagement and relationships with sell-side analysts, buyside investors, and credit rating agencies, and the measurement of investor sentiment and market sector trends. As Treasurer, Justin provides leadership and direction for debt and equity financing matters, financial risk mitigation, and other banking interactions. In addition, Justin provides leadership for the Southwest Gas' sustainability team, and is responsible for raising stakeholder awareness for the company's sustainability efforts and reporting, including the reporting of sustainability metrics and performance objectives.

Justin is responsible for delivering accurate and timely information to investors, responding to their inquiries, identifying and targeting potential investors, organizing and attending investor conferences and roadshows, measuring the effectiveness of investor relations activities, developing and implementing internal investor relations policies and procedures, and ensuring investors have transparent information in order to ensure the company receives a fair value for its equity and debt instruments in the public marketplace. Additionally, he oversees the investment of the pension and other employee retirement assets.

Justin joined Southwest in August 2023. From 2010 to 2023, he served in various accounting and finance roles at IDACORP, Inc. and Idaho Power Company, most recently having served as Director of Investor Relations & Treasury from 2016-2023, and as President of IDACORP Financial Services, Inc. (IFS) from 2016 – 2023. In his roles he oversaw the companies' investor relations, treasury, pension, cash management, and accounts payable functions, as well as IFS' investment in affordable housing and other real estate tax credits. Before joining IDACORP, Justin worked at Deloitte's Seattle and Boise offices from 2003 through 2010, ultimately serving in the role of Audit Manager.

Justin received master's and bachelor's degrees in accountancy from Brigham Young University. He is a Certified Public Accountant licensed in Idaho, and a member of the AICPA and of the National Investor Relations Institute.

SOUTHWEST GAS CORPORATION
PROXY GROUP OF VALUE LINE GAS DISTRIBUTION COMPANIES
LIST OF COMPANIES

Line No.	Symbol	Company	Moody's[1]	Numerical Weight	S&P[1]	Numerical Weight	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
1	ATO	Atmos Energy Corp.	A1	5	A-	7	1
2	NJR	New Jersey Resources Corp.	A1	5			2
3	NWN	Northwest Natural Gas	Baa1	8	A+	5	3
4	OGS	ONE Gas Inc.	A3	7	A-	7	4
5	NI	NiSource Inc.	Baa1	8	BBB+	8	5
6	SR	Spire Inc. [2]	A2/A1	5.5	BBB+/BBB+	8	6
7		**Proxy Group Average**	**A2**	**6.42**	**A-**	**7.00**	7
8	SWX	**Southwest Gas Corporation**	**Baa1**	**8.00**	**BBB**	**9.00**	8

[1] Source: Bloomberg
[2] Reflects ratings for Spire Alabama Inc., and Spire Missouri Inc.

SOUTHWEST GAS CORPORATION
NUMERICAL WEIGHT FOR BOND RATINGS

Moody's Bond Rating	S&P Bond Rating	Numerical Weight
Aaa	AAA	1
Aa1	AA+	2
Aa2	AA	3
Aa3	AA-	4
A1	A+	5
A2	A	6
A3	A-	7
Baa1	BBB+	8
Baa2	BBB	9
Baa3	BBB-	10
Ba1	BB+	11
Ba2	BB	12
Ba3	BB-	13

Company Witness:

Dylan W. D'Ascendis

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
APPLICATION 24-09-___

PREPARED DIRECT TESTIMONY
OF
DYLAN W. D'ASCENDIS

ON BEHALF OF
SOUTHWEST GAS CORPORATION

September 5, 2024

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of
Prepared Direct Testimony
of
Dylan W. D'Ascendis

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Prepared Direct Testimony
of
Dylan W. D'Ascendis

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Exhibit No.___(DWD-2)	Range of Capital Structures for the Utility Proxy Group and their Operating Subsidiaries
Exhibit No.___(DWD-3)	Application of the Discounted Cash Flow Model
Exhibit No.___(DWD-4)	Application of the Risk Premium Model
Exhibit No.___(DWD-5)	Application of the Capital Asset Pricing Model
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BEFORE THE CALIFORNIA PUBLIC UTILITIES COMMISSION

Prepared Direct Testimony
of
<u>DYLAN W. D'ASCENDIS</u>

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Dylan W. D'Ascendis. My business address is 3000 Atrium Way, Suite 200, Mount Laurel, NJ 08054.

Q. 2 By whom and in what capacity are you employed?

A. 2 I am employed by ScottMadden, Inc. as Partner.

Q. 3 On whose behalf are you submitting this testimony?

A. 3 I am submitting this Prepared Direct Testimony (Direct Testimony) before the California Public Utilities Commission (CPUC or Commission) on behalf of Southwest Gas Corporation (Southwest Gas or Company).

Q. 4 Please summarize your educational background and relevant business experience.

A. 4 I have offered expert testimony on behalf of investor-owned utilities before over 35 state regulatory commissions in the United States, the Federal Energy Regulatory Commission (FERC), the Alberta Utility Commission, the Canadian Energy Regulator, an American Arbitration Association panel, and the Superior Court of Rhode Island on issues including, but not limited to, common equity cost rate, rate of return, valuation, capital structure, class cost of service, and rate design.

On behalf of the American Gas Association (AGA), I calculate the AGA Gas Index, which serves as the benchmark against which the performance of the American Gas Index Fund (AGIF) is measured on a monthly basis. The AGA Gas Index and AGIF are a market capitalization weighted index and mutual fund, respectively, comprised of the common stocks of the publicly traded corporate members of the AGA.

I am a member of the Society of Utility and Regulatory Financial Analysts (SURFA). In 2011, I was awarded the professional designation “Certified Rate of Return Analyst” by SURFA, which is based on education, experience, and the successful completion of a comprehensive written examination.

I am also a member of the National Association of Certified Valuation Analysts (NACVA) and was awarded the professional designation “Certified Valuation Analyst” by the NACVA in 2015.

I am a graduate of the University of Pennsylvania, where I received a Bachelor of Arts degree in Economic History. I have also received a Master of Business Administration with high honors and concentrations in Finance and International Business from Rutgers University.

The details of my educational background and expert witness appearances are shown in Appendix A.

Q. 5 What is the purpose of your Prepared Direct Testimony in this proceeding?

A. 5 The purpose of my Prepared Direct Testimony is to present evidence on behalf of Southwest Gas and recommend an appropriate return on common equity (ROE) for the Company’s three California rate jurisdictions (Southern California, Northern California and South Lake Tahoe).

Q. 6 Have you prepared any Exhibits in support of your Direct Testimony?

A. 6 Yes. Exhibit No.___(DWD-1) through Exhibit No.___(DWD-9) were prepared by me or under my direction.

II. SUMMARY

Q. 7 What is your recommended ROE for Southwest Gas' California rate jurisdictions?

A. 7 I recommend that the Commission authorize Southwest Gas the opportunity to earn an ROE of 11.35% for its three California rate jurisdictions. The ratemaking capital structure and cost of long-term debt applicable to the Southern California, Northern California, and South Lake Tahoe jurisdictions is sponsored by Company Witness Justin S. Forsberg. The overall rate of return is summarized on page 1 of Exhibit No.___(DWD-1) and in Tables 1 and 2 below:

Table 1: Summary of Recommended Weighted Average Cost of Capital – Southern California Rate Jurisdiction

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Total Debt	50.00%	4.14%	2.07%
Common Equity	50.00%	11.35%	5.68%
Total	100.00%		7.74%

Table 2: Summary of Recommended Weighted Average Cost of Capital – Northern California and South Lake Tahoe Rate Jurisdiction

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Total Debt	50.00%	4.34%	2.17%
Common Equity	50.00%	11.35%	5.68%
Total	100.00%		7.85%

Q. 8 Please summarize your recommended range of common equity cost rates.

A. 8 My recommended range of common equity costs rates between 9.99% to 12.01% (unadjusted) and 10.46% to 12.48% (adjusted) is summarized on page 2 of Exhibit No.___(DWD-1). I have assessed the market-based common equity cost rates of companies of relatively similar, but not necessarily identical, risk to Southwest Gas. Using companies of relatively comparable risk as proxies is consistent with the principles of fair rate of return established in the *Hope*[1] and *Bluefield*[2] decisions. No proxy group can be identical in risk to any single company, consequently, there must be an evaluation of relative risk between the Company and the proxy group to determine if it is appropriate to adjust the proxy group's indicated rate of return.

[1] *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) (*Hope*).
[2] *Bluefield Water Works Improvement Co. v. Public Serv. Comm'n*, 262 U.S. 679 (1922) (*Bluefield*).

My recommendation results from the application of several cost of common equity models, specifically the Discounted Cash Flow (DCF) model, the Risk Premium Model (RPM), and the Capital Asset Pricing Model (CAPM), to the market data of the Utility Proxy Group whose selection criteria will be discussed below. In addition, I applied the DCF model, RPM, and CAPM to a Non-Price Regulated Proxy Group. The results derived from each are as follows:

Table 3: Summary of Common Equity Cost Rate

Discounted Cash Flow Model (DCF)	9.99%
Risk Premium Model (RPM)	10.82%
Capital Asset Pricing Model (CAPM)	11.57%
Cost of Equity Models Applied to Comparable Risk, Non-Price Regulated Companies	12.01%
Indicated Range of Common Equity Cost Rates Before Adjustments	9.99% - 12.01%
Business Risk Adjustment	0.20%
Credit Risk Adjustment	0.15%
Flotation Cost Adjustment	0.12%
Indicated Cost of Common Equity Cost Rates After Adjustment	10.46% - 12.48%
Recommended Cost of Equity	11.35%

The indicated range of common equity cost rates applicable to the Utility Proxy Group is between 9.99% and 12.01% before any Company-specific adjustments.

To reflect Southwest Gas' specific risks, I adjusted the indicated common equity cost rate model results upward by 0.20% and 0.15% to reflect the Company's greater relative business risk and lower bond rating, as compared to the Utility Proxy Group, respectively. I then adjusted the indicated common equity cost rate upward by 0.12% to account for flotation costs. These adjustments resulted in a Company-specific indicated range of common equity cost rates between 10.46% and 12.48%. From that range, I recommend a ROE of 11.35%.

Q. 9 How is the rest of your Prepared Direct Testimony organized?

A. 9 The remainder of my Prepared Direct Testimony is organized as follows:

- Section III – Provides a summary of financial theory and regulatory principles pertinent to the development of the cost of capital;
- Section IV – Provides a description of the Company and explains the selection of the Utility Proxy Group used to develop my ROE recommendation;
- Section V – Explains the proposed capital structure;
- Section VI – Describes the analyses upon which my ROE recommendation is based;
- Section VII – Summarizes the range of applicable ROEs before adjustments for Company-specific factors;
- Section VIII – Explains my adjustments to the applicable range of ROEs to reflect Company-specific factors; and
- Section IX – Presents my conclusions.

III. GENERAL PRINCIPLES

Q. 10 What general principles have you considered in your analysis?

A. 10 In unregulated industries, marketplace competition is the principal determinant of the price of products or services. For regulated public utilities, regulation must act as a substitute for marketplace competition. Assuring that the utility can fulfill its obligations to the public, while providing safe and reliable service at all times, requires a level of earnings sufficient to maintain the integrity of presently invested capital. Sufficient earnings also permit the attraction of needed new capital at a reasonable cost, for which the utility must compete with other firms of comparable risk, and is consistent with the fair rate of return standards established by the Supreme Court of the United States in the previously cited *Hope* and *Bluefield* cases.

The Court explained the fair rate of return standards in *Hope*, when it stated the following:

> The rate-making process under the Act, *i.e.*, the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests. Thus we stated in the *Natural Gas Pipeline Co.* case that 'regulation does not insure that the business shall produce net revenues.' 315 U.S. p. 590. But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. Cf. *Chicago & Grand Trunk R. Co. v. Wellman*, 143 U.S. 339, 345-346. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[3]

In summary, the Supreme Court of the United States determined that a return that is adequate to attract capital at reasonable terms enables the utility to provide service while maintaining its financial integrity. As discussed above, and in keeping with established regulatory standards, that return should be commensurate with the returns expected elsewhere for investments of equivalent risk. The Commission's decision in this Application, therefore, should provide the Company with the opportunity to earn a return that is: (1) adequate to attract capital

[3] *Hope*, 320 U.S. 591, at 603.

at reasonable cost and terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises having corresponding risks.

It therefore is important that the authorized ROE reflects the risks and prospects of the utility's operations and supports the utility's financial integrity from a stand-alone perspective as measured by its combined business and financial risks.

Q. 11 Within that broad framework, how is the cost of capital estimated in regulatory proceedings?

A. 11 Regulated utilities primarily use common stock and long-term debt to finance their permanent property, plant, and equipment (i.e., rate base). The fair rate of return for a regulated utility is based on its weighted average cost of capital, in which, as noted earlier, the costs of the individual sources of capital are weighted by their respective book values.

The cost of capital is the return investors require to make an investment in a firm. Investors will provide funds to a firm only if the return that they *expect* is equal to, or greater than, the return that they *require* to accept the risk of providing funds to the firm.

The cost of capital (that is, the combination of the costs of debt and equity) is based on the economic principle of "opportunity costs." Investing in any asset (whether debt or equity securities) represents a forgone opportunity to invest in alternative assets. For any investment to be sensible, its expected return must be at least equal to the return expected on alternative, comparable risk investment opportunities. Because investments with like risks should offer similar returns, the opportunity cost of an investment should equal the return available on an investment of comparable risk.

Whereas the cost of debt is contractually defined and can be directly observed as the interest rate or yield on debt securities, the cost of common equity must be estimated based on market data and various financial models. Because the cost of common equity is premised on opportunity costs, the models used to determine it are typically applied to a group of "comparable" or "proxy" companies.

In the end, the estimated cost of capital should reflect the return that investors require in light of the subject company's business and financial risks, and the returns available on comparable investments.

A. Business Risk

Q. 12 Please define business risk and explain why it is important for determining a fair rate of return.

A. 12 The investor-required return on common equity reflects investors' assessment of the total investment risk of the subject firm. Total investment risk is often discussed in the context of business and financial risk.

Business risk reflects the uncertainty associated with owning a company's common stock without the company's use of debt and/or preferred stock financing. One way of considering the distinction between business and financial risk is to view the former as the uncertainty of the expected earned return on common equity, assuming the firm is financed with no debt.

Examples of business risks <u>generally</u> faced by utilities include, but are not limited to, the regulatory environment, mandatory environmental compliance requirements, customer mix and concentration of customers, service territory economic growth, market demand, risks and uncertainties of supply, operations, capital intensity, size, the degree of operating leverage, emerging technologies, the vagaries of weather, and the like, all of which have a direct bearing on earnings. Although analysts, including rating agencies, may categorize business risks individually, as a practical matter, such risks are interrelated and not wholly distinct from one another. Therefore, it is difficult to specifically and numerically quantify the effect of any individual risk on investors' required return, i.e., the cost of capital. For determining an appropriate return on common equity, the relevant issue is where investors see the subject company in relation to other similarly situated utility companies (i.e., the Utility Proxy Group). To the extent investors view a company as being exposed to higher risk, the required return will increase, and vice versa.

For regulated utilities, business risks are both long-term and near-term in nature. Whereas near-term business risks are reflected in year-to-year variability in earnings and cash flow brought about by economic or regulatory factors, long-term business risks reflect the prospect of an impaired ability of investors to obtain both a fair rate of return on, and return of, their capital. Moreover, because utilities accept the obligation to provide safe, adequate, and reliable service at all times (in exchange for a reasonable opportunity to earn a fair return on their investment), they generally do not have the option to delay, defer, or reject capital investments. Because those investments are capital-intensive, utilities generally do not have the option to avoid raising external funds during periods of capital market distress, if necessary.

Because utilities invest in long-lived assets, long-term business risks are of paramount concern to equity investors. That is, the risk of not recovering the return on their investment extends far into the future. The timing and nature of events that may lead to losses, however, also are uncertain and, consequently, those risks and their implications for the required return on equity tend to be difficult to quantify. Regulatory commissions (like investors who commit their capital) must review a variety of quantitative and qualitative data and apply their reasoned judgment to determine how long-term risks weigh in their assessment of the market-required return on common equity.

B. Financial Risk

Q. 13 Please define financial risk and explain why it is important for determining a fair rate of return.

A. 13 Financial risk is the additional risk created by the introduction of debt and preferred stock into the capital structure. The higher the proportion of debt and preferred stock in the capital structure, the higher the financial risk to common equity owners (i.e., failure to receive dividends due to default or other covenants). Therefore, consistent with the basic financial principle of risk and return, common equity investors require higher returns as compensation for bearing higher financial risk.

Q. 14 What is a credit rating?

A. 14 A credit rating reflects an independent rating agency's opinion of the creditworthiness of a particular company, security, or obligation. Credit ratings play an important role in capital markets by providing an effective and objective tool for market participants to evaluate and assess credit risk. In a report on the role and function of credit rating agencies, the Securities and Exchange Commission (SEC) concluded:

> The importance of credit ratings to investors and other market participants had increased significantly, impacting an issuer's

> access to and cost of capital, the structure of financial transactions, and the ability of fiduciaries and others to make particular investments.[4]

As a result, Southwest Gas' credit ratings are a key factor in determining the required yield on the Company's debt securities and bank facilities, and the amount and terms of available unsecured trade credit. Credit rating agencies use both quantitative and qualitative information in the process of developing a credit rating.

Q. 15 Can bond and credit ratings be a proxy for a firm's combined business and financial risks to equity owners (i.e., investment risk)?

A. 15 Yes, similar bond ratings/issuer credit ratings reflect, and are representative of, similar combined business and financial risks (i.e., total risk) faced by bond investors.[5] Although specific business or financial risks may differ between companies, the same bond/credit rating indicates that the combined risks are roughly similar from a debtholder perspective. The caveat is that these debtholder risk measures do not translate directly to risks for common equity.

IV. SOUTHWEST GAS AND THE UTILITY PROXY GROUP

Q. 16 Why is it necessary to develop a proxy group when estimating the ROE for Southwest Gas?

A. 16 Because Southwest Gas is not publicly traded and does not have publicly traded equity securities, it is necessary to develop groups of publicly traded, comparable companies to serve as "proxies" for the Company. In addition to the analytical necessity of doing so, the use of proxy companies is consistent with the *Hope* and

[4] SEC, "Report on the Role and Function of Credit Rating Agencies in the Operation of the Securities Markets," January 24, 2003.

[5] Risk distinctions within S&P's bond rating categories are recognized by a plus or minus, e.g., within the A category, an S&P rating can be an A+, A, or A-. Similarly, risk distinction for Moody's ratings are distinguished by numerical rating gradations; e.g., within the A category, a Moody's rating can be A1, A2 and A3.

Bluefield comparable risk standards, as discussed above. I have selected two proxy groups that, in my view, are fundamentally risk-comparable to Southwest Gas: a Utility Proxy Group and a Non-Price Regulated Proxy Group, which is comparable in total risk to the Utility Proxy Group.

Even when proxy groups are carefully selected, it is common for analytical results to vary from company to company. Despite the care taken to ensure comparability, because no two companies are identical, market expectations regarding future risks and prospects will vary within the proxy group. It therefore is common for analytical results to reflect a seemingly wide range, even for a group of similarly situated companies. At issue is how to estimate the ROE from within that range. That determination will be best informed by employing a variety of sound analyses and, necessarily, must consider the sort of quantitative and qualitative information discussed throughout my Prepared Direct Testimony. Additionally, a relative risk analysis between Southwest Gas and the Utility Proxy Group must be made to determine whether or not explicit Company-specific adjustments need to be made to the Utility Proxy Group-indicated results.

My analyses are based on the Utility Proxy Group containing U.S. natural gas utilities. As discussed earlier, utilities must compete for capital with other companies with commensurate risk (including non-utilities) and, to do so, must be provided the opportunity to earn a fair and reasonable return. Consequently, it is appropriate to consider the Utility Proxy Group's market data in determining the Southwest Gas' ROE.

Q. 17 Are you familiar with Southwest Gas' operations?

A. 17 Yes. Southwest Gas provides natural gas distribution services to approximately 206,000 customers in California.[6] Southwest Gas has long-term issuer ratings of Baa1 from Moody's Investor Services (Moody's) and BBB from Standard and Poor's (S&P). Southwest Gas is not publicly-traded as it comprises a wholly-owned subsidiary of Southwest Gas Holdings, Inc. (SWX or the Parent), which is publicly-traded under ticker symbol SWX.

Q. 18 Please explain how you chose the companies in the Utility Proxy Group.

A. 18 Because the cost of common equity is a comparative exercise, my objective in developing a proxy group was to select companies that are comparable to Southwest Gas. Because the Company is a 100% rate-regulated natural gas utility, I applied the following criteria to select my Utility Proxy Group:

(i) They were included in the Natural Gas Utility Group of *Value Line's Standard Edition* (May 24, 2024) (*Value Line*);

(ii) They have 60% or greater of fiscal year 2023 total operating income derived from, or 60% or greater of fiscal year 2023 total assets attributable to, regulated gas distribution operations;

(iii) At the time of preparation of this testimony, they had not publicly announced that they were involved in any major merger or acquisition activity (i.e., one publicly-traded utility merging with or acquiring another) or any other major development;

(iv) They have not cut or omitted their common dividends during the five years ended 2023 or through the time of preparation of this testimony;

[6] Southwest Gas Holdings, Inc. SEC Form 10-K, (December 31, 2023) at 26.

(v) They have *Value Line* and Bloomberg Professional Services (Bloomberg) adjusted Beta coefficients (beta);

(vi) They have positive *Value Line* five-year dividends per share (DPS) growth rate projections; and

(vii) They have *Value Line*, Zacks, or Yahoo! Finance consensus five-year earnings per share (EPS) growth rate projections.

The following six companies met these criteria:

Table 4: Utility Proxy Group Companies

Company Name	**Ticker Symbol**
Atmos Energy Corporation	ATO
New Jersey Resources Corporation	NJR
NiSource Inc.	NI
Northwest Natural Gas Company	NWN
ONE Gas, Inc.	OGS
Spire Inc.	SR

V. CAPITAL STRUCTURE

Q. 19 Please summarize the components of Southwest Gas' capital structure.

A. 19 The Company's proposed capital structure consists of 50.00% total debt and 50.00% common equity. Southwest Gas' requested capital structure is the capital structure it expects to achieve over the forecasted test year period, as discussed in the Prepared Direct Testimony of Company Witness Justin S. Forsberg.

Q. 20 How does the capital structure affect the rate of return?

A. 20 As discussed above, there are two general categories of risk: business risk and financial risk. The capital structure relates to a company's financial risk, which represents the risk that a company may not have adequate cash flows to meet its financial obligations and is a function of the percentage of debt (or financial leverage) in its capital structure. In that regard, as the percentage of debt in the capital structure increases, so do the fixed obligations for the repayment of that debt. Consequently, as the degree of financial leverage increases, the risk of financial distress (i.e., financial risk) also increases.[7] In essence, even if two firms face the same business risks, a company with meaningfully higher levels of debt in its capital structure is likely to have a higher cost of both debt and equity. Since the capital structure can affect the subject company's overall level of risk, it is an important consideration in establishing a just and reasonable rate of return.

Q. 21 Is there support for the proposition that the capital structure is a key consideration in establishing an appropriate rate of return?

A. 21 Yes. The United States Supreme Court and various utility commissions have long recognized the role of capital structure in the development of a just and reasonable rate of return for a regulated utility. In particular, a utility's leverage, or debt ratio, has been explicitly recognized as an important element in determining a just and reasonable rate of return:

> Although the determination of whether bonds or stocks should be issued is for management, the matter of debt ratio is not exclusively within its province. Debt ratio substantially affects the manner and cost of obtaining new capital. It is therefore an important factor in the rate of return and must necessarily be considered by and come within the authority of the body charged by law with the duty of fixing a just and reasonable rate of return.[8]

Perhaps ultimate authority for balancing the issues of cost and financial integrity is found in the Supreme Court's statement in *Hope*:

> The rate-making process under the Act, i.e., the fixing of 'just and reasonable' rates, involves a balancing of the investor and the

[7] *See,* Roger A. Morin, Modern Regulatory Finance, Public Utility Reports, Inc., 2021, at 51-52. (Morin).
[8] *New England Telephone & Telegraph Co. v. State*, 98 N.H. 211, 97 A.2d 213, (1953) (*citing New England Tel. & Tel. Co. v. Department of Pub. Util.*, 327 Mass. 81, 97 N.E. 2d 509, 514 (1951)); *see also Petitions of New England Tel. & Tel. Co.*, 116 Vt. 480, 80 A2d 671, 685-86 (1951).

consumer interests.[9]

And as the U.S. Court of Appeals, District of Columbia Circuit found in *Communications Satellite Corp. et. al. v. FCC*:

> The equity investor's stake is made less secure as the company's debt rises, but the consumer rate-payer's burden is alleviated.[10]

That is, the U.S. Court of Appeals, District of Columbia Circuit reasoned that because there is a relationship between the capital structure and the cost of common equity, investor and consumer interests must be balanced. Consequently, the principles of fairness and reasonableness with respect to the allowed rate of return and capital structure are considered at both the federal and state levels.

Q. 22 How does Southwest Gas' recommended common equity ratio of 50.00% compare with the common equity ratios maintained by the Utility Proxy Group?

A. 22 Southwest Gas' requested ratemaking common equity ratio of 50.00% is reasonable and consistent with the range of common equity ratios maintained by the Utility Proxy Group. In order to assess the reasonableness of the Company's requested ratemaking common equity ratio, I reviewed the actual common equity ratios maintained by the companies within the Utility Proxy Group. As shown on page 1 of Exhibit No.___(DWD-2), common equity ratios of the Utility Proxy Group companies range from 40.23% to 62.38% for fiscal year end 2023.

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[9] *Hope*, at 603 (1944).
[10] Communications Satellite Corp. et. al. v. FCC, 198 U.S. App. D.C. 60, 63-64611 F.2d 883.

I also considered *Value Line's* projected capital structures for the Utility Proxy Group for 2027-2029. That analysis shows a range of projected common equity ratios between 37.50% and 60.00%.[11]

In addition to comparing Southwest Gas' ratemaking common equity ratio with common equity ratios currently and expected to be maintained by the Utility Proxy Group (i.e., at the holding company level), I also compared the Company's ratemaking common equity ratio with the common equity ratios maintained by the operating subsidiaries of the Utility Proxy Group companies. As shown on page 2 of Exhibit No.___(DWD-2), common equity ratios of the operating utility subsidiaries of the Utility Proxy Group range from 39.60% to 61.24% for fiscal year end 2023.

In my opinion, Southwest Gas' proposed capital structure consisting of 50.00% long-term debt and 50.00% common equity is appropriate for ratemaking purposes. It is appropriate because it is generally consistent with the capital structure ratios (based on total permanent capital) maintained by the Utility Proxy Group on whose market data I base my recommended common equity cost rate. The capital structure as requested by Southwest Gas will continue to support the long-term financial health of the Company.

VI. COMMON EQUITY COST RATE

Q. 23 Is it important that cost of common equity models be market-based?

A. 23 Yes. As discussed previously, regulated public utilities, like Southwest Gas must compete for equity in capital markets along with all other companies of comparable risk, which includes non-utilities. The cost of common equity is thus determined

[11] *See* pages 2-7 of Exhibit No.___(DWD-3).

based on equity market expectations for the returns of those companies. If an individual investor is choosing to invest their capital among companies of comparable risk, they will choose a company providing a higher return over a company providing a lower return.

Q. 24 Are your cost of common equity models market-based?

A. 24 Yes. The DCF model uses market prices in developing the model's dividend yield component. The RPM uses bond ratings and expected bond yields that reflect the market's assessment of bond/credit risk. In addition, betas (β), which reflect the market/systematic risk component of equity risk premium, are derived from regression analyses of market prices. The Predictive Risk Premium Model (PRPM) uses monthly market returns in addition to expectations of the risk-free rate. The CAPM is market-based for many of the same reasons that the RPM is market-based (i.e., the use of expected bond yields and betas). Selection criteria for comparable risk non-price regulated companies are based on regression analyses of market prices and reflect the market's assessment of total risk.

Q. 25 What analytical approaches did you use to determine Southwest Gas' ROE?

A. 25 As discussed earlier, I have relied on the DCF model, the RPM, and the CAPM, which I apply to the Utility Proxy Group described above. I also applied these same models to a Non-Price Regulated Proxy Group described later in this section.

I rely on these models because reasonable investors use a variety of tools and do not rely exclusively on a single source of information or single model. Moreover, the models on which I rely, focus on different aspects of return requirements and provide different insights to investors' views of risk and return. The DCF model, for example, estimates the investor-required return assuming a constant expected dividend yield and growth rate in perpetuity, while Risk

Premium-based methods (i.e., the RPM and CAPM approaches) provide the ability to reflect investors' views of risk, future market returns, and the relationship between interest rates and the cost of common equity. Just as the use of market data for the Utility Proxy Group adds the reliability necessary to inform expert judgment in arriving at a recommended common equity cost rate, the use of multiple generally accepted common equity cost rate models also adds reliability and accuracy when arriving at a recommended common equity cost rate.

A. Discounted Cash Flow Model

Q. 26 What is the theoretical basis of the DCF model?

A. 26 The theory underlying the DCF model is that the present value of an expected future stream of net cash flows during the investment holding period can be determined by discounting those cash flows at the cost of capital, or the investors' capitalization rate. DCF theory indicates that an investor buys a stock for an expected total return rate, which is derived from the cash flows received from dividends and market price appreciation. Mathematically, the dividend yield on market price plus a growth rate equals the capitalization rate; i.e., the total common equity return rate expected by investors.

$K_e = (D_0\ (1+g))/P + g$

where:

K_e = the required Return on Common Equity;

D_0 = the annualized Dividend Per Share;

P = the current stock price; and

g = the growth rate.

Q. 27 Which version of the DCF model did you use?

A. 27 I used the single-stage constant growth DCF model in my analyses.

Q. 28 Please describe the dividend yield you used in applying the constant growth DCF model.

A. 28 The unadjusted dividend yields are based on the proxy companies' dividends as of May 31, 2024, divided by the average closing market price for the 60 trading days ended May 31, 2024.[12]

Q. 29 Please explain your adjustment to the dividend yield.

A. 29 Because dividends are paid periodically (e.g., quarterly), as opposed to continuously (daily), an adjustment must be made to the dividend yield. This is often referred to as the discrete, or the Gordon Periodic, version of the DCF model.

DCF theory calls for using the full growth rate, or D_1, in calculating the model's dividend yield component. Since the companies in the Utility Proxy Group increase their quarterly dividends at various times during the year, a reasonable assumption is to reflect one-half the annual dividend growth rate in the dividend yield component, or $D_{1/2}$. Because the dividend should be representative of the next 12-month period, this adjustment is a conservative approach that does not overstate the dividend yield. Therefore, the actual average dividend yields in Column 1, page 1 of Exhibit No.___(DWD-3) have been adjusted upward to reflect one-half the average projected growth rate shown in Column 6.

[12] *See,* Column 1, page 1 of Exhibit No.___(DWD-3).

Q. 30 Please explain the basis for the growth rates you apply to the Utility Proxy Group in your constant growth DCF model.

A. 30 Investors are likely to rely on widely available financial information services, such as *Value Line*, Zacks, Yahoo! Finance, and S&P Capital IQ. Investors realize that analysts have significant insight into the dynamics of the industries and individual companies they analyze, as well as companies' abilities to effectively manage the effects of changing laws and regulations, and ever-changing economic and market conditions. For these reasons, I used analysts' five-year forecasts of EPS growth in my DCF analysis.

Over the long run, there can be no growth in DPS without growth in EPS. Security analysts' earnings expectations have a more significant influence on market prices than dividend expectations. Thus, using projected earnings growth rates in a DCF analysis provides a better match between investors' market price appreciation expectations and the growth rate component of the DCF.

Q. 31 Please summarize the constant growth DCF model results.

A. 31 As shown on page 1 of Exhibit No.___(DWD-3), for the Utility Proxy Group, the mean result of applying the single-stage DCF model is 10.02%, the median result is 9.95%, and the average of the two is 9.99%. In arriving at a conclusion for the constant growth DCF-indicated common equity cost rate for the Utility Proxy Group, I relied on an average of the mean and the median results of the DCF.

B. The Risk Premium Model

Q. 32 Please describe the theoretical basis of the RPM.

A. 32 The RPM is based on the fundamental financial principle of risk and return; namely, that investors require greater returns for bearing greater risk. The RPM recognizes that common equity capital has greater investment risk than debt capital, as common equity shareholders are behind debt holders in any claim on a company's assets and earnings. As a result, investors require higher returns from common stocks than from bonds to compensate them for bearing the additional risk.

While it is possible to directly observe bond returns and yields, investors' required common equity returns cannot be directly determined or observed. According to RPM theory, one can estimate a common equity risk premium over bonds (either historically or prospectively) and use that premium to derive a cost rate of common equity. The cost of common equity equals the expected cost rate for long-term debt capital, plus a risk premium over that cost rate, to compensate common shareholders for the added risk of being unsecured and last-in-line for any claim on the corporation's assets and earnings upon liquidation.

Q. 33 Please explain the total market approach RPM.

A. 33 The total market approach RPM adds a prospective public utility bond yield to an average of: (1) an equity risk premium that is derived from a beta-adjusted total market equity risk premium; (2) an equity risk premium based on the S&P Utilities Index; and (3) an equity risk premium based on authorized ROEs for natural gas distribution utilities.

Q. 34 Please explain the basis of the expected bond yield of 5.65% applicable to the Utility Proxy Group.

A. 34 The first step in the total market approach RPM analysis is to determine the expected bond yield. Because both ratemaking and the cost of capital, including the common equity cost rate, are prospective in nature, a prospective yield on similarly rated long-term debt is essential. I relied on a consensus forecast of about 50 economists of the expected yield on Aaa-rated corporate bonds for the six calendar quarters ending with the third calendar quarter of 2025, and *Blue Chip's* long-term projections for 2026 to 2030 and 2031 to 2035. As shown on line 1, page 1 of Exhibit No.___(DWD-4), the average expected yield on Moody's Aaa-rated corporate bonds is 5.14%. In order to adjust the expected Aaa-rated corporate bond yield to an equivalent A2-rated public utility bond yield, I made an upward adjustment of 0.51%, which represents a recent spread between Aaa-rated corporate bonds and A2-rated public utility bonds.[13] Adding that recent 0.51% spread to the expected Aaa-rated corporate bond yield of 5.14% results in an expected A2-rated public utility bond yield of 5.65%.

I then reviewed the average credit rating for the Utility Proxy Group from Moody's to determine if an adjustment to the estimated A2-rated public utility bond was necessary. Since the Utility Proxy Group's average Moody's long-term issuer rating is A2, no other adjustment is needed to make the A2 prospective bond yield applicable to the A2-rated public utility bond. The results are a 5.65% expected bond yield applicable to the Utility Proxy Group.

[13] As shown on line 2 and explained in note 2, page 1 of Exhibit No.___(DWD-4).

Table 5: Summary of the Calculation of the Utility Proxy Group Projected Bond Yield[14]

Prospective Yield on Moody's Aaa-Rated Corporate Bonds (*Blue Chip*)	5.14%
Adjustment to Reflect Yield Spread Between Moody's Aaa-Rated Corporate Bonds and Moody's A2-Rated Utility Bonds	0.51%
Prospective Bond Yield Applicable to the Utility Proxy Group	5.65%

To develop the indicated ROE using the total market approach RPM, this prospective bond yield is then added to the average of the three different equity risk premiums described below:

Q. 35 Please explain how the beta-derived equity risk premium is determined.

A. 35 The components of the beta-derived risk premium model are: (1) an expected market equity risk premium over corporate bonds, and (2) beta. The derivation of the beta-derived equity risk premium that I applied to the Utility Proxy Group is shown on lines 1 through 8, on page 6 of Exhibit No.___(DWD-4). The total beta-derived equity risk premium I applied is based on an average of three historical market data-based equity risk premiums, a *Value Line*-based equity risk premium, and combined *Value Line,* Bloomberg, and S&P Capital IQ-based equity risk premium. Each of these is described below.

Q. 36 How did you derive a market equity risk premium based on long-term historical data?

A. 36 To derive an historical market equity risk premium, I used the most recent holding period returns for the large company common stocks less the average historical

[14] As shown on page 1 of Exhibit No.___(DWD-4).

yield on Moody's Aaa/Aa-rated corporate bonds for the period 1928 to 2023.[15] The use of holding period returns over a very long period of time is appropriate because it is consistent with the long-term investment horizon presumed by investing in a going concern, i.e., a company expected to operate in perpetuity.

Kroll's Stocks, Bonds, Bills, and Inflation (SBBI) Yearbook 2023 (SBBI - 2023) long-term arithmetic mean monthly total return rate on large company common stocks was 11.91% and the long-term arithmetic mean monthly yield on Moody's Aaa/Aa-rated corporate bonds was 5.95% from 1928 to 2023.[16] As shown on line 1, page 6 of Exhibit No.___(DWD-4), subtracting the mean monthly bond yield from the total return on large company stocks results in a long-term historical equity risk premium of 5.96%.

I used the arithmetic mean monthly total return rates for the large company stocks and yields (income returns) for the Moody's Aaa/Aa corporate bonds, because they are appropriate for the purpose of estimating the cost of capital as noted in SBBI - 2023.[17] The use of the arithmetic mean return rates and yields is appropriate because historical total returns and equity risk premiums provide insight into the variance and standard deviation of returns needed by investors in estimating future risk when making a current investment. If investors relied on the geometric mean of historical equity risk premiums, they would have no insight into the potential variance of future returns, because the geometric mean relates the change over many periods to a constant rate of change, thereby obviating the year-to-year fluctuations, or variance, which is critical to risk analysis.

[15] Sources: SBBI-2023 Appendix A Tables: Morningstar Stocks, Bonds, Bills, & Inflation 1926-2022 and Bloomberg Professional.
[16] As explained in note 1, page 6 of Exhibit No.___(DWD-4).
[17] *See,* SBBI - 2023, at 193-194.

Q. 37 Please explain the derivation of the regression-based market equity risk premium.

A. 37 To derive the regression-based market equity risk premium of 6.92% shown on line 2, page 6 of Exhibit No.___(DWD-4), I used the same monthly annualized total returns on large company common stocks relative to the monthly annualized yields on Moody's Aaa/Aa-rated corporate bonds as mentioned above. The relationship between interest rates and the market equity risk premium was modeled using the observed monthly market equity risk premium as the dependent variable, and the monthly yield on Moody's Aaa/Aa-rated corporate bonds as the independent variable. I used a linear Ordinary Least Squares (OLS) regression, in which the market equity risk premium is expressed as a function of the Moody's Aaa/Aa-rated corporate bonds yield:

$$RP = \alpha + \beta\ (R_{Aaa/Aa})$$

where:

RP = the market equity risk premium;

α = the regression intercept coefficient;

β = the regression slope coefficient; and

$R_{Aaa/Aa}$ = the Moody's Aaa/Aa rated corporate bond yield.

Using the equation generated by the regression, an expected equity risk premium of 6.92% is calculated using the average forecast of Aaa corporate bond yield of 5.14%, as discussed above.

Q. 38 Please explain the derivation of the PRPM equity risk premium.

A. 38 The PRPM, published in the *Journal of Regulatory Economics,*[18] was developed from the work of Robert F. Engle, who shared the Nobel Prize in Economics in 2003 "for methods of analyzing economic time series with time-varying volatility ("ARCH")."[19] Engle found that volatility changes over time and is related from one period to the next, especially in financial markets. Engle discovered that volatility of prices and returns clusters over time and is therefore highly predictable and can be used to predict future levels of risk and risk premiums.

The PRPM estimates the risk-return relationship directly, as the predicted equity risk premium is generated by predicting volatility or risk. The PRPM is not based on an estimate of investor behavior, but rather on an evaluation of the results of that behavior (i.e., the variance of historical equity risk premiums).

The inputs to the model are the historical monthly returns on large company common stocks minus the monthly yields on Moody's Aaa/Aa-rated corporate bonds during the period from January 1928 through May 2024.[20] Using a generalized form of ARCH, known as GARCH, I calculated each Utility Proxy Group companies projected equity risk premium using Eviews© statistical software. When the GARCH model is applied to the historical return data, it produces a predicted GARCH variance series and a GARCH coefficient. Multiplying the predicted monthly variance by the GARCH coefficient and then annualizing it[21]

[18] Autoregressive conditional heteroscedasticity. See "A New Approach for Estimating the Equity Risk Premium for Public Utilities", Pauline M. Ahern, Frank J. Hanley and Richard A. Michelfelder, Ph.D. *The Journal of Regulatory Economics* (December 2011), 40:261-278.
[19] www.nobelprize.org.
[20] Data from January 1928 to December 2022 is from SBBI - 2023. Data from January 2023 to May 2024 is from Bloomberg.
[21] Annualized Return = (1 + Monthly Return) ^12 - 1.

produces the predicted annual equity risk premium. The resulting PRPM predicted a market equity risk premium of 8.46%.[22]

Q. 39 Please explain the derivation of a projected equity risk premium based on *Value Line* data for your RPM analysis.

A. 39 As noted previously, because both ratemaking and the cost of capital are prospective, a prospective market equity risk premium is needed. The derivation of the forecasted or prospective market equity risk premium can be found in note 4, page 6 of Exhibit No.___(DWD-4). Consistent with my calculation of the dividend yield component in my DCF analysis, this prospective market equity risk premium is derived from an average of the three- to five-year median market price appreciation potential by *Value Line* for the 13 weeks ended May 31, 2024, plus an average of the median estimated dividend yield for the common stocks of the 1,700 firms covered in *Value Line* (Standard Edition).[23]

The average median expected price appreciation is 46%, which translates to a 9.92% annual appreciation, and when added to the average of *Value Line's* median expected dividend yields of 2.13%, equates to a forecasted annual total return rate on the market of 12.05%. The forecasted Moody's Aaa-rated corporate bond yield of 5.14% is deducted from the total market return of 12.05%, resulting in an equity risk premium of 6.91%, as shown on line 4, page 6 of Exhibit No.___(DWD-4).

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[22] Shown on line 3, page 6 of Exhibit No.___(DWD-4).
[23] As explained in detail in note 1, page 2 of Exhibit No.___(DWD-5).

Q. 40 Please explain the derivation of an equity risk premium based on the S&P 500 companies.

A. 40 Using data from *Value Line*, Bloomberg, and S&P Capital IQ, I calculated an expected total return on the S&P 500 using expected dividend yields and long-term growth estimates as a proxy for capital appreciation. The expected total return for the S&P 500 is 15.19%. Subtracting the prospective yield on Moody's Aaa-rated corporate bonds of 5.14% results in a 10.05% projected equity risk premium as shown on page 6, line 5 of Exhibit No.___(DWD-4).

Q. 41 What is your conclusion of a beta-derived equity risk premium for use in your RPM analysis?

A. 41 I gave equal weight to the five equity risk premiums in arriving at my conclusion of 7.66%.[24]

Table 6: Summary of the Calculation of the Equity Risk Premium Using Total Market Returns[25]

Historical Spread Between Total Returns of Large Stocks and Aaa and Aa-Rated Corporate Bond Yields (1928 – 2023)	5.96%
Regression Analysis on Historical Data	6.92%
PRPM Analysis on Historical Data	8.46%
Prospective Equity Risk Premium using Total Market Returns from *Value Line* Summary & Index less Projected Aaa Corporate Bond Yields	6.91%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns for the S&P 500 less Projected Aaa Corporate Bond Yields	10.05%
Average	7.66%

[24] *See*, line 6 on page 6 of Exhibit No.___(DWD-4).
[25] As shown on page 6 of Exhibit No.___(DWD-4).

After calculating the average market equity risk premium of 7.66%, I adjusted it by beta to account for the risk of the Utility Proxy Group. As discussed below, beta is a meaningful measure of prospective relative risk to the market as a whole, and is a logical way to allocate a company's, or proxy group's, share of the market's total equity risk premium relative to corporate bond yields. As shown on page 1 of Exhibit No.___(DWD-5), the average of the mean and median beta for the Utility Proxy Group is 0.81. Multiplying the 0.81 average beta by the market equity risk premium of 7.66% results in a beta-adjusted equity risk premium for the Utility Proxy Group of 6.20%.

Q. 42 How did you derive the equity risk premium based on the S&P Utility Index and Moody's A2-rated public utility bonds?

A. 42 I estimated three equity risk premiums based on S&P Utility Index holding period returns, and one equity risk premium based on the expected returns of the S&P Utilities Index, using data from *Value Line,* Bloomberg, and S&P Capital IQ. Turning first to the S&P Utility Index holding period returns, I derived a long-term monthly arithmetic mean equity risk premium between the S&P Utility Index total returns of 10.54% and monthly A-rated public utility bond yields of 6.43% from 1928 to 2023, to arrive at an equity risk premium of 4.02%.[26] I then used the same historical data to derive an equity risk premium of 4.81% based on a regression of the monthly equity risk premiums. The final S&P Utility Index holding period equity risk premium involved applying the PRPM using the historical monthly equity risk premiums from January 1928 to May 2024 to arrive at a PRPM-derived equity risk premium of 4.39% for the S&P Utility Index.

[26] As shown on line 1, page 9 of Exhibit No.___(DWD-4).

I then derived an expected total return on the S&P Utilities Index of 10.46% using data from *Value Line,* Bloomberg, and S&P Capital IQ and subtracted the prospective Moody's A2-rated public utility bond yield of 5.65%[27] which resulted in an equity risk premium of 4.81%. As with the market equity risk premiums, I averaged each risk premium to arrive at my utility-specific equity risk premium of 4.51%.

Table 7: Summary of the Calculation of the Equity Risk Premium Using S&P Utility Index Holding Returns[28]

Historical Spread Between Total Returns of the S&P Utilities Index and A2-Rated Utility Bond Yields (1928 – 2023)	4.02%
Regression Analysis on Historical Data	4.81%
PRPM Analysis on Historical Data	4.39%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns for the S&P Utilities Index less Projected A2 Utility Bond Yields	4.81%
Average	4.51%

Q. 43 How did you derive an equity risk premium of 4.79% based on authorized ROEs for natural gas distribution utilities?

A. 43 The equity risk premium of 4.79% shown on line 3, page 5 of Exhibit No.___(DWD-4) is the result of a regression analysis based on regulatory awarded ROEs related to the yields on Moody's A2-rated public utility bonds. That analysis is shown on page 10 of Exhibit No.___(DWD-4), which contains the graphical results of a regression analysis of 834 rate cases for natural gas distribution utilities that were fully litigated during the period from January 1, 1980 through May 31, 2024. It

[27] Derived on line 3, page 1 of Exhibit No.___(DWD-4).
[28] As shown on page 9 of Exhibit No.___(DWD-4).

shows the implicit equity risk premium relative to the yields on A2-rated public utility bonds immediately prior to the issuance of each regulatory decision. It is readily discernible that there is an inverse relationship between the yield on A2-rated public utility bonds and equity risk premiums. In other words, as interest rates decline, the equity risk premium rises and vice versa, a result consistent with financial literature on the subject.[29] I used the regression results to estimate the equity risk premium applicable to the projected yield on Moody's A2-rated public utility bonds. Given the expected A2-rated utility bond yield of 5.65%, it can be calculated that the indicated equity risk premium applicable to that bond yield is 4.79%, which is shown on line 3, page 5 of Exhibit No.___(DWD-4).

Q. 44 What is your conclusion of an equity risk premium for use in your total market approach RPM analysis?

A. 44 The equity risk premium I applied to the Utility Proxy Group is 5.17%, which is the average of the beta-adjusted equity risk premium for the Utility Proxy Group, the S&P Utilities Index, and the authorized return utility equity risk premiums of 6.20%, 4.51%, and 4.79%, respectively.[30]

Q. 45 What is the indicated RPM common equity cost rate based on the total market approach?

A. 45 As shown on line 5, page 1 of Exhibit No.___(DWD-4), and shown on Table 8, below, I calculated a common equity cost rate of 10.82% for the Utility Proxy Group based on the total market approach RPM.

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[29] *See, e.g.*, Robert S. Harris and Felicia C. Marston, The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts, *Journal of Applied Finance*, Vol. 11, No. 1, 2001, at 11-12; Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, The Risk Premium Approach to Measuring a Utility's Cost of Equity, *Financial Management*, Spring 1985, at 33-45.
[30] As shown on page 5 of Exhibit No.___(DWD-4).

Table 8: Summary of the Total Market Return Risk Premium Model[31]

Prospective Moody's A2-Rated Utility Bond Applicable to the Utility Proxy Group	5.65%
Prospective Equity Risk Premium	5.17%
Indicated Cost of Common Equity	10.82%

C. The Capital Asset Pricing Model

Q. 46 Please explain the theoretical basis of the CAPM.

A. 46 CAPM theory defines risk as the co-variability of a security's returns with the market's returns as measured by beta (β). A beta less than 1.0 indicates lower variability than the market as a whole, while a beta greater than 1.0 indicates greater variability than the market.

The CAPM assumes that all non-market or unsystematic risk can be eliminated through diversification. The risk that cannot be eliminated through diversification is called market, or systematic, risk. In addition, the CAPM presumes that investors only require compensation for systematic risk, which is the result of macroeconomic and other events that affect the returns on all assets. The model is applied by adding a risk-free rate of return to a market risk premium, which is adjusted proportionately to reflect the systematic risk of the individual security relative to the total market as measured by beta. The traditional CAPM model is expressed as:

$$R_s = R_f + \beta\,(R_m - R_f)$$

Where: R_s = Return rate on the common stock;

R_f = Risk-free rate of return;

R_m = Return rate on the market as a whole; and

[31] As shown on page 1 of Exhibit No.___(DWD-4).

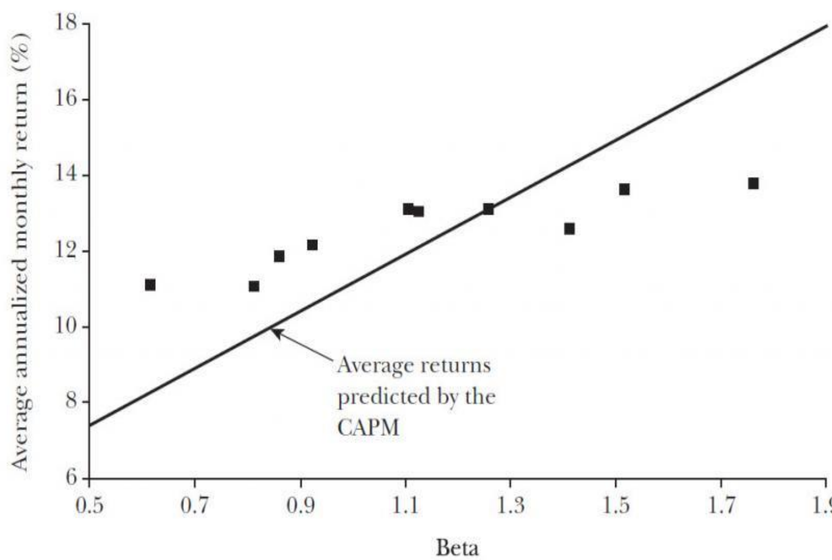
β = Adjusted beta (volatility of the security relative to the market as a whole)

Numerous tests of the CAPM have measured the extent to which security returns and beta are related as predicted by the CAPM, confirming its validity. The empirical CAPM (ECAPM) reflects the reality that while the results of these tests support the notion that beta is related to security returns, the empirical Security Market Line (SML) described by the CAPM formula is not as steeply sloped as the predicted SML.[32]

The ECAPM reflects this empirical reality. Fama and French clearly state regarding Figure 2, below, that "[t]he returns on the low beta portfolios are too high, and the returns on the high beta portfolios are too low."[33]

Figure 2 http://pubs.aeaweb.org/doi/pdfplus/10.1257/0895330042162430

Average Annualized Monthly Return versus Beta for Value Weight Portfolios Formed on Prior Beta, 1928–2003



[32] Morin, at page 223.

[33] Eugene F. Fama and Kenneth R. French, The Capital Asset Pricing Model: Theory and Evidence, *Journal of Economic Perspectives*, Vol. 18, No. 3, Summer 2004 at 33 (Fama & French).

In addition, Morin observes that while the results of these tests support the notion that beta is related to security returns, the empirical SML described by the CAPM formula is not as steeply sloped as the predicted SML. Morin states:

> With few exceptions, the empirical studies agree that … low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted.[34]
>
> * * *
>
> Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:
>
> $$K = RF + x\,(RM - RF) + (1-x)\ \beta(RM - RF)$$
>
> where x is a fraction to be determined empirically. The value of x that best explains the observed relationship [is] Return = 0.0829 + 0.0520 β is between 0.25 and 0.30. If x = 0.25, the equation becomes:
>
> $$K = RF + 0.25(RM - RF) + 0.75\ \beta(RM - RF)$$ [35]

Fama and French provide similar support for the ECAPM when they state:

> The early tests firmly reject the Sharpe-Lintner version of the CAPM. There is a positive relation between beta and average return, but it is too 'flat.'… The regressions consistently find that the intercept is greater than the average risk-free rate… and the coefficient on beta is less than the average excess market return… This is true in the early tests… as well as in more recent cross-section regressions tests, like Fama and French (1992).[36]

Finally, Fama and French further note:

> Confirming earlier evidence, the relation between beta and average return `for the ten portfolios is much flatter than the Sharpe-Linter CAPM predicts. The returns on low beta portfolios are too high, and the returns on the high beta portfolios are too low. For example, the predicted return on the portfolio with the lowest beta is 8.3 percent per year; the actual return as 11.1 percent. The predicted return on the portfolio with the t beta is 16.8 percent per year; the actual is 13.7 percent.[37]

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[34] Morin, at 207.
[35] Morin, at 221.
[36] Fama & French, at 32.
[37] Fama & French, at 33.

Clearly, the justification from Morin, Fama, and French, along with their reviews of other academic research on the CAPM, validate the use of the ECAPM. In view of theory and practical research, I have applied both the traditional CAPM and the ECAPM to the companies in the Utility Proxy Group and averaged the results.

Q. 47 What betas did you use in your CAPM analysis?

A. 47 For betas in my CAPM analysis, I considered two sources: *Value Line* and Bloomberg. While both of those services adjust their calculated (or "raw") beta to reflect their tendency to regress to the market mean of 1.00, *Value Line* calculates beta over a five-year period, while Bloomberg's calculation is based on two years of data.

Q. 48 Please describe your selection of a risk-free rate of return.

A. 48 As shown in Column 5, page 1 of Exhibit No.___(DWD-5), the risk-free rate adopted for both applications of the CAPM is 4.41%. This risk-free rate is based on the average of the *Blue Chip* consensus forecast of the expected yields on 30-year U.S. Treasury bonds for the six quarters ending with the third calendar quarter of 2025, and long-term projections for the years 2026 to 2030 and 2031 to 2035.

Q. 49 Why is the yield on long-term U.S. Treasury bonds appropriate for use as the risk-free rate?

A. 49 The yield on long-term U.S. Treasury bonds is almost risk-free and its term is consistent with the long-term cost of capital to public utilities measured by the yields on Moody's A2-rated public utility bonds; the long-term investment horizon inherent in utilities' common stocks; and the long-term life of the jurisdictional rate base to which the allowed fair rate of return (i.e., cost of capital) will be applied. In contrast, short-term U.S. Treasury yields are more volatile and largely a function of Federal Reserve monetary policy.

Q. 50 Please explain the estimation of the expected risk premium for the market used in your CAPM analyses.

A. 50 The basis of the market risk premium is explained in detail in note 1 on Exhibit No.___(DWD-5). As discussed above, the market risk premium is derived from an average of three historical data-based market risk premiums, one *Value Line* data-based market risk premiums, and one Bloomberg, *Value Line*, and S&P Capital IQ data-based market risk premium.

The long-term income return on U.S. Government securities of 4.99% was deducted from the monthly historical total market return of 12.16%, which results in a historical market equity risk premium of 7.17%.[38] I applied a linear OLS regression to the monthly annualized historical returns on the S&P 500 relative to historical yields on long-term U.S. Government securities. That regression analysis yielded a market equity risk premium of 7.93%. The PRPM market equity risk premium is 9.44% and is derived using the PRPM relative to the yields on long-term U.S. Treasury securities from January 1926 through May 2024.

The *Value Line*-derived forecasted total market equity risk premium is derived by deducting the forecasted risk-free rate of 4.41%, discussed above, from the *Value Line* projected total annual market return of 12.05%, resulting in a forecasted total market equity risk premium of 7.64%.

The S&P 500 projected market equity risk premium using *Value Line,* Bloomberg, and S&P Capital IQ data is derived by subtracting the projected risk-

[38] SBBI - 2023, at Appendix A-1 (1) through A-1 (3) and Appendix A-7 (19) through A-7 (21); Bloomberg Professional.

free rate of 4.41% from the projected total return of the S&P 500 of 15.19%. The resulting market equity risk premium is 10.78%.

These five measures, when averaged, result in an average total market equity risk premium of 8.59%.

Table 9: Summary of the Calculation of the Market Risk Premium for Use in the CAPM[39]

Historical Spread Between Total Returns of Large Stocks and Long-Term Government Bond Yields (1926 – 2023)	7.17%
Regression Analysis on Historical Data	7.93%
PRPM Analysis on Historical Data	9.44%
Prospective Equity Risk Premium using Total Market Returns from *Value Line* Summary & Index less Projected 30-Year Treasury Bond Yields	7.64%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns for the S&P 500 less Projected 30-Year Treasury Bond Yields	10.78%
Average	8.59%

Q. 51 What are the results of your application of the traditional and empirical CAPM to the Utility Proxy Group?

A. 51 As shown on page 1 of Exhibit No.___(DWD-5), the mean result of my CAPM/ECAPM analyses is 11.55%, the median is 11.58%, and the average of the two is 11.57%. Consistent with my reliance on the average of mean and median DCF results discussed above, the indicated common equity cost rate using the CAPM/ECAPM is 11.57%.

[39] As shown on page 2 of Exhibit No.___(DWD-5).

D. Common Equity Cost Rates for a Proxy Group of Domestic, Non-Price Regulated Companies based on the DCF, RPM, and CAPM

Q. 52 Why do you also consider a proxy group of domestic, non-price regulated companies?

A. 52 My interpretation of the *Hope* and *Bluefield* cases is that the cases do not specify that the comparable risk companies had to be utilities. Since the purpose of rate regulation is to be a substitute for marketplace competition, non-price regulated firms operating in the competitive marketplace make an excellent proxy if they are comparable in total risk to the Utility Proxy Group being used to estimate the cost of common equity. The selection of such domestic, non-price regulated competitive firms theoretically and empirically results in a proxy group which is comparable in total risk to the Utility Proxy Group, since all of these companies compete for capital in the exact same markets.

Q. 53 How did you select non-price regulated companies that are comparable in total risk to the Utility Proxy Group?

A. 53 In order to select a proxy group of domestic, non-price regulated companies similar in total risk to the Utility Proxy Group, I relied on betas and related statistics derived from *Value Line* regression analyses of weekly market prices over the most recent 260 weeks (i.e., five years). These selection criteria resulted in a proxy group of 52 domestic, non-price regulated firms comparable in total risk to the Utility Proxy Group. Total risk is the sum of non-diversifiable market risk and diversifiable company-specific risks. The criteria used in selecting the domestic, non-price regulated firms was:

(i) They must be covered by *Value Line* (Standard Edition);

(ii) They must be domestic, non-price regulated companies, i.e., not utilities;

(iii) Their unadjusted betas must lie within plus or minus two standard deviations of the average unadjusted beta of the Utility Proxy Group; and

(iv) The residual standard errors of the *Value Line* regressions which gave rise to the unadjusted betas must lie within plus or minus two standard deviations of the average residual standard error of the Utility Proxy Group.

Betas measure market, or systematic, risk which is not diversifiable. The residual standard errors of the regressions measure each firm's company-specific, diversifiable risk. Companies that have similar betas <u>and</u> similar residual standard errors resulting from the same regression analyses have similar total investment risk.

Q. 54 Have you prepared an Exhibit which shows the data from which you selected the 52 domestic, non-price regulated companies that are comparable in total risk to the Utility Proxy Group?

A. 54 Yes, the basis of my selection and both proxy groups' regression statistics are shown in Exhibit No.___(DWD-6).

Q. 55 Did you calculate common equity cost rates using the DCF model, RPM, and CAPM for the Non-Price Regulated Proxy Group?

A. 55 Yes. Because the DCF model, RPM, and CAPM have been applied in an identical manner as described above, I will not repeat the details of the rationale and application of each model. One exception is in the application of the RPM, where I did not use public utility-specific equity risk premiums, nor did I apply the PRPM to the individual non-price regulated companies.

Page 2 of Exhibit No.___(DWD-7) derives the constant growth DCF model common equity cost rate. As shown, the indicated common equity cost rate, using the constant growth DCF for the Non-Price Regulated Proxy Group comparable in total risk to the Utility Proxy Group, is 11.08%.

Pages 3 through 5 of Exhibit No.___(DWD-7) contain the data and calculations that support the 12.53% RPM common equity cost rate. As shown on line 1, page 3 of Exhibit No.___(DWD-7), the consensus prospective yield on Moody's Baa2-rated corporate bonds for the six quarters ending in the third quarter of 2025, and for the years 2026 to 2030 and 2031 to 2035, is 6.01%.[40] Since the Non-Price Regulated Proxy Group has an average Moody's long-term issuer rating of A3, a downward adjustment of 0.22%[41] to the projected Baa2 corporate bond yield is necessary to reflect the difference in ratings, which results in a projected A3 corporate bond yield of 5.79%.

When the beta-adjusted risk premium of 6.74%[42] relative to the Non-Price Regulated Proxy Group is added to the prospective A3-rated corporate bond yield of 5.79%, the indicated RPM common equity cost rate is 12.53%.

Page 6 of Exhibit No.___(DWD-7) contains the inputs and calculations that support my indicated CAPM/ECAPM common equity cost rate of 12.11%.

Q. 56 What is the cost rate of common equity based on the Non-Price Regulated Proxy Group comparable in total risk to the Utility Proxy Group?

A. 56 As shown on page 1 of Exhibit No.___(DWD-7), the results of the common equity models applied to the Non-Price Regulated Proxy Group – which group is comparable in total risk to the Utility Proxy Group – are as follows: 11.08% (DCF), 12.53% (RPM), and 12.11% (CAPM). The average of the mean and median of

[40] Blue Chip Financial Forecasts, May 31, 2024, at pages 2 and 14.
[41] As demonstrated in line 2 and described in note 2 of page 3 of Exhibit No.___(DWD-7).
[42] Derived on page 5 of Exhibit No.___(DWD-7).

these models is 12.01%, which I used as the indicated common equity cost rates for the Non-Price Regulated Proxy Group.

VII. RANGE OF COMMON EQUITY COST RATES BEFORE ADJUSTMENT

Q. 57 What is the range of indicated common equity cost rates produced by your ROE models?

A. 57 The range of indicated ROEs is from 9.99% (DCF model) to 12.01% (Non-Price Regulated Market Models), which is applicable to the Utility Proxy Group. I used multiple cost of common equity models as primary tools in arriving at my recommended common equity cost rate, because no single model is so inherently precise that it can be relied on to the exclusion of other theoretically sound models. Using multiple models adds reliability to the estimated common equity cost rate, with the prudence of using multiple cost of common equity models supported in both the financial literature and regulatory precedent.

As will be discussed below, Southwest Gas has greater risk than the Utility Proxy Group. Because of this, the indicated range of model results based on the Utility Proxy Group must be adjusted to reflect Southwest Gas' greater relative risk.

VIII. ADJUSTMENTS TO THE COMMON EQUITY COST RATE

A. Business Risk Adjustment

Q. 58 Does a company's size relative to the Utility Proxy Group companies increase its business risk?

A. 58 Yes. A smaller size utility company relative to the Utility Proxy Group companies indicates greater relative business risk for Southwest Gas because, all else being equal, size has a material bearing on risk. Size affects business risk because smaller companies generally are less able to cope with significant events that affect sales, revenues, and earnings. For example, smaller companies face more risk exposure to business cycles and economic conditions, both nationally and locally. Additionally, the loss of revenues from a few larger customers would have a greater effect on a smaller company than on a bigger company with a larger, more diverse, customer base.

As further evidence that smaller firms are riskier, investors generally demand greater returns from smaller firms to compensate for less marketability and liquidity of their securities. Kroll's Cost of Capital Navigator: U.S. Cost of Capital Module ("Kroll") discusses the nature of the small-size phenomenon, providing an indication of the magnitude of the size premium based on several measures of size. In discussing "Size as a Predictor of Equity Premiums," Kroll states:

> The size effect is based on the empirical observation that companies of smaller size are associated with greater risk and, therefore, have greater cost of capital [sic]. The "size" of a company is one of the most important risk elements to consider when developing cost of equity capital estimates for use in valuing a business simply because size has been shown to be a *predictor* of equity returns. In other words, there is a significant (negative) relationship between size and historical equity returns - as size *decreases*, returns tend to *increase*, and vice versa. (footnote omitted) (emphasis in original)[43]

Furthermore, in "The Capital Asset Pricing Model: Theory and Evidence," Fama and French note size is indeed a risk factor which must be reflected when estimating the cost of common equity. On page 38, they note:

> …the higher average returns on small stocks and high book-to-market stocks reflect unidentified state variables that produce undiversifiable risks (covariances) in returns not captured in the

[43] Kroll, Cost of Capital Navigator: U.S. Cost of Capital Module, Size as a Predictor of Equity Returns, at 1.

market return and are priced separately from market betas.[44]

Based on this evidence, Fama and French proposed their three-factor model which includes a size variable in recognition of the effect size has on the cost of common equity.

Also, it is a basic financial principle that the use of funds invested, and not the source of funds, is what gives rise to the risk of any investment.[45] Eugene Brigham, a well-known authority, states:

> A number of researchers have observed that portfolios of small-firms (sic) have earned consistently higher average returns than those of large-firm stocks; this is called the "small-firm effect." On the surface, it would seem to be advantageous to the small firms to provide average returns in a stock market that are higher than those of larger firms. In reality, it is bad news for the small firm; **what the small-firm effect means is that the capital market demands higher returns on stocks of small firms than on otherwise similar stocks of the large firms.** (emphasis added).[46]

Consistent with the financial principle of risk and return discussed above, increased relative risk due to small size must be considered in the allowed rate of return on common equity.

Q. 59 Is there a way to quantify a relative risk adjustment due to Southwest Gas' small size relative to the Utility Proxy Group?

A. 59 Yes. Southwest Gas has greater risk than the average utility in the Utility Proxy Group because of Southwest Gas' smaller size compared to the Utility Proxy Group companies, as measured by an estimated market capitalization for Southwest Gas (whose common stock is not publicly traded).

[44] Fama & French, at 25-43.
[45] Richard A. Brealey and Steward C. Myers, Principles of Corporate Finance (McGraw-Hill Book Company, 1996), at 204-205, 229.
[46] Eugene F. Brigham, Fundamentals of Financial Management, Fifth Edition (The Dryden Press, 1989), at 623.

Table 10: Size as Measured by Market Capitalization for Southwest Gas' Natural Gas Distribution Operations and the Utility Proxy Group

	Market Capitalization* ($ Millions)	Times Greater than the Company
Southwest Gas	$512.073	
Utility Proxy Group	$3,862.973	7.5x
*From page 1 of Exhibit No.___(DWD-10).		

Southwest Gas' estimated market capitalization was $512 million as of May 31, 2024,[47] compared with the median market capitalization of the Utility Proxy Group of $3,863 million as of May 31, 2025. The Utility Proxy Group's market capitalization is 7.5 times the size of Southwest Gas' estimated market capitalization.

As a result, it is necessary to upwardly adjust the indicated range of common equity cost rates to reflect Southwest Gas' greater risk due to its smaller relative size. The determination is based on the size premiums for portfolios of New York Stock Exchange, American Stock Exchange, and NASDAQ listed companies ranked by deciles for the 1926 to 2023 period. The median size premium for the Utility Proxy Group with a market capitalization of $3,863 million falls in the 5th decile, while Southwest Gas' estimated market capitalization of $512 million places it in the 9th decile. The size premium spread between the 5th decile and the 9th decile is 1.04%. Even though a 1.04% upward size adjustment is indicated, I applied a size premium of 0.20% to Southwest Gas' indicated range of common equity cost rates.

[47] $607.450= $720,214,590 (rate base (Southern California + Northern California + South Lake Tahoe) * requested equity ratio) * 142.2% (market-to-book ratio of the Utility Proxy Group) as demonstrated on page 2 of Exhibit No.___(DWD-8).

B. Credit Risk Adjustment

Q. 60 Please discuss your proposed credit risk adjustment.

A. 60 Southwest Gas' long-term issuer ratings are Baa1 and BBB from Moody's and S&P, respectively, which are riskier and equal to the average long-term issuer ratings for the Utility Proxy Group of A2 and A-, respectively.[48]

An indication of the magnitude of the necessary upward adjustment to reflect the greater credit risk inherent in Southwest Gas' Baa1 bond rating relative to the Utility Proxy Group average rating of A2 is two-thirds of a recent three-month average spread between Moody's A2 and Baa2-rated public utility bond yields of 0.23%, shown on page 2 of Exhibit No.___(DWD-4), or 0.15%.[49]

C. Flotation Costs

Q. 61 What are flotation costs?

A. 61 Flotation costs are those costs associated with the sale of new issuances of common stock. They include market pressure and the mandatory unavoidable costs of issuance (e.g., underwriting fees and out-of-pocket costs for printing, legal, registration, etc.). For every dollar raised through debt or equity offerings, the Company receives less than one full dollar in financing.

Q. 62 Why is it important to recognize flotation costs in the allowed common equity cost rate?

A. 62 It is important because there is no other mechanism in the ratemaking paradigm through which such costs can be recognized and recovered. Because these costs are real, necessary, and legitimate, recovery of these costs should be permitted. As noted by Morin:

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[48] Source: S&P Global Market Intelligence.
[49] 0.15% = 0.23% * (2/3); differences due to rounding.

> The costs of issuing these securities are just as real as operating and maintenance expenses or costs incurred to build utility plants, and fair regulatory treatment must permit the recovery of these costs….
>
> The simple fact of the matter is that common equity capital is not free….[Flotation costs] must be recovered through a rate of return adjustment.[50]

Q. 63 Should flotation costs be recognized only if there was an issuance during the test year or there is an imminent post-test year issuance of additional common stock?

A. 63 No. As noted above, there is no mechanism to recapture such costs in the ratemaking paradigm other than an adjustment to the allowed common equity cost rate. Flotation costs are charged to capital accounts and are not expensed on a utility's income statement. As such, flotation costs are analogous to capital investments, albeit negative, reflected on the balance sheet. Recovery of capital investments relates to the expected useful lives of the investment. Since common equity has a very long and indefinite life (assumed to be infinity in the standard regulatory DCF model), flotation costs should be recovered through an adjustment to common equity cost rate, even when there has not been an issuance during the test year, or in the absence of an expected imminent issuance of additional shares of common stock.

Historical flotation costs are a permanent loss of investment to the utility and should be accounted for. When any company, including a utility, issues common stock, flotation costs are incurred for legal, accounting, printing fees and the like. For each dollar of issuing market price, a small percentage is expensed and is permanently unavailable for investment in utility rate base. Since these

[50] Morin, at 329.

expenses are charged to capital accounts and not expensed on the income statement, the only way to restore the full value of that dollar of issuing price with an assumed investor required return of 10% is for the net investment, $0.95, to earn more than 10% to net back to the investor a fair return on that dollar. In other words, if a company issues stock at $1.00 with 5% in flotation costs, it will net $0.95 in investment. Assuming the investor in that stock requires a 10% return on his or her invested $1.00 (i.e., a return of $0.10), the company needs to earn approximately 10.5% on its invested $0.95 to receive a $0.10 return.

Q. 64 Do the common equity cost rate models you have used already reflect investors' anticipation of flotation costs?

A. 64 No. All of these models assume no transaction costs. The literature is quite clear that these costs are not reflected in the market prices paid for common stocks. For example, Brigham and Daves confirm this and provide the methodology utilized to calculate the flotation adjustment.[51] In addition, Morin confirms the need for such an adjustment even when no new equity issuance is imminent.[52] Consequently, it is proper to include a flotation cost adjustment when using cost of common equity models to estimate the common equity cost rate.

Q. 65 How did you calculate the flotation cost allowance?

A. 65 I modified the DCF calculation to provide a dividend yield that would reimburse investors for issuance costs in accordance with the method cited in literature by Brigham and Daves, as well as by Morin. The flotation cost adjustment recognizes the actual costs of issuing equity that were incurred by Southwest Gas since 2000.

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[51] Eugene F. Brigham and Phillip R. Daves, Intermediate Financial Management, 9th Edition, Thomson/Southwestern, at 342.
[52] Morin, at 337-339.

Based on the issuance costs shown on page 1 of Exhibit No.___(DWD-9), an adjustment of 0.12% is required to reflect the flotation costs applicable to the Utility Proxy Group.

Q. 66 What is the indicated cost of common equity after your Company-specific adjustments?

A. 66 Applying the 0.20% size adjustment, the 0.15% credit risk adjustment, and the 0.12% flotation cost adjustment to the indicated range of common equity cost rates between 9.99% and 12.01% results in a Company-specific range of common equity rates between 10.46% and 12.48%.

D. Other Considerations

Q. 67 Does your recommended ROE reflect risks facing natural gas utilities, like Southwest Gas?

A. 67 Yes, my recommended ROE reflects the risks facing the natural gas utility industry, including electrification and decarbonization efforts across the country.

Q. 68 Please provide examples of the electrification and decarbonization efforts in California impacting Southwest Gas.

A. 68 Recent Commission decisions and Senate Bills demonstrate that California is trying to rapidly transition to a carbon neutral economy. For natural gas utilities, this represents a significant threat to their business, as electrification and decarbonization efforts will ultimately result in a loss of customers and revenues.

On September 15, 2022, the Commission decision eliminated natural gas line extension allowances, a 10-year refundable payment option, and a 50% discount payment option provided under then-current natural gas line extension rules, effective July 1, 2023. This decision affected customers in all customer classes.[53]

Additionally, on December 1, 2022, the Commission issued General Order ("GO") 177 that relates to natural gas infrastructure projects. GO 177 requires natural gas utilities to apply for a Certificate of Public Convenience and Necessity (CPCN) for every natural gas infrastructure project with a project cost of at least $75 million. Additionally, projects that are located within 1,000 feet of a "sensitive receptor"[54] and require permitting from local air quality districts will also require a CPCN.[55]

A more recent Commission decision ruled to eliminate electric line extension subsidies for mixed-fuel new construction building projects (defined as projects that rely on gas, propane, or a mix of the two fuels in addition to electricity), effective July 1, 2024.[56]

California Assembly Bill 2513 would prohibit a person from selling, attempting to sell, or offering to sell to a consumer in this state a gas stove, as defined, that is manufactured or sold online on or after January 1, 2025, or sold in a store on or after January 1, 2026, unless the gas stove bears a label attached in a conspicuous location and, for online sales, unless the internet website prominently posts a warning, that sets forth a specified statement relating to air pollutants that can be released by gas, among other requirements.[57]

[53] California Commission Order Instituting Rulemaking Regarding Building Decarbonization, Rulemaking 19-01-011, Decision 22-09-026, September 15, 2022.
[54] Such as housing, healthcare facilities, or educational institutions.
[55] California PUC Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and perform Long-Term Gas System Planning, Rulemaking 20-01-007, Decision 22-12-021, December 1, 2022.
[56] California PUC Order Instituting Rulemaking Regarding Building Decarbonization, Rulemaking 19-01-011, Decision 23-12-037, December 21, 2023.
[57] California Assembly Bill, No. 2513, February 13, 2024.

Q. 69 Did you make a specific adjustment to your recommended ROE to reflect the electrification and decarbonization risk that Southwest Gas faces?

A. 69 No, I did not. To the extent that California's decarbonization initiatives are perceived as more aggressive than other areas of the country, my recommended ROE could be understated.

<u>IX. CONCLUSION</u>

Q. 70 What is your recommended range of ROEs for the Company?

A. 70 Given the discussion above and the results from the analyses, I conclude that a range of ROEs from 10.46% to 12.48% is appropriate for the Company at this time.

Q. 71 In your opinion, is your recommended ROE of 11.35% fair and reasonable to Southwest Gas and its customers?

A. 71 Given my range of ROEs applicable to Southwest Gas, my recommended ROE is reasonable, if not conservative.

Q. 72 In your opinion, is Southwest Gas' proposed capital structure consisting of 50.00% long-term debt and 50.00% common equity fair and reasonable?

A. 72 Yes, it is.

Q. 73 In your opinion, are Southwest Gas' proposed costs of debt of 4.14% (Southern California) and 4.34% (Northern California and South Lake Tahoe) fair and reasonable?

A. 73 Yes, it is.

Q. 74 Does this conclude your Direct Testimony?

A. 74 Yes, it does.

Summary

Dylan is an experienced consultant and a Certified Rate of Return Analyst (CRRA) and Certified Valuation Analyst (CVA). Dylan joined ScottMadden in 2016 and is a leading expert witness with respect to cost of capital, capital structure, and valuation. He has served as a consultant for investor-owned and municipal utilities and authorities for 15 years. Dylan has testified as an expert witness on over 150 occasions regarding rate of return, cost of service, rate design, and valuation before more than 40 regulatory jurisdictions in the United States and Canada, an American Arbitration Association panel, and the Superior Court of Rhode Island. He also maintains the benchmark index against which the Hennessy Gas Utility Mutual Fund performance is measured. Dylan holds a B.A. in economic history from the University of Pennsylvania and an M.B.A. with concentrations in finance and international business from Rutgers University.

Areas of Specialization

- Expert Witness Testimony
- Rates and Regulation
- Return on Equity
- Valuation
- Utility Regulations
- Rate Case Planning, Management, and Support
- Utility Benchmarking

Recent Articles and Speeches

- "Decoupling, Risk Impacts, and the Cost of Capital." Co-authored with Richard A. Michelfelder, Ph.D., Rutgers University and Pauline M. Ahern. The Electricity Journal. March 2020
- "Decoupling Impact and Public Utility Conservation Investment." Co-authored with Richard A. Michelfelder, Ph.D., Rutgers University and Pauline M. Ahern. Energy Policy Journal. 130 (2019), 311-319
- "Establishing Alternative Proxy Groups." Presentation before the Society of Utility and Regulatory Financial Analysts: 51st Financial Forum. April 4, 2019. New Orleans, LA
- "Past Is Prologue: Future Test Year." Presentation before the National Association of Water Companies 2017 Southeast Water Infrastructure Summit. May 2, 2017. Savannah, GA
- "Comparative Evaluation of the Predictive Risk Premium Model™, the Discounted Cash Flow Model and the Capital Asset Pricing Model." Co-authored with Richard A. Michelfelder, Ph.D., Rutgers University, Pauline M. Ahern, and Frank J. Hanley. The Electricity Journal. May 2013
- "Decoupling: Impact on the Risk and Cost of Common Equity of Public Utility Stocks." Presentation before the Society of Utility and Regulatory Financial Analysts: 45th Financial Forum. April 17-18, 2013. Indianapolis, IN

Recent Assignments

- Provided expert testimony on the cost of capital for ratemaking purposes before numerous state utility regulatory agencies
- Maintains the benchmark index against which the Hennessy Gas Utility Mutual Fund performance is measured
- Sponsored valuation testimony for a large municipal water company in front of an American Arbitration Association Board to justify the reasonability of their lease payments to the city
- Co-authored a valuation report on behalf of a large investor-owned utility in response to a new state regulation which allowed the appraised value of acquired assets into rate base

Sponsor	Date	Case/Applicant	Docket No.	Subject
Regulatory Commission of Alaska				
Alaska Power Company	08/23	Alaska Power Company	Docket No. TA 909-2 / U-23-054	Capital Structure
ENSTAR Natural Gas Company	08/22	ENSTAR Natural Gas Company	Docket No. TA334-4	Rate of Return
Cook Inlet Natural Gas Storage Alaska, LLC	07/21	Cook Inlet Natural Gas Storage Alaska, LLC	Docket No. TA45-733	Capital Structure
Alaska Power Company	09/20	Alaska Power Company; Goat Lake Hydro, Inc.; BBL Hydro, Inc.	Tariff Nos. TA886-2; TA6-521; TA4-573	Capital Structure
Alaska Power Company	07/16	Alaska Power Company	Docket No. TA857-2	Rate of Return
Alberta Utilities Commission				
AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	02/23	AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	Proceeding ID. 27084	Determination of Cost-of-Capital Parameters
AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	01/20	AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	2021 Generic Cost of Capital, Proceeding ID. 24110	Rate of Return
Arizona Corporation Commission				
EPCOR Water Arizona, Inc.	06/24	EPCOR Water Arizona, Inc.	Docket No. WS-01303A-24-0130	Rate of Return
Arizona Water Company	05/24	Arizona Water Company – Northern Group	Docket No. W-01445A-24-0117	Rate of Return
Foothills Water & Sewer, LLC	10/23	Foothills Water & Sewer, LLC	Docket No. WS-21182A-23-0292	Rate of Return and Fair Value Rate Base
Arizona Water Company	12/22	Arizona Water Company – Eastern Group	Docket No. W-01445A-22-0286	Rate of Return
EPCOR Water Arizona, Inc.	08/22	EPCOR Water Arizona, Inc.	Docket No. WS-01303A-22-0236	Rate of Return
EPCOR Water Arizona, Inc.	06/20	EPCOR Water Arizona, Inc.	Docket No. WS-01303A-20-0177	Rate of Return
Arizona Water Company	12/19	Arizona Water Company – Western Group	Docket No. W-01445A-19-0278	Rate of Return
Arizona Water Company	08/18	Arizona Water Company – Northern Group	Docket No. W-01445A-18-0164	Rate of Return
Arkansas Public Service Commission				
Summit Utilities Arkansas, Inc.	01/24	Summit Utilities Arkansas, Inc.	Docket No. 23-079-U	Rate of Return
Southwestern Electric Power Co.	07/21	Southwestern Electric Power Co.	Docket No. 21-070-U	Return on Equity
CenterPoint Energy Resources Corp.	05/21	CenterPoint Arkansas Gas	Docket No. 21-004-U	Return on Equity
California Public Utilities Commission				
San Gabriel Valley Water Company	05/23	San Gabriel Valley Water Company	Docket No. A23-05-001	Return on Equity
Colorado Public Utilities Commission				
Atmos Energy Corporation	08/22	Atmos Energy Corporation	Docket No. 22AL-0348G	Rate of Return
Summit Utilities, Inc.	04/18	Colorado Natural Gas Company	Docket No. 18AL-0305G	Rate of Return
Atmos Energy Corporation	06/17	Atmos Energy Corporation	Docket No. 17AL-0429G	Rate of Return
Commission of the Canada Energy Regulator				
Trans-Northern Pipelines Inc.	11/22	Trans-Northern Pipelines Inc.	Docket No. C-22197	Cost of Capital
Delaware Public Service Commission				
Artesian Water Company, Inc.	04/23	Artesian Water Company, Inc.	Docket No. 23-0601	Rate of Return

Sponsor	Date	Case/Applicant	Docket No.	Subject
Delmarva Power & Light Co.	12/22	Delmarva Power & Light Co.	Docket No. 22-0897 (Electric)	Return on Equity
Delmarva Power & Light Co.	01/22	Delmarva Power & Light Co.	Docket No. 22-002 (Gas)	Return on Equity
Delmarva Power & Light Co.	11/20	Delmarva Power & Light Co.	Docket No. 20-0149 (Electric)	Return on Equity
Delmarva Power & Light Co.	10/20	Delmarva Power & Light Co.	Docket No. 20-0150 (Gas)	Return on Equity
Tidewater Utilities, Inc.	11/13	Tidewater Utilities, Inc.	Docket No. 13-466	Capital Structure
Public Service Commission of the District of Columbia				
Washington Gas Light Company	04/22	Washington Gas Light Company	Formal Case No. 1169	Rate of Return
Washington Gas Light Company	09/20	Washington Gas Light Company	Formal Case No. 1162	Rate of Return
Federal Energy Regulatory Commission				
LS Power Grid California, LLC	10/20	LS Power Grid California, LLC	Docket No. ER21-195-000	Rate of Return
Florida Public Service Commission				
Tampa Electric Company	04/24	Tampa Electric Company	Docket No. 20240025-EI	Return on Equity
Peoples Gas System, Inc.	04/23	Peoples Gas System, Inc.	Docket No. 20230023-GU	Rate of Return
Tampa Electric Company	04/21	Tampa Electric Company	Docket No. 20210034-EI	Return on Equity
Peoples Gas System, Inc.	09/20	Peoples Gas System, Inc.	Docket No. 20200051-GU	Rate of Return
Utilities, Inc. of Florida	06/20	Utilities, Inc. of Florida	Docket No. 20200139-WS	Rate of Return
Hawaii Public Utilities Commission				
Launiupoko Irrigation Company, Inc.	12/20	Launiupoko Irrigation Company, Inc.	Docket No. 2020-0217 / Transferred to 2020-0089	Capital Structure
Lanai Water Company, Inc.	12/19	Lanai Water Company, Inc.	Docket No. 2019-0386	Cost of Service / Rate Design
Manele Water Resources, LLC	08/19	Manele Water Resources, LLC	Docket No. 2019-0311	Cost of Service / Rate Design
Kaupulehu Water Company	02/18	Kaupulehu Water Company	Docket No. 2016-0363	Rate of Return
Aqua Engineers, LLC	05/17	Puhi Sewer & Water Company	Docket No. 2017-0118	Cost of Service / Rate Design
Hawaii Resources, Inc.	09/16	Laie Water Company	Docket No. 2016-0229	Cost of Service / Rate Design
Illinois Commerce Commission				
Aqua Illinois, Inc.	01/24	Aqua Illinois, Inc.	Docket No. 24-0044	Rate of Return
Ameren Illinois Company d/b/a Ameren Illinois	01/23	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 23-0082 (Electric)	Return on Equity
Ameren Illinois Company d/b/a Ameren Illinois	01/23	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 23-0067 (Gas)	Return on Equity
Utility Services of Illinois, Inc.	02/21	Utility Services of Illinois, Inc.	Docket No. 21-0198	Rate of Return
Ameren Illinois Company d/b/a Ameren Illinois	07/20	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 20-0308	Return on Equity
Utility Services of Illinois, Inc.	11/17	Utility Services of Illinois, Inc.	Docket No. 17-1106	Cost of Service / Rate Design
Aqua Illinois, Inc.	04/17	Aqua Illinois, Inc.	Docket No. 17-0259	Rate of Return
Utility Services of Illinois, Inc.	04/15	Utility Services of Illinois, Inc.	Docket No. 14-0741	Rate of Return
Indiana Utility Regulatory Commission				
Aqua Indiana, Inc.	03/16	Aqua Indiana, Inc. Aboite Wastewater Division	Docket No. 44752	Rate of Return
Twin Lakes, Utilities, Inc.	08/13	Twin Lakes, Utilities, Inc.	Docket No. 44388	Rate of Return
Kansas Corporation Commission				
Atmos Energy Corporation	07/19	Atmos Energy Corporation	19-ATMG-525-RTS	Rate of Return
Kentucky Public Service Commission				

Sponsor	Date	Case/Applicant	Docket No.	Subject
Bluegrass Water Utility Operating Company	02/23	Bluegrass Water Utility Operating Company	2022-00432	Return on Equity
Atmos Energy Corporation	07/22	Atmos Energy Corporation	2022-00222	PRP Rider Rate
Water Service Corporation of KY	06/22	Water Service Corporation of KY	2022-00147	Rate of Return
Atmos Energy Corporation	07/21	Atmos Energy Corporation	2021-00304	PRP Rider Rate
Atmos Energy Corporation	06/21	Atmos Energy Corporation	2021-00214	Rate of Return
Duke Energy Kentucky, Inc.	06/21	Duke Energy Kentucky, Inc.	2021-00190	Return on Equity
Bluegrass Water Utility Operating Company	10/20	Bluegrass Water Utility Operating Company	2020-00290	Return on Equity
Louisiana Public Service Commission				
Utilities, Inc. of Louisiana	05/21	Utilities, Inc. of Louisiana	Docket No. U-36003	Rate of Return
Southwestern Electric Power Company	12/20	Southwestern Electric Power Company	Docket No. U-35441	Return on Equity
Atmos Energy Corporation	04/20	Atmos Energy Corporation	Docket No. U-35535	Rate of Return
Louisiana Water Service, Inc.	06/13	Louisiana Water Service, Inc.	Docket No. U-32848	Rate of Return
Maine Public Utilities Commission				
Northern Utilities, Inc. d/b/a Unitil	05/23	Northern Utilities, Inc. d/b/a Unitil	Docket No. 2023-00051	Return on Equity
Summit Natural Gas of Maine, Inc.	03/22	Summit Natural Gas of Maine, Inc.	Docket No. 2022-00025	Rate of Return
The Maine Water Company	09/21	The Maine Water Company	Docket No. 2021-00053	Rate of Return
Maryland Public Service Commission				
Washington Gas Light Company	05/23	Washington Gas Light Company	Case No. 9704	Rate of Return
FirstEnergy Service Company	03/23	Potomac Edison Company	Case No. 9695	Rate of Return
Washington Gas Light Company	08/20	Washington Gas Light Company	Case No. 9651	Rate of Return
FirstEnergy Corporation	08/18	Potomac Edison Company	Case No. 9490	Rate of Return
Massachusetts Department of Public Utilities				
Unitil Corporation	9/23	Fitchburg Gas & Electric Co. (Elec.)	D.P.U. 23-80	Rate of Return
Unitil Corporation	9/23	Fitchburg Gas & Electric Co. (Gas)	D.P.U. 23-81	Rate of Return
Unitil Corporation	12/19	Fitchburg Gas & Electric Co. (Elec.)	D.P.U. 19-130	Rate of Return
Unitil Corporation	12/19	Fitchburg Gas & Electric Co. (Gas)	D.P.U. 19-131	Rate of Return
Liberty Utilities	07/15	Liberty Utilities d/b/a New England Natural Gas Company	D.P.U. 15-75	Rate of Return
Minnesota Public Utilities Commission				
Northern States Power Company	11/01	Northern States Power Company	Docket No. G002/GR-21-678	Return on Equity
Northern States Power Company	10/21	Northern States Power Company	Docket No. E002/GR-21-630	Return on Equity
Northern States Power Company	11/20	Northern States Power Company	Docket No. E002/GR-20-723	Return on Equity
Mississippi Public Service Commission				
Great River Utility Operating Co.	07/22	Great River Utility Operating Co.	Docket No. 2022-UN-86	Rate of Return
Atmos Energy Corporation	03/19	Atmos Energy Corporation	Docket No. 2015-UN-049	Capital Structure
Atmos Energy Corporation	07/18	Atmos Energy Corporation	Docket No. 2015-UN-049	Capital Structure
Missouri Public Service Commission				
Confluence Rivers Utility Operating Company, Inc.	01/23	Confluence Rivers Utility Operating Company, Inc.	Case No. WR-2023-0006/SR-2023-0007	Rate of Return
Spire Missouri, Inc.	12/20	Spire Missouri, Inc.	Case No. GR-2021-0108	Return on Equity
Indian Hills Utility Operating Company, Inc.	10/17	Indian Hills Utility Operating Company, Inc.	Case No. SR-2017-0259	Rate of Return
Raccoon Creek Utility Operating Company, Inc.	09/16	Raccoon Creek Utility Operating Company, Inc.	Case No. SR-2016-0202	Rate of Return

Sponsor	Date	Case/Applicant	Docket No.	Subject
Public Utilities Commission of Nevada				
Southwest Gas Corporation	09/23	Southwest Gas Corporation	Docket No. 23-09012	Return on Equity
Southwest Gas Corporation	09/21	Southwest Gas Corporation	Docket No. 21-09001	Return on Equity
Southwest Gas Corporation	08/20	Southwest Gas Corporation	Docket No. 20-02023	Return on Equity
New Hampshire Public Utilities Commission				
Aquarion Water Company of New Hampshire, Inc.	12/20	Aquarion Water Company of New Hampshire, Inc.	Docket No. DW 20-184	Rate of Return
New Jersey Board of Public Utilities				
New Jersey Natural Gas Company	01/24	New Jersey Natural Gas Company	Docket No. GR24010071	Rate of Return
Middlesex Water Company	05/23	Middlesex Water Company	Docket No. WR23050292	Rate of Return
FirstEnergy Service Company	03/23	Jersey Central Power & Light Co.	Docket No. ER23030144	Rate of Return
Atlantic City Electric Company	02/23	Atlantic City Electric Company	Docket No. ER20120746	Return on Equity
Middlesex Water Company	05/21	Middlesex Water Company	Docket No. WR21050813	Rate of Return
Atlantic City Electric Company	12/20	Atlantic City Electric Company	Docket No. ER20120746	Return on Equity
FirstEnergy Service Company	02/20	Jersey Central Power & Light Co.	Docket No. ER20020146	Rate of Return
Aqua New Jersey, Inc.	12/18	Aqua New Jersey, Inc.	Docket No. WR18121351	Rate of Return
Middlesex Water Company	10/17	Middlesex Water Company	Docket No. WR17101049	Rate of Return
Middlesex Water Company	03/15	Middlesex Water Company	Docket No. WR15030391	Rate of Return
The Atlantic City Sewerage Company	10/14	The Atlantic City Sewerage Company	Docket No. WR14101263	Cost of Service / Rate Design
Middlesex Water Company	11/13	Middlesex Water Company	Docket No. WR1311059	Capital Structure
New Mexico Public Regulation Commission				
New Mexico Gas Company	09/23	New Mexico Gas Company	Case No. 23-00255-UT	Return on Equity
Southwestern Public Service Co.	11/22	Southwestern Public Service Co.	Case No. 22-00286-UT	Return on Equity
Southwestern Public Service Co.	01/21	Southwestern Public Service Co.	Case No. 20-00238-UT	Return on Equity
North Carolina Utilities Commission				
Old North State Water Co., Inc.	06/24	Old North State Water Co., Inc.	Docket No. W-1300, Sub 100	Rate of Return
Carolina Water Service, Inc.	07/22	Carolina Water Service, Inc.	Docket No. W-354 Sub 400	Rate of Return
Aqua North Carolina, Inc.	06/22	Aqua North Carolina, Inc.	Docket No. W-218 Sub 573	Rate of Return
Carolina Water Service, Inc.	07/21	Carolina Water Service, Inc.	Docket No. W-354 Sub 384	Rate of Return
Piedmont Natural Gas Co., Inc.	03/21	Piedmont Natural Gas Co., Inc.	Docket No. G-9, Sub 781	Return on Equity
Duke Energy Carolinas, LLC	07/20	Duke Energy Carolinas, LLC	Docket No. E-7, Sub 1214	Return on Equity
Duke Energy Progress, LLC	07/20	Duke Energy Progress, LLC	Docket No. E-2, Sub 1219	Return on Equity
Aqua North Carolina, Inc.	12/19	Aqua North Carolina, Inc.	Docket No. W-218 Sub 526	Rate of Return
Carolina Water Service, Inc.	06/19	Carolina Water Service, Inc.	Docket No. W-354 Sub 364	Rate of Return
Carolina Water Service, Inc.	09/18	Carolina Water Service, Inc.	Docket No. W-354 Sub 360	Rate of Return
Aqua North Carolina, Inc.	07/18	Aqua North Carolina, Inc.	Docket No. W-218 Sub 497	Rate of Return
North Dakota Public Service Commission				
Northern States Power Company	09/21	Northern States Power Company	Case No. PU-21-381	Rate of Return
Northern States Power Company	11/20	Northern States Power Company	Case No. PU-20-441	Rate of Return
Public Utilities Commission of Ohio				
FirstEnergy	06/24	Ohio Edison Co., Cleveland Electric Illuminating Co., Toledo Edison Co.	Case No. 24-0468-EL-AIR	Rate of Return
Aqua Ohio, Inc.	11/22	Aqua Ohio, Inc.	Case No. 22-1094-WW-AIR	Rate of Return
Duke Energy Ohio, Inc.	10/21	Duke Energy Ohio, Inc.	Case No. 21-887-EL-AIR	Return on Equity
Aqua Ohio, Inc.	07/21	Aqua Ohio, Inc.	Case No. 21-0595-WW-AIR	Rate of Return

Sponsor	Date	Case/Applicant	Docket No.	Subject
Aqua Ohio, Inc.	05/16	Aqua Ohio, Inc.	Case No. 16-0907-WW-AIR	Rate of Return
Pennsylvania Public Utility Commission				
Columbia Water Company	05/23	Columbia Water Company	Docket No. R-2023-3040258	Rate of Return
Borough of Ambler	06/22	Borough of Ambler – Bureau of Water	Docket No. R-2022-3031704	Rate of Return
Citizens' Electric Company of Lewisburg	05/22	C&T Enterprises	Docket No. R-2022-3032369	Rate of Return
Valley Energy Company	05/22	C&T Enterprises	Docket No. R-2022-3032300	Rate of Return
FirstEnergy	04/22	Pennsylvania Electric Company	Docket No. R-2024-3047068	Rate of Return
Community Utilities of Pennsylvania, Inc.	04/21	Community Utilities of Pennsylvania, Inc.	Docket No. R-2021-3025207	Rate of Return
Vicinity Energy Philadelphia, Inc.	04/21	Vicinity Energy Philadelphia, Inc.	Docket No. R-2021-3024060	Rate of Return
Delaware County Regional Water Control Authority	02/20	Delaware County Regional Water Control Authority	Docket No. A-2019-3015173	Valuation
Valley Energy, Inc.	07/19	C&T Enterprises	Docket No. R-2019-3008209	Rate of Return
Wellsboro Electric Company	07/19	C&T Enterprises	Docket No. R-2019-3008208	Rate of Return
Citizens' Electric Company of Lewisburg	07/19	C&T Enterprises	Docket No. R-2019-3008212	Rate of Return
Steelton Borough Authority	01/19	Steelton Borough Authority	Docket No. A-2019-3006880	Valuation
Mahoning Township, PA	08/18	Mahoning Township, PA	Docket No. A-2018-3003519	Valuation
SUEZ Water Pennsylvania Inc.	04/18	SUEZ Water Pennsylvania Inc.	Docket No. R-2018-000834	Rate of Return
Columbia Water Company	09/17	Columbia Water Company	Docket No. R-2017-2598203	Rate of Return
Veolia Energy Philadelphia, Inc.	06/17	Veolia Energy Philadelphia, Inc.	Docket No. R-2017-2593142	Rate of Return
Emporium Water Company	07/14	Emporium Water Company	Docket No. R-2014-2402324	Rate of Return
Columbia Water Company	07/13	Columbia Water Company	Docket No. R-2013-2360798	Rate of Return
Penn Estates Utilities, Inc.	12/11	Penn Estates, Utilities, Inc.	Docket No. R-2011-2255159	Capital Structure / Long-Term Debt Cost Rate
South Carolina Public Service Commission				
Blue Granite Water Co.	12/19	Blue Granite Water Company	Docket No. 2019-292-WS	Rate of Return
Carolina Water Service, Inc.	02/18	Carolina Water Service, Inc.	Docket No. 2017-292-WS	Rate of Return
Carolina Water Service, Inc.	06/15	Carolina Water Service, Inc.	Docket No. 2015-199-WS	Rate of Return
Carolina Water Service, Inc.	11/13	Carolina Water Service, Inc.	Docket No. 2013-275-WS	Rate of Return
United Utility Companies, Inc.	09/13	United Utility Companies, Inc.	Docket No. 2013-199-WS	Rate of Return
Utility Services of South Carolina, Inc.	09/13	Utility Services of South Carolina, Inc.	Docket No. 2013-201-WS	Rate of Return
Tega Cay Water Services, Inc.	11/12	Tega Cay Water Services, Inc.	Docket No. 2012-177-WS	Capital Structure
South Dakota Public Service Commission				
Northern States Power Company	06/22	Northern States Power Company	Docket No. EL22-017	Rate of Return
Tennessee Public Utility Commission				
CSWR – Limestone Water Utility Operating Company	07/24	CSWR – Limestone Water Utility Operating Company	Docket No. 24-00044	Capital Structure, Cost of Debt, Return on Equity
Piedmont Natural Gas Company	07/20	Piedmont Natural Gas Company	Docket No. 20-00086	Return on Equity
Public Utility Commission of Texas				
Southwestern Public Service Co.	02/23	Southwestern Public Service Co.	Docket No. 54634	Return on Equity
CSWR – Texas Utility Operating Company, LLC	02/23	CSWR – Texas Utility Operating Company, LLC	Docket No. 54565	Rate of Return

Sponsor	Date	Case/Applicant	Docket No.	Subject
Oncor Electric Delivery Co. LLC	05/22	Oncor Electric Delivery Co. LLC	Docket No. 53601	Return on Equity
Southwestern Public Service Co.	02/21	Southwestern Public Service Co.	Docket No. 51802	Return on Equity
Southwestern Electric Power Co.	10/20	Southwestern Electric Power Co.	Docket No. 51415	Rate of Return
Texas Railroad Commission				
Atmos Pipeline – Texas, a Division of Atmos Energy Corporation	05/23	Atmos Pipeline – Texas, a Division of Atmos Energy Corporation	Docket No. OS-23-00013758	Return on Equity
Virginia State Corporation Commission				
Aqua Virginia, Inc.	07/23	Aqua Virginia, Inc.	PUR-2023-00073	Rate of Return
Washington Gas Light Company	06/22	Washington Gas Light Company	PUR-2022-00054	Return on Equity
Virginia Natural Gas, Inc.	04/21	Virginia Natural Gas, Inc.	PUR-2020-00095	Return on Equity
Massanutten Public Service Corporation	12/20	Massanutten Public Service Corporation	PUE-2020-00039	Return on Equity
Aqua Virginia, Inc.	07/20	Aqua Virginia, Inc.	PUR-2020-00106	Rate of Return
WGL Holdings, Inc.	07/18	Washington Gas Light Company	PUR-2018-00080	Rate of Return
Atmos Energy Corporation	05/18	Atmos Energy Corporation	PUR-2018-00014	Rate of Return
Aqua Virginia, Inc.	07/17	Aqua Virginia, Inc.	PUR-2017-00082	Rate of Return
Massanutten Public Service Corp.	08/14	Massanutten Public Service Corp.	PUE-2014-00035	Rate of Return / Rate Design
Public Service Commission of West Virginia				
FirstEnergy Service Company	05/23	Monongahela Power Company and The Potomac Edison Company	Case No. 23-0460-E-42T	Return on Equity
FirstEnergy Service Company	12/21	Monongahela Power Company and The Potomac Edison Company	Case No. 21-0857-E-CN (ELG)	Return on Equity
FirstEnergy Service Company	11/21	Monongahela Power Company and The Potomac Edison Company	Case No. 21-0813-E-P (Solar)	Return on Equity

Southwest Gas Corporation
Table of Contents
Supporting Exhibits Accompanying the Direct Testimony
of Dylan W. D'Ascendis, CRRA, CVA

Southwest Gas Corporation
Recommended Capital Structure and Cost Rates
for Ratemaking Purposes

Southern California Rate Jurisdiction

Type Of Capital	Ratios (1)	Cost Rate		Weighted Cost Rate
Long-Term Debt	50.00%	4.14%	(1)	2.07%
Common Equity	50.00%	11.35%	(2)	5.68%
Total	100.00%		(3)	7.74%

Northern California and South Lake Tahoe Rate Jurisdiction

Type Of Capital	Ratios (1)	Cost Rate		Weighted Cost Rate
Long-Term Debt	50.00%	4.34%	(1)	2.17%
Common Equity	50.00%	11.35%	(2)	5.68%
Total	100.00%			7.85%

Notes:

(1) Company-provided
(2) From page 2 of this Exhibit.
(3) Note: does not add due to rounding.

Southwest Gas Corporation
Brief Summary of Common Equity Cost Rate

Line No.	Principal Methods	Proxy Group of Six Natural Gas Distribution Companies
1.	Discounted Cash Flow Model (DCF) (1)	9.99%
2.	Risk Premium Model (RPM) (2)	10.82%
3.	Capital Asset Pricing Model (CAPM) (3)	11.57%
4.	Market Models Applied to Comparable Risk, Non-Price Regulated Companies (4)	12.01%
5.	Indicated Range of Common Equity Cost Rates before Adjustment for Company-Specific Risk	9.99% - 12.01%
6.	Business Risk Adjustment (5)	0.20%
7.	Credit Risk Adjustment (6)	0.15%
8.	Flotation Cost Adjustment (7)	0.12%
9.	Indicated Common Equity Cost Rate after Adjustment	10.46% - 12.48%
10.	Recommended Common Equity Cost Rate	11.35%

Notes:
(1) From page 1 of Exhibit No.___(DWD-3)
(2) From page 1 of Exhibit No.___(DWD-4)
(3) From page 1 of Exhibit No.___(DWD-5)
(4) From page 1 of Exhibit No.___(DWD-7)
(5) Adjustment to reflect the Company's greater business risk relative to the Utility Proxy Group as detailed in Mr. D'Ascendis' Prepared Direct Testimony.
(6) Company-specific risk adjustment to reflect Southwest Gas' greater risk due to a lower long-term issuer rating relative to the proxy group as detailed in Mr. D'Ascendis' Prepared Direct Testimony.
(7) From page 1 of Exhibit No.___(DWD-9)

Capital Structure Based upon Total Permanent Capital for the
Proxy Group of Six Natural Gas Distribution Companies
2019 - 2023, Inclusive

	2023	2022	2021	2020	2019	5 YEAR AVERAGE
Atmos Energy						
Long-Term Debt	37.62 %	37.96 %	39.35 %	40.02 %	38.03 %	38.60 %
Preferred Stock	-	-	-	-	-	-
Common Equity	62.38	62.04	60.65	59.98	61.97	61.40
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
New Jersey Resources						
Long-Term Debt	59.16 %	58.49 %	57.81 %	55.35 %	50.11 %	56.18 %
Preferred Stock	-	-	-	-	-	-
Common Equity	40.84	41.51	42.19	44.65	49.89	43.82
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
NiSource Inc.						
Long-Term Debt	57.26 %	55.77 %	57.09 %	61.64 %	56.79 %	57.71 %
Preferred Stock	2.51	9.03	9.55	5.87	6.35	6.66
Common Equity	40.23	35.20	33.36	32.49	36.85	35.63
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	99.99 %	100.00 %
Northwest Natural						
Long-Term Debt [1]	55.11 %	53.21 %	52.12 %	51.81 %	50.43 %	52.54 %
Preferred Stock	-	-	-	-	-	-
Common Equity	44.89	46.79	47.88	48.19	49.57	47.46
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
ONE Gas, Inc.						
Long-Term Debt [1]	44.05 %	42.10 %	41.74 %	41.76 %	37.65 %	41.46 %
Preferred Stock	-	-	-	-	-	-
Common Equity	55.95	57.90	58.26	58.24	62.35	58.54
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Spire Inc.						
Long-Term Debt	54.01 %	51.42 %	52.98 %	49.62 %	45.49 %	50.70 %
Preferred Stock	3.52	3.84	4.28	4.83	5.19	4.33
Common Equity	42.46	44.74	42.74	45.55	49.32	44.97
Total Capital	99.99 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Proxy Group of Six Natural Gas Distribution Companies						
Long-Term Debt	51.20 %	49.83 %	50.18 %	50.03 %	46.42 %	49.53 %
Preferred Stock	1.01	2.15	2.31	1.78	1.92	1.83
Common Equity	47.79	48.03	47.51	48.18	51.66	48.64
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %

Source of Information
Annual Forms 10-K

Southwest Gas Corporation
Operating Subsidiary Company Capital Structures of the
Proxy Group of Six Natural Gas Distribution Companies

Company Name	Parent Company Ticker	2023 Common Equity	2023 Long-Term Debt	Total Capital
Atmos Energy Corporation	ATO	61.24%	38.76%	100.00%
New Jersey Natural Gas Company	NJR	39.60%	60.40%	100.00%
Northern Indiana Public Service Company	NI	59.26%	40.74%	100.00%
Northwest Natural Gas Company	NWN	46.06%	53.94%	100.00%
ONE Gas, Inc.	OGS	48.13%	51.87%	100.00%
Spire Alabama Inc.	SR	54.61%	45.39%	100.00%
Spire Missouri Inc.	SR	50.79%	49.21%	100.00%
	Average	51.38%	48.62%	
	Maximum	61.24%	60.40%	
	Minimum	39.60%	38.76%	

Source: S&P Global Market Intelligence.
Company Financial Statements.
Northern Indiana Public Service Company is from FERC financial Report Form Form No. 1 at PDF 21.

Southwest Gas Corporation
Indicated Common Equity Cost Rate Using the Discounted Cash Flow Model for the
Proxy Group of Six Natural Gas Distribution Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Six Natural Gas Distribution Companies	Average Dividend Yield (1)	Value Line Projected Five Year Growth in EPS (2)	Zack's Five Year Projected Growth Rate in EPS	Yahoo! Finance Projected Five Year Growth in EPS	S&P Capital IQ Projected Five Year Growth in EPS	Average Projected Five Year Growth in EPS (3)	Adjusted Dividend Yield (4)	Indicated Common Equity Cost Rate (5)
Atmos Energy Corporation	2.76 %	7.00 %	7.00 %	7.40 %	NA	7.13 %	2.86 %	9.99 %
New Jersey Resources Corporation	3.91	5.00	NA	6.00	5.87	5.62	4.02	9.64
NiSource Inc.	3.82	9.50	6.00	7.40	7.00	7.48	3.96	11.44
Northwest Natural Holding Company	5.23	6.50	NA	2.80	4.40	4.57	5.35	9.92
ONE Gas, Inc.	4.18	3.50	5.00	5.00	3.00	4.13	4.27	8.40
Spire Inc.	4.98	4.50	5.00	6.36	6.50	5.59	5.12	10.71
							Average	10.02 %
							Median	9.95 %
							Average of Mean and Median	9.99 %

NA= Not Available

Notes:

(1) Indicated dividend at 05/31/2024 divided by the average closing price of the last 60 trading days ending 05/31/2024 for each company.
(2) From pages 2 through 7 of this Exhibit.
(3) Average of columns 2 through 5 excluding negative growth rates.
(4) This reflects a growth rate component equal to one-half the conclusion of growth rate (from column 6) x column 1 to reflect the periodic payment of dividends (Gordon Model) as opposed to the continuous payment. Thus, for Atmos Energy Corporation, 2.76% x (1+(1/2 x 7.13%)) = 2.86%.
(5) Column 6 + Column 7.

Source of Information:

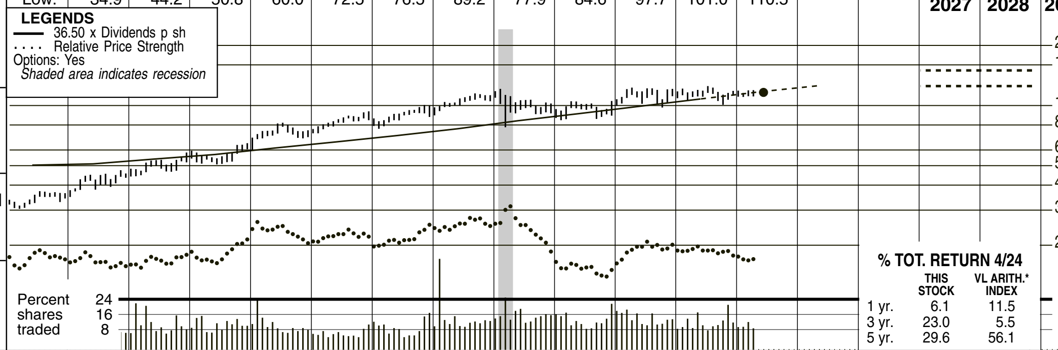
Value Line Investment Survey
www.zacks.com Downloaded on 05/31/2024
www.yahoo.com Downloaded on 05/31/2024
S&P Capital IQ

ATMOS ENERGY CORP. NYSE-ATO

RECENT PRICE 116.33 | P/E RATIO 16.8 (Trailing: 17.4; Median: 20.0) | RELATIVE P/E RATIO 0.92 | DIV'D YLD 2.9% | VALUE LINE

TIMELINESS 4 Lowered 2/16/24
SAFETY 1 Raised 6/6/14
TECHNICAL 3 Lowered 3/22/24
BETA .85 (1.00 = Market)

High:	47.4	58.2	64.8	82.0	93.6	100.8	115.2	121.1	105.3	123.0	125.3	121.5
Low:	34.9	44.2	50.8	60.0	72.5	76.5	89.2	77.9	84.6	97.7	101.0	110.5



18-Month Target Price Range
Low-High: $102-$148 — Midpoint (% to Mid): $125 (5%)

Target Price Range 2027 | 2028 | 2029

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	150	(+30%)	10%
Low	125	(+5%)	5%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	314	322	358
to Sell	281	280	295
Hld's(000)	136508	137279	137294

% TOT. RETURN 4/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	6.1	11.5
3 yr.	23.0	5.5
5 yr.	29.6	56.1

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
79.52	53.69	53.12	48.15	38.10	42.88	49.22	40.82	32.23	26.01	28.00	24.32	22.41	25.73	29.82	28.79	27.10	28.50	Revenues per sh A	37.15
4.19	4.29	4.64	4.72	4.76	5.14	5.42	5.81	6.19	6.62	7.24	7.57	8.03	8.64	9.30	10.04	10.95	11.75	"Cash Flow" per sh	13.65
2.00	1.97	2.16	2.26	2.10	2.50	2.96	3.09	3.38	3.60	4.00	4.35	4.72	5.12	5.60	6.10	6.75	7.20	Earnings per sh AB	8.35
1.30	1.32	1.34	1.36	1.38	1.40	1.48	1.56	1.68	1.80	1.94	2.10	2.30	2.50	2.72	2.96	3.22	3.46	Div'ds Decl'd per sh C■	4.25
5.20	5.51	6.02	6.90	8.12	9.32	8.32	9.61	10.46	10.72	13.19	14.19	15.38	14.87	17.35	18.90	20.00	20.25	Cap'l Spending per sh	20.00
22.60	23.52	24.16	24.98	26.14	28.47	30.74	31.48	33.32	36.74	42.87	48.18	53.95	59.71	66.85	73.20	75.30	78.60	Book Value per sh	83.50
90.81	92.55	90.16	90.30	90.24	90.64	100.39	101.48	103.93	106.10	111.27	119.34	125.88	132.42	140.90	148.49	155.00	158.00	Common Shs Outst'g D	175.00
13.6	12.5	13.2	14.4	15.9	15.9	16.1	17.5	20.8	22.0	21.7	23.2	22.3	18.8	19.3	18.7	Bold figures are		Avg Ann'l P/E Ratio	16.5
.82	.83	.84	.90	1.01	.89	.85	.88	1.09	1.11	1.17	1.24	1.15	1.02	1.12	1.08	Value Line		Relative P/E Ratio	.90
4.8%	5.3%	4.7%	4.2%	4.1%	3.5%	3.1%	2.9%	2.4%	2.3%	2.2%	2.1%	2.2%	2.6%	2.5%	2.6%	estimates		Avg Ann'l Div'd Yield	3.1%

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
4940.9	4142.1	3349.9	2759.7	3115.5	2901.8	2821.1	3407.5	4201.7	4275.4	4200	4500	Revenues ($mill) A	6500
289.8	315.1	350.1	382.7	444.3	511.4	580.5	665.6	774.4	885.9	1025	1115	Net Profit ($mill)	1475
39.2%	38.3%	36.4%	36.6%	27.0%	21.4%	19.5%	18.8%	9.1%	11.4%	15.5%	16.0%	Income Tax Rate	25.0%
5.9%	7.6%	10.5%	13.9%	14.3%	17.6%	20.6%	19.5%	18.4%	20.7%	24.4%	24.8%	Net Profit Margin	22.7%
44.3%	43.5%	38.7%	44.0%	34.3%	38.0%	40.0%	38.4%	37.9%	37.9%	40.0%	40.0%	Long-Term Debt Ratio	40.0%
55.7%	56.5%	61.3%	56.0%	65.7%	62.0%	60.0%	61.6%	62.1%	62.1%	60.0%	60.0%	Common Equity Ratio	60.0%
5542.2	5650.2	5651.8	6965.7	7263.6	9279.7	11323	12837	15180	17509	19450	20700	Total Capital ($mill)	24350
6725.9	7430.6	8280.5	9259.2	10371	11788	13355	15064	17240	19607	21900	23000	Net Plant ($mill)	27000
6.4%	6.6%	7.2%	6.4%	6.9%	6.1%	5.5%	5.5%	5.4%	5.5%	6.5%	6.5%	Return on Total Cap'l	7.5%
9.4%	9.9%	10.1%	9.8%	9.3%	8.9%	8.5%	8.4%	8.2%	8.1%	9.0%	9.0%	Return on Shr. Equity	10.0%
9.4%	9.9%	10.1%	9.8%	9.3%	8.9%	8.5%	8.4%	8.2%	8.1%	9.0%	9.0%	Return on Com Equity	10.0%
4.7%	4.9%	5.1%	4.9%	4.8%	4.6%	4.4%	4.3%	4.2%	4.2%	4.5%	4.5%	Retained to Com Eq	5.0%
50%	51%	50%	50%	48%	48%	49%	49%	49%	49%	49%	49%	All Div'ds to Net Prof	50%

CAPITAL STRUCTURE as of 3/31/24
Total Debt $7535.7 mill. **Due in 5 Yrs** $915.0 mill.
LT Debt $7526.1 mill. **LT Interest** $135.0 mill.
(LT interest earned: 8.3x; total interest coverage: 8.3x)
Leases, Uncapitalized Annual rentals $41.3 mill.

Pfd Stock None

Pension Assets-9/23 $502.4 mill. **Oblig.** $431.6 mill.
Common Stock 150,877,056 shs. **as of 5/3/24**

MARKET CAP: $17.6 billion (Large Cap)

CURRENT POSITION ($MILL.)	2022	2023	3/31/24
Cash Assets	51.6	15.4	262.5
Other	2996.1	870.4	1169.9
Current Assets	3047.7	885.8	1432.4
Accts Payable	496.0	336.1	367.9
Debt Due	2386.4	253.4	9.6
Other	720.2	763.1	677.7
Current Liab.	3602.6	1352.6	1055.2
Fix. Chg. Cov.	1238%	1059%	1070%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-4.0%	-.5%	5.0%
"Cash Flow"	6.5%	7.0%	6.5%
Earnings	9.5%	9.0%	7.0%
Dividends	7.0%	8.5%	7.5%
Book Value	9.5%	12.0%	4.0%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	914.5	1319.1	605.6	568.3	3407.5
2022	1012.8	1649.8	816.4	722.7	4201.7
2023	1484.0	1541.0	662.7	587.7	4275.4
2024	1158.5	1647.2	786.5	607.8	4200
2025	1250	1725	865	660	4500

Fiscal Year Ends	EARNINGS PER SHARE A B E Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	1.71	2.30	.78	.37	5.12
2022	1.86	2.37	.92	.51	5.60
2023	1.91	2.48	.94	.80	6.10
2024	2.08	2.85	1.00	.82	6.75
2025	2.26	2.94	1.10	.90	7.20

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.575	.575	.575	.625	2.35
2021	.625	.625	.625	.68	2.56
2022	.68	.68	.68	.74	2.78
2023	.74	.74	.74	.805	3.03
2024	.805	.805			

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to over three million customers through six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Gas sales breakdown for fiscal 2023: 66.5%, residential; 28.0%, commercial; 3.8%, industrial; and 1.7% other. The company sold Atmos Energy Marketing, 1/17. Officers and directors own approximately .5% of common stock (12/23 Proxy). President and Chief Executive Officer: Kevin Akers. Incorporated: Texas. Address: Three Lincoln Centre, Suite 1800, 5430 LBJ Freeway, Dallas, Texas 75240. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

Atmos Energy has performed nicely, from an earnings standpoint, thus far in fiscal 2024 (ends September 30th). Through the first half, per-share profits of $4.93 were 12.3% higher than the $4.39 amount registered for the same period last year. This was brought about partially by positive rate-case outcomes. Lower bad-debt expense also helped. Furthermore, results were favorably impacted by legislation to reduce property-tax expenses in Texas. But a rise in both depreciation expense and interest charges provided somewhat of an offset. Nevertheless, for the entire year, it appears that the bottom line will increase around 10%, to $6.75 per share, relative to fiscal 2023's $6.10 tally. Concerning fiscal 2025, share net may grow another 7% or so, to $7.20, as operating margins expand further.

There has been action on the rate-filing front. During the first six months, Atmos managed to complete some regulatory proceedings leading to a $138.4 million boost in annual operating income. What's more, there were ratemaking initiatives in progress at the conclusion of March seeking $96.4 million of annual operating income. Of course, there are no guarantees that the company will receive everything it desires.

The capital spending target for fiscal 2024 was raised from $2.9 billion to $3.1 billion. The revised estimate marks a 10.5% increase from fiscal 2023's $2.8 billion figure. Like last year, a substantial amount of the resources is being used to enhance the safety and reliability of Atmos' natural gas distribution and transmission systems. Leadership adds that it projects total capital expenditures from fiscal 2024 through fiscal 2028 to be roughly $17 billion. A meaningful portion of the investments will continue to be deployed to where they are currently. Assuming that finances remain healthy, the company ought to have minimal difficulty accomplishing these objectives.

These top-quality shares have strengthened some in price over the past six months. That's due partly, we think, to the energy firm's solid earnings of late. However, long-term total return potential looks unspectacular. The equity is untimely, as well.

Frederick L. Harris, III — *May 24, 2024*

(A) Fiscal year ends Sept. 30th. (B) Diluted shrs. Excl. nonrec. gains (loss): '10, 5¢; '11, (1¢); '18, $1.43; '20, 17¢. Excludes discontinued operations: '11, 10¢; '12, 27¢; '13, 14¢; '17, 13¢. Next earnings report due early Aug. (C) Dividends historically paid in early March, June, Sept., and Dec. ■ Div. reinvestment plan. Direct stock purchase plan avail. (D) In millions. (E) Qtrs may not add due to change in shrs outstanding.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	100

NEW JERSEY RES. NYSE-NJR

RECENT PRICE 44.12 | P/E RATIO 14.9 (Trailing: 17.3; Median: 17.0) | RELATIVE P/E RATIO 0.82 | DIV'D YLD 3.9% | VALUE LINE

TIMELINESS 4 Raised 3/29/24
SAFETY 2 Lowered 4/17/20
TECHNICAL 5 Lowered 5/3/24
BETA 1.00 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$37-$60	$49 (10%)

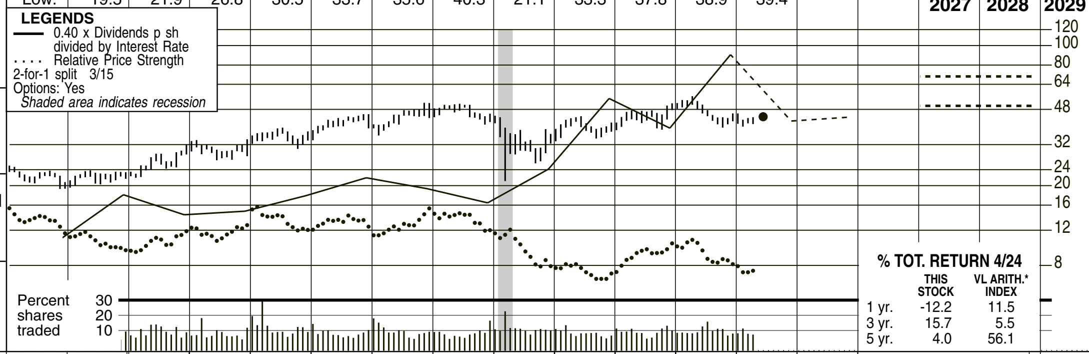
2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+60%)	15%
Low	50	(+15%)	7%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	157	153	161
to Sell	156	163	143
Hld's(000)	71570	69494	70304

High:	23.8	32.1	34.1	38.9	45.4	51.8	51.2	44.7	44.4	51.4	55.8	45.8
Low:	19.5	21.9	26.8	30.5	33.7	35.6	40.3	21.1	33.3	37.8	38.9	39.4



% TOT. RETURN 4/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-12.2	11.5
3 yr.	15.7	5.5
5 yr.	4.0	56.1

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
45.37	31.17	32.05	36.30	27.08	38.38	44.40	32.09	21.90	26.28	33.24	29.01	20.39	22.71	30.38	20.12	21.50	22.00	Revenues per sh A	25.00
1.81	1.58	1.63	1.70	1.86	1.93	2.73	2.52	2.46	2.68	3.72	2.99	3.30	3.36	3.86	4.22	4.55	4.60	"Cash Flow" per sh	5.25
1.35	1.20	1.23	1.29	1.36	1.37	2.08	1.78	1.61	1.73	2.72	1.96	2.07	2.16	2.50	2.70	2.95	3.00	Earnings per sh B	3.50
.56	.62	.68	.72	.77	.81	.86	.93	.98	1.04	1.11	1.19	1.27	1.36	1.45	1.56	1.68	1.76	Div'ds Decl'd per sh C■	1.95
.86	.90	1.05	1.13	1.26	1.33	1.52	3.76	4.15	3.80	4.39	5.83	4.65	5.42	6.50	5.13	4.40	5.50	Cap'l Spending per sh	6.25
8.64	8.29	8.81	9.36	9.80	10.65	11.48	12.99	13.58	14.33	16.18	17.37	19.26	17.18	19.00	20.40	22.30	23.65	Book Value per sh D	27.00
84.12	83.17	82.35	82.89	83.05	83.32	84.20	85.19	85.88	86.32	87.69	89.34	95.80	94.95	95.64	97.57	100.00	100.00	Common Shs Outst'g E	100.00
12.3	14.9	15.0	16.8	16.8	16.0	11.7	16.6	21.3	22.4	15.6	24.3	17.7	17.5	17.0	17.7	Bold figures are		Avg Ann'l P/E Ratio	17.0
.74	.99	.95	1.05	1.07	.90	.62	.84	1.12	1.13	.84	1.29	.91	.94	.98	1.02	Value Line		Relative P/E Ratio	.95
3.3%	3.5%	3.7%	3.3%	3.4%	3.7%	3.5%	3.1%	2.9%	2.7%	2.6%	2.5%	3.5%	3.6%	3.4%	3.3%	estimates		Avg Ann'l Div'd Yield	4.0%

CAPITAL STRUCTURE as of 3/31/24
Total Debt $3070.8 mill. **Due in 5 Yrs** $580 mill.
LT Debt $2726.2 mill. **LT Interest** $125 mill.
Incl. $9.3 mill. capitalized leases.
(Interest coverage: 4.85x)
Pension Assets-9/23 $405.0 mill. **Oblig.** $493.7 mill.

Pfd Stock None

Common Stock 98,822,278 shs. as of 5/3/24

MARKET CAP: $4.4 billion (Mid Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
3738.1	2734.0	1880.9	2268.6	2915.1	2592.0	1953.7	2156.6	2906.0	1963.0	2150	2200	Revenues ($mill) A	2500
176.9	153.7	138.1	149.4	240.5	175.0	196.2	207.7	240.3	261.8	295	300	Net Profit ($mill)	350
30.2%	26.3%	15.5%	17.2%	--	--	NMF	10.3%	21.4%	15.8%	21.5%	22.0%	Income Tax Rate	22.0%
4.7%	5.6%	7.3%	6.6%	8.2%	6.7%	10.0%	9.6%	8.3%	13.3%	13.7%	13.6%	Net Profit Margin	14.0%
38.2%	43.2%	47.7%	44.6%	45.4%	49.8%	55.1%	57.0%	57.8%	58.2%	57.5%	57.0%	Long-Term Debt Ratio	55.0%
61.8%	56.8%	52.3%	55.4%	54.6%	50.2%	44.9%	43.0%	42.2%	41.8%	42.5%	43.0%	Common Equity Ratio	45.0%
1564.4	1950.6	2230.1	2233.7	2599.6	3088.9	4104.2	3793.0	4302.6	4758.8	5250	5500	Total Capital ($mill)	6000
1884.1	2128.3	2407.7	2609.7	2651.0	3041.2	3983.0	4213.5	4649.9	5022.1	5150	5250	Net Plant ($mill)	5550
12.1%	8.6%	6.9%	7.7%	10.1%	6.4%	5.6%	6.5%	5.6%	5.5%	5.5%	5.5%	Return on Total Cap'l	6.0%
18.3%	13.9%	11.8%	12.1%	16.9%	11.3%	10.6%	12.7%	13.2%	13.2%	13.0%	12.5%	Return on Shr. Equity	13.0%
18.3%	13.9%	11.8%	12.1%	16.9%	11.3%	10.6%	12.7%	13.2%	13.2%	13.0%	12.5%	Return on Com Equity	13.0%
11.0%	7.0%	4.8%	5.0%	10.2%	4.6%	4.3%	5.6%	6.2%	5.6%	5.5%	5.0%	Retained to Com Eq	5.5%
40%	50%	60%	59%	40%	59%	60%	56%	53%	58%	57%	59%	All Div'ds to Net Prof	56%

CURRENT POSITION ($MILL.)	2022	2023	3/31/24
Cash Assets	1.1	1.0	5.0
Other	755.0	531.1	548.7
Current Assets	756.1	532.1	553.7
Accts Payable	156.6	151.8	127.2
Debt Due	499.1	368.3	344.6
Other	448.5	286.5	317.3
Current Liab.	1104.2	806.6	789.1
Fix. Chg. Cov.	545%	520%	480%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-3.0%	-6.0%	2.5%
"Cash Flow"	7.0%	4.5%	5.0%
Earnings	5.0%	2.5%	5.0%
Dividends	6.5%	6.5%	5.0%
Book Value	7.5%	7.0%	4.5%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	454.3	802.2	367.6	532.5	2156.6
2022	675.8	912.3	552.3	765.5	2906.0
2023	723.6	644.0	264.1	331.3	1963.0
2024	467.2	657.9	450	574.9	2150
2025	680	575	460	485	2200

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	.46	1.77	d.15	.07	2.16
2022	.69	1.36	d.04	.50	2.50
2023	1.14	1.16	.10	.30	2.70
2024	.74	1.41	.05	.75	2.95
2025	.75	1.45	.05	.75	3.00

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.3125	.3125	.3125	.3325	1.27
2021	.3325	.3325	.3325	.3625	1.36
2022	.3625	.3625	.3625	.3625	1.45
2023	.39	.39	.39	.39	1.56
2024	.42	.42			

BUSINESS: New Jersey Resources Corp. is a holding company providing retail/wholesale energy svcs. to customers in NJ, and in states from the Gulf Coast to New England, and Canada. New Jersey Natural Gas had 576,000 cust. at 9/30/23. Fiscal 2023 volume: 128 bill. cu. ft. (23% interruptible, 50% residential, commercial & firm transportation, 27% other). N.J. Natural Energy subsidiary provides unregulated retail/wholesale natural gas and related energy svcs. 2023 dep. rate: 2.8%. Has 1,350 empls. Off./dir. own less than 1% of common; BlackRock, 15.9%; Vanguard, 11.4% (12/23 Proxy). CEO, President & Director: Steven D. Westhoven. Incorporated: New Jersey. Address: 1415 Wyckoff Road, Wall, NJ 07719. Telephone: 732-938-1480. Web: www.njresources.com.

New Jersey Resources delivered a strong fiscal 2024 second-quarter performance. (Fiscal year ends September 30th.) Despite a lower-than-expected revenue figure due to falling natural gas prices, the company's cost structure allowed earnings to remain unfettered. Indeed, net financial earnings exceeded our projections, landing at $1.41 per share, well above the prior year's tally. This brings the total for the first six months of fiscal 2024 to $2.15, just shy of the $2.30 in the year before, which was boosted by a unique winter storm. The performance was bolstered by significant capital investments of more than $850 million since the last rate case in 2021. Too, the company's SAVEGREEN program, a large energy efficiency filing, helped in catering to New Jersey's increasingly sustainability-focused regulatory climate. Despite some broader headwinds, the company continues to manage its operating costs well.

We have raised our earnings outlook for the next two years. The energy services segment is poised to contribute to our increased expectations due to the earlier mentioned SAVEGREEN program within the context of a particularly strong residential construction market and efficiency incentives in its operating region. On a similar note, Clean Energy Ventures is experiencing rapid deployment with 34 megawatts under construction and a solar pipeline of over 870 megawatts of investment opportunities. Most importantly for sustainable earnings performances henceforth is a new rate case progressing through regulatory channels that should amplify earnings performance substantially in fiscal 2026, if passed.

New Jersey's regional strength provides a solid base for sustainable growth. With a favorable regulatory backdrop characterized by a commitment to the transition to sustainable energy systems, infrastructure investment opportunities are wide, which will help to grow the company's earnings base for the foreseeable future.

The stock remains favorable for low risk and steady income characteristics. The issue has returned about 6% over the past three months but still offers decent value from its income component.

Earl B. Humes *May 24, 2024*

(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings. Qtly. revenues and egs. may not sum to total due to rounding and change in shares outstanding. Next earnings report due early August.
(C) Dividends historically paid in early Jan., April, July, and October. ■ Dividend reinvestment plan available.
(D) Includes regulatory assets in 2023: $585 million, $6.00/share.
(E) In millions, adjusted for 3/15 split.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	40
Earnings Predictability	60

NISOURCE INC. NYSE-NI

RECENT PRICE **28.80** | P/E RATIO **16.9** (Trailing: 17.1; Median: 21.0) | RELATIVE P/E RATIO **0.93** | DIV'D YLD **3.8%** | **VALUE LINE**

TIMELINESS 3 Raised 3/22/24
SAFETY 2 Raised 2/23/24
TECHNICAL 4 Raised 5/24/24
BETA .95 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$25-$40	$33 (15%)

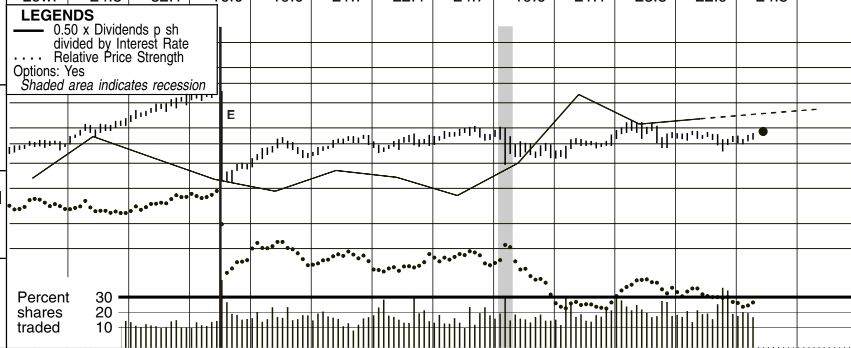
2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+75%)	17%
Low	35	(+20%)	8%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	249	278	313
to Sell	256	234	253
Hld's(000)	393166	394475	413866

High:	33.5	44.9	49.2	26.9	27.8	28.1	30.7	30.5	27.8	32.6	29.0	29.2
Low:	24.8	32.1	16.0	19.0	21.7	22.4	24.7	19.6	21.1	23.8	22.9	24.8



Target Price Range 2027 | 2028 | 2029

% TOT. RETURN 4/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	1.7	11.5
3 yr.	19.1	5.5
5 yr.	18.3	56.1

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
32.36	24.02	22.99	21.33	16.31	18.04	20.47	14.58	13.90	14.46	13.74	13.63	11.95	12.09	14.23	12.33	*13.80*	*14.55*	Revenues per sh	*16.10*
3.32	2.96	3.19	2.98	3.13	3.41	3.60	2.27	2.71	2.07	2.86	3.17	3.15	3.26	3.47	3.64	*3.80*	*4.80*	"Cash Flow" per sh	*4.40*
1.34	.84	1.06	1.05	1.37	1.57	1.67	.63	1.00	.39	1.30	1.31	1.32	1.37	1.47	1.60	*1.70*	*1.85*	Earnings per sh A	*2.20*
.92	.92	.92	.92	.94	.98	1.02	.83	.64	.70	.78	.80	.84	.88	.94	1.00	*1.06*	*1.12*	Div'ds Decl'd per sh B ■	*1.20*
3.54	2.81	2.88	3.99	4.83	5.99	6.42	4.26	4.57	5.03	4.88	4.72	4.49	4.53	6.32	5.93	*7.00*	*6.50*	Cap'l Spending per sh	*6.75*
17.24	17.54	17.63	17.71	17.90	18.77	19.54	12.04	12.60	12.82	13.08	13.36	12.44	13.33	13.14	22.71	*23.20*	*22.15*	Book Value per sh C	*20.40*
274.26	276.79	279.30	282.18	310.28	313.68	316.04	319.11	323.16	337.02	372.36	382.14	391.76	404.30	411.10	446.38	*450.00*	*450.00*	Common Shs Outst'g D	*450.00*
12.1	14.3	15.3	19.4	17.9	18.9	22.7	37.3	23.2	NMF	19.3	21.3	18.7	18.0	19.6	16.8	*Bold figures are*		Avg Ann'l P/E Ratio	*19.0*
.73	.95	.97	1.22	1.14	1.06	1.19	1.88	1.22	NMF	1.04	1.13	.96	.99	11.8	.97	*Value Line*		Relative P/E Ratio	*1.05*
5.7%	7.6%	5.7%	4.5%	3.8%	3.3%	2.7%	3.5%	2.8%	2.8%	3.1%	2.9%	3.4%	3.6%	3.3%	3.7%	*estimates*		Avg Ann'l Div'd Yield	*3.0%*

CAPITAL STRUCTURE as of 3/31/24
Total Debt $12970.9 mill. **Due in 5 Yrs** $4175 mill.
LT Debt $11724.6 mill. **LT Interest** $450 mill.
(Interest cov. earned: 4.5x) (54% of Cap'l)

Leases, Uncapitalized Annual rentals $9.6 mill.
Pension Assets-12/22 $1.4 bill. **Oblig.** $1.4 bill.

Pfd Stock $486 mill. **Pfd Div'd** $42.8 mill.

Common Stock 448,305,338 shs.
as of 4/30/24
MARKET CAP: $12.9 billion (Large Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
6470.6	4651.8	4492.5	4874.6	5114.5	5208.9	4681.7	4899.6	5850.6	5505.4	*6200*	*6550*	Revenues ($mill)	*7250*
530.7	198.6	328.1	128.6	478.3	549.8	562.6	626.3	648.2	716.3	*765*	*835*	Net Profit ($mill)	*990*
36.9%	41.6%	35.7%	71.0%	19.7%	17.0%	18.3%	15.7%	17.2%	17.8%	*19.0%*	*19.0%*	Income Tax Rate	*19.0%*
--	--	--	--	--	--	--	2.0%	2.3%	3.5%	*3.0%*	*2.5%*	AFUDC % to Net Profit	*2.5%*
56.9%	60.7%	59.8%	63.5%	55.3%	56.8%	61.6%	56.9%	55.7%	52.2%	*52.5%*	*52.5%*	Long-Term Debt Ratio	*55.0%*
43.1%	39.3%	40.2%	36.5%	37.9%	36.9%	32.5%	33.5%	31.6%	45.5%	*40.0%*	*40.0%*	Common Equity Ratio	*37.5%*
14331	9792.0	10129	11832	12856	13843	14972	16131	17099	21192	*22000*	*21000*	Total Capital ($mill)	*24450*
16017	12112	13068	14360	15543	16912	16620	17882	19843	22275	*24500*	*25750*	Net Plant ($mill)	*28000*
5.3%	4.0%	5.0%	2.6%	5.1%	5.3%	5.0%	4.9%	3.8%	3.4%	*3.5%*	*4.0%*	Return on Total Cap'l	*4.0%*
8.6%	5.2%	8.1%	3.0%	8.3%	9.2%	9.8%	9.0%	9.3%	7.1%	*7.5%*	*8.5%*	Return on Shr. Equity	*9.0%*
8.6%	5.2%	8.1%	3.0%	9.6%	9.7%	10.4%	10.6%	12.0%	7.4%	*8.5%*	*10.0%*	Return on Com Equity	*11.0%*
3.4%	NMF	3.0%	NMF	4.0%	3.8%	3.8%	4.2%	4.0%	2.8%	*3.5%*	*4.0%*	Retained to Com Eq	*5.0%*
61%	NMF	63%	NMF	60%	64%	67%	64%	64%	63%	*62%*	*61%*	All Div'ds to Net Prof	*55%*

CURRENT POSITION ($MILL.)	2022	2023	3/31/24
Cash Assets	40.8	2245.4	102.2
Other	2543.5	2254.0	1958.0
Current Assets	2584.3	4499.4	2060.2
Accts Payable	899.5	749.4	612.5
Debt Due	1791.9	3072.4	1246.3
Other	1969.1	1443.3	1266.2
Current Liab.	4660.5	5265.1	3125.0
Fix. Chg. Cov.	255%	225%	425%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-5.0%	-3.5%	*5.5%*
"Cash Flow"	.5%	6.5%	*5.5%*
Earnings	1.5%	15.0%	*9.5%*
Dividends	-.5%	3.5%	*4.5%*
Book Value	-3.0%	.5%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1545.6	986.0	959.4	1408.6	4899.6
2022	1873.3	1183.2	1089.5	1704.6	5850.6
2023	1966.0	1090.0	1027.4	1422.0	5505.4
2024	1706.3	*1400*	*1200*	*1893.7*	*6200*
2025	*1805*	*1480*	*1270*	*1995*	*6550*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.77	.13	.11	.39	1.37
2022	.75	.12	.10	.50	1.47
2023	.77	.11	.19	.53	1.60
2024	.85	*.15*	*.13*	*.57*	*1.70*
2025	*.90*	*.20*	*.15*	*.60*	*1.85*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.21	.21	.21	.21	.84
2021	.22	.22	.22	.22	.88
2022	.235	.235	.235	.235	.94
2023	.25	.25	.25	.25	1.00
2024	.265	.265			

BUSINESS: NiSource Inc. is a holding company for Northern Indiana Public Service Company (NIPSCO), which supplies electricity and gas to the northern third of Indiana. Customers: 488,833 electric in Indiana, 3,200,000 gas in Indiana, Ohio, Pennsylvania, Kentucky, Virginia, Maryland, through its Columbia subsidiaries. Revenue breakdown, 2024: electrical, 32%; gas, 67%; other, less than 1%. Generating capacity, coal, 69.4%; purchased & other, 30.6%. 2022 reported depreciation rates: 3.5% electric, 2.4% gas. Has 7,364 employees. Chairman: Richard L. Thompson. President & Chief Executive Officer: Lloyd Yates. Incorporated: Indiana. Address: 801 East 86th Avenue, Merrillville, Indiana 46410. Telephone: 877-647-5990. Internet: www.nisource.com.

NiSource had a strong earnings performance in the first quarter of 2024. The company continued its streak of consecutive quarterly growth by posting earnings of $0.85 per share, a 10% increase from the previous year. While this matched our target, the metric shows an outperformance considering the significant expansion of the number of diluted shares outstanding in the quarter, which we did not anticipate. The shares were likely issued in response to a large portion of debt that came due in the quarter, reflecting the utility's challenge of financing in the current high interest-rate environment. Still, investment is critical for the company's growth. Fortunately, the utility enjoys a strong regulatory environment across its geographies in Indiana, Ohio, Pennsylvania and Virginia, which together contributed to a rate-base of $18.8 billion at the end of 2023.

Our near-term earnings targets remain unchanged at the current juncture. Year-end earnings per share of $1.70 is likely, due to our anticipation of rate-base growth of roughly 8%-10%. The company has plans for significant capital expansion, including $16.4 billion aimed at enhancing system reliability and the transition to more sustainable energy sources. NiSource's track record for efficient capital allocation has led to consistent regulatory execution and affordable energy for its customers, supporting a low operating-risk profile. Too, tailwinds from sustainable investments, such as solar projects and infrastructure hardening, are likely to synergize with trends within the mid-west, such as the reshoring of manufacturing and the increasing development of data centers within its operating footprint. Economic conditions permitting, we anticipate steady earnings growth through to late decade.

Our stock projections reflect NiSource's strong prospects. Despite a strong return of more than 12% over the past three months, these good quality shares still reflect appealing value to the risk-sensitive accounts. The stock's high marks for Price Stability (95) pair well with it's above-average dividend yield of 3.8% to create a strong offering to income-style conservative investors.

Earl B. Humes *May 24, 2024*

(A) Dil. EPS. Excl. gains (losses) on disc. ops.: '08, ($1.14); '15, (30¢); '18, ($1.48). Next egs. report due early August. Qtl'y egs. may not sum to total due to rounding.
(B) Div'ds historically paid in mid-Feb., May, Aug., Nov. ■ Div'd reinv. avail.
(C) Incl. intang in '23: $1485.9 million, $3.33/sh.
(D) In mill.
(E) Spun off Columbia Pipeline Group (7/15)

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	20
Earnings Predictability	60

N.W. NATURAL NYSE-NWN

RECENT PRICE	38.48	P/E RATIO	15.4 (Trailing: 16.9 / Median: 24.0)	RELATIVE P/E RATIO	0.85	DIV'D YLD	5.1%	VALUE LINE

TIMELINESS **3** Raised 3/22/24
SAFETY **2** Raised 2/23/24
TECHNICAL **4** Raised 5/17/24
BETA .85 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$33-$54	$44 (15%)

2027-29 PROJECTIONS

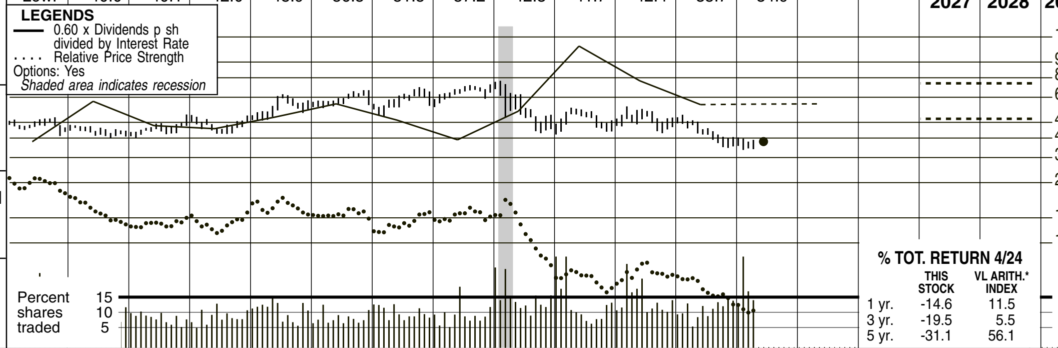
	Price	Gain	Ann'l Total Return
High	75	(+95%)	22%
Low	50	(+30%)	11%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	122	115	123
to Sell	123	110	90
Hld's(000)	26926	27474	28414

High:	46.6	52.6	52.3	66.2	69.5	71.8	74.1	77.3	56.8	57.6	52.4	40.3
Low:	40.0	40.1	42.0	48.9	56.5	51.5	57.2	42.3	41.7	42.4	35.7	34.9

Target Price Range 2027 | 2028 | 2029



% TOT. RETURN 4/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-14.6	11.5
3 yr.	-19.5	5.5
5 yr.	-31.1	56.1

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
39.16	38.17	30.56	31.72	27.14	28.02	27.64	26.39	23.61	26.52	24.45	24.49	25.29	27.64	29.20	31.82	*29.50*	*29.25*	Revenues per sh	*31.25*
5.31	5.20	5.18	5.00	4.94	5.04	5.05	4.91	4.93	1.04	5.28	5.15	5.69	6.17	5.71	5.83	*5.85*	*6.65*	"Cash Flow" per sh	*7.20*
2.57	2.83	2.73	2.39	2.22	2.24	2.16	1.96	2.12	d1.94	2.33	2.19	2.30	2.56	2.54	2.59	*2.50*	*3.00*	Earnings per sh A	*3.20*
1.52	1.60	1.68	1.75	1.79	1.83	1.85	1.86	1.87	1.88	1.89	1.90	1.91	1.92	1.93	1.94	*1.95*	*1.96*	Div'ds Decl'd per sh B■	*1.98*
3.92	5.09	9.35	3.76	4.91	5.13	4.40	4.37	4.87	7.43	7.43	7.95	9.18	9.49	9.53	8.70	*9.25*	*9.50*	Cap'l Spending per sh	*10.00*
23.71	24.88	26.08	26.70	27.23	27.77	28.12	28.47	29.71	25.85	26.41	28.42	29.05	30.04	33.08	34.12	*36.55*	*36.60*	Book Value per sh D	*36.10*
26.50	26.53	26.58	26.76	26.92	27.08	27.28	27.43	28.63	28.74	28.88	30.47	30.59	31.13	35.53	37.63	*39.00*	*41.00*	Common Shs Outst'g C	*45.00*
18.1	15.2	17.0	19.0	21.1	19.4	20.7	23.7	26.9	- -	26.6	30.9	25.0	19.5	19.6	16.6	*Bold figures are*		Avg Ann'l P/E Ratio	*20.0*
1.09	1.01	1.08	1.19	1.34	1.09	1.09	1.19	1.41	- -	1.44	1.65	1.28	1.06	1.13	.96	*Value Line*		Relative P/E Ratio	*1.10*
3.3%	3.7%	3.6%	3.9%	3.8%	4.2%	4.1%	4.0%	3.3%	3.0%	3.0%	2.8%	3.3%	3.8%	3.9%	4.5%	*estimates*		Avg Ann'l Div'd Yield	*3.3%*

CAPITAL STRUCTURE as of 3/31/24
Total Debt $1670.3 mill. **Due in 5 Yrs** $1415 mill.
LT Debt $1574.7 mill. **LT Interest** $80 mill.

(Total interest coverage: 5.0x)

Pension Assets-12/23 $283.0 mill.
Oblig. $425.5 mill.

Pfd Stock None

Common Stock 38,028,137 shares
as of 4/26/24

MARKET CAP $1.5 billion (Small Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
754.0	723.8	676.0	762.2	706.1	746.4	773.7	860.4	1037.4	1197.5	*1150*	*1200*	Revenues ($mill)	*1400*
58.7	53.7	58.9	d55.6	67.3	65.3	70.3	78.7	86.3	93.9	*97.5*	*125*	Net Profit ($mill)	*145*
41.5%	40.0%	40.9%	- -	26.4%	16.2%	23.1%	25.8%	25.2%	25.7%	*25.0%*	*25.0%*	Income Tax Rate	*25.0%*
7.8%	7.4%	8.7%	NMF	9.5%	8.8%	9.1%	9.1%	8.3%	7.8%	*8.5%*	*10.3%*	Net Profit Margin	*10.2%*
44.8%	42.5%	44.4%	47.9%	48.1%	48.2%	49.2%	52.8%	51.5%	52.6%	*50.0%*	*50.0%*	Long-Term Debt Ratio	*50.0%*
55.2%	57.5%	55.6%	52.1%	51.9%	51.8%	50.8%	47.2%	48.5%	47.4%	*50.0%*	*50.0%*	Common Equity Ratio	*50.0%*
1389.0	1357.7	1529.8	1426.0	1468.9	1672.0	1748.8	1979.7	2421.6	2709.2	*2850*	*3000*	Total Capital ($mill)	*3250*
2121.6	2182.7	2260.9	2255.0	2421.4	2438.9	2654.8	2871.4	3114.4	3358.0	*3500*	*3675*	Net Plant ($mill)	*3900*
5.8%	5.5%	5.1%	NMF	5.8%	5.2%	5.2%	5.1%	3.6%	3.5%	*3.5%*	*4.0%*	Return on Total Cap'l	*4.5%*
7.6%	6.9%	6.9%	NMF	8.8%	7.5%	7.9%	8.4%	7.3%	7.3%	*7.0%*	*8.0%*	Return on Shr. Equity	*9.0%*
7.6%	6.9%	6.9%	NMF	8.8%	7.5%	7.9%	8.4%	7.3%	7.3%	*7.0%*	*8.0%*	Return on Com Equity	*9.0%*
1.1%	.6%	.9%	NMF	2.1%	1.4%	1.7%	2.4%	2.1%	1.7%	*1.5%*	*3.0%*	Retained to Com Eq	*3.5%*
85%	92%	87%	NMF	76%	82%	79%	71%	79%	75%	*78%*	*65%*	All Div'ds to Net Prof	*62%*

CURRENT POSITION ($MILL.)	2022	2023	3/31/24
Cash Assets	29.3	32.9	72.4
Other	714.9	568.5	465.3
Current Assets	744.2	601.4	537.7
Accts Payable	180.7	145.4	107.9
Debt Due	348.9	240.7	95.6
Other	369.1	310.8	264.8
Current Liab.	898.7	696.9	468.3
Fix. Chg. Cov.	320%	240%	535%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-2.5%	- -	*4.5%*
"Cash Flow"	1.0%	2.5%	*5.0%*
Earnings	-1.0%	2.5%	*6.5%*
Dividends	1.5%	.5%	*.5%*
Book Value	1.0%	.5%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	315.9	148.9	101.5	294.1	860.4
2022	350.3	195.0	116.8	375.3	1037.4
2023	462.4	237.9	141.5	355.7	1197.5
2024	433.5	*220*	*130*	*366.5*	*1150*
2025	*450*	*230*	*135*	*385*	*1200*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1.94	d.02	d.67	1.31	2.56
2022	1.80	.05	d.56	1.36	2.54
2023	2.01	.03	d.65	1.21	2.59
2024	1.69	*.05*	*d.65*	*1.41*	*2.50*
2025	*2.10*	*.05*	*d.60*	*1.45*	*3.00*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.4775	.4775	.4775	.48	1.91
2021	.48	.48	.48	.483	1.92
2022	.483	.483	.483	.485	1.93
2023	.485	.485	.485	.488	1.94
2024	.488	.488			

BUSINESS: Northwest Natural Holding Co. distributes natural gas to 1,000 communities, 795,000 customers, in Oregon (88% of customers) and in southwest Washington state. Principal cities served: Portland and Eugene, OR; Vancouver, WA. Service area population: 3.7 mill. (77% in OR). Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline system. Owns local underground storage. Rev. breakdown: residential, 38%; commercial, 23%; industrial, gas transportation, 39%. Employs 1,380. BlackRock Inc. owns 17.6% of shares; Vanguard, 12.4%; Off./Dir., .84% (4/24 proxy). CEO: David H. Anderson. Inc.: Oregon. Address: 220 NW 2nd Ave., Portland, OR 97209. Tel.: 503-226-4211. Internet: www.nwnatural.com.

Northwest Natural Holdings continues to face challenging earnings comparisons. The northwestern natural gas utility saw its earnings decrease year-over-year for the fourth consecutive quarter in the March period to start 2024. Earnings per share in the company's cyclical-peak season amounted to $1.69, well below our target for a flat performance versus the year-prior's $2.01 result. The downturn in performance was primarily due to regulatory lag effects on its capital investments and rising cost pressures resulting in higher pension, depreciation, and interest expenses. Despite this, strengths such as a 1.7% growth in its customer base, low regional unemployment, and a peak-day delivery record of 8 million thermal units, paint an backdrop of strong demand. However, we expect that cost-of-living concerns across its operating footprint have led regulators to scrutinize the company's filings and tighten up on the rate-base regulatory approval process, hampering results of late.

We've cut our near-term earnings target to reflect the likelihood of continued regulatory challenges. While underlying operations should continue to grow steadily based on demographic trends, profitability leading into the cyclical-low season is likely to underwhelm. Instead, the company is refocusing its efforts on infrastructure hardening, including a planned $82 million investment that is slated for the current year as part of its rate case filings. We expect a relief in the final stanza of the year with rate adjustments likely to be resolved by November.

The long-term outlook here is more nuanced. Northwest is positioned in a strong geographic market that is undergoing a heavy investment cycle into clean-energy and energy-efficiency initiatives that ought to provide ample tailwinds to late decade. However, we also note some potential risks as both wildfires and seismic events have the potential to cause impairment to the company's infrastructure.

These good quality shares offer solid return potential and an above average dividend. The stock is a strong pick for conservative accounts, due to its Price Stability (85) and Financial Strength (A).

Earl B. Humes *May 24, 2024*

(A) Diluted earnings per share. Excludes nonrecurring items: '08, ($0.03); '09, $0.06; May not sum due to rounding. Next earnings report due in early August.
(B) Dividends historically paid in mid-February, May, August, and November.
■ Dividend reinvestment plan available.
(C) In millions.
(D) Includes intangibles. In 2023: $163 million, $4.33/share.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	25
Earnings Predictability	15

ONE GAS, INC. NYSE-OGS

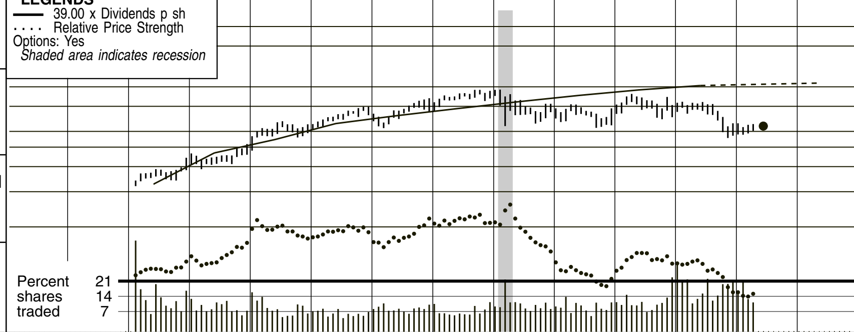
RECENT PRICE	63.81	P/E RATIO	16.0 (Trailing: 15.8; Median: 21.0)	RELATIVE P/E RATIO	0.88	DIV'D YLD	4.2%	VALUE LINE

TIMELINESS 3 Raised 12/8/23
SAFETY 2 New 6/2/17
TECHNICAL 3 Raised 5/24/24
BETA .85 (1.00 = Market)

High:	44.3	51.8	67.4	79.5	87.8	96.7	97.0	81.9	92.3	84.3	66.5
Low:	31.9	38.9	48.0	61.4	62.2	75.8	63.7	62.5	68.9	55.5	57.7

Target Price Range
2027 | 2028 | 2029

LEGENDS
—— 39.00 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



% TOT. RETURN 4/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-12.9	11.5
3 yr.	-11.3	5.5
5 yr.	-15.6	56.1

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$42-$77	$60 (-5%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	105	(+65%)	16%
Low	75	(+20%)	8%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	158	148	159
to Sell	133	153	160
Hld's(000)	53044	51074	52932

The shares of ONE Gas, Inc. began trading "regular-way" on the New York Stock Exchange on February 3, 2014. That happened as a result of the separation of ONEOK's natural gas distribution operation. Regarding the details of the spinoff, on January 31, 2014, ONEOK distributed one share of OGS common stock for every four shares of ONEOK common stock held by ONEOK shareholders of record as of the close of business on January 21. It should be mentioned that ONEOK did not retain any ownership interest in the new company.

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
34.92	29.62	27.30	29.43	31.08	31.32	28.78	33.72	46.58	41.95	***39.30***	***42.50***	**Revenues per sh**	***70.15***
4.52	4.82	5.43	5.96	6.32	6.96	7.36	7.71	8.13	9.04	***9.65***	***10.70***	**"Cash Flow" per sh**	***13.95***
2.07	2.24	2.65	3.02	3.25	3.51	3.68	3.85	4.08	4.14	***4.00***	***4.20***	**Earnings per sh A**	***5.00***
.84	1.20	1.40	1.68	1.84	2.00	2.16	2.32	2.48	2.60	***2.64***	***2.68***	**Div'ds Decl'd per sh B■**	***2.85***
5.70	5.63	5.91	6.81	7.50	7.91	8.87	9.23	11.01	11.79	***11.95***	***12.15***	**Cap'l Spending per sh**	***12.60***
34.45	35.24	36.12	37.47	38.86	40.35	42.01	43.81	46.69	48.91	***50.15***	***53.55***	**Book Value per sh**	***60.20***
52.08	52.26	52.28	52.31	52.57	52.77	53.17	53.63	55.35	56.55	***56.50***	***56.50***	**Common Shs Outst'g C**	***57.00***
17.8	19.8	22.7	23.5	23.1	25.3	21.7	18.9	19.9	18.0	***Bold figures are***		**Avg Ann'l P/E Ratio**	***18.0***
.94	1.00	1.19	1.18	1.25	1.35	1.11	1.02	1.16	1.01	***Value Line***		**Relative P/E Ratio**	***1.00***
2.3%	2.7%	2.3%	2.4%	2.5%	2.3%	2.7%	3.2%	3.1%	3.5%	***estimates***		**Avg Ann'l Div'd Yield**	***3.2%***
1818.9	1547.7	1427.2	1539.6	1633.7	1652.7	1530.3	1808.6	2578.0	2372.0	***2220***	***2400***	**Revenues ($mill)**	***4000***
109.8	119.0	140.1	159.9	172.2	186.7	196.4	206.4	221.7	231.2	***225***	***235***	**Net Profit ($mill)**	***285***
38.4%	38.0%	37.8%	36.4%	23.7%	18.7%	17.5%	16.3%	17.3%	14.9%	***15.5%***	***16.0%***	**Income Tax Rate**	***20.0%***
6.0%	7.7%	9.8%	10.4%	10.5%	11.3%	12.8%	11.4%	8.6%	9.7%	***10.1%***	***9.8%***	**Net Profit Margin**	***7.1%***
40.1%	39.5%	38.7%	37.8%	38.6%	37.7%	41.5%	61.1%	50.7%	43.8%	***45.0%***	***45.0%***	**Long-Term Debt Ratio**	***51.0%***
59.9%	60.5%	61.3%	62.2%	61.4%	62.3%	58.5%	38.9%	49.3%	56.2%	***55.0%***	***55.0%***	**Common Equity Ratio**	***49.0%***
2995.3	3042.9	3080.7	3153.5	3328.1	3415.5	3815.7	6032.9	5246.2	4926.3	***5150***	***5500***	**Total Capital ($mill)**	***7000***
3293.7	3511.9	3731.6	4007.6	4283.7	4565.2	4867.1	5190.8	5628.8	6135.2	***6425***	***6800***	**Net Plant ($mill)**	***8000***
4.4%	4.7%	5.2%	5.8%	5.9%	6.4%	6.0%	3.9%	5.0%	5.9%	***5.5%***	***5.5%***	**Return on Total Cap'l**	***5.5%***
6.1%	6.5%	7.4%	8.2%	8.4%	8.8%	8.8%	8.8%	8.6%	8.4%	***8.0%***	***8.0%***	**Return on Shr. Equity**	***8.5%***
6.1%	6.5%	7.4%	8.2%	8.4%	8.8%	8.8%	8.8%	8.6%	8.4%	***8.0%***	***8.0%***	**Return on Com Equity**	***8.5%***
3.7%	3.1%	3.5%	3.7%	3.7%	3.8%	3.7%	3.5%	3.4%	3.2%	***3.0%***	***3.0%***	**Retained to Com Eq**	***3.5%***
40%	53%	52%	55%	56%	56%	58%	60%	60%	62%	***66%***	***64%***	**All Div'ds to Net Prof**	***57%***

CAPITAL STRUCTURE as of 3/31/24
Total Debt $3128.0 mill. **Due in 5 Yrs** $890.0 mill.
LT Debt $2146.4 mill. **LT Interest** $120.0 mill.
(LT interest earned: 3.4x; total interest coverage: 3.4x)
Leases, Uncapitalized Annual rentals $6.7 mill.
Pfd Stock None
Pension Assets-12/23 $977.0 mill.
Oblig. $962.1 mill.
Common Stock 56,569,396 shs.
as of 4/29/24
MARKET CAP: $3.6 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2022	2023	3/31/24
Cash Assets	9.7	18.8	11.5
Other	1207.9	746.4	652.2
Current Assets	1217.6	765.2	663.7
Accts Payable	360.5	278.1	196.6
Debt Due	572.7	888.9	981.6
Other	256.2	310.2	225.3
Current Liab.	1189.4	1477.2	1403.5
Fix. Chg. Cov.	540%	390%	420%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	- -	7.0%	*9.5%*
"Cash Flow"	- -	7.0%	*9.0%*
Earnings	- -	6.0%	*3.5%*
Dividends	- -	8.5%	*2.5%*
Book Value	- -	4.5%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	625.3	315.6	273.9	593.8	1808.6
2022	971.5	428.9	359.4	818.2	2578.0
2023	1032.1	398.1	335.8	606.0	2372.0
2024	758.3	***410***	***350***	***701.7***	***2220***
2025	***800***	***430***	***410***	***760***	***2400***

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1.79	.56	.38	1.12	3.85
2022	1.83	.59	.44	1.23	4.08
2023	1.84	.58	.45	1.27	4.14
2024	1.75	***.56***	***.43***	***1.26***	***4.00***
2025	***1.85***	***.60***	***.48***	***1.27***	***4.20***

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.54	.54	.54	.54	2.16
2021	.58	.58	.58	.58	2.32
2022	.62	.62	.62	.62	2.48
2023	.65	.65	.65	.65	2.60
2024	.66	.66			

BUSINESS: ONE Gas, Inc. provides natural gas distribution services to more than two million customers. There are three divisions: Oklahoma Natural Gas, Kansas Gas Service, and Texas Gas Service. The company purchased 160 Bcf of natural gas supply in 2023, compared to 165 Bcf in 2022. Total volumes delivered by customer (fiscal 2023): transportation, 59.3%; residential, 29.7%; commercial & industrial, 10.6%; other, .4%. ONE Gas has around 3,900 employees. BlackRock owns 14.5% of common stock; The Vanguard Group, 11.6%; American Century Investment, 7.5%; officers and directors, 1.5% (4/24 Proxy). CEO: Robert S. McAnnally. Incorporated: Oklahoma. Address: 15 East Fifth Street, Tulsa, Oklahoma 74103. Tel.: 918-947-7000. Internet: www.onegas.com.

ONE Gas, Inc. began 2024 in low gear. First-quarter earnings per share slipped about 5%, to $1.75, relative to last year's $1.84 figure. That was traced partly to higher employee-related costs, given planned investments in the company's workforce and ongoing in-sourcing efforts. Also, sales volumes decreased and interest expense rose. But new rates did provide somewhat of an offset. Still, right now, it appears that the bottom line will recede around 3% for the whole year, to $4.00 per share, versus the $4.14 tally generated in 2023. But turning to 2025, a 5% recovery, to $4.20 a share, seems plausible. That's based, to a certain degree, on our assumption that the business environment is generally favorable.

Prospects out to the end of the decade appear promising. ONE Gas remains the top natural gas distributor, as measured by number of customers, in both Oklahoma and Kansas, and holds the number-three position in Texas. (Services are provided to more than two million residential, commercial, and transportation clients at present.) Furthermore, we believe those markets have decent growth potential and are located in one of the most active drilling areas in the United States. Also, supported by the solid balance sheet, the company ought to continue to meet its working capital requirements, capital expenditures, and other obligations with little difficulty.

There are risk factors to bear in mind, however. ONE Gas' lack of geographic diversification leaves it somewhat more susceptible to regional economic downturns and regulations. Moreover, there's competition from other energy suppliers, including propane dealers and electric companies. Finally, pipeline ruptures, leaks, and other unfortunate occurrences can take a major toll on corporate profits if not adequately covered by insurance.

The stock has some investment appeal. Its dividend yield is respectable in comparison with other equities within *Value Line's* Natural Gas Utility Industry. Also, capital appreciation possibilities over the 2027-2029 horizon look worthwhile. Consider, too, the 2 (Above Average) rank for Safety and high Price Stability score of 90 out of 100.

Frederick L. Harris, III *May 24, 2024*

(A) Diluted EPS. Excludes nonrecurring gain: 2017, $0.06. Next earnings report due early Aug. Quarterly EPS figures for 2022 don't equal total due to rounding.
(B) Dividends historically paid in early March, June, Sept., and Dec. ■ Dividend reinvestment plan. Direct stock purchase plan.
(C) In millions.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	50
Earnings Predictability	100

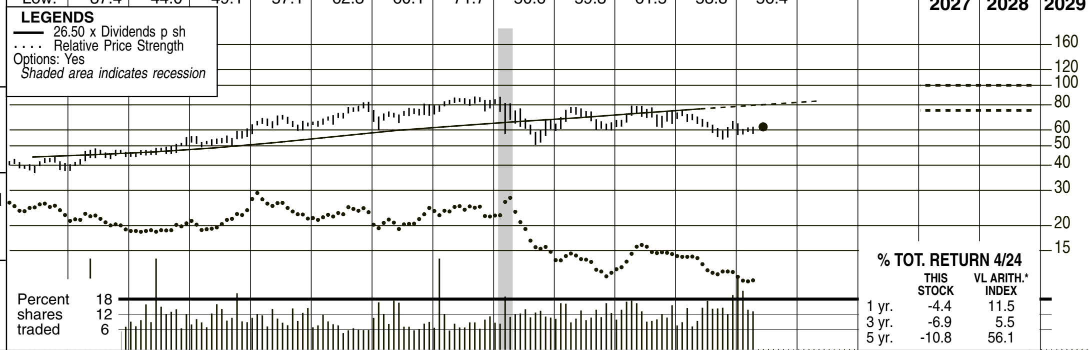
SPIRE INC. NYSE-SR

RECENT PRICE 62.20 | P/E RATIO 14.5 (Trailing: 15.7; Median: 19.0) | RELATIVE P/E RATIO 0.80 | DIV'D YLD 5.0% | VALUE LINE

TIMELINESS 3 Raised 2/16/24
SAFETY 2 Raised 6/20/03
TECHNICAL 4 Raised 5/17/24
BETA .85 (1.00 = Market)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	48.5	55.2	61.0	71.2	82.9	81.1	88.0	88.0	77.9	79.2	75.8	64.6
Low:	37.4	44.0	49.1	57.1	62.3	60.1	71.7	50.6	59.3	61.5	53.8	56.4

LEGENDS
— 26.50 x Dividends p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



18-Month Target Price Range
Low-High Midpoint (% to Mid)
$44-$72 $58 (-5%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	100	(+60%)	16%
Low	75	(+20%)	10%

Institutional Decisions

	2Q2023	3Q2023	4Q2023
to Buy	142	131	140
to Sell	138	144	123
Hld's(000)	46098	48374	48459

% TOT. RETURN 4/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-4.4	11.5
3 yr.	-6.9	5.5
5 yr.	-10.8	56.1

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
100.44	85.49	77.83	71.48	49.90	31.10	37.68	45.59	33.68	36.07	38.78	38.30	35.96	43.24	41.88	50.12	***45.20***	***45.65***	Revenues per sh A	***57.25***
4.22	4.56	4.11	4.62	4.58	3.12	3.87	6.15	6.16	6.54	7.55	7.12	5.25	9.09	8.44	8.60	***8.80***	***9.25***	"Cash Flow" per sh	***11.00***
2.64	2.92	2.43	2.86	2.79	2.02	2.35	3.16	3.24	3.43	4.33	3.52	1.44	4.96	3.95	3.85	***4.30***	***4.55***	Earnings per sh A B	***5.50***
1.49	1.53	1.57	1.61	1.66	1.70	1.76	1.84	1.96	2.10	2.25	2.37	2.49	2.60	2.74	2.88	***3.02***	***3.16***	Div'ds Decl'd per sh C ■	***3.60***
2.57	2.36	2.56	3.02	4.83	4.00	3.96	6.68	6.42	9.08	9.86	16.15	12.37	12.09	10.52	12.45	***13.70***	***13.90***	Cap'l Spending per sh	***14.50***
22.12	23.32	24.02	25.56	26.67	32.00	34.93	36.30	38.73	41.26	44.51	45.14	44.19	46.74	49.08	50.29	***52.65***	***55.75***	Book Value per sh D	***66.05***
21.99	22.17	22.29	22.43	22.55	32.70	43.18	43.36	45.65	48.26	50.67	50.97	51.60	51.70	52.50	53.20	***58.50***	***60.00***	Common Shs Outst'g E	***62.00***
14.3	13.4	13.7	13.0	14.5	21.3	19.8	16.5	19.6	19.8	16.7	22.8	51.1	13.6	17.5	17.3	*Bold figures are*		Avg Ann'l P/E Ratio	***16.0***
.86	.89	.87	.82	.92	1.20	1.04	.83	1.03	1.00	.90	1.21	2.62	.73	1.01	1.00	*Value Line*		Relative P/E Ratio	***.90***
3.9%	3.9%	4.7%	4.3%	4.1%	4.0%	3.8%	3.5%	3.1%	3.1%	3.1%	3.0%	3.4%	3.8%	4.0%	4.3%	*estimates*		Avg Ann'l Div'd Yield	***4.1%***

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
1627.2	1976.4	1537.3	1740.7	1965.0	1952.4	1855.4	2235.5	2198.5	2666.3	***2645***	***2740***	Revenues ($mill) A	***3550***
84.6	136.9	144.2	161.6	214.2	184.6	88.6	271.7	220.8	217.5	***240***	***260***	Net Profit ($mill)	***340***
27.6%	31.2%	32.5%	32.4%	- -	15.7%	12.3%	20.1%	21.1%	15.1%	***19.5%***	***19.5%***	Income Tax Rate	***24.0%***
5.2%	6.9%	9.4%	9.3%	10.9%	9.5%	4.8%	12.2%	10.0%	8.2%	***9.1%***	***9.5%***	Net Profit Margin	***9.6%***
55.1%	53.0%	50.9%	50.0%	45.7%	45.0%	49.0%	52.5%	51.2%	54.9%	***52.0%***	***52.0%***	Long-Term Debt Ratio	***51.0%***
44.9%	47.0%	49.1%	50.0%	54.3%	49.7%	46.1%	43.2%	44.6%	41.3%	***44.0%***	***44.0%***	Common Equity Ratio	***45.0%***
3359.4	3345.1	3601.9	3986.3	4155.5	4625.6	4946.0	5597.3	5777.0	6471.3	***7000***	***7600***	Total Capital ($mill)	***9100***
2759.7	2941.2	3300.9	3665.2	3970.5	4352.0	4680.1	5055.7	5370.4	5778.9	***6150***	***6530***	Net Plant ($mill)	***7675***
3.1%	5.1%	4.9%	5.0%	6.3%	5.1%	2.9%	5.8%	4.9%	4.8%	***5.0%***	***5.0%***	Return on Total Cap'l	***5.5%***
5.6%	8.7%	8.2%	8.1%	9.5%	7.3%	3.5%	10.2%	7.8%	7.5%	***8.0%***	***8.0%***	Return on Shr. Equity	***8.5%***
5.6%	8.7%	8.2%	8.1%	9.5%	7.9%	3.2%	10.6%	8.0%	7.6%	***8.0%***	***8.0%***	Return on Com Equity	***8.5%***
1.5%	3.7%	3.3%	3.3%	4.7%	2.7%	NMF	5.1%	2.5%	1.9%	***2.0%***	***1.5%***	Retained to Com Eq	***2.5%***
73%	58%	59%	60%	51%	66%	NMF	54%	71%	76%	***77%***	***79%***	All Div'ds to Net Prof	***70%***

CAPITAL STRUCTURE as of 3/31/24
Total Debt $4514.4 mill. **Due in 5 Yrs** $2310.0 mill.
LT Debt $3421.4 mill. **LT Interest** $140.0 mill.
(Total interest coverage: 2.4x)

Leases, Uncapitalized Annual rentals $9.8 mill.
Pension Assets-9/23 $630.3 mill. **Oblig.** $832.5 mill.
Pfd Stock $242.0 mill. **Pfd Div'd** $14.8 mill.
Common Stock 57,747,978 shs.
as of 4/28/24

MARKET CAP: $3.6 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2022	2023	3/31/24
Cash Assets	6.5	5.6	25.6
Other	1585.5	1071.3	980.1
Current Assets	1592.0	1076.9	1005.7
Accts Payable	617.4	253.1	193.4
Debt Due	1318.7	1112.1	1093.0
Other	417.5	390.2	363.9
Current Liab.	2353.6	1755.4	1650.3
Fix. Chg. Cov.	393%	294%	315%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-1.0%	4.5%	*4.0%*
"Cash Flow"	8.0%	5.0%	*4.0%*
Earnings	5.0%	3.0%	*4.5%*
Dividends	5.0%	5.5%	*4.5%*
Book Value	5.5%	3.5%	*5.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.)A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	512.6	1104.9	327.8	290.2	2235.5
2022	555.4	880.9	448.0	314.2	2198.5
2023	814.0	1123.4	418.5	310.4	2666.3
2024	756.6	1128.5	***434.9***	***325***	***2645***
2025	***790***	***1135***	***465***	***350***	***2740***

Fiscal Year Ends	EARNINGS PER SHARE A B F Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	1.65	3.55	.03	d.26	4.96
2022	1.01	3.27	d.10	d.20	3.95
2023	1.66	3.33	d.48	d.66	3.85
2024	1.52	3.58	***d.34***	***d.46***	***4.30***
2025	***1.50***	***3.45***	***d.16***	***d.24***	***4.55***

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.6225	.6225	.6225	.6225	2.49
2021	.65	.65	.65	.65	2.60
2022	.685	.685	.685	.685	2.74
2023	.72	.72	.72	.72	2.88
2024	.755	.755			

BUSINESS: Spire Inc., formerly known as the Laclede Group, Inc., is a holding company for natural gas utilities, which distributes natural gas across Missouri, including the cities of St. Louis and Kansas City, Alabama, and Mississippi. Has roughly 1.7 million customers. Acquired Missouri Gas 9/13, Alabama Gas Co 9/14. Utility therms sold and transported in fiscal 2023: 3.2 bill. Revenue mix for regulated operations: residential, 67%; commercial and industrial, 25%; transportation, 5%; other, 3%. Officers and directors own 2.9% of common shares; American Century Companies, 15.4% (12/23 proxy). Chairman: Edward Glotzbach; CEO: Steve Lindsey. Inc.: Missouri. Address: 700 Market Street, St. Louis, Missouri 63101. Tel.: 314-342-0500. Internet: www.spireenergy.com.

Spire managed to post decent bottom-line results in the second quarter of fiscal 2024 (which concluded on March 31st). Indeed, earnings per share of $3.58 were 7.5% above the previous year's $3.33 tally. That was brought about, to a certain extent, by the Gas Utility division, which benefited partly from improved results at Spire Alabama. The Gas Marketing segment had a better showing for that period, too.

Higher profits appear to be in store for the year as a whole, as well. The company did get off to a slow start, with first-quarter share net receding 8.4%, to $1.52, relative to last year's $1.66 figure. That was attributed partly to the fact that, for both the Gas Marketing and Midstream divisions, fiscal 2023's very favorable market conditions did not reoccur. But, as mentioned, Spire's second-quarter performance was decent. Furthermore, bottom-line comparisons during the second half ought to be easier. (Losses are typical over that time frame because of the seasonality of the business.) All told, we expect full-year share net to rebound about 12%, to $4.30, versus fiscal 2023's $3.85 result. Concerning next year, profits might increase another 6% or so, to $4.55 a share, assuming additional widening of operating margins.

The Financial Strength rating sits at B++. When the second quarter ended, cash and equivalents were $25.6 million. Furthermore, there was $1.3 billion available through a revolving credit facility expiring in July, 2027. Also, long-term debt resided at a manageable 50% of total capital, and short-term obligations of almost $1.1 billion did not seem to be a major obstacle. So, the company should continue to satisfy its commitments, which include working capital requirements and capital expenditures, with minimal difficulty.

The equity ought to draw the attention of some investors. Its dividend yield stacks up well compared to those of other stocks in *Value Line's* Natural Gas Utility Industry. What's more, capital appreciation potential over the 2027-2029 horizon looks worthwhile. Meanwhile, SR shares are pegged to mimic the market over the next six to 12 months (Timeliness rank 3: Average).

Frederick L. Harris, III *May 24, 2024*

(A) Fiscal year ends Sept. 30th. (B) Based on diluted shares outstanding. Excludes gain from discontinued operations: '08, 94¢. Next earnings report due late July. (C) Dividends paid in early January, April, July, and October. ■ Dividend reinvestment plan available. (D) Incl. deferred charges. In '23: $1,171.6 mill., $22.02/sh. (E) In millions. (F) Qtly. egs. may not sum due to rounding or change in shares outstanding.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	35
Earnings Predictability	45

Southwest Gas Corporation
Indicated Common Equity Cost Rate
Through Use of a Risk Premium Model
Using an Adjusted Total Market Approach

Line No.		Proxy Group of Six Natural Gas Distribution Companies
1.	Prospective Yield on Aaa Rated Corporate Bonds (1)	5.14 %
2.	Adjustment to Reflect Yield Spread Between Aaa Rated Corporate Bonds and A2 Rated Public Utility Bonds (2)	0.51
3.	Adjusted Prospective Yield on A2 Rated Public Utility Bonds	5.65 %
4.	Equity Risk Premium (3)	5.17
5.	Risk Premium Derived Common Equity Cost Rate	10.82 %

Notes: (1) Consensus forecast of Moody's Aaa Rated Corporate bonds from Blue Chip Financial Forecasts (see pages 7 and 8 of this Exhibit).
(2) The average yield spread of A2 rated public utility bonds over Aaa rated corporate bonds of 0.51% from page 2 of this Exhibit.
(3) From page 5 of this Exhibit.

Southwest Gas Corporation
Interest Rates and Bond Spreads for
Moody's Corporate and Public Utility Bonds

Selected Bond Yields

	[1]	[2]	[3]
	Aaa Rated Corporate Bond	A2 Rated Public Utility Bond	Baa2 Rated Public Utility Bond
May-2024	5.25 %	5.74 %	5.97 %
Apr-2024	5.28	5.79	6.01
Mar-2024	5.01	5.55	5.79
Average	5.18 %	5.69 %	5.92 %

Selected Bond Spreads

A2 Rated Public Utility Bonds Over Aaa Rated Corporate Bonds:
0.51 % (1)

Baa2 Rated Public Utility Bonds Over A2 Rated Public Utility Bonds:
0.23 % (2)

Notes:
(1) Column [2] - Column [1].
(2) Column [3] - Column [2].

Source of Information:
Bloomberg Professional Services

Southwest Gas Corporation
Comparison of Long-Term Issuer Ratings for the
Proxy Group of Six Natural Gas Distribution Companies

	Moody's Long-Term Issuer Rating May 2024		Standard & Poor's Long-Term Issuer Rating May 2024	
Proxy Group of Six Natural Gas Distribution Companies	Long-Term Issuer Rating	Numerical Weighting (1)	Long-Term Issuer Rating	Numerical Weighting (1)
Atmos Energy Corporation	A1	5.0	A-	7.0
New Jersey Resources Corporation	A1	5.0	NR	- -
NiSource Inc.	Baa1	8.0	BBB+	8.0
Northwest Natural Holding Company	Baa1	8.0	A+	5.0
ONE Gas, Inc.	A3	7.0	A-	7.0
Spire Inc.	A1/A2	5.5	BBB+	8.0
Average	A2	6.4	A-	7.0
Southwest Gas Corporation	Baa1	8.0	BBB	9.0

Notes:
(1) Ratings are that of the average of each company's utility operating subsidiaries
(2) From page 4 of this Exhibit.

Source Information: Moody's Investors Service
Standard & Poor's Global Utilities Rating Service

Numerical Assignment for
Moody's and Standard & Poor's Bond Ratings

Moody's Bond Rating	Numerical Bond Weighting	Standard & Poor's Bond Rating
Aaa	1	AAA
Aa1	2	AA+
Aa2	3	AA
Aa3	4	AA-
A1	5	A+
A2	6	A
A3	7	A-
Baa1	8	BBB+
Baa2	9	BBB
Baa3	10	BBB-
Ba1	11	BB+
Ba2	12	BB
Ba3	13	BB-
B1	14	B+
B2	15	B
B3	16	B-

Southwest Gas Corporation
Judgment of Equity Risk Premium for the
Proxy Group of Six Natural Gas Distribution Companies

Line No.		Proxy Group of Six Natural Gas Distribution Companies	
1.	Calculated equity risk premium based on the total market using the beta approach (1)	6.20	%
2.	Mean equity risk premium based on a study using the holding period returns of public utilities with A2 rated bonds (2)	4.51	
3.	Predicted Equity Risk Premium Based on Regression Analysis of 834 Fully-Litigated Natural Gas Distribution Cases (3)	4.79	
4	Average equity risk premium	5.17	%

Notes: (1) From page 6 of this Exhibit.
(2) From page 9 of this Exhibit.
(3) From page 10 of this Exhibit.

Southwest Gas Corporation
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for the
Proxy Group of Six Natural Gas Distribution Companies

Line No.	Equity Risk Premium Measure	Proxy Group of Six Natural Gas Distribution Companies	
1.	Kroll Equity Risk Premium (1)	5.96	%
2.	Regression on Kroll Risk Premium Data (2)	6.92	
3.	Kroll Equity Risk Premium based on PRPM (3)	8.46	
4	Equity Risk Premium Based on Value Line Summary and Index (4)	6.91	
5.	Equity Risk Premium Based on Bloomberg, Value Line, and S&P Global Market Intelligence S&P 500 Companies (5)	10.05	
6.	Conclusion of Equity Risk Premium	7.66	%
7.	Adjusted Beta (6)	0.81	
8.	Forecasted Equity Risk Premium	6.20	%

Notes:
(1) Based on the arithmetic mean historical monthly returns on large company common stocks from Kroll minus the arithmetic mean monthly yield of Moody's average Aaa and Aa2 corporate bonds from 1928-2023.
(2) This equity risk premium is based on a regression of the monthly equity risk premiums of large company common stocks relative to Moody's average Aaa and Aa2 rated corporate bond yields from 1928-2023 referenced in Note 1 above. Using the equation generated from the regression, an expected equity risk premium is calculated using the average consensus forecast of Aaa corporate bonds of 5.14% (from page 1 of this Exhibit).
(3) The Predictive Risk Premium Model (PRPM) is discussed in the accompanying direct testimony. The Ibbotson equity risk premium based on the PRPM is derived by applying the PRPM to the monthly risk premiums between Ibbotson large company common stock monthly returns and average Aaa and Aa corporate monthly bond yields, from January 1928 through May 2024.
(4) The equity risk premium based on the Value Line Summary and Index is derived by subtracting the average consensus forecast of Aaa corporate bonds of 5.14% (from page 1 of this Exhibit) from the projected 3-5 year total annual market return of 12.05% (described fully in note 1 on page 2 of Exhibit No.__(DWD-5)).
(5) Using data from the Bloomberg Professional Services, Value Line, and S&P Capital IQ for the S&P 500 for the S&P 500, an expected total return of 15.19% was derived based upon expected dividend yields and long-term earnings growth estimates as a proxy for capital appreciation. Subtracting the average consensus forecast of Aaa corporate bonds of 5.14% results in an expected equity risk premium of 10.05%.
(6) Average of mean and median beta from Exhibit DWD-5.

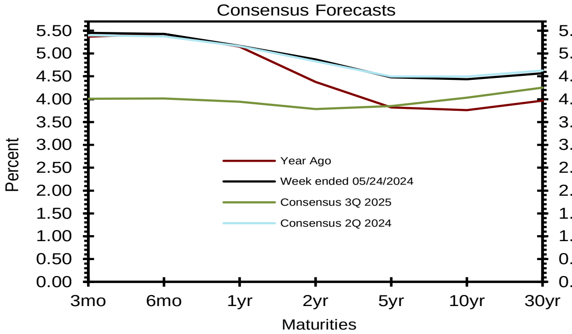
Sources of Information:
Kroll 2023 SBBI® Yearbook
Industrial Manual and Mergent Bond Record Monthly Update.
Value Line Summary and Index
Blue Chip Financial Forecasts, May 31, 2024
S&P Capital IQ
Bloomberg Professional Services

Consensus Forecasts of U.S. Interest Rates and Key Assumptions

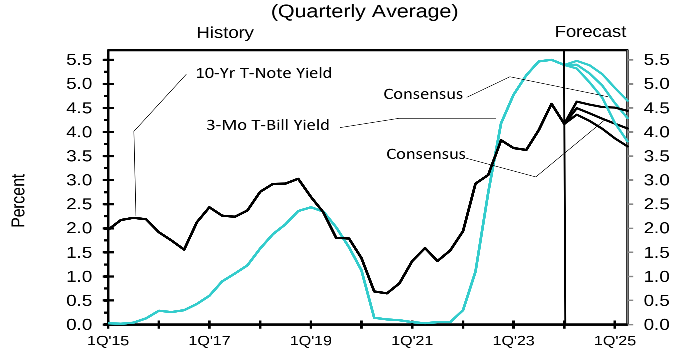
	History								Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month			*Latest Qtr*	2Q	3Q	4Q	1Q	2Q	3Q
Interest Rates	May 24	May 17	May 10	May 3	Apr	Mar	Feb	1Q 2024	**2024**	**2024**	**2024**	**2025**	**2025**	**2025**
Federal Funds Rate	5.33	5.33	5.33	5.33	5.33	5.33	5.33	5.33	**5.4**	**5.2**	**5.0**	**4.7**	**4.4**	**4.1**
Prime Rate	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.50	**8.5**	**8.4**	**8.1**	**7.8**	**7.6**	**7.3**
SOFR	5.31	5.31	5.31	5.32	5.32	5.31	5.31	5.31	**5.3**	**5.3**	**5.0**	**4.7**	**4.4**	**4.1**
Commercial Paper, 1-mo.	5.31	5.33	5.32	5.32	5.31	5.32	5.31	5.32	**5.3**	**5.2**	**5.0**	**4.7**	**4.4**	**4.0**
Treasury bill, 3-mo.	5.45	5.45	5.46	5.46	5.44	5.47	5.44	5.45	**5.4**	**5.2**	**5.0**	**4.6**	**4.3**	**4.0**
Treasury bill, 6-mo.	5.43	5.42	5.42	5.43	5.38	5.36	5.28	5.28	**5.4**	**5.2**	**4.9**	**4.6**	**4.3**	**4.0**
Treasury bill, 1 yr.	5.17	5.14	5.13	5.19	5.14	4.99	4.92	4.90	**5.2**	**5.0**	**4.7**	**4.4**	**4.2**	**3.9**
Treasury note, 2 yr.	4.87	4.80	4.83	4.93	4.87	4.59	4.54	4.48	**4.8**	**4.6**	**4.4**	**4.1**	**3.9**	**3.8**
Treasury note, 5 yr.	4.48	4.43	4.49	4.61	4.56	4.20	4.19	4.12	**4.5**	**4.4**	**4.2**	**4.1**	**3.9**	**3.9**
Treasury note, 10 yr.	4.44	4.42	4.48	4.61	4.54	4.21	4.21	4.16	**4.5**	**4.4**	**4.3**	**4.2**	**4.1**	**4.0**
Treasury note, 30 yr.	4.57	4.56	4.63	4.73	4.66	4.36	4.38	4.33	**4.6**	**4.5**	**4.5**	**4.4**	**4.3**	**4.3**
Corporate Aaa bond	5.28	5.27	5.34	5.45	5.38	5.11	5.13	5.08	**5.3**	**5.2**	**5.1**	**5.1**	**5.0**	**5.0**
Corporate Baa bond	5.76	5.76	5.83	5.94	5.88	5.62	5.65	5.60	**6.1**	**6.0**	**6.0**	**5.9**	**5.9**	**5.9**
State & Local bonds	4.29	4.21	4.23	4.32	4.28	4.12	4.12	4.11	**4.4**	**4.3**	**4.2**	**4.2**	**4.2**	**4.2**
Home mortgage rate	6.94	7.02	7.09	7.22	6.99	6.82	6.78	6.75	**7.0**	**6.9**	**6.7**	**6.5**	**6.4**	**6.3**
	History								**Consensus Forecasts-Quarterly**					
	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	**2Q**	**3Q**	**4Q**	**1Q**	**2Q**	**3Q**
Key Assumptions	2022	2022	2022	2023	2023	2023	2023	2024	**2024**	**2024**	**2024**	**2025**	**2025**	**2025**
Fed's AFE $ Index	113.5	118.8	119.8	115.5	114.6	115.0	116.6	115.5	**117.1**	**117.7**	**116.9**	**116.5**	**116.2**	**116.0**
Real GDP	-0.6	2.7	2.6	2.2	2.1	4.9	3.4	1.3	**2.2**	**1.7**	**1.6**	**1.8**	**1.9**	**2.0**
GDP Price Index	9.1	4.4	3.9	3.9	1.7	3.3	1.6	3.0	**2.8**	**2.5**	**2.3**	**2.3**	**2.3**	**2.2**
Consumer Price Index	10.0	5.3	4.0	3.8	3.0	3.4	2.7	3.8	**3.5**	**2.7**	**2.5**	**2.4**	**2.4**	**2.4**
PCE Price Index	7.2	4.7	4.1	4.2	2.5	2.6	1.8	3.3	**2.9**	**2.3**	**2.2**	**2.3**	**2.2**	**2.2**

Forecasts for interest rates and the Federal Reserve's Advanced Foreign Economies Index represent averages for the quarter. Forecasts for Real GDP, GDP Price Index, CPI and PCE Price Index are seasonally adjusted annual rates of change (saar). Individual panel members' forecasts are on pages 4 through 9. Historical data: Treasury rates from the Federal Reserve Board's H.15; AAA-AA and A-BBB corporate bond yields from Bank of America-Merrill Lynch and are 15+ years, yield to maturity; State and local bond yields from Bank of America-Merrill Lynch, A-rated, yield to maturity; Mortgage rates from Freddie Mac, 30-year, fixed; SOFR from the New York Fed. All interest rate data are sourced from Haver Analytics. Historical data for Fed's Major Currency Index are from FRSR H.10. Historical data for Real GDP, GDP Price Index and PCE Price Index are from the Bureau of Economic Analysis (BEA). Consumer Price Index history is from the Department of Labor's Bureau of Labor Statistics (BLS).

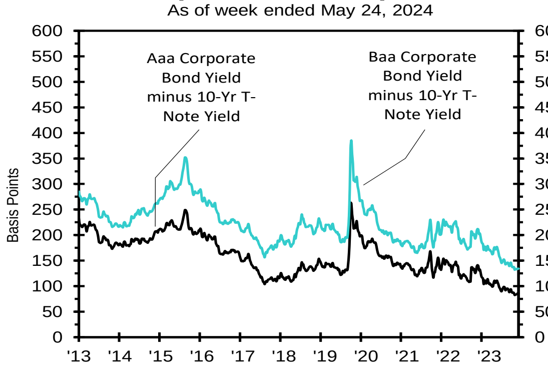
US Treasury Yield Curve
Week ended May 24, 2024 & Year Ago vs.
2Q 2024 & 3Q 2025
Consensus Forecasts



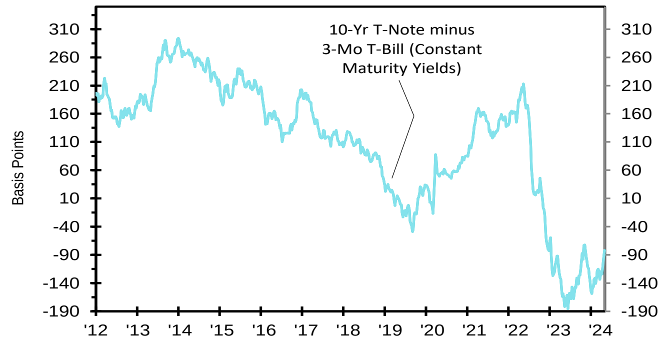
US 3-Mo T-Bills & 10-Yr T-Note Yield
(Quarterly Average)



Corporate Bond Spreads
As of week ended May 24, 2024



US Treasury Yield Curve
As of week ended May 24, 2024



Long-Range Survey:

The table below contains the results of our twice-annual long-range CONSENSUS survey. There are also Top 10 and Bottom 10 averages for each variable. Shown are consensus estimates for the years 2025 through 2030 and averages for the five-year periods 2026-2030 and 2031-2035. Apply these projections cautiously. Few if any economic, demographic and political forces can be evaluated accurately over such long time spans.

		------------------------ Average For The Year ------------------------						Five-Year Averages	
		2025	2026	2027	2028	2029	2030	2026-2030	2031-2035
1. Federal Funds Rate	**CONSENSUS**	**4.1**	**3.4**	**3.2**	**3.2**	**3.3**	**3.3**	**3.3**	**3.2**
	Top 10 Average	4.5	3.8	3.8	3.8	3.8	3.8	3.8	3.8
	Bottom 10 Average	3.6	3.0	2.7	2.7	2.7	2.7	2.8	2.7
2. Prime Rate	**CONSENSUS**	**7.1**	**6.5**	**6.4**	**6.4**	**6.4**	**6.3**	**6.4**	**6.3**
	Top 10 Average	7.5	6.9	6.9	6.9	6.9	6.9	6.9	6.8
	Bottom 10 Average	6.8	6.1	5.9	5.8	5.8	5.7	5.9	5.7
3. SOFR	**CONSENSUS**	**4.0**	**3.4**	**3.3**	**3.3**	**3.2**	**3.2**	**3.3**	**3.2**
	Top 10 Average	4.3	3.7	3.7	3.6	3.6	3.6	3.6	3.6
	Bottom 10 Average	3.8	3.1	2.9	2.8	2.8	2.7	2.8	2.7
4. Commercial Paper, 1-Mo	**CONSENSUS**	**4.0**	**3.4**	**3.4**	**3.3**	**3.3**	**3.3**	**3.4**	**3.3**
	Top 10 Average	4.2	3.6	3.6	3.6	3.5	3.5	3.6	3.6
	Bottom 10 Average	3.8	3.2	3.0	3.0	3.0	2.9	3.0	2.9
5. Treasury Bill Yield, 3-Mo	**CONSENSUS**	**4.0**	**3.4**	**3.3**	**3.2**	**3.2**	**3.2**	**3.2**	**3.2**
	Top 10 Average	4.4	3.7	3.7	3.7	3.7	3.7	3.7	3.7
	Bottom 10 Average	3.6	3.0	2.8	2.7	2.7	2.7	2.8	2.6
6. Treasury Bill Yield, 6-Mo	**CONSENSUS**	**4.0**	**3.5**	**3.4**	**3.4**	**3.4**	**3.3**	**3.4**	**3.3**
	Top 10 Average	4.3	3.8	3.8	3.7	3.7	3.7	3.8	3.7
	Bottom 10 Average	3.7	3.2	3.0	2.9	2.9	2.8	3.0	2.8
7. Treasury Bill Yield, 1-Yr	**CONSENSUS**	**4.0**	**3.6**	**3.5**	**3.5**	**3.5**	**3.5**	**3.5**	**3.4**
	Top 10 Average	4.3	3.9	3.9	3.9	3.9	3.9	3.9	3.8
	Bottom 10 Average	3.8	3.4	3.2	3.1	3.0	3.0	3.1	3.0
8. Treasury Note Yield, 2-Yr	**CONSENSUS**	**3.8**	**3.7**	**3.6**	**3.6**	**3.6**	**3.6**	**3.6**	**3.6**
	Top 10 Average	4.1	4.0	4.1	4.1	4.1	4.1	4.1	4.1
	Bottom 10 Average	3.5	3.3	3.2	3.1	3.1	3.1	3.2	3.0
9. Treasury Note Yield, 5-Yr	**CONSENSUS**	**3.9**	**3.8**	**3.8**	**3.9**	**3.9**	**3.9**	**3.9**	**3.9**
	Top 10 Average	4.2	4.2	4.3	4.3	4.5	4.4	4.3	4.5
	Bottom 10 Average	3.6	3.5	3.4	3.3	3.4	3.4	3.4	3.3
10. Treasury Note Yield, 10-Yr	**CONSENSUS**	**4.0**	**4.0**	**4.0**	**4.0**	**4.2**	**4.2**	**4.1**	**4.2**
	Top 10 Average	4.4	4.5	4.5	4.6	4.7	4.7	4.6	4.8
	Bottom 10 Average	3.7	3.6	3.5	3.5	3.6	3.6	3.5	3.6
11. Treasury Bond Yield, 30-Yr	**CONSENSUS**	**4.2**	**4.2**	**4.2**	**4.3**	**4.4**	**4.4**	**4.3**	**4.4**
	Top 10 Average	4.5	4.6	4.7	4.8	4.9	4.9	4.7	4.9
	Bottom 10 Average	3.9	3.9	3.8	3.8	3.8	3.9	3.8	3.8
12. Corporate Aaa Bond Yield	**CONSENSUS**	**5.1**	**5.1**	**5.1**	**5.2**	**5.3**	**5.3**	**5.2**	**5.2**
	Top 10 Average	5.4	5.4	5.6	5.7	5.8	5.8	5.7	5.8
	Bottom 10 Average	4.8	4.7	4.7	4.7	4.7	4.7	4.7	4.7
13. Corporate Baa Bond Yield	**CONSENSUS**	**6.0**	**6.0**	**6.1**	**6.1**	**6.2**	**6.2**	**6.1**	**6.2**
	Top 10 Average	6.3	6.3	6.5	6.6	6.7	6.7	6.5	6.7
	Bottom 10 Average	5.7	5.7	5.6	5.6	5.6	5.7	5.6	5.7
14. State & Local Bonds Yield	**CONSENSUS**	**4.1**	**4.1**	**4.2**	**4.2**	**4.3**	**4.4**	**4.2**	**4.3**
	Top 10 Average	4.4	4.5	4.5	4.6	4.7	4.7	4.6	4.8
	Bottom 10 Average	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.7
15. Home Mortgage Rate	**CONSENSUS**	**6.3**	**6.1**	**6.1**	**6.1**	**6.1**	**6.2**	**6.1**	**6.1**
	Top 10 Average	6.7	6.5	6.5	6.5	6.6	6.6	6.6	6.6
	Bottom 10 Average	6.0	5.7	5.7	5.6	5.6	5.6	5.6	5.5
A. Fed's AFE Nominal $ Index	**CONSENSUS**	**115.6**	**114.6**	**114.3**	**113.9**	**113.4**	**112.8**	**113.8**	**112.3**
	Top 10 Average	116.9	116.3	115.8	115.7	115.3	115.1	115.6	114.8
	Bottom 10 Average	114.2	113.0	112.7	112.1	111.5	110.9	112.0	110.1

		--------------------- Year-Over-Year, % Change ---------------------						Five-Year Averages	
		2025	2026	2027	2028	2029	2030	2026-2030	2031-2035
B. Real GDP	**CONSENSUS**	**1.9**	**2.0**	**2.1**	**2.1**	**2.0**	**2.0**	**2.1**	**2.0**
	Top 10 Average	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.2
	Bottom 10 Average	1.6	1.8	1.9	1.8	1.8	1.8	1.8	1.8
C. GDP Chained Price Index	**CONSENSUS**	**2.3**	**2.2**	**2.2**	**2.1**	**2.2**	**2.1**	**2.2**	**2.1**
	Top 10 Average	2.6	2.4	2.4	2.3	2.3	2.3	2.4	2.3
	Bottom 10 Average	2.1	2.0	2.0	2.0	2.0	2.0	2.0	2.0
D. Consumer Price Index	**CONSENSUS**	**2.4**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**
	Top 10 Average	2.7	2.4	2.4	2.4	2.4	2.4	2.4	2.4
	Bottom 10 Average	2.1	2.1	2.0	2.0	2.0	2.0	2.0	2.0
E. PCE Price Index	**CONSENSUS**	**2.2**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**
	Top 10 Average	2.4	2.3	2.3	2.3	2.3	2.3	2.3	2.2
	Bottom 10 Average	2.0	1.9	1.9	1.9	2.0	2.0	1.9	2.0

Projected Market Appreciation of the S&P Utility Index
Derivation of Mean Equity Risk Premium Based Studies
Using Holding Period Returns and
Projected Market Appreciation of the S&P Utility Index

Line No.		Implied Equity Risk Premium using Prospective Interest Rates
1.	Historical Equity Risk Premium (1)	4.02 %
2.	Regression of Historical Equity Risk Premium (2)	4.81
3	Forecasted Equity Risk Premium Based on PRPM (3)	4.39
4.	Forecasted Equity Risk Premium based on Projected Total Return on the S&P Utilities Index (Bloomberg, Value Line, and S&P Capital IQ Data) (4)	4.81
5.	Average Equity Risk Premium (5)	4.51 %

Notes: (1) Based on S&P Public Utility Index monthly total returns and Moody's Public Utility Bond average monthly yields from 1928-2023. Holding period returns are calculated based upon income received (dividends and interest) plus the relative change in the market value of a security over a one-year holding period.

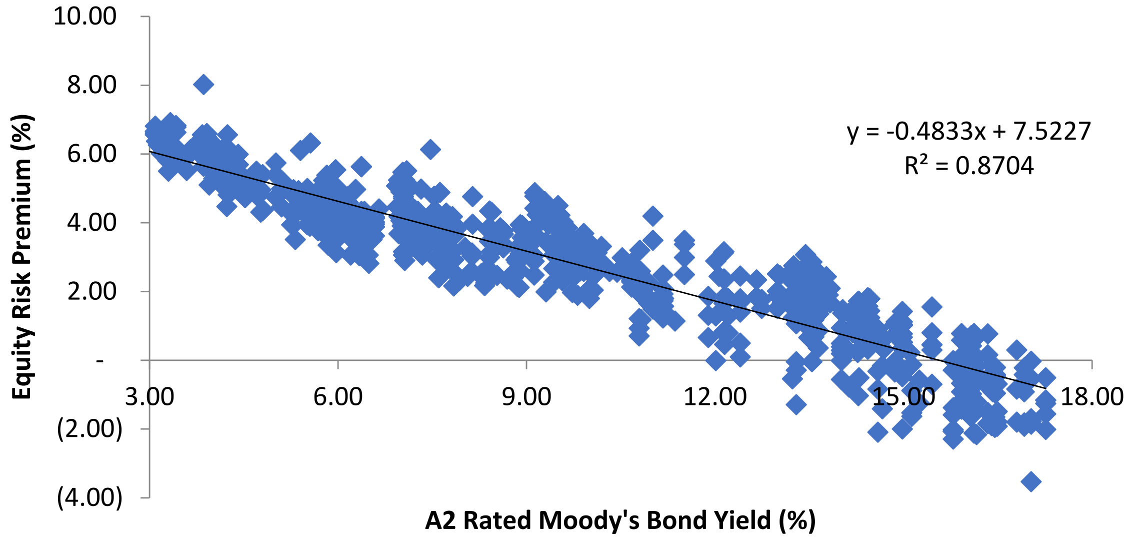
(2) This equity risk premium is based on a regression of the monthly equity risk premiums of the S&P Utility Index relative to Moody's A2 rated public utility bond yields from 1928 - 2023 referenced in note 1 above. Using the equation generated from the regression, an expected equity risk premium is calculated using the prospective A2 rated public utility bond yield of 5.65% (from line 3, page 1 of this Exhibit).

(3) The Predictive Risk Premium Model (PRPM) is applied to the risk premium of the monthly total returns of the S&P Utility Index and the monthly yields on Moody's A2 rated public utility bonds from January 1928 - May 2024.

(4) Using data from Bloomberg, Value Line, and S&P Capital IQ for the S&P Utilities Index, an expected return of 10.46% was derived based on expected dividend yields and long-term growth estimates as a proxy for market appreciation. Subtracting the expected A2 rated public utility bond yield of 5.65%, calculated on line 3 of page 1 of this Exhibit results in an equity risk premium of 4.81%. (10.46% - 5.65% = 4.81%)

(5) Average of lines 1 through 4.

Southwest Gas Corporation
Prediction of Equity Risk Premiums Relative to Moody's A2 Rated Utility Bond Yields



Constant	Slope	Prospective A2 Rated Utility Bond (1)	Prospective Equity Risk Premium
7.5227 %	-0.4833	5.65 %	4.79 %

Notes:

(1) From line 3 of page 1 of this Exhibit.

Source of Information: Regulatory Research Associates.

Southwest Gas Corporation
Indicated Common Equity Cost Rate Through Use
of the Traditional Capital Asset Pricing Model (CAPM) and Empirical Capital Asset Pricing Model (ECAPM)

Proxy Group of Six Natural Gas Distribution Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Six Natural Gas Distribution Companies	Value Line Adjusted Beta	Bloomberg Adjusted Beta	Average Beta	Market Risk Premium (1)	Risk-Free Rate (2)	Traditional CAPM Cost Rate	ECAPM Cost Rate	Indicated Common Equity Cost Rate (3)
Atmos Energy Corporation	0.85	0.76	0.80	8.59 %	4.41 %	11.28 %	11.71 %	11.50 %
New Jersey Resources Corporation	1.00	0.74	0.87	8.59	4.41	11.89	12.16	12.02
NiSource Inc.	0.95	0.77	0.86	8.59	4.41	11.80	12.10	11.95
Northwest Natural Holding Company	0.85	0.63	0.74	8.59	4.41	10.77	11.33	11.05
ONE Gas, Inc.	0.85	0.64	0.75	8.59	4.41	10.85	11.39	11.12
Spire Inc.	0.85	0.79	0.82	8.59	4.41	11.46	11.84	11.65
Mean			0.81			11.34 %	11.76 %	11.55 %
Median			0.81			11.37 %	11.78 %	11.58 %
Average of Mean and Median			0.81			11.36 %	11.77 %	11.57 %

Notes on page 2 of this Exhibit.

Southwest Gas Corporation
Notes to Accompany the Application of the CAPM and ECAPM

Notes:

(1) The market risk premium (MRP) is derived by using five different measures from four sources: Kroll, Value Line, Bloomberg, and S&P Capital IQ as illustrated below:

	Using Prospective Interest Rates	
Measure 1: Kroll Arithmetic Mean MRP (1926-2023)		
Arithmetic Mean Monthly Returns for Large Stocks 1926-2023:	12.16	%
Arithmetic Mean Income Returns on Long-Term Government Bonds:	4.99	
MRP based on Kroll Historical Data:	7.17	%
Measure 2: Application of a Regression Analysis to Kroll Historical Data (1926-2023)	7.93	%
Measure 3: Application of the PRPM to Kroll Historical Data (January 1926 - May 2024)	9.44	%
Measure 4: Value Line Projected MRP (Thirteen weeks ending May 31, 2024)		
Total projected return on the market 3-5 years hence*:	12.05	%
Risk-Free Rate (see notes 2 and 3):	4.41	
MRP based on Value Line Summary & Index:	7.64	%
*Forcasted 3-5 year capital appreciation plus expected dividend yield		
Measure 5: Bloomberg, Value Line, and S&P Capital IQ Projected Return on the Market based on the S&P 500		
Total return on the Market based on the S&P 500:	15.19	%
Risk-Free Rate (see notes 2 and 3):	4.41	
MRP based on Bloomberg, Value Line, and S&P Capital IQ data	10.78	%
Average of all MRP Measures:	8.59	%

(2) For reasons explained in the Direct Testimony, the appropriate risk-free rate for cost of capital purposes is the average forecast of 30 year Treasury Bonds per the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts. (See pages 7 and 8 of Exhibit No.___(DWD-4).) The projection of the risk-free rate is illustrated below:

Second Quarter 2024	4.60	%
Third Quarter 2024	4.50	
Fourth Quarter 2024	4.50	
First Quarter 2025	4.40	
Second Quarter 2025	4.30	
Third Quarter 2025	4.30	
2026-2030	4.30	
2031-2035	4.40	
	4.41	%

(4) Average of Column 6 and Column 7.

Sources of Information:
Value Line Summary and Index
Blue Chip Financial Forecasts, May 31, 2024
Kroll 2023 SBBI® Yearbook
S&P Capital IQ
Bloomberg Professional Services

Southwest Gas Corporation
Basis of Selection of the Group of Non-Price Regulated Companies
Comparable in Total Risk to the Proxy Group of Six Natural Gas Distribution Companies

The criteria for selection of the proxy group of non-price regulated companies comparable in total risk to the proxy group of six natural gas distribution companies was that the non-price regulated companies be domestic and reported in Value Line Investment Survey (Standard Edition).

The proxy group of non-price regulated companies was selected based on the unadjusted beta range of 0.64 - 0.92 and residual standard error of the regression range of 2.7845 - 3.3209 of the proxy group of six natural gas distribution companies.

These ranges are based upon plus or minus two standard deviations of the unadjusted beta and standard error of the regression. Plus or minus three standard deviations captures 95.50% of the distribution of unadjusted betas and residual standard errors of the regression.

The standard deviation of the Utility Proxy Group's residual standard error of the regression is 0.1341. The standard deviation of the standard error of the regression is calculated as follows:

$$\text{Standard Deviation of the Std. Err. of the Regr.} = \frac{\text{Standard Error of the Regression}}{\sqrt{2N}}$$

where: N = number of observations. Since Value Line betas are derived from weekly price change observations over a period of five years, N = 259

$$\text{Thus,} \quad 0.1341 = \frac{3.0527}{\sqrt{518}} = \frac{3.0527}{22.7596}$$

Source of Information: Value Line Proprietary Database, March 2024.
Value Line Investment Survey (Standard Edition).

Southwest Gas Corporation
Basis of Selection of Comparable Risk
Domestic Non-Price Regulated Companies

Proxy Group of Six Natural Gas Distribution Companies	[1] Value Line Adjusted Beta	[2] Unadjusted Beta	[3] Residual Standard Error of the Regression	[4] Standard Deviation of Beta
Atmos Energy Corporation	0.85	0.75	2.9055	0.0650
New Jersey Resources Corporation	0.95	0.92	3.0281	0.0678
NiSource Inc.	0.90	0.83	2.6617	0.0596
Northwest Natural Holding Company	0.85	0.71	3.3660	0.0753
ONE Gas, Inc.	0.85	0.71	3.2528	0.0728
Spire Inc.	0.85	0.74	3.1022	0.0694
Average	0.88	0.78	3.0527	0.0683
Beta Range (+/- 2 std. Devs. of Beta)	0.64	0.92		
2 std. Devs. of Beta	0.14			
Residual Std. Err. Range (+/- 2 std. Devs. of the Residual Std. Err.)	2.7845	3.3209		
Std. dev. of the Res. Std. Err.	0.1341			
2 std. devs. of the Res. Std. Err.	0.2682			

Source of Information: Value Line Proprietary Database, March 2024.

Southwest Gas Corporation
Proxy Group of Non-Price Regulated Companies
Comparable in Total Risk to the
Proxy Group of Six Natural Gas Distribution Companies

	[1]	[2]	[3]	[4]
Proxy Group of Fifty-Two Non-Price Regulated Companies	Value Line Adjusted Beta	Unadjusted Beta	Residual Standard Error of the Regression	Standard Deviation of Beta
3M Company	0.95	0.90	2.8014	0.0627
Abbott Labs.	0.90	0.79	2.9435	0.0659
AbbVie Inc.	0.85	0.71	2.9836	0.0668
Agilent Technologies	0.95	0.86	2.8446	0.0636
Air Products & Chem.	0.90	0.84	3.0254	0.0677
Alphabet Inc.	0.90	0.80	3.1753	0.0710
Altria Group	0.85	0.76	2.8496	0.0638
Apple Inc.	0.95	0.90	3.1817	0.0712
Archer Daniels Midl'	0.95	0.90	3.2558	0.0728
Assurant Inc.	0.90	0.79	3.0402	0.0680
AutoZone Inc.	0.95	0.88	3.2696	0.0732
Booz Allen Hamilton	0.85	0.73	3.2604	0.0730
Brady Corp.	0.95	0.90	2.8700	0.0642
BWX Technologies	0.80	0.67	3.2423	0.0725
CACI Int'l	0.90	0.79	2.9988	0.0671
Casey's Gen'l Stores	0.90	0.79	3.1675	0.0709
Cencora	0.80	0.65	2.9558	0.0661
Cisco Systems	0.85	0.74	2.8338	0.0634
CSW Industrials	0.85	0.77	3.2757	0.0733
Danaher Corp.	0.90	0.81	3.0396	0.0680
Dolby Labs.	0.95	0.86	2.9431	0.0659
Exponent, Inc.	0.95	0.88	3.3207	0.0743
Fastenal Co.	0.90	0.79	2.9654	0.0664
Franklin Electric	0.90	0.82	2.9449	0.0659
GATX Corp.	0.95	0.90	2.9590	0.0662
Henry (Jack) & Assoc	0.85	0.74	3.1969	0.0715
Hunt (J.B.)	0.95	0.91	3.2879	0.0736
L3Harris Technologie	0.90	0.83	3.1265	0.0704
Landstar System	0.80	0.65	2.8850	0.0646
Lockheed Martin	0.85	0.74	2.8649	0.0641
McKesson Corp.	0.85	0.70	3.1414	0.0703
Microsoft Corp.	0.90	0.78	2.8521	0.0638
MSC Industrial Direc	0.90	0.84	2.9743	0.0666
Oracle Corp.	0.85	0.70	3.1087	0.0696
O'Reilly Automotive	0.90	0.84	3.0511	0.0683
OSI Systems	0.90	0.81	3.0233	0.0676
Packaging Corp.	0.95	0.85	2.8655	0.0641
Pfizer, Inc.	0.80	0.67	3.1656	0.0708
Philip Morris Int'l	0.95	0.87	2.8492	0.0638
Prestige Consumer	0.85	0.76	3.2454	0.0726
Selective Ins. Group	0.85	0.74	2.9866	0.0668
Sensient Techn.	0.90	0.84	2.8182	0.0631
Service Corp. Int'l	0.90	0.84	3.1819	0.0712
Sherwin-Williams	0.95	0.89	2.9050	0.0650
Smith (A.O.)	0.90	0.79	3.0917	0.0692
Thermo Fisher Sci.	0.85	0.76	2.8528	0.0638
UniFirst Corp.	0.90	0.81	3.0645	0.0686
UnitedHealth Group	0.95	0.91	3.1317	0.0701
Universal Corp.	0.80	0.68	3.2741	0.0733
VeriSign Inc.	0.90	0.80	2.8918	0.0647
Waters Corp.	0.95	0.85	3.1725	0.0710
Watsco, Inc.	0.85	0.77	3.1365	0.0702
Average	0.89	0.80	3.0441	0.0681
Proxy Group of Six Natural Gas Distribution Companies	0.88	0.78	3.0527	0.0683

Source of Information: Value Line Proprietary Database, March 2024.

Southwest Gas Corporation
Summary of Cost of Equity Models Applied to
Proxy Group of Non-Price Regulated Companies
Comparable in Total Risk to the Proxy Groups

Principal Methods	Proxy Group of Fifty-Two Non-Price Regulated Companies	
Discounted Cash Flow Model (DCF) (1)	11.08	%
Risk Premium Model (RPM) (2)	12.53	
Capital Asset Pricing Model (CAPM) (3)	12.11	
Mean	11.91	%
Median	12.11	%
Average of Mean and Median	12.01	%

Notes:
(1) From page 2 of this Exhibit.
(2) From page 3 of this Exhibit.
(3) From page 6 of this Exhibit.

Southwest Gas Corporation
DCF Results for the Proxy Group of Non-Price-Regulated Companies Comparable in Total Risk to the
Proxy Group of Six Natural Gas Distribution Companies and Proxy Group of Fifty-Two Non-Price Regulated Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	
Proxy Group of Fifty-Two Non-Price Regulated Companies	Average Dividend Yield	Value Line Projected Five Year Growth in EPS	Zack's Five Year Projected Growth Rate in EPS	Yahoo! Finance Projected Five Year Growth in EPS	S&P Capital IQ Projected Five Year Growth in EPS	Average Projected Five Year Growth Rate in EPS (1)	Adjusted Dividend Yield	Indicated Common Equity Cost Rate (2)	
3M Company	3.00 %	30.50 %	7.50 %	(4.86) %	(3.33) %	19.00 %	3.29 %	22.29 %	(3)
Abbott Labs.	2.02	4.00	9.00	7.50	7.67	7.04	2.09	9.13	
AbbVie Inc.	3.68	4.00	6.90	6.21	7.29	6.10	3.79	9.89	
Agilent Technologies	0.66	8.00	6.80	4.95	5.26	6.25	0.68	6.93	
Air Products & Chem.	2.90	10.50	7.50	6.58	10.48	8.77	3.03	11.80	
Alphabet Inc.	0.50	12.00	17.50	18.24	17.21	16.24	0.54	16.78	
Altria Group	8.98	6.00	3.20	3.39	3.76	4.09	9.16	13.25	
Apple Inc.	0.57	6.50	12.50	9.72	10.63	9.84	0.60	10.44	
Archer Daniels Midl'	3.28	7.50	NA	(4.20)	(2.85)	7.50	3.40	10.90	
Assurant Inc.	1.63	9.50	6.20	6.20	6.19	7.02	1.69	8.71	
AutoZone Inc.	-	12.50	13.20	11.65	14.83	13.05	-	NA	
Booz Allen Hamilton	1.38	8.50	13.70	13.70	11.66	11.89	1.46	13.35	
Brady Corp.	1.56	13.00	7.70	7.70	8.96	9.34	1.63	10.97	
BWX Technologies	1.01	6.50	9.40	2.49	10.44	7.21	1.05	8.26	
CACI Int'l	-	7.00	10.40	6.70	11.17	8.82	-	NA	
Casey's Gen'l Stores	0.54	11.00	9.70	10.31	9.74	10.19	0.57	10.76	
Cencora	0.87	6.50	10.70	9.34	10.03	9.14	0.91	10.05	
Cisco Systems	3.31	4.50	5.50	3.47	3.49	4.24	3.38	7.62	
CSW Industrials	0.35	12.50	15.00	12.00	15.00	13.63	0.37	14.00	
Danaher Corp.	0.43	7.00	8.60	7.52	7.93	7.76	0.45	8.21	
Dolby Labs.	1.47	9.50	NA	16.00	NA	12.75	1.56	14.31	
Exponent, Inc.	1.30	7.50	NA	15.00	NA	11.25	1.37	12.62	
Fastenal Co.	2.20	9.00	9.00	6.33	NA	8.11	2.29	10.40	
Franklin Electric	0.99	7.00	12.00	13.40	12.00	11.10	1.04	12.14	
GATX Corp.	1.76	11.50	NA	12.00	NA	11.75	1.86	13.61	
Henry (Jack) & Assoc	1.31	6.50	7.50	7.50	8.23	7.43	1.36	8.79	
Hunt (J.B.)	0.96	7.50	13.60	7.60	11.29	10.00	1.01	11.01	
L3Harris Technologie	2.18	9.50	9.20	9.22	9.16	9.27	2.28	11.55	
Landstar System	0.73	3.00	NA	12.00	11.00	8.67	0.76	9.43	
Lockheed Martin	2.77	9.50	4.10	3.48	2.73	4.95	2.84	7.79	
McKesson Corp.	0.46	8.00	13.60	11.76	12.40	11.44	0.49	11.93	
Microsoft Corp.	0.72	14.00	16.10	15.03	13.72	14.71	0.77	15.48	
MSC Industrial Direc	3.55	5.00	NA	9.12	NA	7.06	3.68	10.74	
Oracle Corp.	1.32	10.00	9.70	9.91	11.40	10.25	1.39	11.64	
O'Reilly Automotive	-	10.50	13.00	11.40	13.25	12.04	-	NA	
OSI Systems	-	10.50	11.00	8.00	11.50	10.25	-	NA	
Packaging Corp.	2.75	9.00	2.80	(14.29)	4.94	5.58	2.83	8.41	
Pfizer, Inc.	6.13	2.50	10.70	(0.49)	10.01	7.74	6.37	14.11	
Philip Morris Int'l	5.47	5.00	7.50	9.56	8.68	7.69	5.68	13.37	
Prestige Consumer	-	6.00	8.00	8.00	8.50	7.63	-	NA	
Selective Ins. Group	1.38	16.50	16.20	17.15	17.17	16.75	1.50	18.25	
Sensient Techn.	2.30	2.50	NA	3.80	15.00	7.10	2.38	9.48	
Service Corp. Int'l	1.68	5.50	10.10	12.00	10.12	9.43	1.76	11.19	
Sherwin-Williams	0.89	11.00	10.90	11.37	10.42	10.92	0.94	11.86	
Smith (A.O.)	1.49	9.00	9.00	10.00	10.00	9.50	1.56	11.06	
Thermo Fisher Sci.	0.27	6.00	9.90	6.82	9.30	8.01	0.28	8.29	
UniFirst Corp.	0.80	9.50	NA	7.80	NA	8.65	0.83	9.48	
UnitedHealth Group	1.54	12.00	12.50	12.92	10.29	11.93	1.63	13.56	
Universal Corp.	6.36	18.50	NA	NA	NA	18.50	6.95	25.45	(3)
VeriSign Inc.	-	12.50	NA	8.00	NA	10.25	-	NA	
Waters Corp.	-	6.50	5.30	5.54	6.45	5.95	-	NA	
Watsco, Inc.	2.45	9.00	NA	4.42	NA	6.71	2.53	9.24	
	NA= Not Available						Mean	11.18 %	
							Median	10.97 %	
							Average of Mean and Median	11.08 %	

Notes:
(1) Average of columns 2 through 5 excluding negative growth rates.
(2) The application of the DCF model to the domestic, non-price regulated comparable risk companies is identical to the application of the DCF to the Utility Proxy Groups. The dividend yield is derived by using the 60 day average price and the spot indicated dividend as of 05/31/2024. The dividend yield is then adjusted by 1/2 the average projected growth rate in EPS, which is calculated by averaging the 5 year projected growth in EPS provided by Value Line, www.zacks.com, www.yahoo.com, and S&P Capital IQ (excluding any negative growth rates) and then adding that growth rate to the adjusted dividend yield.

(3) Results were excluded from the final average and median as they were more than two standard deviations from the proxy group's mean.

Source of Information: Value Line Investment Survey.
www.zacks.com, Downloaded on 05/31/2024
www.yahoo.com, Downloaded on 05/31/2024
S&P Capital IQ

Southwest Gas Corporation
Indicated Common Equity Cost Rate
Through Use of a Risk Premium Model
Using an Adjusted Total Market Approach

Line No.		Proxy Group of Fifty-Two Non-Price Regulated Companies using Prospective Interest Rates
1.	Prospective Yield on Baa2 Rated Corporate Bonds (1)	6.01 %
2.	Adjustment to Reflect Bond rating Difference of Non-Price Regulated Companies (2)	(0.22)
3.	Adjusted Bond Yield	5.79
4.	Equity Risk Premium (3)	6.74
5.	Risk Premium Derived Common Equity Cost Rate	12.53 %

Notes: (1) Average forecast of Baa corporate bonds based upon the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts dated May 31, 2024 (see pages 7 and 8 of Exhibit No.___(DWD-4)). The estimates are detailed below.

Second Quarter 2024	6.10 %
Third Quarter 2024	6.00
Fourth Quarter 2024	6.00
First Quarter 2025	5.90
Second Quarter 2025	5.90
Third Quarter 2025	5.90
2026-2030	6.10
2031-2035	6.20
Average	6.01 %

(2) The average yield spread of Baa2 rated corporate bonds over A2 corporate bonds for the three months ending May 2024. To reflect the A3 average rating of both Non-Price Regulated Proxy Groups, the yield on Baa corporate bonds must be adjusted by 2/3 of the spread between A2 and Baa2 corporate bond yields as shown below:

	A2 Corp. Bond Yield	Baa2 Corp. Bond Yield	Spread
May 2024	5.62 %	5.95 %	0.33 %
April 2024	5.67	6.00	0.33
March 2024	5.42	5.75	0.33
		Average yield spread	0.33
		2/3 of spread	0.22

(3) From page 5 of this Exhibit.

Southwest Gas Corporation
Comparison of Long-Term Issuer Ratings for the
Proxy Group of Fifty-Two Non-Price Regulated Companies

Proxy Group of Fifty-Two Non-Price Regulated Companies	Moody's Long-Term Issuer Rating May 2024		Standard & Poor's Long-Term Issuer Rating May 2024	
	Long-Term Issuer Rating	Numerical Weighting (1)	Long-Term Issuer Rating	Numerical Weighting (1)
3M Company	A3	7.0	BBB+	8.0
Abbott Labs.	Aa3	4.0	AA-	4.0
AbbVie Inc.	A3	7.0	A-	7.0
Agilent Technologies	Baa1	8.0	BBB+	8.0
Air Products & Chem.	A2	6.0	A	6.0
Alphabet Inc.	Aa2	3.0	AA+	2.0
Altria Group	A3	7.0	BBB	9.0
Apple Inc.	Aaa	1.0	AA+	2.0
Archer Daniels Midl'	A2	6.0	A	6.0
Assurant Inc.	Baa2	9.0	BBB	9.0
AutoZone Inc.	Baa1	8.0	BBB	9.0
Booz Allen Hamilton	N/A	--	N/A	--
Brady Corp.	N/A	--	N/A	--
BWX Technologies	Ba3	13.0	BB	12.0
CACI Int'l	N/A	--	BB+	11.0
Casey's Gen'l Stores	N/A	--	N/A	--
Cencora	Baa2	9.0	BBB+	8.0
Cisco Systems	A1	5.0	AA-	4.0
CSW Industrials	N/A	--	N/A	--
Danaher Corp.	A3	7.0	A-	7.0
Dolby Labs.	N/A	--	N/A	--
Exponent, Inc.	N/A	--	N/A	--
Fastenal Co.	N/A	--	N/A	--
Franklin Electric	N/A	--	N/A	--
GATX Corp.	Baa2	9.0	BBB	9.0
Henry (Jack) & Assoc	N/A	--	N/A	--
Hunt (J.B.)	Baa1	8.0	BBB+	8.0
L3Harris Technologie	Baa2	9.0	BBB	9.0
Landstar System	N/A	--	N/A	--
Lockheed Martin	A2	6.0	A-	7.0
McKesson Corp.	A3	7.0	BBB+	8.0
Microsoft Corp.	Aaa	1.0	AAA	1.0
MSC Industrial Direc	N/A	--	N/A	--
Oracle Corp.	Baa2	9.0	BBB	9.0
O'Reilly Automotive	Baa1	8.0	BBB	9.0
OSI Systems	N/A	--	N/A	--
Packaging Corp.	Baa2	9.0	BBB	9.0
Pfizer, Inc.	A2	6.0	A	6.0
Philip Morris Int'l	A2	6.0	A-	7.0
Prestige Consumer	N/A	--	BB	12.0
Selective Ins. Group	Baa2	9.0	BBB	9.0
Sensient Techn.	WR	--	NR	--
Service Corp. Int'l	Ba3	13.0	BB+	11.0
Sherwin-Williams	Baa2	9.0	BBB	9.0
Smith (A.O.)	N/A	--	N/A	--
Thermo Fisher Sci.	A3	7.0	A-	7.0
UniFirst Corp.	N/A	--	N/A	--
UnitedHealth Group	A2	6.0	A+	5.0
Universal Corp.	WR	--	BBB-	10.0
VeriSign Inc.	Baa3	10.0	BBB	9.0
Waters Corp.	N/A	--	N/A	--
Watsco, Inc.	N/A	--	N/A	--
Average	A3	7.3	BBB+	7.6

Notes:
(1) From page 4 of Exhibit No.___(DWD-4).

Source of Information:
Bloomberg Professional Services.

Southwest Gas Corporation
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for
Two Groups of Non-Price Regulated Companies of Comparable Risk to the
Proxy Group of Six Natural Gas Distribution Companies and Proxy Group of Fifty-Two Non-Price Regulated Companies

Line No.	Equity Risk Premium Measure	Proxy Group of Fifty-Two Non-Price Regulated Companies	
1.	Kroll Equity Risk Premium (1)	5.96	%
2.	Regression on Kroll Risk Premium Data (2)	6.92	
3.	Kroll Equity Risk Premium based on PRPM (3)	8.46	
4.	Equity Risk Premium Based on Value Line Summary and Index (4)	6.91	
5.	Equity Risk Premium Based on Bloomberg, Value Line, and S&P Global Market Intelligence S&P 500 Companies (5)	10.05	
6.	Conclusion of Equity Risk Premium	7.66	%
7.	Adjusted Beta (6)	0.88	
8.	Forecasted Equity Risk Premium	6.74	%

Notes:
(1) From note 1 of page 6 of Exhibit No.__(DWD-4).
(2) From note 2 of page 6 of Exhibit No.__(DWD-4).
(3) From note 3 of page 6 of Exhibit No.__(DWD-4).
(4) From note 4 of page 6 of Exhibit No.__(DWD-4).
(5) From note 5 of page 6 of Exhibit No.__(DWD-4).
(6) Average of mean and median beta from page 6 of this Exhibit.

Sources of Information:
Stocks, Bonds, Bills, and Inflation - 2023 SBBI Yearbook, Kroll.
Value Line Summary and Index.
Blue Chip Financial Forecasts, May 31, 2024
Bloomberg Professional Services.

Southwest Gas Corporation
Traditional CAPM and ECAPM Results for the Proxy Groups of Non-Price-Regulated Companies Comparable in Total Risk to the
Proxy Group of Six Natural Gas Distribution Companies and Proxy Group of Fifty-Two Non-Price Regulated Companies

Using Prospective Interest Rates

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Fifty-Two Non-Price Regulated Companies	Value Line Adjusted Beta	Bloomberg Beta	Average Beta	Market Risk Premium (1)	Risk-Free Rate (2)	Traditional CAPM Cost Rate	ECAPM Cost Rate	Indicated Common Equity Cost Rate (3)
3M Company	0.95	1.02	0.99	8.59 %	4.41 %	12.92 %	12.94 %	12.93 %
Abbott Labs.	0.90	0.82	0.86	8.59	4.41	11.80	12.10	11.95
AbbVie Inc.	0.85	0.59	0.72	8.59	4.41	10.60	11.20	10.90
Agilent Technologies	0.95	1.14	1.04	8.59	4.41	13.35	13.26	13.30
Air Products & Chem.	0.90	0.84	0.87	8.59	4.41	11.89	12.16	12.02
Alphabet Inc.	0.90	1.15	1.03	8.59	4.41	13.26	13.20	13.23
Altria Group	0.85	0.62	0.74	8.59	4.41	10.77	11.33	11.05
Apple Inc.	0.95	1.09	1.02	8.59	4.41	13.17	13.13	13.15
Archer Daniels Midl'	0.95	0.71	0.83	8.59	4.41	11.54	11.91	11.72
Assurant Inc.	0.90	0.78	0.84	8.59	4.41	11.63	11.97	11.80
AutoZone Inc.	0.95	0.69	0.82	8.59	4.41	11.46	11.84	11.65
Booz Allen Hamilton	0.85	0.84	0.84	8.59	4.41	11.63	11.97	11.80
Brady Corp.	0.95	0.76	0.86	8.59	4.41	11.80	12.10	11.95
BWX Technologies	0.80	0.80	0.80	8.59	4.41	11.28	11.71	11.50
CACI Int'l	0.90	0.83	0.86	8.59	4.41	11.80	12.10	11.95
Casey's Gen'l Stores	0.90	0.73	0.81	8.59	4.41	11.37	11.78	11.57
Cencora	0.80	0.62	0.71	8.59	4.41	10.51	11.13	10.82
Cisco Systems	0.85	0.78	0.81	8.59	4.41	11.37	11.78	11.57
CSW Industrials	0.85	0.88	0.86	8.59	4.41	11.80	12.10	11.95
Danaher Corp.	0.90	1.05	0.98	8.59	4.41	12.83	12.87	12.85
Dolby Labs.	0.95	0.92	0.93	8.59	4.41	12.40	12.55	12.48
Exponent, Inc.	0.95	1.02	0.98	8.59	4.41	12.83	12.87	12.85
Fastenal Co.	0.90	0.99	0.95	8.59	4.41	12.57	12.68	12.63
Franklin Electric	0.90	0.94	0.92	8.59	4.41	12.31	12.49	12.40
GATX Corp.	0.95	0.93	0.94	8.59	4.41	12.49	12.62	12.55
Henry (Jack) & Assoc	0.85	0.87	0.86	8.59	4.41	11.80	12.10	11.95
Hunt (J.B.)	0.95	1.03	0.99	8.59	4.41	12.92	12.94	12.93
L3Harris Technologie	0.90	0.91	0.91	8.59	4.41	12.23	12.42	12.33
Landstar System	0.80	0.89	0.85	8.59	4.41	11.71	12.04	11.87
Lockheed Martin	0.85	0.63	0.74	8.59	4.41	10.77	11.33	11.05
McKesson Corp.	0.80	0.53	0.67	8.59	4.41	10.17	10.88	10.52 (4)
Microsoft Corp.	0.90	1.07	0.98	8.59	4.41	12.83	12.87	12.85
MSC Industrial Direc	0.90	0.91	0.91	8.59	4.41	12.23	12.42	12.33
Oracle Corp.	0.85	1.03	0.94	8.59	4.41	12.49	12.62	12.55
O'Reilly Automotive	0.90	0.69	0.80	8.59	4.41	11.28	11.71	11.50
OSI Systems	0.90	0.97	0.93	8.59	4.41	12.40	12.55	12.48
Packaging Corp.	0.95	0.87	0.91	8.59	4.41	12.23	12.42	12.33
Pfizer, Inc.	0.80	0.72	0.76	8.59	4.41	10.94	11.46	11.20
Philip Morris Int'l	0.95	0.77	0.86	8.59	4.41	11.80	12.10	11.95
Prestige Consumer	0.85	0.66	0.76	8.59	4.41	10.94	11.46	11.20
Selective Ins. Group	0.85	0.55	0.70	8.59	4.41	10.42	11.07	10.75
Sensient Techn.	0.90	1.02	0.96	8.59	4.41	12.66	12.74	12.70
Service Corp. Int'l	0.95	0.83	0.89	8.59	4.41	12.06	12.29	12.18
Sherwin-Williams	0.95	1.11	1.03	8.59	4.41	13.26	13.20	13.23
Smith (A.O.)	0.90	1.05	0.97	8.59	4.41	12.74	12.81	12.78
Thermo Fisher Sci.	0.85	1.02	0.94	8.59	4.41	12.49	12.62	12.55
UniFirst Corp.	0.90	0.85	0.88	8.59	4.41	11.97	12.23	12.10
UnitedHealth Group	0.95	0.48	0.72	8.59	4.41	10.60	11.20	10.90
Universal Corp.	0.80	0.67	0.73	8.59	4.41	10.68	11.26	10.97
VeriSign Inc.	0.90	0.99	0.95	8.59	4.41	12.57	12.68	12.63
Waters Corp.	0.95	1.10	1.03	8.59	4.41	13.26	13.20	13.23
Watsco, Inc.	0.85	1.21	1.03	8.59	4.41	13.26	13.20	13.23
		Mean	0.88			11.96 %	12.22 %	12.12 %
		Median	0.88			11.93 %	12.20 %	12.10 %
		Average of Mean and Median	0.88			11.95 %	12.21 %	12.11 %

Notes:
(1) From note 1 of page 2 of Exhibit No.___(DWD-5).
(2) From note 2 of page 2 of Exhibit No.___(DWD-5).
(3) Average of CAPM and ECAPM cost rates.
(4) Results were excluded from the final average and median as they were more than two standard deviations from the proxy group's mean.

Southwest Gas Corporation
Derivation of Investment Risk Adjustment Based upon
Kroll Associates' Size Premia for the Decile Portfolios of the NYSE/AMEX/NASDAQ

Line No.		[1] Market Capitalization on May 31, 2024 (millions)	[1] (times larger)	[2] Applicable Decile of the NYSE/AMEX/ NASDAQ (1)	[3] Applicable Size Premium (2)	[4] Spread from Applicable Size Premium (3)
1.	Southwest Gas Corporation (4)	$ 512.073		9	1.99%	
2.	Proxy Group of Six Natural Gas Distribution Companies (4)	$ 3,862.973	7.5 x	5	0.95%	1.04%

	[A] Decile	[B] Market Capitalization of Smallest Company (millions)	[C] Market Capitalization of Largest Company (millions)	[D] Size Premium (Return in Excess of CAPM)*
Largest	1	$ 36,942.976	$ 2,662,326.048	-0.06%
	2	14,910.719	36,391.113	0.46%
	3	7,493.607	14,820.048	0.61%
	4	4,622.261	7,461.284	0.64%
	5	3,011.224	4,621.785	0.95%
	6	1,864.293	3,010.806	1.21%
	7	1,050.083	1,862.491	1.39%
	8	555.880	1,046.037	1.14%
	9	213.039	554.523	1.99%
Smallest	10	1.576	212.644	4.70%

*From 2024 Kroll Cost of Capital Navigator

Notes:
(1) Gleaned from Columns [B] and [C] on the bottom of this page. The appropriate decile (Column [A]) corresponds to the market capitalization of the proxy group, which is found in Column [1].
(2) Corresponding risk premium to the decile is provided in Column [D] on the bottom of this page.
(3) Line No. 1 Column [3] – Line No. 2 Column [3]. For example, the 1.04% in Column [4], Line No. 2 is derived as follows 1.04% = 1.99% - 0.95%.
(4) From page 2 of this Exhibit.

Southwest Gas Corporation
Market Capitalization of Southwest Gas Corporation and the
Proxy Group of Six Natural Gas Distribution Companies and Proxy Group of Fifty-Two Non-Price Regulated Companies

Company	Exchange	[1] Common Stock Shares Outstanding at Fiscal Year End 2023 (millions)	[2] Book Value per Share at Fiscal Year End 2023 (1)	[3] Total Common Equity at Fiscal Year End 2023 (millions)	[4] Closing Stock Market Price on May 31, 2024	[5] Market-to-Book Ratio on May 31, 2024 (2)	[6] Market Capitalization on May 31, 2024 (3) (millions)
Southwest Gas Corporation		NA	NA	360.107 (4)	NA		
Based upon Proxy Group of Six Natural Gas Distribution Companies						142.2 (5)	$ 512.073 (6)
Proxy Group of Six Natural Gas Distribution Companies							
Atmos Energy Corporation	NYSE	148.493	$ 73.203	10,870.064	$ 115.920	158.4 %	$ 17,213.283
New Jersey Resources Corporation	NYSE	97.584	20.400	1,990.735	43.460	213.0	4,241.020
NiSource Inc.	NYSE	447.382	17.398	7,783.500	29.060	167.0	13,000.911
Northwest Natural Holding Company	NYSE	37.631	34.116	1,283.838	37.420	109.7	1,408.152
ONE Gas, Inc.	NYSE	56.546	48.914	2,765.877	61.630	126.0	3,484.925
Spire Inc.	NYSE	53.170	54.867	2,917.300	61.290	111.7	3,258.803
Median		77.065	$ 41.515	$ 2,841.589	$ 52.375	142.2 %	$ 3,862.973

NA= Not Available

Notes: (1) Column 3 / Column 1.
(2) Column 4 / Column 2.
(3) Column 1 * Column 4.
(4) Requested rate base multiplied by the requested common equity ratio.
(5) The market-to-book ratio of Southwest Gas Corporation on May 31, 2024 is assumed to be equal to the market-to-book ratio of the Proxy Group of Six Natural Gas Distribution Companies on May 31, 2024 as appropriate.
(6) Column [3] multiplied by Column [5].

Source of Information: 2023 Annual Forms 10K
yahoo.finance.com
Bloomberg Professional

Southwest Gas Corporation
Derivation of the Flotation Cost Adjustment to the Cost of Common Equity

Equity Issuances

		[Column 1]	[Column 2]	[Column 3]	[Column 4]	[Column 5]	[Column 6]	[Column 7]	[Column 8]
Date of Offering	Transaction (1)	Shares Issued	Average Offering Price per Share	Total Offering Expense per Share	Net Proceeds per Share (2)	Gross Equity Issue before Costs	Total Net Proceeds	Total Flotation Costs	Flotation Cost Percentage (7)
3/7/2023	Equity Offering	4,112,607	$ 60.12	$ 2.160	$ 57.9601	$ 247,249,933 (3)	$ 238,367,042 (4)	$ 8,882,891 (5)	3.59%
3/28/2022	Equity Offering	6,325,000	$ 74.00	$ 2.613	$ 71.3871	$ 468,050,000 (3)	$ 451,523,313 (4)	$ 16,526,688 (5)	3.53%
11/26/18	Equity Offering	3,565,000	$ 75.50	$ 2.716	$ 72.7836	$ 269,157,500 (3)	$ 259,473,524 (4)	$ 9,683,977 (5)	3.60%
April 2021 Shelf	Equity Offering					$ 70,360,412 (1)	$ 69,656,808 (1)	$ 703,604 (6)	1.00%
May 2019 Shelf	Equity Offering					$ 253,551,490 (1)	$ 251,015,975 (1)	$ 2,535,515 (6)	1.00%
March 2017 Shelf	Equity Offering					$ 149,999,920 (1)	$ 148,500,011 (1)	$ 1,499,909 (6)	1.00%
March 2015 Shelf	Equity Offering					$ 35,522,812 (1)	$ 35,167,584 (1)	$ 355,228 (6)	1.00%
	Total Public Issuances					$ 1,493,892,067	$ 1,453,704,256	$ 40,187,811	2.69%

Flotation Cost Adjustment

	[Column 9]	[Column 10]	[Column 11]	[Column 12]	[Column 13]	[Column 14]
	Average Dividend Yield (8)	Average Projected EPS Growth Rate (8)	Adjusted Dividend Yield (9)	Average DCF Cost Rate Unadjusted for Flotation (10)	DCF Cost Rate Adjusted for Flotation (11)	Flotation Cost Adjustment (12)
Proxy Group of Six Natural Gas Distribution Companies	4.15 %	5.75 %	4.27 %	10.02 %	10.14 %	0.12 %

Notes:
(1) From Company SEC filings
(2) Col. 2 - Col. 3
(3) Col. 1 x Col. 2
(4) Col. 1 x Col. 4
(5) Col. 1 x Col. 3
(6) Col. 5 - Col. 6
(7) (Col. 5 - Col. 6) / Col. 5
(8) From page 1 of Exhibit No.__(DWD-3).
(9) Col. 9 * (1 + (0.5 * Col. 10))
(10) Col. 10 + Col. 11
(11) (Col. 11 / (1 - Col. 8)) + Col. 10
(12) Col. 13 - Col. 12

Company Witness:
Valeria S. Annibali

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
APPLICATION 24-09-___

PREPARED DIRECT TESTIMONY
OF
VALERIA S. ANNIBALI

ON BEHALF OF
SOUTHWEST GAS CORPORATION

SEPTEMBER 5, 2024

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Prepared Direct Testimony
of
VALERIA S. ANNIBALI

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Prepared Direct Testimony
of
VALERIA S. ANNIBALI

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Valeria S. Annibali. My business address is 8360 S. Durango Drive, Las Vegas, Nevada 89113.

Q. 2 By whom and in what capacity are you employed?

A. 2 I am employed by Southwest Gas Corporation (Southwest Gas or Company) in the Gas Supply Department. My title is Manager, Sustainable Gas Supply.

Q. 3 Please summarize your educational background and relevant business experience.

A. 3 My educational background and relevant business experience are summarized in Appendix A to this testimony.

Q. 4 Have you previously testified before any regulatory commission?

A. 4 Yes. I have previously provided written testimony in proceedings before the Public Utilities Commission of Nevada (PUCN) and the California Public Utilities Commission (Commission). I have also testified in person before the PUCN.

Q. 5 What is the purpose of your prepared direct testimony in this proceeding?

A. 5 The purpose of my prepared direct testimony is to provide an update on the existing 2021-2025 Conservation and Energy Efficiency (CEE) Plan and to sponsor Southwest Gas' 2026 – 2030 CEE Plan, which I detail herein, and in Exhibit No.__(VSA-1) and Exhibit No.__(VSA-4), attached to this testimony.

Q. 6 Please summarize your prepared direct testimony.

A. 6 My prepared direct testimony consists of the following key issues:

- An overview of Southwest Gas' Existing CEE Plan for Program Years (PY) 2021-2025;
- An overview of Southwest Gas' Proposed CEE Plan for PY 2026-2030;
- The Purpose and Process for Minor Program Modifications;
- Cost recovery for CEE Plan(s); and
- A request for modification or additional funding between General Rate Cases (GRCs).

II. OVERVIEW OF EXISTING CEE PLAN

Q. 7 Provide an overview of Southwest Gas' existing CEE Plan approved in its last general rate case Application (A.) 19-08-015.

A. 7 The Company's existing CEE Plan, proposed in A.19-08-015, was approved in Decision (D.) 21-03-052[1] and includes the following programs:

- Residential Equipment Rebates – This program offers rebates to qualifying energy efficient water heating and space heating equipment to residential customers in single family, multifamily, and mobile homes.
- Commercial Equipment Rebates – This program offers energy audits, direct-install measures, and rebates for qualifying energy-efficient water

[1] D.21-03-052 – *Decision Granting Joint Motion for Approval of Settlement Between Southwest Gas Corporation, Public Advocates Office and City of Victorville Adopting Test Year 2021 General Rate Increases.*

heating, space heating, and commercial food service equipment to commercial customers.

- Residential Equipment Direct-Install (REDI) – This program is a "no upfront cost" to the customer energy assistance program, and offers the direct-installation of water heating and space heating equipment to residential customers in single-family, multifamily, and mobile homes. REDI targets residential customers that do not qualify for Southwest Gas' income-qualified Energy Savings Assistance (ESA) program. Additionally, REDI program participants may also take advantage of the Residential Equipment Rebates program.
- New Homes Rebates – This program offers rebates to homebuilders for single family homes built to the State of California Title 24 Energy Efficiency Standards and are equipped with energy efficient natural gas tankless water heaters and furnaces.
- Solar Thermal Rebates – This program offers rebates to both residential and commercial customers for solar thermal systems for commercial pools, commercial and multifamily, and single-family residences.

A full list of all the approved programs and measures in Southwest Gas' existing CEE Plan for PY 2021 – 2025 are provided in Exhibit No.___(VSA-1)

Q. 8 Describe the CEE Plan annual funding authorized in D.21-03-052.

A. 8 Southwest Gas was authorized an annual budget of $250,000 with the option to submit a Tier 3 Advice Letter to request additional funding up to a maximum of $500,000 per year beginning two years after the issuance of D.21-03-052.

Q. 9 Has Southwest Gas obtained approval from the Commission to increase its annual CEE Plan budget?

A. 9 Yes, in April 2023, the Commission authorized Southwest Gas to increase its CEE Plan budget to $500,000 per year through the remainder of its current GRC cycle or 2025.[2] Southwest Gas demonstrated that given the demand and annual spend for its Residential and Commercial Equipment Rebate programs, it was not able to implement its authorized REDI, New Home Rebates, and Solar Thermal Rebates programs without increased budgetary authority. Southwest Gas filed advice letter AL1243 requesting authorization of increased funding of $250,000 to be able to offer customers the REDI program, the California New Homes program, and the Solar Thermal Rebates program. The REDI program would focus on several weatherization measures, while the New Homes program would encourage homebuilders to build their products with high efficiency water heaters and natural gas furnaces. Lastly, the Solar Thermal Rebates program would provide rebates to residential and commercial customers who installed qualifying solar thermal facilities with natural gas backup.

Q. 10 **What is Southwest Gas' experience offering Residential and Commercial Rebates to customers?**

A. 10 In 2023, the Residential Rebates program offered by Southwest Gas provided 705 equipment rebates, totaling $71,550, and resulted in approximately 22,500 therm savings which is equal to a reduction in 119 metric tons of CO_2 or the

[2] Resolution G-3594. Southwest Gas Tier 3 Advice Letter 1243-G Requesting Increase in Funding for Conservation and Energy Efficiency Programs during Program Years 2023 through 2025, approved April 27, 2023.

equivalent to greenhouse gas (GHG) emissions from 28 gasoline-powered passenger vehicles driven for one year. In the current PY to date, Southwest Gas processed 185 rebates, totaling $18,075, and approximately 6,700 therm savings which is equal to a reduction in 35 metric tons of CO_2 or the equivalent to GHG emissions from 9 gasoline-powered passenger vehicles driven for one year.

In 2023, the Commercial Rebates program offered by Southwest Gas provided 65 equipment rebates, totaling $63,850, and resulted in approximately 22,800 therm savings which is equal to a reduction in 121 metric tons of CO_2or the equivalent to GHG emissions from 29 gasoline-powered passenger vehicles driven for one year. In the current PY to date, Southwest Gas processed 14 rebates, totaling $12,200, and resulted in approximately 2,800 therm savings which is equal to a reduction in 15 metric tons of CO_2 or the equivalent to GHG emissions from 4 gasoline-powered passenger vehicles driven for one year.

Exhibit No. ___(VSA-2) provides annual participation levels, therm savings, and annual expenditures for PY 2021 through 2023.

Q. 11 What is Southwest Gas' experience offering the REDI program?

A. 11 During the initial rollout of the REDI program in 2023, Southwest Gas experienced a delay in the contracting process with a vendor, which in turn delayed a full rollout of the program. However, Southwest Gas believes the benefits of REDI for its residential customers continue to be advantageous. In 2024, the Company worked with the contracted vendor to accelerate the rollout in California. The REDI program will target customers who do not qualify for the ESA Program. As a result, Southwest Gas believes demand for the REDI program will be high, as discussed further in Section III below.

Q. 12 What is Southwest Gas' experience offering the New Home Rebates Program?

A. 12 Southwest Gas performed outreach to educate homebuilders on the equipment requirements needed to qualify for the New Homes Rebates Program. Although this program experienced an initial lack of awareness from customer-facing employees to help promote and offer the program to homebuilders, it has been well received by homebuilders who have learned about the program and its rebates. Southwest Gas experienced some spend for this program during the 2021-2023 PY as demonstrated in Exhibit No.__(VSA-2). However, given the homebuilders' high interest at this time, Southwest Gas expects participation to increase, which poses a challenge with respect to the existing amount of annual program funding. As discussed further below, I address Southwest Gas' proposal to increase the authorized annual program budgets for its CEE Plan.

Q. 13 Has Southwest Gas implemented its Solar Thermal Rebates program?

A. 13 Yes. The Solar Thermal Rebates program is active, and the rebate is available to residential and commercial customers. Southwest Gas has only one active contractor working within the program across multiple states. As of 2023, Southwest Gas removed the OG-300 requirement on residential installations to ease the burden on contractors and encourage greater participation.

Q. 14 Has Southwest Gas expended its annual CEE Plan budget?

A. 14 No. Southwest Gas has not expended the entirety of the annual CEE Plan budget. The Company spent 98% of its annual CEE Plan budget ($243,918 of $250,000) in 2021, 99% ($247,746 of $250,000) in 2022, and 60% ($297,704 of $500,000) in 2023 as demonstrated in Exhibit No.__(VSA-2). Southwest

Gas carefully manages its CEE Plan budgets to encourage broad participation while being mindful of spending due to the one-way balancing account. Southwest Gas works diligently to review interest in any of its CEE programs to ensure program needs can be met. Because costs exceeding the annual budget cannot be recovered, Southwest Gas closely examines budgets for programs with high interest to ensure they stay within authorized limits.

<u>III. OVERVIEW OF COMPANY'S PROPOSED CEE PLAN</u>

Q. 15 What programs are included in the Company's proposed CEE Plan for PY 2026 – 2030?

A. 15 Southwest Gas is proposing to continue the same five CEE programs as discussed above for the 2026 – 2030 GRC cycle.

Q. 16 Was a cost-effectiveness evaluation performed for the Company's proposed CEE Plan for years 2026 – 2030?

A. 16 Yes. A cost-effectiveness evaluation was performed utilizing the following five types of tests: total resource cost (TRC) test, utility cost test (UCT), ratepayer impact measure (RIM) test, participant cost test (PCT), and societal cost test (SCT). Excluding renewables (solar thermal systems), only cost-effective measures, identified as those with a TRC ratio of 1.0 or above, have been included in Southwest Gas' proposed CEE Plan for years 2026 – 2030.

Q. 17 What is the budget for Southwest Gas' proposed CEE Plan for the years 2026 – 2030?

A. 17 Southwest Gas is proposing to increase its annual CEE Plan budget to $650,000, an increase of $150,000 from the authorized in Resolution 3594-G. Additionally, and similar to the option provided to the Company in D.21-03-052, Southwest Gas proposes that it maintain the ability to request to increase its annual program funding through an Advice Letter submission for up to a maximum of $900,000 per year, as explained below.

Q. 18 Please explain how Southwest Gas plans to utilize the proposed $650,000 annual CEE Plan budget.

A. 18 Southwest Gas plans to utilize the $650,000 annual budget for the five programs mentioned herein, including program administration, increased program outreach, and customer rebates, including the costs of direct-install measures.

The Company anticipates the Residential and Commercial Equipment Rebates programs will maintain participation at current or near current levels with an estimated 520 participants in the Residential Equipment Rebates program and an estimated 176 participants in the Commercial Equipment Rebates program. With respect to the New Home Rebates program and the Solar Thermal Rebates program, Southwest Gas is continuing to work with implementation contractors to maximize program participation. Southwest Gas estimates that New Home Rebates will range from $400 to $750 per home for an estimated 217 homes. Based on the historic limited vendor outreach, Southwest Gas budgeted only 1 participant for the Solar Thermal Rebates in CZ14. The Company plans to increase its outreach efforts and may request additional funding through the Advice Letter process discussed below.

Table 1 below reflects how Southwest Gas will utilize the $650,000 annual CEE Plan budget for each of its CEE programs:

PYs 2026 – 2030 Estimated Annual Expenditures	
Residential Equipment Rebates	$160,000
Commercial Equipment Rebates	$200,000

Solar Thermal Rebates	$30,000
New Home Rebates	$150,000
REDI	$100,000
CEE Plan Administration – Education & Outreach	$10,000
Total	**$650,000**

Q. 19 Please explain why Southwest Gas anticipates the REDI Program will be successful?

A. 19 Southwest Gas believes the REDI Program will achieve high participation rates given that it will allow customers who may exceed the current income thresholds under the ESA program qualifications, to still participate in REDI and obtain various home weatherization measures. For instance, in northern California, Southwest Gas identified a challenge in getting customers qualified for ESA due to customers exceeding the prescribed income guidelines. Targeting these customers first will help those in need, especially those who are located in heavy snowfall communities surrounding the Lake Tahoe region and experience some of the coldest weather throughout California, and where homes rely heavily on natural gas for reliable home heating in the winter months. Southwest Gas expects the REDI Program to assist these communities in experiencing increased energy savings.

While Southwest Gas will focus its outreach efforts on its Northern California service territories, it is anticipated that participation in the Company's Southern California service territory will be high due to the higher estimate of potentially eligible customers for its low-income programs including ESA and the California Alternate Rates for Energy (CARE) programs[3]. Moreover, given that the REDI Program is not income based, Southwest Gas also has the ability to target a wider range of other customers to maximize program participation.

Please refer to Exhibit No. __(VSA-3) for estimated participation in the Company's five programs.

IV. CEE PLAN COST RECOVERY, PROGRAM MODIFICATIONS, AND REQUEST FOR BUDGET INCREASE

Q. 20 How does Southwest Gas currently recover its CEE Plan costs?

A. 20 Southwest Gas currently records and recovers its CEE Plan program costs through its Conservation and Energy Efficiency Balancing Account (CEEBA) and CEEBA surcharge rate component of the Company's Public Purpose Program (PPP) surcharge as approved in D.14-06-028.

Q. 21 Is the Company proposing to update the CEE rate as part of this General Rate Case?

A. 21 No. Southwest Gas will continue to adjust its CEEBA surcharge rate as part of its annual PPP surcharge rate adjustments submitted on or before October 31 through a Tier 2 Advice Letter, effective January 1 of the following year.

Q. 22 What process did D.21-03-052 provide Southwest Gas to make minor program modifications and request an increase in annual program funding?

---

[3] Based on the 2024 Athens Survey (Exhibit No. _(VSA-5), Southwest Gas has 62,557 estimated CARE-eligible households. Households that do not qualify under the CARE/ESA income requirements are eligible for REDI.

A. 22 D.21-03-052 authorized Southwest Gas to make minor program modifications through a Tier 2 Advice Letter, and a Tier 3 Advice Letter to request an increase to annual program funding.

Q. 23 Is Southwest Gas proposing any changes to program measures that would require a budget increase in the CEE Plan?

A. 23 Yes. These programs include some of the measures in Southwest Gas' existing CEE Plan, as well as additional commercial equipment measures to expand customers' opportunities to reduce their energy consumption and utility bills. Southwest Gas is proposing to add natural gas measures for the California foodservice program, previously not included in the 2021-2025 CEE Plan. Two tiers of some measures such as commercial fryers and fireplaces may be offered to incentivize the installation of high-efficiency equipment and offset the higher incremental cost. A complete list of all measures, including requirements, rebate amounts, estimated annual energy therm savings by climate zone, and TRC ratios by climate zone, under each program in the Company's proposed CEE Plan is detailed in Exhibit No.__(VSA-4)

Q. 24 Is Southwest Gas proposing any changes to the Advice Letter process for minor program modifications and additional funding requests between GRCs?

A. 24 Yes. Southwest Gas proposes to change the Advice Letter process as follows:

Tier 1 Advice Letter - A Tier 1 Advice Letter will be used for minor program modifications and updating equipment rebate amounts if such updates are consistent with Statewide Foodservice Instant Rebates Programs (Statewide

Program) sponsored by the large investor-owned utilities (IOUs)[4] already approved by the Commission. Southwest Gas believes that modifying its various commercial foodservice equipment measure requirements and rebate amounts consistent with the Statewide Program will maximize its program participation by offering its customers program measures and rebates comparable to other utilities. In addition, Southwest Gas utilizes the same third-party administrator as the IOUs, Energy Solutions, to administer its point-of-sale (POS) commercial foodservice rebates. As such, aligning Southwest Gas' commercial foodservice equipment rebates with the Statewide Program will also be administratively less burdensome for Energy Solutions when offering and processing POS foodservice equipment rebates. In addition, updating the rebate amounts through the Tier 1 Advice Letter process will further assist Southwest Gas to instantaneously update the amounts for added consistency and timeliness.

Tier 2 Advice Letter - A Tier 2 Advice Letter will be used to request increased funding for the programs if, for example, real or anticipated program demand is expected to exceed authorized funding levels.

Q. 25 Does this complete your prepared direct testimony?

A. 25 Yes.

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[4] Southern California Gas Company, San Diego Gas & Electric Company, Pacific Gas and Electric Company and Southern California Edison Company.

SUMMARY OF QUALIFICATIONS
VALERIA S. ANNIBALI

I hold a Bachelor of Arts degree in Economics and International Affairs from James Madison University and a Master of Science Degree in Applied Economics from Johns Hopkins University.

I first worked for Southwest Gas Corporation (Southwest Gas or Company) between September 2015 and January 2020. During that period, I held the positions of Senior Analyst in Gas Purchasing and Transportation and Senior Analyst in Regulation and Energy Efficiency. While in Gas Purchasing and Transportation my primary responsibilities included negotiating daily and monthly gas purchase transactions that helped ensure that Southwest Gas purchased gas supplies at the best cost considering market price impacts and ensuring reliability scheduling supplies on interstate natural gas pipelines. As a Senior Analyst in Regulation and Energy Efficiency, I supported in the development of the Company's renewable natural gas and decarbonization initiatives including tariffs, internal and external presentations, and customer communication initiatives. I also assisted in the development of financial and operational analysis in preparation of cost recovery initiatives for federal and state regulatory filings, prepared regulatory filings including testimony drafting, and provided responses to data requests from state and federal commission Staff and other public agencies.

Between January 2020 and December 2021, I relocated to Houston, Texas where I was a Manager at Deloitte & Touche's Regulatory and Operational Risk offering within Risk and Financial Advisory service. During my time with Deloitte, I led client engagements including compliance risk assessments related to federal and state regulatory requirements, solution implementation for business strategies and policies, business process development, organizational structure changes, management reporting, and trading and risk systems effectiveness evaluations. I also provided subject matter expertise on federal and state regulatory matters to advise and develop innovative approaches supporting utility and oil and gas clients with compliance matters including controls testing, reporting, record keeping, and reconciliation.

In December 2021, I returned to work at Southwest Gas where I now hold the position of Manager/Sustainable Gas Supply. I am accountable for the negotiation and administration of the Company's sustainable gas purchase contracts, including but not limited to contracts for renewable natural gas, biogas, hydrogen, carbon offsets, as well as the administration of the Company's California Cap & Trade allowance purchase program, and various regulatory filings to which Gas Supply contributes. My responsibilities include soliciting, negotiating, and contracting for the sustainable gas supply resources and integrating sustainable gas supplies into the Company's supply portfolios. I am also responsible for responding to data requests from the Federal Energy Regulatory Commission (FERC), state commissions, and intervenors that relate to Company's sustainable gas supply practices. I also oversee the Company's Energy Efficiency activities across all three states that we serve: Arizona, Nevada and California.

Prior to joining Southwest Gas in 2015, I was an Energy Industry Analyst at the FERC's Office of Enforcement between October 2011 and September 2015. I managed national and regional initiatives on gas-electric coordination, led natural gas technical analysis, apprised Commissioners of latest market developments, and produced and presented technical as well as seasonal market assessments at Commission Open Meetings. Prior to FERC, I was a senior analyst at various consultancies responsible for natural gas market fundamentals and price forecasting.

CA CEE PLAN - PROGRAMS AND MEASURES FOR YEARS 2021-2025

Program and Measures	Measure Requirement [1]	Rebate Amount	Estimated Annual Savings (therms) [2]		TRC Ratio	
			Climate Zone (CZ) 14 [3]	CZ 16 [4]	CZ 14 [3]	CZ 16 [4]
Residential Equipment Direct-Install (RED) - available for single family, multifamily*, and mobile homes					**1.52**	
Faucet Aerator - Kitchen	Gallons per minute (GPM) rating ≤ 1.5	$5.80 / unit	6.69	8.37	6.33	7.92
Faucet Aerator - Lavatory/Bathroom	GPM rating ≤ 1.0	$5.62 / unit	3.26	4.08	3.18	3.98
Low-Flow Showerhead	GPM rating ≤ 1.5	$30 / unit	8.42	10.54	1.81	2.27
Smart Low-Flow Showerhead	GPM rating ≤ 1.5	$55.42 / unit	10.28	12.41	1.20	1.45
*Duct Sealing (excludes multifamily)	Post-sealing leakage ≤ 15%	$252.69 / home	26.94	60.72	1.05	2.46
Residential Equipment Rebates - available for single family, multifamily, and mobile homes					**1.30**	
Natural Gas Tankless Water Heater (TWH)	Uniform Energy Factor (UEF) ≥ 0.81	$300 / unit	39.50		1.08	
Natural Gas Gravity Wall Furnace	Annual Fuel Utilization Efficiency AFUE ≥ 70%	$25 / unit	14.99	21.18	4.09	5.78
Natural Gas Fireplace - Tier 1	70% - 74.9% efficient with intermittent pilot light	$50 / unit	16.00	27.00	2.06	3.48
Natural Gas Fireplace - Tier 2	Efficiency ≥ 75% with intermittent pilot light	$100 / unit	28.00	47.00	1.86	3.12
Smart Thermostat (excludes CZ 14)	ENERGY STAR qualified	$100 / unit	N/A	48.23	N/A	1.94
New Home Rebates - available for single family homes only					**1.50**	
Title 24 Home - Single Story Tier 1	Natural Gas TWH - UEF ≥ 0.81 and Natural Gas Furnace - AFUE ≥ 92%	$400 / home	68.15	85.52	1.62	2.04
Title 24 Home - Two Story Tier 1	Natural Gas TWH - UEF ≥ 0.81 and Natural Gas Furnace - AFUE ≥ 92%	$650 / home	105.34	122.36	1.24	1.44
Title 24 Home - Single Story Tier 2	Natural Gas TWH - UEF ≥ 0.81 and Natural Gas Furnace - AFUE ≥ 96%	$500 / home	75.49	97.59	1.64	2.13
Title 24 Home - Two Story Tier 2	Natural Gas TWH - UEF ≥ 0.81 and Natural Gas Furnace - AFUE ≥ 96%	$750 / home	118.69	140.59	1.34	1.59
Commercial Equipment Rebates					**1.65**	
Commercial Energy Audit	American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE) Level II	$5,000 / facility	N/A	N/A	N/A	N/A
Faucet - Tier 1	GPM rating ≤ 1.0	$5.13 / unit	3.58	4.69	4.05	5.31
Faucet - Tier 2	GPM rating ≤ 0.5	$5.13 / unit	6.25	8.19	7.08	9.27
Low-Flow Showerhead - Tier 1	GPM rating ≤ 1.8	$14.90 /unit	6.87	8.60	2.68	3.35
Low-Flow Showerhead - Tier 2	GPM rating ≤ 1.5	$14.90 /unit	11.45	14.33	4.46	5.59
Pre-Rinse Spray Valve - Tier 1	GPM rating ≤ 1.07	$49 / unit	16.04	19.44	2.17	1.30
Pre-Rinse Spray Valve - Tier 2	GPM rating ≤ 0.75	$49 / unit	55.52	67.29	3.73	4.52
Natural Gas Storage Water Heater (≤ 75,000 Btu/hr) - Tier 1	Thermal Efficiency ≥ 83%	$1.50 / MBtuh	0.65	0.76	1.90	2.19
Natural Gas Storage Water Heater (≤ 75,000 Btu/hr) - Tier 2	Thermal Efficiency ≥ 90%	$5.00 / MBtuh	2.01	2.32	1.75	2.02
Natural Gas Storage Water Heater (> 75,000 Btu/hr) - Tier 1	Thermal Efficiency ≥ 83%	$1.50 / MBtuh	0.59	0.75	2.02	2.57
Natural Gas Storage Water Heater (> 75,000 Btu/hr) - Tier 2	Thermal Efficiency ≥ 90%	$5.00 / MBtuh	1.80	2.31	1.89	2.43
Natural Gas Tankless Water Heater (≤ 200,000 Btu/hr)	UEF ≥ 0.81	$10.00 / MBtuh	2.28	2.61	1.09	1.25
Natural Gas Condensing Furnace	AFUE ≥ 95%	$2.50 / MBtuh	1.26	1.57	2.99	3.72
Natural Gas Condensing HVAC Boiler (≥ 300,000 Btu/hr)	Thermal Efficiency ≥ 94%	$2.50 / MBtuh	0.93	1.16	2.07	2.58
Combination Oven	Fisher-Nickel qualified	$1,500 / unit	1,163.67		1.96	
Convection Oven (full sized)	Fisher-Nickel qualified	$500 / oven chamber	250.00		1.57	
Convection Oven (half sized)	Fisher-Nickel qualified	$250 / oven chamber	162.00		2.56	
Conveyor Broiler	Fisher-Nickel qualified	$1,000 / unit	2,079.00		5.79	
Underfired Broiler	Fisher-Nickel qualified	$1,000 / unit	653.33		2.40	
Conveyor Oven (≥ 25" wide)	Fisher-Nickel qualified	$750 / unit	884.00		3.27	
Fryer	Fisher-Nickel qualified	$500 / vat	548.00		4.21	
Griddle	Fisher-Nickel qualified	$125 / 3 feet	126.00		3.50	
Rack Oven	Fisher-Nickel qualified	$1,000 / oven chamber	2,104.00		4.35	
Steam Cooker	Fisher-Nickel qualified	$1,000 / unit	2,595.00		7.35	
Solar Thermal Rebates					**0.40**	
Solar Thermal Commercial Pools	Collector must be OG-100 certified	$7.00 / therm	1,997.00	1,720.00	1.71	1.92
Solar Thermal Commercial and Multifamily	Collector must be OG-100 certified	$20.19 / therm	2,021.00	1,668.00	0.42	0.32
Solar Thermal Single Family Residential	System must be OG-300 certified	$29.85 / therm	136.00	120.00	0.17	0.16
CEE Plan					**1.31**	

[1] Equipment must use natural gas directly or utilize the appropriate natural gas fueled water or space heating source.

[2] Average therm savings for all property/facility types.

[3] Southwest Gas' service areas in CZ 14 include: Adelanto, Apple Valley, Barstow, Lenwood, North Barstow, Daggett, Helendale, Hesperia, Oak Hills, Hinkley, Lucerne Valley, Oro Grande, Victorville, and Yermo. The Company also serves a small area in CZ 15 (Needles), which has been included in the savings and cost-effectiveness analysis for CZ 14.

[4] Southwest Gas' service areas in CZ 16 include: Big Bear City, Big Bear Lake, Fawnskin, Sugarloaf, Carnelian Bay, Homewood, Tahoma, Kings Beach, Tahoe City, Tahoe Vista, South Lake Tahoe, Northstar, and Truckee.

CA CEE PLAN - ANNUAL EXPENDITURES, THERM SAVINGS, AND PARTICIPATION FOR YEARS 2021-2023 [1]

Program and Measures	2021			2022			2023		
	Expenditures	Therm Savings	Participation	Expenditures	Therm Savings	Participation	Expenditures	Therm Savings	Participation
Commercial Incentives Program									
Administration	$152,887.76	N/A	N/A	$87,394.44	N/A	N/A	$113,139.68	N/A	N/A
Combination Oven <15 pans	$0.00	0.00	0	$0.00	0.00	0	$6,000.00	1,321.20	4
Combination Oven >28 pans	$0.00	0.00	0	$0.00	0.00	0	$2,000.00	137.00	1
Convection Oven - Full	$0.00	0.00	0	$3,500.00	1,250.00	5	$5,400.00	2,250.00	9
Conveyor Broiler >26"	$0.00	0.00	0	$0.00	0.00	0	$1,500.00	1,158.00	1
Conveyor Broiler 20-26"	$0.00	0.00	0	$0.00	0.00	0	$1,500.00	1,896.00	1
Domestic Hot Water Boiler	$0.00	0.00	0	$0.00	0.00	0	$2,700.00	3,838.00	2
Fryer, Tier 1	$900.00	375.00	1	$32,400.00	9,309.00	29	$27,000.00	6,525.00	29
Fryer, Tier 2	$8,196.00	5,670.00	11	$7,000.00	2,070.00	5	$11,700.00	4,438.20	13
Griddle	$0.00	0.00	0	$2,400.00	252.00	2	$1,050.00	252.00	2
Rack Oven, Double	$0.00	0.00	0	$0.00	0.00	0	$5,000.00	1,053.00	3
Storage Water Heater	$0.00	0.00	0	$1,200.00	2.31	1	$0.00	0.00	0
Commercial Incentives Program Totals	**$161,983.76**	**6,045.00**	**12**	**$133,894.44**	**12,883.31**	**42**	**$176,989.68**	**22,868.40**	**65**
Residential Incentives Program									
Administration	$35,010.53	N/A	N/A	$41,622.71	N/A	N/A	$37,876.20	N/A	N/A
Clothes Dryer Residential	$1,925.00	173.50	39	$4,150.00	368.52	83	$5,300.00	474.51	106
Clothes Washer Residential	$2,175.00	389.61	66	$3,025.00	554.63	102	$4,675.00	821.36	129
Natural Gas Fireplace - Tier 1	$150.00	48.00	3	$100.00	43.00	2	$200.00	64.00	4
Natural Gas Fireplace - Tier 2	$200.00	56.00	2	$200.00	56.00	2	$300.00	84.00	3
Natural Gas Gravity Wall Furnace	$50.00	29.98	2	$125.00	81.14	5	$0.00	0.00	0
Natural Gas Storage Water Heater	$675.00	231.62	9	$825.00	279.28	11	$675.00	235.05	9
Natural Gas Tankless Water Heater	$15,300.00	2,686.00	68	$25,650.00	4,503.00	114	$27,000.00	4,740.00	120
Smart Thermostat	$20,900.00	10,128.30	210	$32,100.00	15,481.83	321	$33,400.00	16,108.82	334
Residential Incentives Program Totals	**$76,385.53**	**13,743.01**	**399**	**$107,797.71**	**21,367.40**	**640**	**$109,426.20**	**22,527.74**	**705**
New Home Incentives Program									
Administration	$0.00	N/A	N/A	$0.00	N/A	N/A	$2,000.00	N/A	N/A
New Home Incentives Program Totals	**$0.00**	**N/A**	**N/A**	**$0.00**	**N/A**	**N/A**	**$2,000.00**	**N/A**	**N/A**
Residential Equipment Direct Install (REDI) Program									
Administration	$0.00	N/A	N/A	$2,404.30	N/A	N/A	$2,000.00	N/A	N/A
Residential Equipment Direct Install (REDI) Program Totals	**$0.00**	**N/A**	**N/A**	**$2,404.30**	**0.00**	**0**	**$2,000.00**	**N/A**	**N/A**
Solar Thermal Incentives Program									
Administration	$0.00	N/A	N/A	$0.00	N/A	N/A	$2,000.00	N/A	N/A
Solar Thermal Incentives Program Totals	**$0.00**	**N/A**	**N/A**	**$0.00**	**0.00**	**0**	**$2,000.00**	**N/A**	**N/A**
Total Incentives	**$50,471.00**	**19,788.01**	**411**	**$112,675.00**	**34,250.71**	**682**	**$135,400.00**	**45,396.14**	**770**
Total Administration Expenses	**$187,898.29**	**N/A**	**N/A**	**$131,421.45**	**N/A**	**N/A**	**$157,015.88**	**N/A**	**N/A**
Total Generic Expenses	**$5,549.18**	**N/A**	**N/A**	**$3,649.18**	**N/A**	**N/A**	**$5,288.16**	**N/A**	**N/A**
CA CEE Plan Grand Total	**$243,918.47**	**19,788.01**	**411**	**$247,745.63**	**34,250.71**	**682**	**$297,704.04**	**45,396.14**	**770**

[1] Expenditures per Southwest Gas general ledger.

Southwest Gas Corporation
Application 21-08-XXX
Proposed Program Annual Estimates for Plan Years 2026-2030
Exhibit No. __(VSA-3)

PYs 2026 – 2030 Proposed Program	Estimated Annual Expenditures	Estimated Annual Savings (Therms)	Estimated Annual Participation
Residential Equipment Rebates	$160,000	259	520
Commercial Equipment Rebates	$200,000	17,047	176
Solar Thermal Rebates	$30,000	1,997	1
New Home Rebates	$150,000	814	217
Residential Equipment Direct Install (REDI)	$100,000	238	1,110
CEE Plan Administration – Education & Outreach	$10,000	0	0
Total	**$650,000**	**20,355**	**2,024**

CA CEE PLAN - ANNUAL EXPENDITURES, THERM SAVINGS, AND PARTICIPATION FOR YEARS 2026-2030

Measure	Measure Requirement [1]	Rebate Amount	Estimated Annual Savings (Therms) [2]		TRC Ratio	
			CZ 14 [3]	CZ 16 [4]	CZ 14 [3]	CZ 16 [4]
Commercial Equipment Rebates						
Conveyor Oven (>25")	ENERGY STAR or FSTC/CaliforniaEnergy Wise listed	$1,400.00 / chamber	422.00		1.23	
Convection Oven - Full Sized	ENERGY STAR or FSTC/CaliforniaEnergy Wise listed	$700.00 / chamber	356.00		1.79	
Convection Oven - Half Sized	ENERGY STAR or FSTC/CaliforniaEnergy Wise listed	$700.00 / chamber	231.00		1.56	
Combi Oven, < 15 pans	ENERGY STAR or FSTC/CaliforniaEnergy Wise listed	$1,500.00 / unit	798.00		1.40	
Combi Oven, 15-28 pans	ENERGY STAR or FSTC/CaliforniaEnergy Wise listed	$2,000.00 / unit	1,121.00		1.80	
Combi Oven, > 28 pans	ENERGY STAR or FSTC/CaliforniaEnergy Wise listed	$3,000.00 / unit	1,573.00		1.81	
Steam Cooker	ENERGY STAR or FSTC/CaliforniaEnergy Wise listed	$2,000.00 / unit	1,100.00		3.23	
Fryer - Tier 1	ENERGY STAR or FSTC/CaliforniaEnergy Wise listed	$750.00 / vat	375.00		2.64	
Fryer - Tier 2	ENERGY STAR or FSTC/CaliforniaEnergy Wise listed	$1,200.00 / vat	414.00		1.74	
Griddle	ENERGY STAR or FSTC/CaliforniaEnergy Wise listed	$200.00 / ft.	125.00		1.89	
Conveyor Broiler (< 20")	ENERGY STAR or FSTC/CaliforniaEnergy Wise listed	$2,000.00 / unit	1,150.00		3.05	
Conveyor Broiler (20"-26")	ENERGY STAR or FSTC/CaliforniaEnergy Wise listed	$2,500.00 / unit	1,930.00		4.11	
Convyor Broiler (> 26")	ENERGY STAR or FSTC/CaliforniaEnergy Wise listed	$4,000.00 / unit	3,160.00		5.54	
Rotisserie (Small)	ENERGY STAR or FSTC/CaliforniaEnergy Wise listed	$1,500.00 / unit	850.00		3.36	
Rotisserie (Medium)	ENERGY STAR or FSTC/CaliforniaEnergy Wise listed	$2,000.00 / unit	1,100.00		2.76	
Rotisserie (Large)	ENERGY STAR or FSTC/CaliforniaEnergy Wise listed	$3,000.00 / unit	1,960.00		3.18	
Underfire Broiler	ENERGY STAR or FSTC/CaliforniaEnergy Wise listed	$650.00 / ft.	218.00		1.92	
Pre-Rinse Spray Valve - Tier 1	GPM rating ≤ 1.07	$49.00 / unit	16.20	19.20	4.70	2.75
Pre-Rinse Spray Valve - Tier 2	GPM rating ≤ 0.75	$49.00 / unit	31.20	36.90	2.53	3.00
Commercial Storage Tank WH - Average of all facility types	>75k btu - 90Et	$5.00 / MBtu	2.09	2.30	1.52	1.76
Commercial Storage Tank WH - Average of all facility types	>75k btu - 83Et	$1.50 / MBtu	0.65	0.75	1.65	1.90
Commercial Tankless WH - Average of all facility types and efficiencies	< 200k BTU	$4.00 / MBtu	4.25	4.81	6.79	7.69
Commercial Storage Heaters	>75 kBtuh,90% TE	$5.00 / MBtu	3.47	3.97	1.12	1.29
Gas Draft HVAC Boiler	300-2500 Kbtuh - 90% TE	$2.50 / MBtu	1.20	1.39	1.69	1.96
Gas Draft HVAC Boiler	300-2500 Kbtuh - 96% TE	$5.00 / MBtu	2.30	2.66	1.75	2.02
Commercial Faucet - Public & Private Lavoratory	1.0 gpm	$7.17 / unit	3.19	8.41	1.54	4.07
Commercial Faucet - Public & Private Lavoratory	0.5 gpm	$7.17 / unit	5.55	7.34	2.69	3.55
Commercial Showerheads	≤ 1.4 gpm - Average of all facility types	$14.90 / unit	2.54	3.21	2.54	3.21
New Home Rebates						
Title 24 Tankless WH Tier 1 - Single Story	Natural Gas TWH - UEF ≥ 0.81 and Natural Gas Furnace - AFUE ≥ 92%	$400 / home	68.15	85.52	2.17	2.72
Title 24 Tankless WH Tier 2 - Single Story	Natural Gas TWH - UEF ≥ 0.81 and Natural Gas Furnace - AFUE ≥ 96%	$500 / home	75.49	97.59	2.18	2.82
Title 24 Tankless WH Tier 1 - Two Story	Natural Gas TWH - UEF ≥ 0.81 and Natural Gas Furnace - AFUE ≥ 92%	$650 / home	105.34	122.36	1.67	1.94
Title 24 Tankless WH Tier 2 - Two Story	Natural Gas TWH - UEF ≥ 0.81 and Natural Gas Furnace - AFUE ≥ 96%	$750 / home	118.69	140.59	1.79	2.13
Residential Equipment Direct Install (REDI)						
Residential Faucet Aerator - 1.5 GPM - Kitchen	GPM rating ≤ 1.5	$5.80 / unit	6.53	8.23	6.44	8.12
Residential Faucet Aerator - 1.0 GPM - Lavoratory	GPM rating ≤ 1.0	$5.62 / unit	3.18	4.02	3.24	4.09
Residential Low Flow Showerhead - 1.5 GPM	GPM rating ≤ 1.5	$30 / unit	8.22	10.35	2.37	2.98
Residential Low Flow Showerhead with TSV - 1.5 GPM	GPM rating ≤ 1.5	$55.42 / unit	10.01	12.65	1.56	1.97
Residential Duct Leakage - Mobile Home	Post-sealing leakage ≤ 15%	$252.69 / home	32.71	52.94	2.32	4.11
Residential Duct Leakage - Single Family	Post-sealing leakage ≤ 15%	$252.69 / home	21.16	68.50	1.50	4.85
Residential Equipment Rebates						
Residential Tankless Water Heater	ENERGY STAR listed	$225 / unit	89.30	102.00	1.69	1.93
Smart Thermostat	ENERGY STAR qualified	$100 / unit	22.20	[redacted]	2.14	[redacted]
Fireplace - Tier 1	70% - 74.9% efficient with intermittent pilot light	$50 / unit	7.18	6.48	1.25	1.13
Fireplace - Tier 2	Efficiency ≥ 75% with intermittent pilot light	$100 / unit	12.70	11.40	1.13	1.02
Solar Thermal Commercial						
Solar Thermal Commercial Pools	Collector must be OG-100 certified	$13,979 / unit	1,997.00	[redacted]	1.78	[redacted]

[1] Equipment must use natural gas directly or utilize the appropriate natural gas fueled water or space heating source.

[2] Average therm savings for all property/facility types.

[3] Southwest Gas' service areas in CZ 14 include: Adelanto, Apple Valley, Barstow, Lenwood, North Barstow, Daggett, Helendale, Hesperia, Oak Hills, Hinkley, Lucerne Valley, Oro, Grande, Victorville, and Yermo. The Company also serves a small area in CZ 15 (Needles), which has been included in the savings and cost-effectiveness analysis for CZ 14.

[4] Southwest Gas' service areas in CZ 16 include: Big Bear City, Big Bear Lake, Fawnskin, Sugarloaf, Carnelian Bay, Homewood, Tahoma, Kings Beach, Tahoe City, Tahoe Vista, South Lake Tahoe, Northstar, and Truckee.

Southwest Gas – Estimated CARE Penetration as of December 31, 2023					
County	Total Households	Demographic Eligibility Rate - Income at 200% of Federal Poverty Guideline	Eligible Households	Participating CARE Households	Estimated CARE Penetration Rate
EL DORADO	15,767	0.211398	3,333	2,049	61%
NEVADA	8,786	0.156513	1,375	339	25%
PLACER	8,918	0.225206	2,008	342	17%
SAN BERNARDINO	143,724	0.388527	55,841	56,132	101%
TOTAL	**177,195**	**0.353042**	**62,557**	**58,862**	**94%**

[1] Prepared by Athens Research and submitted to the SMJUs on March 22, 2024. SMJUs are Southwest Gas, Alpine, BVES, Liberty, PacifiCorp, and West Coast Gas.