

Rate Study

February 2025



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February 2025

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SUBJECT: Natural Gas Cost of Service and Rate Study

Dear Lisa:

Attached please find the Natural Gas Cost of Service and Rate Study report for the City of Palo Alto (City) prepared by EES Consulting (EES), a GDS Associates company.

We based the conclusions and recommendations contained within this report upon industry practice and accepted rate setting principles. The assumptions are consistent with the financial and metering data provided for revenue requirement, customer, and system data and costs.

EES developed the study with mutual aid of the City's staff and appreciate the internal effort to refine the study. The findings, conclusions and recommendations of this report supply the basis for the development of fair and equitable rates for the City.

Very truly yours,

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1 Executive Summary

The City of Palo Alto (City) retained EES Consulting (EES), a GDS Associates company, to perform a natural gas cost of service analysis (COSA) and rate study for Fiscal Year 2025-2026 (FY 2025-2026)¹ as part of its ongoing efforts to maintain fiscally prudent, fair, cost-based rates for its natural gas customers. The natural gas COSA is primarily concerned with the development of distribution rates.

In addition to the distribution rates that are the subject of this Study, the City charges four additional rates to customers that pass on costs that are outside of the immediate control of the City, such as the cost of purchasing gas and transporting it to the City's distribution system. These four rates are: 1) the gas commodity rate, which represents the cost of buying gas in the markets, 2) the gas transportation rate, which represents the cost of transporting purchased gas to Palo Alto, 3) the Cap and Trade compliance rate, which represents the cost of mandated participation in the State's cap and trade program, and 4) the carbon offset rate, which represents the cost of buying offsets for the City's Carbon Neutral Gas Portfolio. These four charges are discussed at the end of this Study.

The starting point for the current study was the COSA that EES performed for FY 2019-2020 (COSA 2020). The City updated that COSA model for FY 2020-2021 (COSA 2021), with some assistance by EES. Since then, the City has implemented distribution rate adjustments by uniformly adjusting distribution rates using the percent change in distribution revenue requirement; thus, distribution rates since 2021 have reflected the COSA 2020 analysis framework.

This Study is a comprehensive update to the 2020 COSA. All Study assumptions and inputs have been updated and new rate designs incorporated into the recommendations. EES also modernized and streamlined the COSA model to facilitate future updates.

EES worked closely with the City's technical staff and management to refine data inputs for gas sales and updated expenses, and assets. EES had no issues obtaining appropriate data responses or clarification when necessary and commends the transparency of the process and the capability of internal resources.

1.1 SYSTEM DESCRIPTION

The City's gas utility serves approximately 23,500 customer accounts over an area of approximately 26 square miles. The gas utility is responsible for the operations and maintenance of the distribution system, and it purchases all of its gas from outside suppliers. Total gas consumption in the City forecasted for FY 2025-2026 is 25.8 million therms. EES expects sales to continue near their current weather-adjusted level of 25 to 26 million therms per year and near the current volume of services. Table 1-1 shows the number of services and annual gas use for each rate class.

¹ July 2025 through June 2026.

TABLE 1-1: NUMBER OF SERVICES UNDER CURRENT RATE SCHEDULES AND FORECASTED ANNUAL USE IN FY 2025-2026

Rate Schedule	Services	Annual Use, therms
G1 Residential	21,255	9,762,524
G2 Residential Master Metered and Commercial	2,193	11,506,051
G3 Large Commercial	30	4,510,914
Total	23,477	25,779,489

Gas utility rate schedules consist of a fixed monthly service charge and volumetric rates. The Monthly Service Charge (\$/meter/month) and Distribution Charges (\$/therm) vary by rate class. Volumetric charges are used for both commodity purchases and recovery of variable distribution costs.

Table 1-2 summarizes the rate classes and current rate design for the distribution portion of the rate schedule. It does not include volumetric supply charges: Commodity Charge (Monthly Market Based), Cap and Trade Compliance Charge, Transportation Charge and Carbon Offset Charge.

TABLE 1-2: CURRENT DISTRIBUTION RATE DESIGN

Utility Rate Schedule	Description	Current Rate Design
G1: Residential	Separately metered: Single-family residential customers Multi-family residential customers	Service Charge, \$/meter/month 2-Tier Volumetric Charge with seasonal lower-cost tier 1 quantities Tier 1 Summer: ¹ 20 therms/30-day-billing Tier 1 Winter: 60 therms/30-day-billing Tier 2: All other therms
G2: Residential Master-Metered and Commercial ("Small Commercial")	Commercial customers who use less than 250,000 therms per year at one site, and master-metered residential customers in multifamily residential facilities	Service Charge, \$/meter/month Volumetric Charge, \$/therm
G3: Large Commercial	Commercial customers who use at least 250,000 therms per year at one site. ²	Service Charge, \$/meter/month Volumetric Charge, \$/therm

1. Summer rates effective April 1 through October 31. Winter rates effective November 1 through March 31.

² In addition to these standard rate classes, CPAU provides CNG service under the G10 rate schedule. The CNG customer receives service using specific facilities. The service provided has not changed since the previous cost of service study, and the cost to serve the G10 customer has increased at the same rate as for the distribution expenses overall. For this reason, the G10 rate should be adjusted by the average system increases. For FY 2025-2026, the G10 rate should be increased 8.7%.

1.2 RATE STUDY OVERVIEW

The purpose of this report is to discuss the data inputs, assumptions and results that were part of developing the rate study. A comprehensive rate study generally consists of three separate, yet interrelated analyses. These three analyses include a revenue requirement, COSA, and rate design examination.

1. **Revenue Requirement Analysis:** This analysis examines the various sources and uses of funds for the utility, and it determines the overall revenue required to operate the utility.
2. **Cost-of-Service Analysis (COSA):** COSA is used to determine the fair allocation of the total revenue requirement to the various customer classes of service (e.g., residential, small commercial, large commercial). This analysis provides a determination of the level of revenue responsibility of each class of service and the adjustments from current revenues required to meet the cost of service.
3. **Rate Design Analysis:** The third analysis involves evaluating the rate design options available and designing rate schedules that can be applied to each rate class to collect revenues to cover the cost to serve customers in that class.

1.2.1 Revenue Requirement

The first step in completing a rate study is to develop the revenue required from rates (revenue requirement). A revenue requirement analysis compares the overall revenues of the utility to its expenses and helps determine the need for an overall adjustment to rate levels. Over the course of the study period, the City prepared several financial analyses that included a forecast of FY 2025-2026 sales, revenues and expenses. The City has an in-depth accounting and data system that keeps track of ongoing and budgeted or approved expenditures. EES based the forecasts on projected FY 2026 expenses and sales estimates for the natural gas utility. For this COSA, EES maintained a cash-basis method for determining the City's revenue requirement based on the City's financial forecast.

FY 2025-2026 natural gas commodity costs are included in City's financial plan. However, these costs are adjusted monthly to pass through actual commodity rates charged to the City by its wholesaler. Therefore, commodity charges are not set based on the COSA; the COSA focuses narrowly on setting appropriate distribution charges for the year.

Table 1-3 summarizes the FY 2025-2026 distribution revenue requirement totaling \$41.3 million. At current rates, there is a revenue shortfall of \$3.3 million. A rate increase of 8.7% to the distribution rate would collect the required revenue to meet distribution costs.

TABLE 1-3: DISTRIBUTION REVENUE REQUIREMENT: FY 2025-2026

	Revenue Requirement
Distribution O&M	\$9,797,408
Customer Accounts and Services	\$3,208,008
Administration and General	\$5,002,927
Debt Service & CIP from Rates	\$8,339,643
General Fund Transfer	\$9,734,580
Total Expenses	\$36,082,566
Transfers to Reserves	\$5,874,887
Other Revenues	-\$689,111
Total Revenue Required from Rates (Revenue Requirement)	\$41,268,342
Revenues Based on Rates Currently in Effect	\$37,957,863
Additional Rate Revenue Needed	\$3,310,479
Total Required Rate Revenue Increase (Decrease)	8.7%

1.2.2 Cost of Service Analysis

Cost-of-service is important for the fair allocation of the revenue requirement to the various customer classes of service. The revenue requirement shown in Table 1-3 for the City was functionalized, classified and allocated.

- **Functionalization** is the attribution of each cost line-item to production (commodity), transportation, distribution, or shared services. This COSA evaluates only Distribution costs and distribution-related overhead.
- **Classification** is the determination of whether the costs associated with a functionalized line item are most appropriately allocated based on energy use (therms), demand (maximum system capacity), or customer (simply having a service).
- **Allocation** is the process of using the classification for each functionalized line item to assign costs to each customer class. For example, a cost item classified as “energy use” might be allocated based on annual therm use. This means that the line-item cost is directly correlated to the quantity of energy used by each customer class annually. This process is described in more detail in the section titled “Cost of Service Analysis.”

Ultimately, the COSA process requires analysis of how each customer class contributes to the expenses incurred by the utility to provide service. Table 1-4 shows, by customer class, the revenue requirement and revenue change needed for FY 2025-2026.

TABLE 1-4: DISTRIBUTION COSA RESULTS: FY 2025-2026

	Projected FY 2025-2026 Revenues	Revenue Requirement	Projected FY 2025-2026 Deficiency/ (Surplus)	Revenue Change Needed
G1 – Residential	\$16,311,063	\$18,853,368	\$2,542,305	15.59%
G2 – Small Commercial	\$16,565,086	\$16,568,614	\$3,527	0.02%
G3 – Large Commercial	\$5,081,713	\$5,846,360	\$764,647	15.05%
Total	\$37,957,863	\$41,268,342	\$3,310,479	8.7%

1.2.3 Rate Design Recommendations

The final step in the rate study process is to design rates for each class of service. In California, local governments are subject to Article XIII C of the California Constitution, as amended by Proposition 26. As a result, the City sets rates based on COSA results. The goal of rate design is to create rates that recover costs from customers within each class according to the utility’s respective cost of providing service. The basis for each rate design recommendation is provided in this section followed by the recommended rates.

All rate classes are charged a monthly service charge and volumetric charge to recover distribution costs. EES is not recommending changes to this basic rate design structure, except for a refinement in the development of the Monthly Service Charge for G2 based on additional analysis of that class’s usage and costs – Section 1.2.3.2, Commercial provides more details on this change.

1.2.3.1 Residential

The G1 distribution rates consist of a monthly service charge and volumetric tier rates: the Tier 1 rate applies to usage up to the baseline quantity and the Tier 2 rate applies to all usage above the baseline. EES recommends no change to the G1 rate structure because it effectively recovers energy and demand or capacity costs incurred by the class.

While the tier rates do not change between seasons, the baseline quantity above which Tier 2 rates apply does change and is higher in winter than in the summer because natural gas heat is more prevalent in the winter and causes higher consumption.³ This ensures that those customers contributing to higher seasonal demand are paying appropriately for their share of the demand-related cost in a tiered rate. EES evaluated the G1 tier rates using the Average and Excess (A&E) method (discussed in more detail in Section 3.4) and proposes a modest adjustment to the summer baseline from 20 to 23 therms per thirty-day billing period.

³ Usage above the Tier 1 baseline quantity is charged Tier 2 rate. The current quantity is 20 therms/30-day-billing in summer and 60 therms/30-day-billing in winter.

Table 1-5 summarizes the costs to be recovered in each rate component for G1.

TABLE 1-5: G1 RATES AND COST RECOVERY

Rate Component	Recovers The Following Costs:
Monthly Service Charge	Customer-related costs such as customer service, billing, and overhead adders
Tier 1 Volumetric Rate	Energy-related costs plus 54% of demand-related distribution unit costs*
Tier 2 Volumetric Rate	Energy-related costs plus 46% of demand-related distribution unit costs*

*See calculations in Section 4.1.1. Residential (G1) Rate Design, Table 4-5.

1.2.3.2 Commercial

EES recommends no change to the volumetric charge structure for the two commercial classes (G2 and G3). Within the commercial rate class, there are inherent size differences, in terms of physical space and energy use, related to the types of business.

It is not appropriate to charge larger-usage businesses more through a volumetric tiered rate structure because the larger sized customers have sufficient minimum monthly consumption to account for variances in distribution costs on a per therm basis. For example, when comparing the minimum level of monthly consumption to the annual consumption, all commercial classes have minimum consumption over 59%, whereas residential minimum consumption by the same measure is only 36%. Therefore, tiered volumetric Distribution Charges for commercial classes are not necessary, but do have a place for the residential class. There is not a sufficient under-recovery of demand-related distribution costs from minimum volumes to warrant a tiered rate for commercial classes.

This Study updated input, assumptions and calculations of fixed charges. The resulting changes proposed to the Monthly Service Charge for G2 are based on a refinement of cost functionalization developed in the study. This methodology and assumptions are detailed in Section 3. In addition to the methodology review, EES performed additional analysis on G2 meter capacity related costs by comparing the average consumption for various meter capacities. Fixed costs are generally higher for customers with larger capacity service because of the larger and more expensive equipment required to provide higher volume service.

Based on the findings of this analysis, EES determined customer-related costs for three categories defined by meter capacity. Table 1-6 illustrates the recommended rate for the G2 class and the number of services within each G2 subgroup. With the recommended rates, G2 customers would be charged a Monthly Service Charge based on maximum meter capacity; customers with lower-capacity meters would pay a lower Monthly Service Charge than those with higher capacity meters. For example, a customer with a meter capacity of 200 standard cubic feet per hour (scfh) would pay the lowest Monthly Service Charge, at \$29.06.

For G3, the meter capacity of services is much more uniform within the rate class. Also, importantly, the meter costs associated with G3 consumption levels are similar.

TABLE 1-6: G2 MONTHLY SERVICE CHARGES: FY 2025-2026

CPAU Approved Maximum Meter Capacity (scfh ⁴)	Number of Services	Current Monthly Service Charge \$/Meter/Month	Recommended Monthly Service Charge \$/Meter/Month
Up to 220	1,134	\$156.90	\$29.06
Above 220 but Below 4,000	942	\$156.90	\$94.94
4,000 and Above	116	\$156.90	\$417.62
Total G2	2,193		

While Table 1-6 shows the lower Monthly Service Charge for smaller G2 customers (defined as customers with meter capacity up to 220 scfh), Table 1-7 illustrates that this same group of customers should also receive an overall rate decrease. The column “Revenue Requirement” in Table 1-7 presents the total revenue requirement amounts (including fixed and variable costs) that correspond to the recommended Monthly Service Charges shown in Table 1-6 above. The recommended rates for G2 are provided in Section 1.2.4.

TABLE 1-7: G2 REVENUES AND REVENUE REQUIREMENT: FY 2025-2026

CPAU Approved Maximum Meter Capacity (scfh)	Projected FY 2026 Revenues at Current Monthly Service Charge	Revenue Requirement	Projected FY 2026 Deficiency/(Surplus)	Revenue Change Needed
Up to 220	\$2,948,824	\$1,713,540	(\$1,235,283)	-41.9%
Above 220 but Below 4,000	\$7,685,399	\$7,987,841	\$302,442	3.9%
4,000 and Above	\$5,930,863	\$6,867,232	\$936,369	15.8%
Total G2	\$16,565,086	\$16,568,614	\$3,527	0.0%

⁴ All meters have a manufacturer-rated capacity and an approved for engineering maximum capacity. The CPAU approved capacity is typically slightly lower than the manufacturer maximum capacity due to connected characteristics and other variable conditions. CPAU approved maximum meter capacities in this staff report are all at an assumed pressure of 7 inches of water column (equivalent to 0.25 pounds per square inch).

1.2.4 Rate Change Recommendations

Table 1-8 provides a comparison of current rates and recommended rates for FY 2026, including the newly developed G2 Monthly Service Charge by meter capacity.

TABLE 1-8: CURRENT AND RECOMMENDED RATES

	Current Rate	Recommended FY 2025-2026 Rate	\$ Change	Percent Change
G1 Residential				
Monthly Service Charge	\$16.93	\$19.52	\$2.59	15.3%
Distribution Charge (\$/therm)				
Tier 1 For Winter: first 60 therms/30-day-billing For Summer: first 20 therms/30-day-billing (current); first 23 therms/30-day-billing (recommended)	\$0.8229	\$1.2274	\$0.4045	49.2%
Tier 2 For Winter: over 60 therms/30-day-billing For Summer: over 20 therms/30-day-billing (current); over 23 therms/30-day-billing (recommended)	\$2.1043	\$1.8972	-\$0.2071	-9.8%
G2 – Small Commercial (Total)				
Monthly Service Charge	\$156.90	\$78.00	-\$78.90	-50.3%
Distribution Charge (\$/therm)	\$1.0809	\$1.2616	\$0.1807	16.7%
G2: Meter Capacity ≤ 220 scfh				
Monthly Service Charge	\$156.90	\$29.06	-\$127.84	-81.5%
Distribution Charge (\$/therm)	\$1.0809	\$1.2616	\$0.1807	16.7%
G2: Meter Capacity > 220 scfh and < 4,000 scfh				
Monthly Service Charge	\$156.90	\$94.94	-\$61.96	-39.5%
Distribution Charge (\$/therm)	\$1.0809	\$1.2616	\$0.1807	16.7%
G2: Meter Capacity ≥ 4,000 scfh				
Monthly Service Charge	\$156.90	\$417.62	\$260.72	166.2%
Distribution Charge (\$/therm)	\$1.0809	\$1.2616	\$0.1807	16.7%
G3 Large Commercial				
Monthly Service Charge	\$717.89	\$1,713.67	\$995.78	138.7%
Distribution Charge (\$/therm)	\$1.0702	\$1.1616	\$0.0914	8.5%

2 Revenue Requirement Development

This section presents the development of the natural gas revenue requirement in the COSA study. Simply stated, a revenue requirement analysis compares the overall revenues of the utility to its expenses and determines the overall adjustment to rate levels required.

2.1 OVERVIEW OF THE CITY’S REVENUE REQUIREMENT METHODOLOGY

The City utilizes the cash basis approach for determining its revenue requirement. The revenue requirement for the City’s natural gas utility includes the elements shown in Table 2-1.

TABLE 2-1: ELEMENTS OF A CASH BASIS REVENUE REQUIREMENT

+ Operating Expenses	
✓ Natural Gas Supply Expense	
✓ Distribution O&M Expense	
✓ Customer Accounting Expenses	
✓ Administrative and General Expense	
+ Capital Improvements Funded from Rates	
+ General Fund Transfer	
=	Total Revenue Requirement
-	Transfers from Reserves
-	Miscellaneous Revenue Sources
=	Net Revenues Required From Rates (or Net Revenue Requirement)

In this basic analytical framework, the first step in determining the revenue requirement is to select a period over which to review revenues and expenses. This COSA uses a future fiscal year test period to correspond with the City’s budget year. The revenue requirement in this COSA reflects the City-provided financial forecast (budget) for FY 2025-2026.

The next step in the analysis was to translate the City-budgeted costs into the system of accounts used by a natural gas utility.

2.2 SUPPLY COSTS

While this Study does not include an analysis for gas supply costs, a summary of these costs is provided here for reference. As with most natural gas utilities, a major expense associated with operating the utility is the cost of natural gas supply. The City is projecting FY 2025-2026 gas supply costs at \$25.8 million or 38 percent of the total FY 2025-2026 revenue requirement. Supply costs are charged to customers via four pass-through rate components. The following rate components are adjusted monthly to reflect actual costs:

1. Gas commodity: This represents the cost of buying gas in the market.
2. Gas transportation: This reflects the cost of transporting purchased gas from the delivery points to Palo Alto.
3. Cap and Trade compliance: This covers the cost of mandated participation in the State’s cap and trade program.
4. Carbon offset charge: This accounts for the cost of buying offsets needed to comply with the City’s Carbon Neutral Gas Portfolio Program.

While the cost of natural gas supply is included in the COSA, it is treated as a separate category as the cost of natural gas supply is collected through separate rate components. A description of these separate rates is provided in Section 4.2.

2.3 DISTRIBUTION COSTS

Total FY 2025-2026 revenue requirement for distribution is projected to be \$41.3 million. Distribution operating expenses include the following (other expenses are discussed in Sections 2.4 through 2.7):

- Physical system costs of \$9.8 million. These costs include the operations and maintenance of distribution system infrastructure such as distribution mains, regulators and meters.
- Customer service-related costs of \$3.2 million. These costs include meter reading, billing, key account representatives and general customer service.
- Administrative and general costs of \$5.0 million. These costs include functions like accounting, purchasing, legal, and other administrative functions provided by the City's General Fund staff, as well as Utilities Department administrative overhead, insurance, rent, and transfers to city non-enterprise funds for items such as utility building improvements and to other enterprise funds for items such as the gas utility's share of Geographic Information System project costs.

The customer service category includes \$0.5 million in expenses for energy efficiency, conservation (demand side management), and low-income assistance programs. These expenses are incurred by the gas enterprise as part of a program established by the City pursuant to California Public Utilities Code Section 898. By virtue of this program, gas customers are exempted from a state surcharge that would otherwise be collected on utility bills pursuant to Public Utilities Code Section 890. The City's energy efficiency and demand-side management programs reduce customer gas demand, and are designed to reduce the need for capital expenditures that would otherwise be needed to expand the capacity of the gas distribution system.

2.4 DEBT SERVICE AND RATE-FUNDED CAPITAL IMPROVEMENT PROGRAM (CIP)

The City must cover its capital improvement projects (CIP) through either debt or cash from rates or through external sources such as grants or loans. For FY 2025-2026 the City has debt service payments of \$0.8 million for past borrowings to fund CIP, specifically the 2011 Series A Utility Revenue Refunding Bonds. This bond issuance was to refinance the \$18 million principal remaining on the Utility Revenue Bonds, 2002 Series A issued for the Gas and Water Utilities to finance various improvements to the distribution systems. The majority of CIP is funded from rate revenues. For FY 2026, the budgeted CIP is \$7.5 million. This amount is in effect, partially offset by contributions made by new customers in the form of connection fees. The \$0.7 million in connection fees is included in other revenues, which is further discussed below. Total FY 2025-2026 debt service and rate-funded CIP is \$8.3 million before customer contributions.

2.5 GENERAL FUND TRANSFER

The City calculates the equity transfer from its natural gas utility based on a methodology approved by voters in November 2022.⁵ The General Fund Transfer is estimated to be \$9.7 million in FY 2025-2026.

2.6 MISCELLANEOUS/OTHER REVENUES

The City receives additional operating and non-operating revenues and contributions. These come in the form of interest revenues, connection fees and other miscellaneous service revenues. Interest revenues are interest earned on the utility's reserves. Connection fees are contributions paid by customers to cover the cost of new facilities built on their behalf. For FY 2025-2026, the projection for these revenues and contributions is \$0.7 million.⁶ These miscellaneous/other revenues are separate from fixed and volumetric charges for natural gas service and are therefore considered an offset to the total revenue required from retail rates.

2.7 TRANSFERS TO/FROM RESERVES

In its FY 2025-2026 natural gas financial forecast, the City is anticipating that \$5.9 million of rate revenues will need to be added to the reserves in FY 2025-2026 to restore both the operating and CIP reserves. The operating reserve balance is adjusted to meet future debt service requirements as projected from the City's financial plan. Additionally, the City plans to make contributions to the CIP reserve fund to balance year-to-year fluctuations in CIP expenditures. The use of the reserve fund allows the City to have more stable and gradual rate increases over time.

2.8 SUMMARY OF REVENUE REQUIREMENT

The City's Distribution revenue requirement for the FY 2025-2026 test period is summarized in Table 2-2. A rate increase of 8.7% is required to meet projected FY 2025-2026 costs.

⁵ In November 2022, voters approved Measure L, amending the Municipal Code, Section 2.28.185, "Natural Gas Utility Transfer" states: "Each fiscal year the City Council may transfer from the natural gas utility to the general fund an amount equal to 18% of the gross revenues of the gas utility received during the fiscal year two fiscal years before the fiscal year of the transfer. At its discretion, the City Council may decide to transfer a lesser amount. The projected cost of the transfer shall be included in the City's retail natural gas rates as part of the cost of providing gas service."

⁶ Misc. Revenues also includes customer discounts and uncollectible bills. These items reduce the amount of funds needed to be collected from retail gas rate revenues because they are recovered from non-rate revenues including interest income from investments. Therefore, the total Misc. Revenues is the total non-rate revenue net of these expenses.

TABLE 2-2: SUMMARY OF NATURAL GAS DISTRIBUTION REVENUE REQUIREMENT: FY 2025-2026

	Revenue Requirement
Distribution O&M	\$9,797,408
Customer Accounts and Services	\$3,208,008
Administration and General	\$5,002,927
Debt Service & CIP from Rates	\$8,339,643
General Fund Transfer	\$9,734,580
Total Expenses	\$36,082,566
Transfers to Reserves	\$5,874,887
Other Revenues	-\$689,111
Total Revenue Required from Rates (Revenue Requirement)	\$41,268,342
Revenues Based on Rates Currently in Effect	\$37,957,863
Additional Rate Revenue Needed without Gas Supply	\$3,310,479
Total Required Rate Revenue Increase (Decrease)	8.7%

3 Cost of Service Analysis

The objective of the cost-of-service analysis (COSA) is to allocate the costs in the revenue requirement to each customer class of service to determine the cost to serve those customers. An essential principle of cost allocation is the concept of cost-causation. Cost-causation evaluates which customer or group of customers causes the utility to incur certain costs by linking system facility investments and the operating costs to serve certain facilities to the way customers use those facilities and services. This section of the report discusses the general approach used to allocate the City's costs and presents a summary of the results.

3.1 COSA DEFINITION AND GENERAL PRINCIPLES

A COSA study allocates the costs of providing utility service to the various customer classes served by the utility based upon the cost-causal relationship associated with specific expense items. This approach is taken to develop a fair and equitable designation of costs to each class of service. The COSA allocates joint and common costs among the various classes using factors appropriate to each type of expense. The COSA is the second step in a traditional three-step process for developing natural gas service rates, after development of the revenue requirement but before designing rates.

This COSA study is an embedded cost analysis. Embedded costs generally reflect the actual costs incurred by the utility and closely track the costs kept in its accounting records.

There are three basic steps to follow in developing a COSA, namely: functionalization; classification; allocation.

Functionalization separates costs into major categories that reflect the different services provided to customers and the types of assets used to provide those services. The primary functional categories for the City's natural gas utility are supply and distribution.

Classification determines the portion of each cost that is related to specific cost-causal factors, or "classifiers." These classifiers might be demand-related (related to the class of service's peak energy usage over a given period), energy-related (related to the total energy used by the class of service over a given period), or customer-related (costs incurred as a result of receiving service, regardless of the energy use or peak demand). Natural gas supply or commodity costs are related to the amount of natural gas purchased and are therefore considered energy-related. The distribution system is designed to extend service to all customers attached to the system and to meet both the peak day demand and the annual energy requirement of each customer, meaning that costs are both demand-related and energy-related. Some operational costs, such as billing, are generally customer-related. Costs can also be classified based on system revenues or directly assigned to a customer or group of customers if appropriate.

Allocation of costs to specific classes of service happens after those costs have been classified. Allocation factors are chosen to allocate the costs assigned to each classification, and the share of costs allocated to each class of service are based on the class's contribution to the specific allocation factor selected. For example, certain distribution costs might be classified as partially demand-related and partially energy-related. The demand-related costs could be allocated to the classes of service using each class's contribution to the annual system peak day demand (the highest day for the system as a whole at any time during the year), while the energy-related costs would be allocated to classes based on their annual energy usage. In this example, the allocation factors are 1) each class of service's contribution to the

annual system peak day demand, and 2) the annual energy usage of each class of service. An analysis of customer requirements and usage characteristics is completed to develop allocation factors reflecting each of the classifiers employed within the COSA.

3.2 CITY NATURAL GAS DISTRIBUTION COSA METHODOLOGY

3.2.1 Functionalization

As mentioned previously, this rate study addresses only the distribution portion of the City's gas utility. As such, all costs included in the revenue requirement have already been functionalized as Distribution. Distribution services include all services required to transport the natural gas commodity from the point of interconnection across the City's distribution system to end-users at their meters.

3.2.2 Classification and Allocation of Costs

The classification and allocation factors used for each component of the rate base and revenue requirement are shown in Table 3-1 and Table 3-2 and are discussed in more detail below. (Rate base for the City's natural gas utility consists of investment of physical assets. It includes general plant and distribution plant investment and is net of accumulated depreciation. EES typically relies on an audited fiscal year for rate base amounts, whereas revenue requirement is a forecasted future year.)

Descriptions of each factor are included in Table 3-3. In general, this COSA employs the same methodology used in the 2020 COSA but with a few changes to allocation factors based on updated cost-causation themes.

Distribution costs are classified into the following components: demand, energy, customer, and direct assignments. The demand component reflects the portion of costs driven by peak demand for natural gas. The energy component is related to costs incurred to provide the annual amount of gas to customers or groups of customers. The customer component covers the facility and operating costs that vary with the number of customers, such as meters and billing. Directly assigned costs are costs that can be attributed to just one or more rate classes. The following are the specific classifiers used for the City's distribution function:

- **Demand.** Demand-related costs are those that vary with the peak demand or the maximum rates of natural gas supply to classes of service. Customer and system demands for this analysis are measured in peak day therms. Demand costs are generally related to the size of facilities needed to meet a customer's maximum daily demand. Generally, the rate base is allocated based on the Average & Excess method which involves a demand component (see Section 3.3). The allocated rate base is then used to allocate certain revenue requirement expenses.
- **Energy.** Energy-related costs are those that vary with the total amount of natural gas consumed by customer class. Usage measured in therms is used in this portion of the analysis. Energy costs are the costs of consumption over a specified period of time, such as a month or year. Reserve contributions are an example of a cost item that is allocated to customer classes based on therms used. This ensures that each customer contributes to the reserve fund based on their use of the system.
- **Customer.** Customer-related costs are those that vary with the number of customers. Customer costs are weighted to account for differences in the cost of providing services to those customers. For example, the service line and metering associated with serving a large commercial customer

is more costly and requires substantially more work and material than that for a small residential customer. Customer service expenses are typically allocated to customers based on some measure of number of customers or weighted customer service factors based on the amount of time and complexity to provide service to different types of customers.

- **Direct Assignment.** Some costs are directly assigned to specific classes of service. For example, costs associated with specific account representatives to large commercial customers are allocated directly to the G3 rate class. In exchange, G3 does not share in other customer service costs incurred by the other classes.

The methodology for classification and allocation of the City's rate base is summarized in Table 3-1. All line items in this table are functionalized as Distribution.

Note that the rate base does not reflect the annual expenses associated with running the utility but instead reflects the capital investments made by the utility for the physical assets in the distribution system. The purpose of looking at the rate base in the COSA is to set the cost causation associated with the physical assets, which are then used to guide the allocation of the annual expenses. Working capital is traditionally added to cover the cash on hand needed to run the utility. An estimate of 1/8th of operating costs is typically used to reflect the lag time between revenue collections and accounts payable.

TABLE 3-1: DISTRIBUTION RATE BASE

Asset Description	Asset Value FY 2021-2022 ⁷	Classification and Allocation Factor	Description
Distribution Plant			
Equip-Meters	\$12,334,716	CUSTM	Number of Services Weighted by Meters and Services
Equip-Services	\$59,109,371	AE	Average & Excess
Equip-Misc.	\$2,729,148	AE	Average & Excess
Equipment-Regulators	\$976,067	AE	Average & Excess
Equip-Distribution Mains	\$77,559,779	AE	Average & Excess
Equip-Measuring	\$2,869,793	AE	Average & Excess
Total Distribution Plant	\$155,578,873		(Distribution Rate Base)
General Plant			
Building-Gen Plant	\$1,910,425	GPLT	Gross Plant without General Plant And Intangibles
Equip-Gen Plant	\$2,911,310	GPLT	Gross Plant without General Plant And Intangibles
Total General Plant	\$4,821,735		(General Plant Rate Base)
Total Gross Plant in Service	\$160,400,608		(Gross Plant)
Less: Accumulated Depreciation			
Distribution Plant	\$49,833,503	RBD	Distribution Rate Base
General Plant	\$3,812,789	RBGP	General Plant Rate Base
Total Accumulated Depreciation	\$53,646,292		
Total Net Plant	\$106,754,316		(Net Plant)
Working Capital: 1/8 Operating Costs	\$2,251,043	OMWOP	Operation & Maintenance Expense without Production
TOTAL RATE BASE	\$109,005,358		(Rate Base)
Constructions Working in Progress (CWIP)			
Distribution Plant	\$6,127,014	RBD	Distribution Rate Base
General Plant	\$1,902,306	RBGP	General Plant Rate Base
Total CWIP	\$8,029,320		
TOTAL RATE BASE plus CWIP	\$117,034,679		

Next, the methodology for classification and allocation for the City's Natural Gas Distribution revenue requirement can be found in Table 3-2. More detail on the classification and allocation factor codes used in the classification and allocation process can be found in Table 3-3.

⁷ Fiscal year ending June 30, 2022 was the audited asset values available for the study period.

TABLE 3-2: DISTRIBUTION REVENUE REQUIREMENT

	FY 2025-2026	Classification and Allocation Factor	Description
Distribution Operation & Maintenance			
Engineering Support	768,861	RBD	Distribution Rate Base
Operations & Maintenance	9,028,547	RBD	Distribution Rate Base
Total Distribution	9,797,408		
Customer Service, Accounts, & Sales			
Admin - Customer & Marketing	\$227,967	CUSTW	Number of Services Weighted for Accounting/Metering
Meter Reading	\$485,915	CUSTM	Number of Services Weighted for Meters & Services
Utility Billing	\$543,152	CUSTW	Number of Services Weighted for Accounting/Metering
Credit & Collections	\$9,850	CUSTW	Number of Services Weighted for Accounting/Metering
Key & Major Accounts	\$155,106	DA1	Direct Assignment to Large Commercial (G3)
Customer Service	\$1,266,689	CUSTW2	Number of Services Weighted for Accounting/Metering excluding G3
Low Income Programs	\$53,792	therm	Annual Energy (therms)
Efficiency - Demand Side Mngmt	\$465,537	therm	Annual Energy (therms)
Total Customer Service, Accounts & Sales	\$3,208,008		
Administrative & General			
Administrative & General Salaries⁸	\$1,451,715	OMAG	O&M Expense without Production and Admin & General Expense
Allocated Charges⁹	\$2,735,638	OMAG	O&M Expense without Production and Admin & General Expense
Rents	\$574,830	OMAG	O&M Expense without Production and Admin & General Expense
Transfers to Non-Enterprise Funds	\$59,411	OMAG	O&M Expense without Production, and Admin & General Expense
Transfers to Enterprise Funds	\$181,333	OMAG	O&M Expense without Production, and Admin & General Expense

⁸ Administrative and General Salaries includes salaries and benefits for staff assigned directly to Gas Utility Administration.

⁹ Allocated charges are general costs incurred on behalf of all of the City's utilities (water, wastewater, fiber, electric and gas) that are individually determined and allocated to each business line, as well as salaries and benefits allocated based on Capital Improvement Project cost centers.

	FY 2025-2026	Classification and Allocation Factor	Description
Administrative & General Salaries	\$5,002,927		
Total Costs with A&G	\$18,008,343		
Interest and Debt Service Expense			
Interest on Long-Term Debt	\$23,348	NETPLT	Net Plant
Principal on Long-Term Debt	\$778,250	NETPLT	Net Plant
System Improvement	\$7,538,046	NETPLT	Net Plant
Total Debt Service /Capital Improvement	\$8,339,643		
General Fund Transfer	\$9,734,580	REV	Current Rate Revenues
Reserves Contribution	\$5,874,887	therm	Annual Energy (therms)
Revenue Requirement Before Other Revenues	\$41,957,453		
Other Revenues/Discounts			
Customer Discounts ¹⁰	-\$318,105	NETPLT	Net Plant
Connection Fees	\$700,000	NETPLT	Net Plant
Misc. Revenue and other contributions (Other)	-\$449,823	NETPLT	Net Plant
Transfer Credits	\$131,346	NETPLT	Net Plant
Interest Income (Loss) from Investments	\$625,693	NETPLT	Net Plant
Total Other Revenues	\$689,111		
REVENUE REQUIREMENT for COST ALLOCATION	\$41,268,342		

Table 3-3 shows how each factor code classifies then allocates the costs to classes of service. The Average & Excess (AE) allocator is described in greater detail below the table.

¹⁰ This includes uncollectible accounts for bad debt, low-income rate assistance discounts, and pre-1970s retired employee discounts on utility bills at a primary residence. The low-income rate assistance discounts and pre-1970s retired employee discounts on utility bills at a primary residence are funded through non-rate revenues including interest income from investments.

TABLE 3-3: NATURAL GAS DISTRIBUTION REVENUE REQUIREMENT

Factor Code	Factor Name	Classification	Allocation Basis
AE	Average and Excess	100% Demand	An allocation of demand costs that calculates the difference between the peak demand and average demand – A more detailed explanation of the Average and Excess allocation framework is later in the report.
Therm	Annual Energy (therm)	100% Energy	Energy consumption of each class of service in annual therms
CUSTW	Customers Weighted for Accounting/Metering	100% Customer	Number of services weighted for cost of accounting and metering
CUSTM	Customers Weighted for Meters and Services	100% Customer	Number of services weighted for cost of installing, maintaining and reading meters
CUSTW2	Customers Weighted for Accounting/Metering w/o G3	100% Customer	Number of services weighted for cost of accounting and metering but excluding G3 costs
DA1	Direct Assignment for Large Commercial	100% Customer	Direct assignment of key account costs to G3, large commercial class
RBD	On the Basis of Distribution Rate Base	42% Demand 50% Energy 8% Customer	Classified and allocated to classes of service based on the net book value of all shared services assets and other capital assets assigned to each class of service
OMAG	On the Basis of O&M (w/o Gas Supply and A&G)	32% Demand 42% Energy 26% Customer	Allocated based on O&M expenses without Gas Supply and A&G expenses
RBGP	On the Basis of General Plant Rate Base	42% Demand 50% Energy 8% Customer	Classified and allocated to classes of service based on the book value of all general plant assets assigned to each class of service
GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)	42% Demand 50% Energy 8% Customer	Allocated on the basis of the gross book value of all capital assets (initial cost) assigned to each class of service.
NETPLT	On the Basis of Net Plant	42% Demand 50% Energy 8% Customer	Allocated on the basis of the net book value of all capital assets (initial cost less accumulated depreciation) assigned to each class of service.
OMWOP	On the Basis of O&M (w/o Purchased Gas Supply)	32% Demand 42% Energy 26% Customer	Allocated based on O&M expenses without the cost of Purchased Gas Supply

3.3 AVERAGE & EXCESS (A&E)

The Average and Excess method (A&E method) compares the baseline capacity and energy used (the “average,” or “baseline”) against the maximum capacity and energy used on a seasonal basis (the “excess”). This captures the level of system capacity required to serve the customer during peak times as opposed to average times. The previous COSA study functionalized and classified distribution system costs as 100% demand related, and then used each customer’s share of non-coincident peak demand to allocate those distribution costs across customer classes.

As part of this study, EES revised the A&E method calculations because it recognizes that part of the system is built to serve the customer/energy use and part of the system was built to serve the demand

component whereas the previous method primarily attributed system sizing entirely to demand. The revised A&E method classifies distribution system costs to demand and energy. Then costs are allocated to customer classes based on an estimate of average demand and maximum (excess) demand for each class. This current A&E method provides the basis for calculating fixed and variable unit costs. It also equitably determines residential Tier 1 and Tier 2 rates (described later).

Based on monthly sales by customer class, the A&E method used in this Study makes the following assumptions:

1. Average demand represents the investment needed to serve the average customer in each class;
2. Excess use is the additional investment needed to serve customers with demands that vary by season. Those customers with higher excess use require a larger investment in the system compared with customers whose usage remains close to the minimum use year-round.¹¹

The current A&E method assumes that the marginal costs of the distribution system do not decrease as capacity increases. The method also provides cost allocation across customer classes consistent with the average use of each class while still maintaining a cost obligation for classes where excess use varies significantly from average use.

3.3.1 Average & Excess Calculation

The A&E method classifies (splits) distribution costs between energy and demand components. This classification recognizes that a portion of the distribution system is engineered to serve a customer with minimal use (energy). In addition, another portion of the distribution system investment is needed to meet customer maximum use (demand). In order to apportion the system between minimum use characteristics and maximum demand characteristics, we approximate this share of the system using the classification split as described below.

Table 3-4 demonstrates the classification using a minimum average use and excess use method (the A&E method). Minimum average use is defined as annual use calculated assuming customer use is equal to the lowest monthly use year-round (this lowest therms/month/customer occurs in October for residential and November for commercial). As noted above, the minimum average use is used to approximate the share of distribution system needed to serve a customer within each class at their minimum level of consumption. Using this method, the relevant costs are then split between the share of the minimum average use (energy-related in row d) and share of excess demand (demand-related in row e).

¹¹ A good example of this type of customer is an individually metered multi-family unit. These customers have low average use and the services needed for each unit are lower in cost (shared) compared with services needed to serve a single family home (not shared).

TABLE 3-4: AVERAGE & EXCESS CLASSIFICATION

	Formula	Total
Annual Sales, Therms	a	25,779,489
Minimum Average Use, Therms	b	13,936,088
Excess Use, Therms	c	11,843,401
Energy-Related	$d = b \div a$	54%
Demand-Related	$e = c \div a$	46%

Once classified as energy and demand costs, distribution system costs are allocated to customer classes. For the energy-related costs, the cost allocation is based on the customer class' average use of the system. Average use is appropriate since it reflects annual usage characteristics while the minimum would reflect only the low season usage (summer). For demand-related, the cost allocation is based on customer class' share of maximum use. The result is that all customers using the system will pay for their share of fixed distribution costs based on their usage level, and customers with higher variation in use (demand) will also pay their fair share of demand-related system costs. The recommended rate design within each class determines how these costs are recovered.

3.4 CUSTOMER CLASSES OF SERVICE

Customer classes of service refer to the arrangement of customers into groups that reflect common usage characteristics or facility requirements.¹² The classes of service used within this Study were as follows: Residential (G1); Small Commercial (G2); and Large Commercial (G3). The City also serves one Compressed Natural Gas (CNG) customer whose costs are paid by the City's Public Works department; the costs and revenues for this City-owned service are part of the overall revenue requirement. These rates should continue to increase at system average rates as they have been over recent periods because the nature of service has not changed. Thus, it is reasonable that the CNG customer's cost of service has increased at the same rate as the distribution expenses overall.

3.5 COST OF SERVICE RESULTS

Given the key assumptions and updates discussed above, the COSA was completed. Tables 3-5 and 3-6 provide a summary of the Rate Base and Revenue Requirement amounts allocated to the various customer classes.¹³ These schedules are calculated by multiplying the applicable classification and allocation factors to each cost in the rate base and revenue requirement.

¹² Breakpoints between or within rate classes are sometimes referred to as segmentation in rate making.

¹³ The rate base and revenue requirement tabs of the COSA model also show the rate base and revenue requirement allocated to each class of service.

TABLE 3-5: DISTRIBUTION RATE BASE ALLOCATION RESULTS: FY 2025-2026

Asset Description	Total	G1 Residential	G2 Small Commercial	G3 Large Commercial
Distribution Plant				
Equip-Meters	\$12,334,716	\$9,135,516	\$2,878,448	\$320,752
Equip-Services	\$59,109,371	\$24,674,393	\$25,111,143	\$9,323,835
Equip-Misc.	\$2,729,148	\$1,139,245	\$1,159,411	\$430,492
Equipment-Regulators	\$976,067	\$407,446	\$414,658	\$153,963
Equip-Distribution Mains	\$77,559,779	\$32,376,261	\$32,949,339	\$12,234,179
Equip-Measuring	\$2,869,793	\$1,197,956	\$1,219,160	\$452,677
Total Distribution Plant	\$155,578,873	\$68,930,816	\$63,732,158	\$22,915,899
General Plant				
Building-Gen Plant	\$1,910,425	\$846,434	\$782,597	\$281,395
Equip-Gen Plant	\$2,911,310	\$1,289,886	\$1,192,604	\$428,820
Total General Plant	\$4,821,735	\$2,136,319	\$1,975,201	\$710,215
Total Gross Plant in Service	\$160,400,608	\$71,067,135	\$65,707,359	\$23,626,113
Less: Accumulated Depreciation				
Distribution Plant	\$49,833,503	\$22,079,245	\$20,414,062	\$7,340,197
General Plant	\$3,812,789	\$1,689,295	\$1,561,891	\$561,602
Total Accumulated Depreciation	\$53,646,292	\$23,768,540	\$21,975,953	\$7,901,799
Total Net Plant	\$106,754,316	\$47,298,595	\$43,731,406	\$15,724,314
Working Capital				
1/8 Operating Expenses	\$2,251,043	\$1,131,981	\$820,532	\$298,530
Total Working Capital	\$2,251,043	\$1,131,981	\$820,532	\$298,530
TOTAL RATE BASE	\$109,005,358	\$48,430,576	\$44,551,938	\$16,022,845
Total CWIP	\$8,029,320	\$3,557,473	\$3,289,173	\$1,182,674
TOTAL RATE BASE plus CWIP	\$117,034,679	\$51,988,048	\$47,841,112	\$17,205,519

TABLE 3-6: DISTRIBUTION REVENUE REQUIREMENT ALLOCATION RESULTS: FY 2025-2026

Plant Description	FY 2026 Total	G1 Residential	G2 Small Commercial	G3 Large Commercial
Distribution				
Engineering Support	768,861	340,652	314,960	113,249
Operations & Maintenance	9,028,547	4,000,190	3,698,502	1,329,855
Total Distribution	9,797,408	4,340,842	4,013,463	1,443,104
Customer Service, Accounts, & Sales				
Admin - Customer & Marketing	\$227,967	\$179,500	\$41,741	\$6,727
Meter Reading	\$485,915	\$359,885	\$113,394	\$12,636
Utility Billing	\$543,152	\$427,673	\$99,452	\$16,027
Credit & Collections	\$9,850	\$7,756	\$1,804	\$291
Key & Major Accounts	\$155,106	\$0	\$0	\$155,106
Customer Service	\$1,266,689	\$1,027,704	\$238,985	\$0
Low Income Programs	\$53,792	\$20,371	\$24,009	\$9,413
Efficiency - Demand Side Management	\$465,537	\$176,296	\$207,781	\$81,460
Total Customer Service	\$3,208,008	\$2,199,184	\$727,166	\$281,658
Administrative & General				
Administrative & General Salaries	\$1,451,715	\$730,023	\$529,167	\$192,525
Allocated Charges	\$2,735,638	\$1,375,669	\$997,173	\$362,797
Rents	\$574,830	\$289,064	\$209,532	\$76,233
Transfers to Non-Enterprise Funds	\$59,411	\$29,876	\$21,656	\$7,879
Transfers to Enterprise Funds	\$181,333	\$91,187	\$66,098	\$24,048
Total Administrative & General	\$5,002,927	\$2,515,819	\$1,823,626	\$663,482
Total Costs with A&G	\$18,008,343	\$9,055,845	\$6,564,254	\$2,388,244
Interest and Debt Service Expense				
Interest on Long-Term Debt	\$23,348	\$10,344	\$9,564	\$3,439
Principal on Long-Term Debt	\$778,250	\$344,812	\$318,806	\$114,632
System Improvement	\$7,538,046	\$3,339,809	\$3,087,925	\$1,110,312
Total Debt Service /CIP Expense	\$8,339,643	\$3,694,965	\$3,416,296	\$1,228,383
General Fund Transfer	\$9,734,580	\$4,183,095	\$4,248,241	\$1,303,244
Reserves Contribution	\$5,874,887	\$2,224,781	\$2,622,114	\$1,027,992
Revenue Requirement Before Other Revenues	\$41,957,453	\$19,158,686	\$16,850,905	\$5,947,862
Other Revenues/Discounts				
Customer Discounts	-\$318,105	-\$140,940	-\$130,310	-\$46,855
Connection Fees	\$700,000	\$310,142	\$286,752	\$103,106
Misc. Revenue (Other)	-\$449,823	-\$199,299	-\$184,268	-\$66,256
Transfer Credits	\$131,346	\$58,194	\$53,805	\$19,347
Income (Loss) from Equity Investments	\$625,693	\$277,220	\$256,312	\$92,161
Total Other Revenues	\$689,111	\$305,318	\$282,291	\$101,502
NET REVENUE REQUIREMENT	\$41,268,342	\$18,853,368	\$16,568,614	\$5,846,360

Table 3-7 provides a summary of the COSA results with the recommended revenue changes. These results are the basis for the recommended distribution charges provided in the next section.

TABLE 3-7: DISTRIBUTION COSA RESULTS: FY 2025-2026

	Projected FY 2026 Revenues	Revenue Requirement	Projected FY 2026 Deficiency	Revenue Change Needed
G1 – Residential	\$16,311,063	\$18,853,368	\$2,542,305	15.59%
G2 – Small Commercial	\$16,565,086	\$16,568,614	\$3,527	0.02%
G3 – Large Commercial	\$5,081,713	\$5,846,360	\$764,647	15.05%
Total	\$37,957,863	\$41,268,342	\$3,310,479	8.7%

Residential and Large Commercial classes require higher rate increases compared to the G2 class. EES compared this study with the previous analysis (FY 2019-2020) and found the following significant drivers for these results:

1. Overall, the FY 2025-2026 Distribution revenue requirement is 171% of the FY 2019-2020 revenue requirement. The increase is due to multiple years of significant inflationary pressures and planned fund contributions.
2. The allocation of the General Fund Transfer was updated from Net Plant to Revenue. As a result, G1 is being allocated a larger share of the General Fund Transfer. Despite the adverse impact on G1 rates, this update better aligns the expense item with cost since the General Fund Transfer is calculated based on gross revenues.
3. The Rate Base Allocation of Distribution assets was updated to reflect updated Average & Excess calculations. This change moved some asset value from G2 to G1 due to the greater variability in seasonal use by G1 customers. This allocation flows through to expense items allocated based on the same version of rate base, and it results in a larger share of expenses being allocated to G1 compared to the 2020 study and less cost being allocated to G2.
4. Customer allocators such as meters and services, and weighed customers, were updated to reflect current meter cost and billing cost information. These updates resulted in larger shares of expenses allocated to G1 and G3.
5. Average use for G1 and G3 are lower in FY 2025-2026 compared with FY 2019-2020. When average use is lower, fixed costs are spread across a smaller number of therms impacting the overall rate adjustment needed.

In addition, all rate change aspects in this report are for distribution charges only and do not include changes to supply. When considering overall rate impacts, it is important to note that most of these rate changes are forecasted to be less than a 10% impact when considering combined commodity and distribution charges.

4 Rate Design

The final step in the rate study process is to design rates for each class of service or customer class. In California, local governments are subject to Article XIII C of the California Constitution, amended by Proposition 26 (2010). As a result, the City has set rates to match the COSA results for each customer class. It is important to note that the results of the revenue requirement and COSA study are based on forecasted load data estimates and usage pattern assumptions. Actual load and usage patterns may differ from forecast. For this Study, rates are developed based on the forecast loads and observed historical usage patterns for each customer class.

The rates for the Residential and Commercial customers are designed to reflect the differences in costs among the various customer classes. The costs per customer class differ based on the seasonal shape of consumption (referred to as energy use) as well as the daily peak demand for each customer class. Differences in energy use by season and the level of peak demand have an impact on the utility's need for distribution facilities and the costs to operate and maintain those facilities.

4.1 RECOMMENDED RATE DESIGN: DISTRIBUTION

This section of the report reviews the present rate structures for the City and provides a comparison with the recommended rates based on this cost of service study. Table 4-1 summarizes the current rate design for each rate schedule and recommended rate design updates. As mentioned previously, the recommended rate design is the same as the current rate design with the exception of some updates and refinement as described below.

TABLE 4-1: NATURAL GAS DISTRIBUTION RATE DESIGN RECOMMENDATION OVERVIEW

Rate Schedule	Current Rate Design	Recommended Rate Design
Residential G1	Fixed Monthly Charge Seasonal Tiered Rate with Inclining Blocks	<ul style="list-style-type: none"> • Update fixed and volumetric charges to cost of service unit costs • Calculate tiered rates based on A&E cost allocation • Update Tier 1 summer baseline quantity
Small Commercial G2	Fixed Monthly Charge Volumetric Charge	<ul style="list-style-type: none"> • Update fixed and volumetric charges to cost of service • Implement three separate fixed monthly charges based on meter's maximum capacity
Large Commercial G3	Fixed Monthly Charge Volumetric Charge	<ul style="list-style-type: none"> • Update fixed and volumetric charges to cost of service unit costs

Table 1-8 in Section 1.2.3, Rate Recommendations, summarizes the current and FY 2025-2026 recommended rates for each class. The rate recommendations and bill impacts by rate class are provided below.

4.1.1 Residential (G1)

The G1 distribution rates consist of a monthly service charge and volumetric tier rates: The Tier 1 rate applies to usage up to the baseline quantity and the Tier 2 rate applies to all usage above the baseline. While the tier rates do not change between seasons, the baseline quantity varies by season, and is higher in winter than in the summer because natural gas heat is more prevalent in the winter. This ensures that those customers contributing to higher seasonal demand are paying appropriately for their share of the

demand-related cost.

EES evaluated the current G1 Tier breakpoints using sales data for several test periods, based on the current rate design. EES confirmed that the winter baseline of 60 therms/30-day-billing still reflects of the winter average at 60 therms/30-day-billing: EES recommends continuing to set the winter baseline to 60 therms/30-day-billing. However, the data, more than not, suggest that the summer baseline should be increased from 20 to 23 therms/30-day-billing. Table 4-2 below shows the current baseline and average consumption values supporting EES recommendation.

TABLE 4-2: BASELINE CALCULATIONS ASSESSMENT

Tier 1 Baseline Assessment	Therms/30-day-billing	
	Summer	Winter
Current Baseline	20	60
Average Consumption		
FY 2022 Actual	22	60
FY 2023 Actual	24	70
FY 2024 Actual	21	53
Gas Forecast FY 2026	24	56
Average of 3 Historical Years and 1 Forecast Year	23	60
	Summer	Winter
Recommended Baseline	23	60

Further, considering the costs that should be collected in Tier 1 vs. Tier 2 rates, EES used the same Average and Excess calculations applied to distribution rate base or plant to determine the amount the current rate design should collect at each rate. The excess calculation compares the difference between the minimum and maximum use to produce the excess portion of average and excess. Using the excess calculations, EES can determine how much Tier 1 baseline consumption is above minimum use and assign that portion of excess demand costs to the Tier 1 rate. The result includes 54% of demand costs in the Tier 1 rate and the remainder of demand costs assigned to the Tier 2 rate.

Table 4-3 summarizes the costs to be recovered in each rate component for G1.

TABLE 4-3: G1 RATES AND COST RECOVERY

Rate Component	Recovers The Following Costs:
Monthly Service Charge	Customer-related costs such as customer service, billing, and overhead adders
Tier 1 Volumetric Rate	Energy-related costs plus 54% of demand-related distribution unit costs
Tier 2 Volumetric Rate	Energy-related costs plus 46% of demand-related distribution unit costs

This result indicates that the rate design, if appropriately balanced as proposed, collects distribution system costs between the tiers based on how those costs are classified and allocated in the COSA and the seasonal Tier 1 baseline quantities.

The recommended volumetric rates for Residential are based on the volume of therms in each tier and the relative share of demand-related distribution costs. Based on the baseline usage, or Tier 1 allocation, 54% of G1 consumption is within the Tier 1 (6.9 million therms). This volume is compared with the minimum average use volume of 3.6 million therms. Minimum Average Use is the average volume of

therms across all Residential customers per day multiplied by the number of days in a year (Table 4-4).

TABLE 4-4: G1 MINIMUM AVERAGE USE

Minimum Average Use/30-Day-Billing	14 therms
Annual Minimum Average Use	14 therms × 12 30-day-billings × 21,255 meters = 3.6 million therms

The current average Tier 1 volume on an annual basis is equal to 26 therm/30-day-billing which is significantly higher than the minimum of 14 therms/30-day-billing calculated for minimum use. Therefore, the Tier 1 volume also exceeds the annual minimum average use, and EES determined that a share of demand-related costs should be allocated to the Tier 1 rate.

The share of demand-related costs to be collected in the Tier 1 rate is calculated by taking the share of Tier 1 consumption in excess of the Minimum Average Use, as shown in Table 4-5.¹⁴

TABLE 4-5: G1 TIER 1 DEMAND-RELATED COSTS

	Formula	Total
Annual G-1 Sales, Therms	<i>A</i>	9,762,524
Minimum Average Use, Therms	<i>B</i>	3,558,936
Tier 1 Use, Therms as proposed	<i>C</i>	6,935,563
Tier 1 Use Exceeding Minimum Average Use, Therms	$d = c - b$	3,376,628
Excess Use (Demand-Related), Therms	$f = a - b$	6,203,589
Share of Demand-Related Costs in Tier 1 Baseline	$g = d \div f$	54.4%

This methodology helps to align the tiered rates more closely to the cost of service for each block of service volume. If the Tier 1 baseline seasonal quantities are adjusted in the future, this analysis should be updated to reflect the new quantities.

Table 4-6 shows the bill impacts for average customer use in summer and winter.

¹⁴ It is necessary to evaluate the minimum average use and compare those quantities to the Tier 1 quantities. If the Tier 1 quantity were equal to the minimum use, 100% of demand-related distribution costs should be collected through the Tier 2 rate. However, because the baseline Tier 1 quantity is approximately equal to average seasonal use, that average use includes some component of demand cost. Therefore, a portion of demand-related costs should be collected from the Tier 1 rate.

TABLE 4-6: G1 BILL IMPACTS AT AVERAGE CUSTOMER USE, DISTRIBUTION ONLY

	At Current FY 25 Rates	At Recommended FY 26 Rates		\$ Change	% Change	Average Use Therms/30- day-billing
G1 Summer	\$43.83	\$51.09		\$7.26	16.6%	22.0
G1 Winter	\$92.54	\$107.75		\$15.21	16.4%	61.1

Table 4-7 shows the impacts for a range of customer bills under various low, median and high usage levels.

TABLE 4-7: G1 BILL IMPACTS AT VARIOUS USAGE LEVELS, DISTRIBUTION ONLY

Season	Usage (Therms/month)	At Current FY 25 Rates	At Recommended FY 26 Rates	Bill Impact \$/Month	Bill Impact (%)
Summer	10	\$33.75	\$40.38	\$6.64	19.7%
	(Median) 17	\$45.52	\$54.99	\$9.47	20.8%
	30	\$79.70	\$86.50	\$6.80	8.5%
	45	\$124.15	\$127.84	\$3.69	3.0%
Winter	30	\$68.69	\$83.41	\$14.73	21.4%
	(Median) 51	\$104.92	\$128.14	\$23.22	22.1%
	80	\$180.07	\$203.03	\$22.96	12.8%
	150	\$390.54	\$399.00	\$8.47	2.2%
Annual	(Median) 31	\$70.27	\$85.47	\$15.20	21.6%

4.1.2 Small Commercial and Residential Master-Metered (G2)

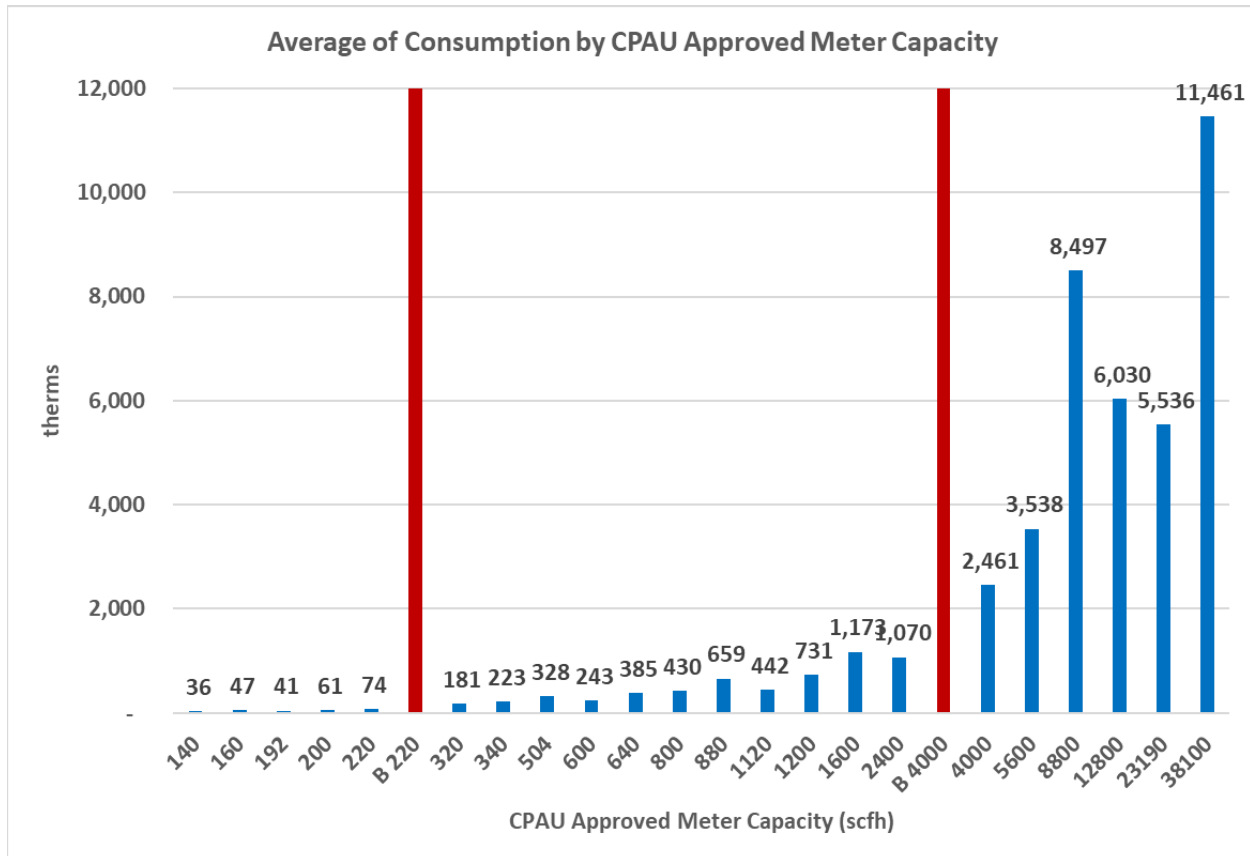
The current G2 distribution rate design is composed of a fixed monthly service charge and a volumetric charge. As described in Section 1.2, Rate Study Overview, EES performed a detailed analysis of G2 usage and costs and recommends a refinement in the development of the Monthly Service Charge for G2. Figures 4-1 and 4-2 show examples of usage and cost characteristic analysis.

The fixed monthly service charge for a given rate schedule (customer class) is set to recover the customer-related costs allocated to that schedule. Weighted meter cost is a major factor used to allocate customer-related fixed costs to various rate schedules. This COSA uses updated meter costs that reflect latest available data on meter cost and associated capacity of installed meters.

G2 is different from G1 and G3 in that its approximately 2,100 services have a much wider range of usage, as well as meter types and capacities. EES examined G2 meter types and corresponding average usage data to determine whether and how it can inform the development of G2 monthly service charge to better reflect customer-related fixed costs.

Figure 4-1 shows how G2 meter capacity and associated average consumption. Size correlates to usage; as expected, larger meters have larger average usage.¹⁵ Larger meters require larger service lines (connecting the meter to the distribution system) and generally impose greater demand on the system.

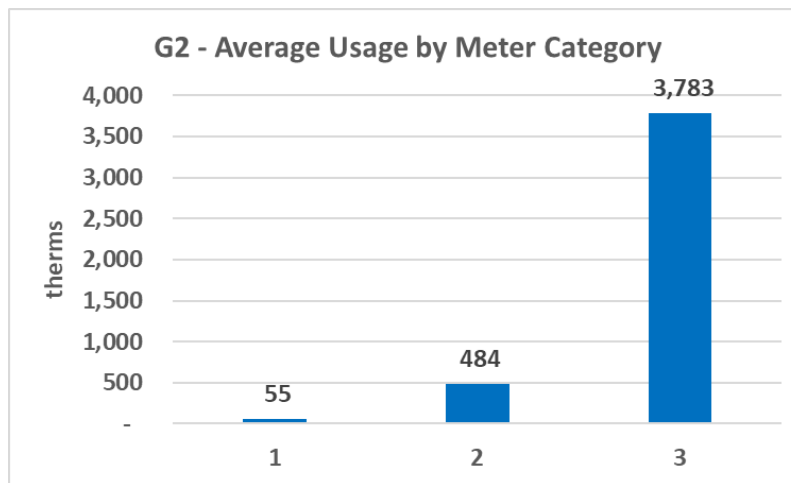
FIGURE 4-1: AVERAGE MONTHLY USAGE BY METER CAPACITY



Moreover, EES observes distinct patterns and separations in average usage levels that support three G2 meter groupings based on maximum meter capacity. Figure 4-2 shows the distinct average usage levels associated with the following three groupings by maximum meter capacity (in standard cubic feet per hour or scfh).

1. Up to 220 scfh (≤ 220 scfh)
2. Above 220 scfh and below 4,000 scfh (> 200 scfh and $< 4,000$ scfh)
3. 4,000 scfh and above ($\geq 4,000$ scfh)

¹⁵ This is expected because meter capacity is sized to match the customer's usage demand. [City of Palo Alto, Utility Rule and Regulation 15, Section B.6: Meter Installations, Capacity of Meters, April 2023.pdf](#).

FIGURE 4-2: G2 – AVERAGE MONTHLY USAGE BY METER CATEGORY

Thus, EES recommends implementing a Monthly Service Charge based on the G2 service's maximum meter capacity and calculates these charges using allocated costs that are based on each grouping's weighted meter costs.

The above three G2 meter ranges were chosen as a result of detailed examination of the distribution of usage across different meter types and capacities, according to summary data in Figures 4-1 and 4-2. The calculation for the volumetric charge applicable to all G2 usage remains unchanged. See Table 1-6, G2 Monthly Service Charges: FY 2025-2026, and Table 1-8, Current and Recommended Rates.

Table 4-8 shows the G2 bill impacts for representative accounts in each G2 subgroup. Impacts for average use and for 50% of average use are provided.

TABLE 4-8: G2 BILL IMPACTS

	At Current FY 2024-2025 Rate	At Recommended FY 2025-2026 Rate	\$ Change	% Change	Average Therms/Mo	# of Accounts
G2 Total	\$629.59	\$629.72	\$0.13	0.0%	437	2,193
G2: ≤ 220 scfh						1,134
Average Use	\$216.71	\$98.87	-\$117.84	-54.4%	55	
50% of Average Use	\$186.81	\$63.96	-\$122.84	-65.8%	28	
G2: > 220 and < 4,000 scfh						942
Average Use	\$679.70	\$705.15	\$25.45	3.7%	484	
50% of Average Use	\$418.30	\$400.05	-\$18.26	-4.4%	242	
G2: ≥4,000 scfh						116
Average Use	\$4,245.43	\$5,189.76	\$944.33	22.2%	3,783	
50% of Average Use	\$2,201.16	\$2,803.69	\$602.53	27.4%	1,891	

4.1.3 Large Commercial (G3)

The present G3 rate design is composed of a monthly service charge and a volumetric charge. As noted earlier, this class generally has large capacity meters and a high consumption threshold for service. G3

rate schedule applies to commercial customers who use at least 250,000 therms per year at one site.¹⁶ This threshold, which defines the rate class, results in a group of customers with similar services, sizing requirements and usage characteristics. Therefore, it is not necessary to develop tiered rates or fixed charge variances within this class. No change is recommended in the overall design of these charges.

For illustrative purposes, Table 4-9 presents the G3 bill impact at 20,833 therms, which is 1/12 of the annual threshold level for G3 service.

TABLE 4-9: G3 BILL IMPACTS

	At Current FY 2024-2025 Rate	At Recommended FY 2025-2026 Rate	\$ Change	% Change
G3 Large Commercial	\$41,287.45	\$44,186.73	\$2,899.28	7.0%

4.2 SUPPLY CHARGES

The primary focus of the rate study was the distribution charges which vary based on budgets and operating needs. The City also must pass through costs that vary based on external factors and market conditions. These appear in rate schedules as Supply Charges. Supply charges include the Commodity, Cap and Trade Compliance, Carbon Offset, and Transportation Charges. These charges are on a \$/therm basis and require frequent updates due to the variable nature of the underlying costs.

Currently, the City has a range included in the rate schedules. Table 4-10 shows the current ranges.

TABLE 4-10: SUPPLY CHARGES

Supply Charges	\$/therm
1. Commodity (Monthly Market Based)	\$0.10-\$4.00
2. Cap and Trade Compliance Charges	\$0.00-\$0.25
3. Transportation Charge	\$0.00-\$0.30
4. Carbon Offset Charge	\$0.00-\$0.10

EES examined both the current calculation of each charge and the basis for that calculation, as well as whether the charge should remain a pass-through with a range or not.

EES does not recommend any changes to the Commodity charge range. For the Commodity supply charge, Council amended the Gas Utility Long-term Plan (GULP) Objectives, Strategies and Implementation Plan including collecting funds via a gas price mitigation adder to manage potential future short-term natural gas price spikes above the \$4.00 per therm maximum charge (Resolution 10187, August 19, 2024). The Commodity charge range, therefore, is consistent with the Council-approved strategy.

¹⁶ Utility Rate Schedule G-3.

The City's gas utility is a covered entity under the California Air Resources Board (CARB) Cap-and-Trade program, in this program the City is obligated to purchase allowances to cover all greenhouse gas emissions resulting from natural gas use within Palo Alto's service territory. EES recommends eliminating the ranges for the Cap and Trade Compliance charge and instead converting this charge to a pass-through of the City's actual costs because the City has little to no control over them, and they are largely non-discretionary. The Cap and Trade Compliance Charge is calculated based on the Cap-and-Trade program's quarterly auction allowance closing prices.

Likewise, EES recommends eliminating the ranges for the Transportation Charge and passing through these charges. The Transportation charge is the rate the City pays Pacific Gas and Electric Company (PG&E) to transport gas from the PG&E Citygate to the City of Palo Alto distribution system. PG&E is regulated by the California Public Utilities Commission. Palo Alto has no control over these charges and no alternatives for transporting gas to its distribution system. The Transportation Charge is based on PG&E's wholesale tariff (G-WSL).¹⁷

Recently, the Transportation Charge exceeded the published range and the Council increased the upper limit on the Transportation Charge.¹⁸ This is likely to occur for both the Transportation Charge and the Cap and Trade Compliance Charges in the future. Because the true costs can vary outside of the ranges provided, the ranges do not appear to provide material value to customers. If the costs vary outside the upper limit of the range, the costs above the limit are paid for by the gas utility's reserves unless the Council increased the upper limit. Updating the ranges with a wider spread would also provide less practical information to customers. Therefore, EES recommends eliminating the ranges for the Cap and Trade Compliance and Transportation charges. Two years of historical monthly values for the Transportation Charge and Cap and Trade Compliance Charge are posted publicly on the City's website for reference.¹⁹

EES does not recommend changes to the Carbon Offset Charge range. In December 7, 2020 Council adopted Resolution 9930 amending the Carbon Neutral Gas Plan. This program is voluntary in the sense that it is a local program approved by the City Council rather than a compliance obligation imposed by the state or another governing body. The amended plan limited the purchase price of offsets to \$19 per ton CO₂e, consistent with the original maximum 10 cents per therm rate impact; therefore, the range is consistent with the Council-approved program.

Second, EES recommends providing more detailed information on the source costs and calculation for all four of the supply charges. Recommended additions include language in Table 4-10.

¹⁷ https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS_SCHS_G-WSL.pdf

¹⁸ On October 7, 2024, Council adopted Resolution 10190 increasing the upper limit on the Transportation Charge on all of the City's gas rate schedules from \$0.25 per therm to \$0.30 per therm effective November 1, 2024.

¹⁹ Residential: <https://www.cityofpaloalto.org/files/assets/public/v/25/utilities/rates-schedules-for-utilities/residential-utility-rates/monthly-gas-volumetric-and-service-charges-residential-3.pdf> and

Non-Residential and Residential Master-Metered:

<https://www.cityofpaloalto.org/files/assets/public/v/24/utilities/business/business-rates/monthly-gas-volumetric-and-service-charges-commercial-3.pdf>

TABLE 4-10: SUPPLY LANGUAGE

Supply Charges	Description
1. Commodity (Monthly Market Based)	<p>This charge is based on the monthly natural gas Bidweek Price Index for delivery at PG&E Citygate, adjusted to account for delivery losses to the customer's meter. The Commodity Charge also includes adjustments to account for Council-approved programs implemented to reduce the cost of Gas, including a municipal purchase discount (Adopted via Resolution 9451, on September 15, 2014), and \$0.055 per therm for mitigating the impact of short-term natural gas market price spikes.</p> <p>The Commodity Charge calculation formula is:</p> $ \begin{aligned} &\text{PG\&E Citygate Monthly Bidweek Price (\$/MMBtu)} \\ &+ \text{Gas Supplier Adder (\$/MMBtu)} \\ &- \text{Municipal Gas Discount (\$/MMBtu)} \\ &\times (1 + \text{Distribution Loss Multiplier}) \\ &+ \text{Gas Price Spike Mitigation Charge (\$/MMBtu)} \\ &\div 10 \text{ (conversion from MMBtu to therm) (MMBtu/therm)} \\ &= \text{Commodity Rate (\$/therm)} \end{aligned} $ <p>Where :</p> <p>PG&E Citygate Monthly Bidweek Price is the monthly price for PG&E Citygate as reported in the first issue of the month of Natural Gas Intelligence's Bidweek Survey as published by Intelligence Press Inc.</p> <p>The Gas Supplier Adder is the premium or discount applied to the Bidweek Price Index, based on the City's actual transactions with its natural gas suppliers.</p> <p>The Distribution Loss Multiplier, updated annually, is calculated by the variances of gas supply purchases and gas retail sales for the past three fiscal years.</p>
2. Cap and Trade Compliance Charge	<p>The Cap and Trade Compliance Charge reflects the City's cost of regulatory compliance with the State's Cap and Trade Program, including the cost of acquiring compliance instruments sufficient to cover the Gas Utility's compliance obligations. The Cap and Trade Compliance Charge is adjusted in response to market conditions, retail sales volumes, and the quantity of allowances required. The calculation formula is based on carbon allowance auction prices and allowances needed to comply with state law. One allowance is equal to 1 metric ton (MT) of CO₂.</p> <p>The Cap and Trade Compliance Charge calculation formula is:</p> $ \begin{aligned} &\text{Most Recent Auction Price (\$/MT CO}_2\text{)} \\ &\times \text{Number of Allowances Required (\%)} \\ &\times \text{(conversion from MT CO}_2\text{ to therm) (MT CO}_2\text{/therm)} \\ &= \text{\$/Therm} \end{aligned} $ <p>Where:</p> $ \begin{aligned} &\text{Number of Allowances Required (\%)} = \\ &(\text{Projected Emissions for Current Year} - \text{Palo Alto's Allocated Allowances for Current Year}) \\ &\div \text{Projected Emissions for Current Year} \end{aligned} $

3. Transportation Charge	<p>The Transportation Charge is based on the current PG&E G-WSL rate for Palo Alto, accounting for delivery losses to Customer Meters. The current rates are shown in this tariff https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS_SCHDS_G-WSL.pdf, provided by PG&E. Additionally, there is a distribution loss factor (updated annually), which is calculated by the variances of gas supply purchases and gas retail sales for the past three fiscal years.</p> <p>The Transportation Charge calculation formula is:</p> $\begin{aligned} &\text{PG\&E G-WSL Transportation Charges (\$/therm)} \\ &- \text{Cap and Trade Cost Exemption (\$/therm)} \\ &\times (1 + \text{Distribution Losses Multiplier}) \\ &= \text{Transportation Charge (\$/therm)} \end{aligned}$ <p>Where: The Distribution Loss Multiplier, updated annually, is calculated by the variances of gas supply purchases and gas retail sales for the past three fiscal years.</p>
4. Carbon Offset Charge	<p>The Carbon Offset Charge reflects the City's cost to purchase offsets for greenhouse gases produced when Gas is burned. The Carbon Offset Charge will change in response to market conditions, sales volumes, and the quantity of offsets purchased within the Council-approved cap of \$19 per MT CO₂e, calculated annually.</p> <p>The Carbon Offset Charge calculation formula is:</p> $\begin{aligned} &\text{Weighted Average Cost of Carbon Offset (\$/MT CO}_2\text{)} \\ &\times (\text{conversion from MT CO}_2\text{ to therms}) (\text{MT CO}_2\text{/therms}) \\ &\div \text{Annual Gas Sales (therms)} \\ &= \text{Carbon Offset Charge (\$/therm)} \end{aligned}$ <p>Where: Purchase Price of Carbon Offset \leq \$19/MT CO₂e</p>