PREPARED BY EES CONSULTING

City of Palo Alto

Electric Cost of Service and Rate Study
DRAFT 10

March 6, 2024

EES Consulting
a GDS Associates Company

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Amber Gschwend, Managing Director
amber.gschwend@gdsassociates.com

March 1, 2024

Mr. Micah Babbitt
City of Palo Alto
250 Hamilton Avenue
Palo Alto, CA 94301

SUBJECT: Electric Cost of Service and Rate Study – DRAFT 8

Dear Mr. Babbitt:

Please find attached the draft report for the Electric Cost of Service and Rate Study performed for the City of Palo Alto (City).

We appreciate all of the help you and your staff have provided in conjunction with this study. Please feel free to contact me directly with any questions or comments.

Very truly yours,

Amber Gschwend
Managing Director, EES Consulting

Contents

1 Executive Summary

The City of Palo Alto (City) retained EES Consulting (EES), a GDS Associates Company, to perform an electric cost of service analysis (COSA) and rate study as part of its ongoing efforts to maintain fiscally prudent and fair, cost-based rates for its electric customers. 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 are the revenue requirement, the COSA, and the rate design.

1.1 REVENUE REQUIREMENT

A revenue requirement analysis compares the overall revenues of the utility to its expenses and helps determine whether an overall adjustment to rate levels is required. For this analysis, a "cash basis" method was used for determining the City's revenue requirement. Recorded annual operating expenses for Fiscal Year (FY) 2021-22 as well as the FY 2022-23, FY 2023-24, and FY 2024-25 approved and budget forecasts provided by the City were used to determine the revenue requirement. The study relies on the proposed FY2024-25 budget for the revenue requirement study.

If the City's rates currently in effect remain unchanged, FY 2024-25 revenues from all sources would equal $219.3 million, while budgeted expenses and reserve contributions are $215.5 million.[1] The revenue adjustment necessary to avoid surplus funds is a 2.2% decrease. Table 1-1 summarizes the FY 2024-25 revenue requirement.

TABLE 1-1: SUMMARY OF THE REVENUE REQUIREMENT – FY2024-25

Power Supply (Commodity)	$115,533,652
Distribution	$28,005,465
Customer Accounts and Services	$12,608,722
Administration and General	$7,698,473
Capital Projects Funded from Rates	$6,500,000
Debt Service	$4,770,582
General Fund Transfer	$15,121,000
Reserve Contribution	$25,333,578
Total Expenses	**$215,571,473**
Other Revenues	$50,984,335
Total Revenue Required from Rates (Revenue Requirement)	$164,587,138
Revenue Based on Rates Currently in Effect	$168,321,326
Additional Rate Revenue Needed (Surplus)	($3,734,187)
Net Required Rate Revenue Increase (Decrease)	**(2.2%)**

[1] Expenses exclude capital expenses reimbursed by connection fees or other direct reimbursement agreements.

1.1.1 Rate Classes

Part of the revenue requirement analysis includes an analysis of revenue from current retail rates ($168.3 million in Table 1-1). These revenues are calculated for each rate class to later determine if each class is collecting its assigned revenue goal (determined by the COSA). The following rate classes are modeled in the Revenue Requirement Study and COSA:

E-1 Residential: All residential customers, excluding master-metered multifamily customers.

E-2 Small Commercial: Electric service for small commercial customers and master-metered multifamily customers. Any customer with energy usage over 8,000 kWh per month for three consecutive months would be moved to E-4 (see below), while any E-4 customer with energy usage below 6,000 kWh per month for 12 consecutive months would be switched to E-2. When analyzing customer load data this study used the rate schedule designation for each customer in the utility billing system to determine whether the customer currently fell into the E-2 or E-4 class.

E-4 Medium Commercial: Demand metered electric service for commercial customers with a maximum demand below 1,000 kilowatts per month and usage over 8,000 kWh per month.

E-7 Large Commercial: Demand metered electric service for commercial customers with a maximum demand of at least 1,000 kilowatts per month per site, and who have sustained this demand level for at least 3 consecutive months during previous 12-month period.

Street and Traffic Lights: This class applies to all street and highway lighting installations that the City of Palo Alto Utilities Department elects to operate and maintain, generally lights owned by the City, the County, or another government entity and located on public streets.

For purposes of the analysis in this study, customers are assigned to a customer class without regard to whether they participate in Palo Alto Green, Net Energy Metering, Time of Use Metering or Low Income programs.

Master-metered multi-family customers are treated as commercial customers rather than residential customers.

1.2 COST OF SERVICE ANALYSIS

A COSA is concerned with the equitable allocation of the revenue requirement to the various customer classes of service. The revenue requirement shown in Table 1-1 for the City was functionalized, classified and allocated. Specifically:

- **Functionalization** is the attribution of each cost line-item to Power Supply (Commodity) (purchase or production of electric energy), Transmission (transmitting electric energy via power lines rated for

115 kiloVolts (kV) and above),[2] Distribution (moving electric energy from supply or transmission infrastructure to end users via power lines rated for less than 115 kV), and Customer (primarily costs associated with metering and billing). The City does not own any power lines that would be categorized as Transmission, so there were no costs allocated to this function.

- **Classification** is the determination of whether the costs associated with a functionalized line item are most appropriately allocated based on energy use (kWh), demand (kW-- the maximum usage of energy over a specified period of time), or customer (simply having a service account).
- **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 an annual kWh allocator. This means that the line-item cost is directly correlated to the quantity of energy used by each customer class annually. Another example of an energy-based allocator for energy classified costs would be kWh used in the month of January. This process is described in more detail in the section titled "Cost of Service Analysis."

Table 1-2 shows the results of the COSA. It shows the revenues that would be realized in FY 2024-25 without any rate changes (i.e. keeping the rates currently in effect), the share of the FY 2024-25 revenue requirement that should be allocated to each rate class as determined by the COSA, and the surplus/(deficiency) in revenue if current rates are left unchanged. Without a rate change, FY 2024-25 revenues will be slightly more than allocated FY 2024-25 costs for some classes of service. The variance between revenues and costs is greater for some classes than others. The last column of Table 1-2 shows the increase or decrease in revenue required for each rate class.

The results of the COSA are summarized in Table 1-2 and the COSA methodology is described in more detail below in the "Cost of Service Analysis" section of this report.

TABLE 1-2: SUMMARY OF COST OF SERVICE ANALYSIS FOR FY 2024-25 TEST YEARS

	Projected Revenues under Current Rates	Net Revenue Requirement	Projected Surplus/ (Deficiency) in Revenue Based on Current Rates	Revenue Increase/ (Decrease) Needed[3]
Residential E-1	$27,309,759	$27,852,514	-$542,755	2.0%
Small Commercial E-2	$11,784,676	$11,067,556	$717,121	-6.1%
Medium Commercial E-4	$67,707,023	$65,186,601	$2,520,422	-3.7%
Large Commercial E-7	$59,295,683	$58,473,708	$821,975	-1.4%
Street and Traffic Lighting	$2,224,184	$2,006,759	$217,425	-9.8%
TOTAL	**$168,321,326**	**$164,587,138**	**$3,734,187**	**-2.2%**

[2] Note that the Transmission function is for costs associated with moving electric energy over CPAU-owned transmission lines. Payments for transmission service on lines owned by other utilities are included in the Power Supply (Commodity) function.

[3] Projected FY 2024-25 revenue surplus/(deficiency) divided by projected FY 2024-25 revenue based on rates currently in effect.

The projected cost of service allocation has changed across rate classes since the study completed in 2016. The primary drivers for the changes include the following:

1. Updated electric usage information (more detail provided in Section 4.4 Cost of Service Results).
2. Increase in Residential usage results in more costs assigned to residential class.
    a. Decreased Commercial usage, yielding Residential contributing a greater percentage of total energy usage.
    b. Increased residential usage as a class is due to higher average electric usage. Average residential usage increased from 457 kWh/mo in 2019 to 526 kWh/mo in FY2020-2021. The increased average use may be from multiple factors including increased adoption of electric vehicles and air conditioning, electrification, or the work from home trend beginning at the start of the 2020 pandemic.
3. The current E-1 (residential) rate structure includes a two-tier energy rate. Tier 1 energy rates apply to kWh usage up to 330 kWh per month. Tier 2 energy rates apply to usage above 330 kWh per month. COSA. The ratio of the Tier 2 rate to the Tier 1 rate has declined over time due to changes in the utility's costs, but this means that the increase in Tier 2 usage relative to Tier 1 usage has not resulted in as significant an increase in residential rate revenue in recent years than would otherwise be expected. This results in an even greater increase needed for the residential class than would be required just based on the average residential usage increase alone.
4. Streetlights have lower expenses due to newer LED bulbs requiring less in operations and maintenance costs.

1.3 EXISTING RATES OVERVIEW

The rates for residential and commercial customers are designed to take into account differences in energy costs for various generating resources as well as the impacts seasonal changes in energy use and peak demand have on the utility's distribution capacity needs.

The E-1 (Residential) rate is an inclining 2-tier metered rate. Electric use below a certain threshold is charged at one rate per kWh and each kWh used in excess of that threshold is charged at a higher rate. The rates at each tier are comprised of a Commodity rate (which captures Power Supply charges and purchased transmission service) and a Distribution rate. In addition, E-1 customers pay a separate "public benefits charge" on a per kWh basis for all energy consumed, regardless of tier.

The E-2 (Small Commercial) is a seasonal metered rate. For purposes of this rate, the year is divided into two seasons, each of which has a different rate per kWh used. The summer season (period) is defined as May 1 through October 31. The winter period is November 1 through April 30. The higher rate that is applicable during the summer reflects the higher cost of energy during summer months, and the cost of the extra infrastructure needed to meet the City's seasonal non-residential peak, which occurs in the summer (unlike the residential class, which peaks in the winter). Due to the diversity of usage characteristics within the E-2 customer class, the seasonal structure better captures these seasonal distribution cost variations than a tiered rate structure would. The rates for each season are comprised of a "commodity" rate and a "distribution" rate. Additionally, E-2 customers pay the "public benefits charge" at the same rate as is charged to E-1 customers.

The E-4 (Medium Commercial) and E-7 (Large Commercial) rates are seasonal metered rates, but for each season there is both an Energy Charge (measuring consumption in kWh) and a Demand Charge (measuring, in kW, the peak energy delivered in the highest 15-minute period of the day). Because the infrastructure costs of meeting the peak demand are collected through the Demand Charge, the rate variations between seasons only reflect seasonal variation in the utility's costs. The Energy Charge and the Demand Charge for each season are each comprised of a "commodity" rate and a "distribution" rate. Additionally, E-4 and E-7 customers pay the "public benefits charge" at the same rate as is charged to other customers.

TOU rates are made available to E-4 and E-7 customers; these rates reflect both seasonal and hourly demand and energy cost of service. TOU rates are applied to electricity usage and demand as measured during 3 periods: peak, mid-peak, and off peak. TOU rates differ between seasons as well. Customers on the regular E-4 or E-7 rate schedules may opt to be billed according to the TOU rate schedule if desired. TOU rates are meant to reflect the hourly and seasonally varying costs of providing electric service and need to be adjusted as those costs change over time.

1.4 RATE DESIGN

1.4.1 Distribution Rates

The allocation of distribution costs is based on an analysis of the average and excess monthly energy and capacity costs associated with that rate class: the 'Average and Excess' method. The Average and Excess method compares the average capacity and energy used against the maximum capacity and energy used over the season (the "excess"). This captures the level of system capacity required to serve the customer during peak times as opposed to average times.

As mentioned, the distribution rate design for E-1 consists of a 2-tier rate. The Tier 1 distribution rate recovers the cost of providing distribution capacity to each customer. The Tier 1 rate includes costs associated with the capacity requirements during the lower usage months: May through October. This level of capacity is used year-round. The additional costs associated with the distribution capacity needed to serve higher winter demands is collected through the Tier 2 distribution rate.

For E-2 costs associated with demand-related system costs (such as transformers or lines) were separated into seasons using the average and excess demand information from the COSA. The methodology assigns costs associated with average demand to both seasons, while costs related to the distribution capacity required to serve peak demands is allocated to the summer season.[4] For the E-4 and E-7 rates the demand-related system costs are recovered through demand charges.

The recommended rate design for each rate class includes a monthly customer charge. This customer charge is based on a portion of the utility's fixed costs for metering and billing. The customer charge ensures that even for customers who consume zero or negative energy, the customer charge would recover the meter reading and billing costs.

[4] Summer is May 1-October 31. Commercial customers have higher usage during summer whereas residential customers have higher usage during winter.

1.4.2 Commodity Rates

The City purchases wholesale electricity from a variety of resources including, for example, hydropower, wind resources, or market transactions. Each resource provides benefit to the utility and its ratepayers in the form of energy, capacity, or renewable attributes. All California utilities are required to meet capacity requirements (known as resource adequacy) determined by the CPUC (California Public Utility Commission) and the CEC (California Energy Commission). These requirements ensure that the grid, as a whole, can meet electric demands across various electric usage scenarios. The City's capacity costs are directly impacted by how and when electric customers consume electricity. Lastly, the City does not own its own transmission lines to transfer energy from the generators it contracts with to the City's distribution system and therefore purchases transmission services from others. The commodity rates reflect the cost of providing energy, capacity, renewable energy, and purchased transmission service to end-use customers.

In the case of E-1, the lower Tier 1 commodity rate recovers costs associated with lower cost energy resources. The higher Tier 2 commodity rate recovers higher cost resources.

The current rate design for non-residential classes remains largely the same in the proposals. Commodity rates for rate classes E-2 (Small Commercial), E-4 (Medium Commercial), and E-7 (Large Commercial), are determined such that the costs for each generating resource are assigned to the season in which the costs are incurred. Demand rates are calculated by allocating average capacity costs to both summer and winter rates. Because summer peaks drive capacity costs for the utility, the costs of meeting capacity requirements are allocated to the summer (peak demand) season.

1.5 RECOMMENDATION

Based on the projected revenue requirement and COSA analysis, the following observations can be made for the City:

- The City needs a small rate decrease to match FY 2024-25 revenue and expenses.
- Revenues for each rate class should be aligned with the costs allocated to that rate class
- Rate design recommendations include:
  - Adjust the E-1 Tier 1 quantity of kWh for increased average usage within this class, as discussed in Section 5.1.
  - Implement a monthly customer charge for all classes to recover billing and metering costs.
  - Adjust TOU periods for optional TOU rates to better align with marginal energy and system peak demand costs.
  - Consider additional rate assistance for low-income households as E-1 rates transition to flat rate design and a minimum bill is implemented. Low-income program funds are collected through the Public Benefits Charge paid by all customers.

TABLE 1.3: RECOMMENDED RATES

	Commodity	Distribution	PBC	Total
Residential (E-1)				
Tier 1 (up to ~~461~~ 450 kWh), $/kWh	$0.10270	$0.08642	$0.00549	$0.19461
Tier 2 (> ~~461~~ 450 kWh), $/kWh	$0.13240	$0.08079	$0.00549	$0.21868
Customer Charge, $/month				$4.64
Small Commercial (E-2)				
Summer, $/kWh	$0.14926	$0.09735	$0.00549	$0.25210
Winter, $/kWh	$0.09242	$0.06623	$0.00549	$0.16414
Customer Charge, $/month				$5.60
Medium Commercial (E-4)				
Summer, $/kWh	$0.12318	$0.02520	$0.00549	$0.15387
Winter, $/kWh	$0.07949	$0.02520	$0.00549	$0.11018
Summer, $/kW-month	$10.98	$34.31		$45.29
Winter, $/kW-month	$2.57	$21.16		$23.73
Customer Charge, $/month				$113.73
Medium Commercial (E-4 TOU)				
Summer Peak (4-9 pm)	$0.17038	$0.02538	$0.00549	$0.20125
Summer Mid Peak (2-4 pm and 9-11 pm)	$0.14041	$0.02538	$0.00549	$0.17128
Summer Off Peak (all other hours)	$0.10556	$0.02538	$0.00549	$0.13643
Winter Peak (4-9 pm)	$0.11976	$0.02500	$0.00549	$0.15025
Winter Mid Peak (9 am -2 pm)	$0.09452	$0.02500	$0.00549	$0.12501
Winter Off Peak (all other hours)	$0.06525	$0.02500	$0.00549	$0.09574
Summer Peak Period Demand, $/kW-month	$9.72	$17.18		$26.90
Summer Max Demand, $/kW-month	$1.29	$17.18		$18.47
Winter Peak Period Demand, $/kW-month	$1.30	$10.73		$12.03
Winter Max Demand, $/kW-month	$1.30	$10.73		$12.03
Customer Charge, $/month				$113.73
Large Commercial (E-7)				
Summer, $/kWh	$0.12659	$0.00362	$0.00549	$0.13570
Winter, $/kWh	$0.07894	$0.00354	$0.00549	$0.08797
Summer, $/kW-month	$11.95	$28.41		$40.36
Winter, $/kW-month	$2.79	$25.00		$27.79
Customer Charge, $/month				$520.80
Large Commercial (E-7 TOU)				
Customer Charge, $/month				$520.80
Summer Peak (4-9 pm)	$0.18019	$0.00362	$0.00549	$0.18930
Summer Mid Peak (2-4 pm and 9-11 pm)	$0.14850	$0.00362	$0.00549	$0.15761
Summer Off Peak (all other hours)	$0.11164	$0.00362	$0.00549	$0.12075
Winter Peak (4-9 pm)	$0.12104	$0.00354	$0.00549	$0.13007
Winter Mid Peak (9 am -2 pm)	$0.09552	$0.00354	$0.00549	$0.10455
Winter Off Peak (all other hours)	$0.06594	$0.00354	$0.00549	$0.07497
Summer Peak Period Demand, $/kW-month	$11.28	$14.71		$25.99
Summer Max Demand, $/kW-month	$1.45	$14.71		$16.16

	Commodity	Distribution	PBC	Total
Winter Peak Period Demand, $/kW-month	$1.45	$12.99		$14.44
Winter Max Demand, $/kW-month	$1.45	$12.99		$14.44

2 Overview of Rate Setting Principles

EES Consulting (EES), a GDS Associates Company, was retained by the City of Palo Alto (City) to perform a comprehensive electric cost of service and rate study. Performing an electric rate study is necessary to assure that City rates are structured to be fair, equitable and based on the cost of providing service to all City customers. Further, on September 1, 2021, the City's Utilities Advisory Commission approved an Electric Rate Policy[5] which includes 5 guidelines for electric cost of service and rate-making:

1. Rates must be based on the cost of providing service.
2. The effect of any recommended rate design changes on low-income customers should be considered, to the extent permissible within a cost-based rate structure.
3. Rates should not create unnecessary barriers to building and vehicle electrification, including public EV charging, while remaining cost-based.
4. Rates should not create unnecessary barriers to on-site generation and storage while simultaneously avoiding subsidies between customer classes.
5. The COSA and rate design should support a transition to more time variant rates (such as TOU, seasonal, etc.) as advanced metering infrastructure (AMI) is deployed.

This Study was prepared while considering the above guidelines. In conducting a cost of service and rate study, three inter-related analyses are performed:

1. **Revenue Requirement Analysis:** This analysis examines the various sources and uses of funds for the utility and determines the overall revenue required to operate the utility.
2. **Cost of Service Analysis (COSA):** The COSA is used to determine the fair and equitable allocation of the total revenue requirement to the various customer classes of service (e.g. residential, small non-residential, medium non-residential, etc.). 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 equitably collect revenues that match the cost to serve each customer in that class.

2.1 OVERVIEW AND ORGANIZATION OF REPORT

This report is divided into sections that follow these three analyses. This first section is a generic discussion of the theory and financial principles behind setting rates. This is followed by a section discussing the development of the revenue requirement analysis for the City. The next section discusses the COSA. Finally, rate design options are presented in the fourth and final section. A technical appendix is attached

[5] https://www.cityofpaloalto.org/files/assets/public/agendas-minutes-reports/agendas-minutes/utilities-advisory-commission/archived-agenda-and-minutes/agendas-and-minutes-2021/09-01-2021-special/id-13426-item-3.pdf

at the end of this report that provides details of the various analyses. The schedules contained in the technical appendix are referenced throughout the report.

The purpose of this section of the report is to provide a brief overview of the fundamentals of cost identification and allocation for purposes of developing electric rates. From this base-level of knowledge, more insight and understanding can be obtained from the following sections of the report that discuss the specifics of the Revenue Requirement, Cost of Service, and Rate Design analyses mentioned above.

2.2 OVERVIEW OF REVENUE REQUIREMENT

The revenue requirement is the amount of revenue required to be collected from retail rates in order for the utility to cover costs. The revenue requirement includes all electric department expenses (operating and non-operating) less non-rate revenue such as interest income or other unrelated credits. For this study, a cash basis was used to determine the City's electric utility revenue requirement. The cash basis methodology aligns with the City's electric utility budgeting process. Revenue projections and expenses for fiscal year 2024-25 are the basis for the revenue requirement study.

2.3 COST OF SERVICE OVERVIEW

After the total revenue requirement has been determined, the requirement is allocated across the various classes[6] of service based on a cost-based methodology that reflects cost causation between customer characteristics and the Commodity (also known as Power Supply) costs (purchase or generation of the electric commodity and purchased transmission service) and Distribution (delivery of electric service across City-owned distribution line). A COSA begins by assigning each cost in a utility's revenue requirement into major categories such as Commodity, Transmission, Distribution and Customer. This is called "functionalization." Next, the functionalized costs are classified to specific categories, such as demand-related, energy-related, costs based on the portion of the utility's rate base (its distribution assets and general plant assets) serving each customer type, services provided to customers (purchase and delivery/distribution of power), customer-related or a direct assignment of costs to one or more class. This classification is the basis for developing the COSA unit costs (average cost-based rates in terms of $/kWh, $/kW, or $/customer). Allocation factors are factors that add to 100% across all service classes. An example of an allocation factor is the share of the total number of customers or the share of retail sales. These factors are used to spread costs to each class of service. Once the revenue requirement has been allocated to each class of service a determination of the necessary revenue goal for each class can be made.

2.4 RATE DESIGN ANALYSIS

The final step in the rate study process is to design rates for each class of service. Rates can be structured in many ways, but ultimately, they should reflect the types of costs that the utility incurs to serve the

[6] The relevant classes of service for the City of Palo Alto include E-1, E-2, E-4, E-7, and lighting and streetlights. Classes of service can mean rate classes or just customer type such as residential, small general service, industrial etc. In this study, all residential customers are included in E-1, all small general service are in E-2, and E-4 and E-7 include both non-TOU and TOU customers within each respective class.

customer (e.g. demand-, energy- and customer-related costs), and should collect the required level of revenues to safely and reliably operate the utility.

The Power Supply (Commodity) rate design options can provide accurate, cost-based prices for the cost of power supply. Specifically, electric utility rate design should reflect the power supply cost structure and how each class of service is responsible for its fair share of each power supply cost component. Given appropriate prices, consumers can then make informed decisions regarding their electricity use.

The distribution portion of retail rates should be developed such that each ratepayer is responsible for their fair share of the electric distribution service provided. Distribution rates can be bundled with Power Supply (Commodity) rates or unbundled and shown separately as the City has continued to do. Depending on the unique nature of each utility, class of service, or utility goals distribution rate design can vary. While the COSA provides average distribution costs for each class, the rates that are implemented may be designed a number of ways. Regardless of rate design choice, retail rates should follow best practices[7] for rate design which include:

- Promote efficient use of energy and competing products and services
- Simplicity, easy to understand, publicly acceptable, and feasible to implement
- Recovers the revenue requirement
- Provides stability and minimizes adverse impacts on customers
- Fairly apportions cost of service among different consumers

Rate design recommendations are presented in Section 5.

[7] Summarized from Bonbright's Eight Criteria of Sound Rate Structure.

3 Development of the Revenue Requirements

This section of the report presents the development of the electric revenue requirement for the City. Simply stated, a revenue requirement analysis compares the overall revenues of the utility to its expenses and determines the overall adjustment to rate levels that is required.

3.1 OVERVIEW OF THE CITY'S REVENUE REQUIREMENT METHODOLOGY

The City utilizes the "cash basis" approach for determining its revenue requirement. In summary, the components of its revenue requirement include the elements shown in Table 3-1.

TABLE 3-1: ELEMENTS OF A CASH BASIS REVENUE REQUIREMENT

+	Operation and Maintenance Expenses (O&M)	
	✓	Power Supply Expense
	✓	Distribution Expense
	✓	Customer Accounting Expenses
	✓	Administrative and General Expense
+	Capital Improvements funded from Rates	
+	Debt Service (Interest and Principal)	
+	General Fund Transfer	
	=	Total Revenue Requirement
	-	Transfers from Reserves
	-	Miscellaneous Revenue Sources
	=	Net Revenues Required from Rates

From this basic analytical framework, the next step in determining the revenue requirement is to select a time period over which to project revenue and expenses. In the case of the City, a fiscal year test period was utilized (July through June) rather than a calendar year test period. The recommended rate changes are for July 1, 2024; therefore, the 2024-25 fiscal year (July 2024 through June 2025), was chosen as the test period for the COSA.

The next step in the analysis was to translate the City budgeted costs into the system used by the Federal Electric Regulatory Commission (FERC), the FERC System of Accounts. A summary of the FY 2024-25 revenue requirement (using the FERC System of Accounts) is provided in Schedule 1.4, and the details are shown in Schedule 3.1.

3.2 POWER SUPPLY COSTS (COMMODITY)

As with most electric utilities, the major expense associated with operating the utility is power supply. Approximately $115.5 million, or 54 percent of the FY 2024-25 total revenue requirement of the utility, is power supply costs, as shown in Schedule 3.1. Power supply costs include costs from renewable and non-renewable resources, including Western Area Power Administration (WAPA), Northern California Power Agency (NCPA) resources and power purchase agreements. In addition, power supply costs include California Independent System Operator (CAISO) transmission and ancillary charges. The City's proposed FY 2024-25 Operating Budget was used for power supply expenses.

3.3 OTHER OPERATIONS AND MAINTENANCE COSTS

The City's proposed FY 2024-25 Operating Budget determines the other operations and maintenance (O&M) costs. Total FY 2024-25 O&M costs (excluding power supply) are projected to be $48.3 million. As shown in Schedules 1.4 and 3.1, this is made up of the following:

- Distribution O&M costs of $28.0 million. These costs include maintenance of distribution system infrastructure such as lines, transformers, meters, and substations.
- Customer Service-related costs of $12.6 million. These costs include meter reading, billing, key account representatives and general customer service.
- Administrative and general costs of $7.7 million. These costs include functions like accounting, benefit overhead, insurance, and other types of administrative overhead.

FY 2024-25 O&M and Power Supply (Commodity) costs together total $163.8 million, as shown in Schedules 1.4 and 3.1.

3.4 GENERAL FUND TRANSFER

The City calculates the equity transfer from its Electric Utility based on a methodology adopted by Council in 2009,[8] which has remained unchanged since then. The methodology includes a risk and tax adjustment to PG&E's approved return on equity (ROE). Through the budgeting process, the City has identified PG&E's ROE for calendar year 2023 at 10.0%. Using the recommended tax adjustment (70%) and risk adjustment (85%), the City's calculated ROR is 6.1% for FY 2024-25. The total rate base of $248 million means that the General Fund Transfer is projected to be $15.1 million.

3.5 RATE-FUNDED CAPITAL IMPROVEMENT PROGRAM (CIP)

For FY 2024-25, the budgeted CIP is $6.5 million, as shown in Schedules 1.4 and 3.1. This excludes any capital expenses reimbursed by customers through connection fees or reimbursement agreements.

3.6 TRANSFER FROM RESERVES

In its FY 2024-25 proposed budget, the City plans to contribute approximately $25.3 million to reserves. This contribution is necessary to replenish reserve levels recently withdrawn due to differences between the timing of the commencement of the utility's grid modernization capital project and the timing of the

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[8] City of Palo Alto City Manager's Report (CMR) 280:09, "Adoption of an Ordinance Adopting the Fiscal Years 2010 and 2011 Budget, Including the Fiscal Year 2010 Capital Improvement Program, Changes to the Municipal Fee Schedule, Utility Rates and Charges, Equity Transfer Methodology Change and Changes to Compensation Plans," June 15, 2009 and CMR 260:09, "Recommendation to City Council to Change the Methodology Used to Calculate the Equity Transfer from Utilities Funds to the General Fund," May 26, 2009. https://portal.laserfiche.com/Portal/DocView.aspx?id=46024&repo=r-704298fc&searchid=7d78969f-7381-4bf1-ab9c-06cabaec6e19

first debt issuance associated with that project. See the FY 2024-25 Electric Utility Financial Plan for more detail.

3.7 MISCELLANEOUS REVENUES

The City receives additional operating and non-operating revenues and contributions, which are distinct from ratepayer revenues. These come in the form of carbon allowance revenues, interest revenues, miscellaneous service revenues, rents and other revenue. Service revenues received from connections and other fees offset the costs of those services. Interest revenues represent interest on the utility's reserves. Miscellaneous service revenues also include minor revenue sources like pole attachment fees for other utilities such as telecommunications, transfers from other City-owned utilities for shared services, and charges for damaged utility property. Other revenues include wholesale sales of surplus energy. For FY 2024-25 the projection for such revenues and contributions is $51.0 million, as shown in Schedules 1.4 and 3.1.

3.8 SUMMARY OF REVENUE REQUIREMENT

Once all of the components of the cash basis revenue requirement have been determined, the parts can be summed to equal the total revenue requirement. The City's revenue requirement for the FY 2024-25 test period is summarized in Table 3-2. More detail on the individual components of the revenue requirement can be found in Schedules 1.4 and 3.1.

TABLE 3-2: SUMMARY OF THE REVENUE REQUIREMENT – FY: 2024 -25

Purchased Power	$115,533,652
Distribution	$28,005,465
Customer Accounts and Services	$12,608,722
Administration and General	$7,698,473
Capital Projects Funded from Rates	$6,500,000
Debt Service	$4,770,582
General Fund Transfer	$15,121,000
Reserve Contribution	$25,333,578
Total Expenses	**$215,571,473**
Other Revenues	$50,984,335
Total Revenue Required from Rates (Revenue Requirement)	$164,587,138
Revenue Based on Rates Currently in Effect	$168,321,326
Additional Rate Revenue Needed (Surplus)	($3,734,187)
Net Required Rate Revenue Increase (Decrease)	**(2.2%)**

3.9 RECOMMENDATION

The City's revenues are slightly more than its cost obligations in FY 2024-25 using current rates; therefore, a rate reduction is recommended. It is important to note that the City's revenue-to-cost balance needs to be continually monitored. The City regularly reviews revenue requirements to update retail rates and ensure financial objectives are met.

4 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 a cost 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 will discuss the general approach used to apportion the City's costs, and will provide a summary of the results.

4.1 CUSTOMER CLASSES

A primary input into the COSA is the classes of service. Classes can be modeled by each rate schedule; however, rate schedules for similar customers may also be combined in the COSA. Combining rate schedules recognizes that those groups of customers have similar usage characteristics. For example, E-4 Medium Commercial and TOU-E-4 Medium Commercial customers are likely to have similar load characteristics. The following rate classes are modeled in the COSA:

E-1 Residential: All residential customers, excluding from master-metered multifamily customers.

E-2 Small Commercial: Electric service for small commercial customers and master-metered multifamily customers. Any customer with energy usage over 8,000 kWh per month for three consecutive months would be moved to E-4 (see below), while any E-4 customer with energy usage below 6,000 kWh per month for 12 consecutive months would be switched to E-2. When analyzing customer load data this study used the rate schedule designation for each customer in the utility billing system to determine whether the customer currently fell into the E-2 or E-4 class.

E-4 Medium Commercial: Demand metered electric service for commercial customers with a maximum demand below 1,000 kilowatts per month and usage over 8,000 kWh per month.

E-7 Large Commercial: Demand metered electric service for commercial customers with a maximum demand of at least 1,000 kilowatts per month per site, and who have sustained this demand level for at least 3 consecutive months during previous 12-month period.

Street and Traffic Lights: This class applies to all street and highway lighting installations that the City of Palo Alto Utilities Department elects to operate and maintain, generally lights owned by the City, the County, or another government entity and located on public streets.

For purposes of the analysis in this study, customers are assigned to a customer class without regard to whether they participate in Palo Alto Green, Net Energy Metering, Time of Use Metering or Low Income programs.

Master-metered multi-family customers are treated as commercial customers rather than residential customers.

4.2 COSA 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. Because the majority of costs are not incurred by any one type of customer, 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 electric service rates, after development of the revenue requirement but before designing rates.

This COSA is performed using the embedded cost methodology. Embedded costs reflect the actual costs incurred by the utility and closely track the expenses kept in its accounting records.

There are three basic steps to follow in developing a COSA:

- Functionalization
- Classification
- Allocation

Functionalization separates costs into major categories that reflect the different services provided to customers. The functional categories for the City are Power Supply (Commodity) and Distribution. Shared service costs (generally overhead) that will be allocated across both functional categories are also identified in this phase.

Classification determines the portion of each cost that is related to identified "classifiers" (cost-causal factors). Table 4-3 shows the classifiers used in this analysis. Generally, costs are classified as one or more of: 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), and customer-related (costs incurred as a result of receiving service, regardless of the energy use or peak demand), though there are some other classifiers. Power Supply (Commodity) costs are related to generating and supplying power to customers on the system and are often demand- or energy-related. The distribution system is designed to extend service to all customers attached to the system and to meet the peak demand requirement of each customer, meaning that costs are often demand-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 (for example, for street lighting customers).

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 Power Supply (Commodity) costs might be classified as partially demand-related and partially energy-related. The demand-related Power Supply (Commodity) costs would be allocated to the classes of service using each class's contribution to the annual system peak demand (the highest demand 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 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.

4.3 FUNCTIONALIZATION OF COSTS

As discussed above, the first step in the COSA process following finalization of the revenue requirement is to functionalize the revenue requirement.

Certain types of costs in the revenue requirement (primarily O&M costs associated with various types of capital assets) are allocated based on the use of the underlying capital assets by customer class. To determine this, the underlying capital assets of the utility (the "rate base") are functionalized into cost categories and allocated to customer classes. The functionalization, classification, and allocation of the rate base will be used as a basis for functionalization, classification, and allocation of certain types of operating expenses in the revenue requirement, such as maintenance of the capital assets included in the rate base.

In the City's case, the rate base and revenue requirement are functionalized into Power Supply (Commodity), Distribution, and Shared Services functional categories. Schedule 3.1 shows the functional category for each cost in the revenue requirement, while Schedule 3.3 shows the results of the functionalization and classification of each cost. Schedules 4.1 and 4.2 show the same information for the rate base. The functional categories are described in more detail below:

- ***Power Supply (Commodity)*.** The Power Supply functional category includes all power-related services that are obtained by the utility through generation and direct purchase. The City purchases power from a variety of renewable and hydroelectric generating sources, as well as purchasing power in the energy markets. The transmission services that the City must acquire to deliver the purchased power supply to the service area are included in purchased power costs.

- ***Distribution*.** Distribution services include all services required to move the electricity from the point of interconnection between the transmission system and the distribution system to the end user of the power. These include substations, primary and secondary poles and conductors, line transformers, services and meters as well as customer costs and any direct assignment items.

- ***Shared Services.*** Shared services include assets used across multiple functions or costs that apply across multiple functions, such as facilities used for general management of the operation or insurance or benefits costs. Assets and costs in the shared services category are not shown in the attached schedules as a separate functional category. Instead, they are allocated across the Power Supply (Commodity) and Distribution functions as overhead.

4.4 CLASSIFICATION AND ALLOCATION OF COSTS

The next step in performing a COSA is to classify and allocate the functionalized expenses. The classifications and allocations are directly related to specific consumption behavior or system configuration measurements such as coincident peak (CP) or non-coincident peak (NCP)[9] demand, energy

[9] Coincident peak represents the customer class's contribution to the system peak demand (i.e. its demand coincident with, or at the time of, the system peak), while non-coincident peak represents the customer class's peak

consumption, or number of customers. Each cost in the revenue requirement will be classified into one or more categories and will then be allocated to customer classes of service based on a specific allocator. For example, 7% of the costs associated with the Calaveras hydroelectric generating resource were classified into the demand classification and 93% were classified into the energy classification, with the demand classifier allocated to classes of service based on each class's CP demand, and the energy portion of the cost allocated based on each class's annual energy consumption.

The classification and allocation factors used for each component of the rate base and revenue requirement are shown in Tables 4-1 and4-2 and are discussed in more detail below. Descriptions of each factor are included in Table 4-3.

The following are the specific classifiers used in the City's COSA within the Power Supply and Distribution functions. As noted earlier, the Shared Services function is spread across the Power Supply and Distribution functions as overhead, so it does not have its own classifiers:

- **Power Supply (Commodity) Function**

  Within this study, Power Supply (Commodity) function costs are classified to demand and energy based on discussion with the City staff related to cost causation. The specific classifiers used for the Power Supply (Commodity) function include:

  - ***Energy*.** Energy-related costs are those that vary with the total amount of electricity consumed by a customer. Electricity usage measured in kWh 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.

  - ***Demand*.** Demand-related costs are those that vary with the maximum demand or the maximum rates of energy supplied to classes of service. Customer and system demands for this analysis were measured in kW. Demand costs are generally related to the size (capacity) of facilities needed to meet a customer's maximum demand at any point in time. Resource capacity costs are functionalized as demand. When referring to customer peak electricity use or requirements, the term demand is used. When referring to resource attributes, the term capacity is used.

  In order to classify Power Supply (Commodity) costs, each resource or type of cost was evaluated based on how the City is charged and whether the resource provides energy or capacity[10] to the City. Power purchase agreements for the output from the Western Area Power Administration (WAPA) and Calaveras hydroelectric generating resources and all renewable resources provide differing amounts of energy and capacity, and so were classified according to the relative market value of the energy and capacity provided by each resource. An analysis of the amount of capacity and energy provided

demand regardless of when it occurs. A customer class's demand at the time of the system peak demand may be lower than its peak demand, which may occur at some other time of the year.

[10] When referring to a generating resource, "capacity" refers to its potential generating capacity regardless of whether it is actually generating energy. Capacity must be held to meet customer peak demand, regardless of whether it is used to generate energy at all times of the year. Capacity costs are usually assigned to the demand classifier.

by each resources was done, and the market value of each of those was calculated based on historical energy and capacity prices. The market value is used rather than actual operating expenses since the resources generate revenues that offset their operating expenses, and the actual cost to Palo Alto depends on the market value for energy, and capacity less the individual resource cost. The ratio of energy to capacity value was used to classify the cost of the resource and assign resource costs to energy or demand.

Costs associated with services provided to the City by Northern California Power Agency (NCPA) (such as scheduling generating resources and interacting with the California Independent System Operator (CAISO) on the City's behalf) are classified as energy costs because these services are necessitated by City's energy purchases. Purchases of energy from marketers[11] are classified as energy-related costs, while purchases of capacity are classified as demand-related costs.[12] CAISO transmission costs are classified as energy-related costs, as this is the way those costs are allocated to distribution utilities by the CAISO, and the CAISO transmission costs therefore vary with the total City system energy.

- **Distribution Function**

  Distribution services include all services required to get energy supply from the point of interconnection between the transmission system and the utility's service area to the end user of the power. Most distribution costs are split between demand and customer components. The demand component is the cost of facilities like distribution substations, lines, or line transformers built to serve a particular peak demand. The customer component is the cost of facilities that varies with the number of customers, such as meters. The following are the specific classifiers used for the City's distribution function:

  - ***Demand*.** Demand-related costs are those that vary with the maximum demand or the maximum rates of energy supplied to classes of service. Customer and system demands for this analysis are measured in kW. Demand costs are generally related to the size of facilities needed to meet a customer's maximum demand at any point in time.

  - ***Customer*.** Customer-related costs are those that vary with the number of customers. Customer costs may be weighted to account for differences in the cost of providing services to those customers. For example, the service drop and metering associated with serving a large commercial customer is more costly and requires substantially more work and material than the service and meter for a small residential customer.

  - ***Direct Assignment*.** Some costs are directly assigned to specific classes of service. Costs associated with providing account representatives to large customers are allocated directly to those classes of service. Direct maintenance costs associated with streetlights and traffic signals are directly

[11] City purchases energy and capacity from various marketers and other agencies (BP Energy Company, Cargill Power Markets, Exelon Generation Co., Iberdrola Renewables, Nextera Energy Marketing, Pacificorp, Powerex, Shell Energy North America, and Turlock Irrigation District) through its Electric Master Agreements.

[12] Energy purchases require that energy is delivered to the system during some specified period of time, while capacity purchases enable the City to count generating capacity from a specific generating unit owned by another agency or marketer toward the generating capacity requirements imposed on it by the CAISO.

allocated to the streetlight / traffic signal class. Schedules 3.5 and 4.4 provide the background information for all directly assigned costs associated with the revenue requirement and rate base.

The methodology for functionalization, classification, and allocation of the City's rate base is summarized in Table 4-1 and in Technical Appendix Schedule 4.1. The results of the process for the rate base can be found in Schedule 4.2. The same information for the revenue requirement can be found in Table 7, Schedule 3.1, and Schedule 3.3. More detail on the classification and allocation factor codes used in the classification and allocation process can be found in Table 8. Schedule 6.1 shows how each code is used to separate costs into functions (power supply and distribution) and classifications (demand, energy, customer, and direct assignment). Schedule 6.2 shows the way each code then allocates the costs within each classification across classes of service.

TABLE 4-1: RATE BASE FUNCTIONALIZATION, CLASSIFICATION AND ALLOCATION

FERC Account	Asset Description	Functionalization Category	Classification and Allocation Factor Code[13]
	Distribution Plant		
361.0	Structures and Improvements	Distribution	NCPP
362.0	Station Equipment – Distribution	Distribution	NCPP
363.0	Storage & Battery Equipment	Distribution	NCPP
364.0	Poles, Towers & Fixtures	Distribution	100% DP
365.0	Overhead Conductor & Devices	Distribution	100% DC
366.0	Underground Conduit	Distribution	100% DC
367.0	Underground Conductors	Distribution	100% DC
368.0	Line Transformers	Distribution	100% DT
369.0	Services	Distribution	SERV
370.0	Meters	Distribution	CUSTM
371.0	Installations on Customer Premises	Distribution	CUSTM
373.0	Street Lighting Systems	Distribution	DA1
	General Plant		
390.0	Structures & Improvements	Shared Services	GPLT
391.0	Office Furniture & Equipment	Shared Services	GPLT
392.0	Transportation Equipment	Shared Services	GPLT
394.0	Tools, Shop & Garage Equipment	Shared Services	GPLT
397.0	Communication Equipment	Shared Services	GPLT
398.0	Miscellaneous Equipment	Shared Services	GPLT
399.0	Other Tangible Property – EV Charging	Shared Services	GPLT
	Accumulated Depreciation		
	Distribution Plant	Distribution	RBD-NoDA
	General Plant	Shared Services	RBGP
	Street Lighting	Distribution	DA1
	Working Capital		

[13] See Table 4.3 for more detail and fully spelled-out acronyms

	90 Days Distribution O&M	Shared Services	OMWOP
	90 Days of Commodity Cost	Power Supply	OMP
	1/12 Purchased Transmission Charges	Power Supply	OMPT
	Construction Work in Progress		
	Construction Work in Progress	Distribution	RBD

TABLE 4-2: REVENUE REQUIREMENT FUNCTIONALIZATION, CLASSIFICATION AND ALLOCATION

FERC Account	Plant Description	Functionalization Category	Classification and Allocation Factor Code[14]
	Power Purchases		
555.70	Western Power Purchases	Power Supply	WEST
555.71	Contra Surplus Energy	Power Supply	kWh
555.72	NCPA Pooling	Power Supply	kWh
555.73	NCPA Facilities	Power Supply	kWh
555.74	Local Capacity Purchase	Power Supply	CP12
555.76	Renewable Energy	Power Supply	REN
555.77	Carbon Neutral Purchases (RECs)	Power Supply	kWh
555.78	Market Power Purchases	Power Supply	kWh
555.80	TANC & Calaveras O&M	Power Supply	CALA
555.90	CVP O&M	Power Supply	WEST
555.15	Resource Management Admin	Power Supply	kWh
	Other		
555.10	Surplus Energy	Power Supply	kWh
555.30	Carbon Allowance Revenues	Power Supply	kWh
	Distribution		
580.0	Operations Supervision and Engineering	Distribution	RBD
586.0	Meters	Distribution	CUSTW
587.0	Customer Installations	Distribution	CUSTW
588.0	Miscellaneous Distribution	Distribution	RBD-NoDA
589.0	Rents	Distribution	RBD-NoDA
590.0	Maintenance Supervision and Engineering	Distribution	RBD-NoDA
593.0	Maintenance of Overhead Lines	Distribution	RBOH
594.0	Maintenance Of Underground Lines	Distribution	RBUG
596.0	Street Lighting & Signal Systems	Distribution	DA1
598.0	Maintenance of Misc. Distribution Plant	Distribution	RBD
598.1	Communication O&M	Distribution	RBD-NoDA
	Customer Service, Accounts & Sales		
901.0	Supervision	Distribution	CUSTW
902.0	Meter Reading Expenses	Distribution	CUSTMR
903.0	Cust. Records Collection Expense	Distribution	REV
904.0	Uncollectable Accounts	Distribution	REV
906.0	Customer Service & Information	Distribution	CUST
907.0	Customer Communication & Education	Distribution	CUST
910.0	Misc. Customer Service & Information	Distribution	CUST
916.0	Misc. Sales Expense	Distribution	CUST
906.1	Key Accounts	Distribution	OM
906.2	Energy Efficiency & Demand-Side Management (DSM)	Distribution	DSMEE

[14] See Table 4.3 for more detail.

906.3	Low Income Residential Energy Assistance Program	Distribution	DSMEE
	Administrative and General (A&G) Expenses		
920.0	Salaries	Shared Services	OMAG
921.0	Office Supplies and Expense	Shared Services	OMAG
923.0	Outside Services	Shared Services	OMAG
924.0	Property Insurance	Shared Services	NETPLT
925.0	Injuries and Damages	Shared Services	OMAG
926.0	Employee Pension and Benefits	Shared Services	OMAG
927.0	Franchise Requirements	Shared Services	OMAG
930.2	Miscellaneous General Expense	Shared Services	OMAG
930.3	Environmental Fees	Shared Services	OMAG
932.0	Maintenance of General Plant & Communication Equipment	Shared Services	OMAG
935.0	Cost Plan Charges	Shared Services	OMAG
	Interest and Debt Service Expense		
427.0	Interest and Debt Service Electric	Shared Services	NETPLT
	Capital Projects From Rates		
	Distribution	Distribution	RBD-NoDA Services
	Other Contributions		
	General Fund Transfer	Shared Services	GF
	Other Transfers In/Out	Shared Services	NETPLT
	Reserve Contribution	Shared Services	RContr
	Misc. & Other Revenues and Income		
451.0	Connect / Re-Connect Fees	Shared Services	OMAG
419/424	Dividends from Affiliates, Interest	Power Supply	WEST
415/416	Income from Equity Investments	Shared Services	OM
421.0	Misc. Income (RA Sales & Surplus Sales)	Power Supply	kWh
421.1	Public Benefits Revenue	Power Supply	kWh

TABLE 4-3: CLASSIFICATION AND ALLOCATION FACTORS

Factor Code	Factor Name	Classification	Allocation Basis
Rate Base Classification and Allocation Factors			
NCPP	Non-coincident Peak - Primary	100% Demand	The total peak kW demand, regardless of when it occurs.
100% DP	100% Demand (Poles, Towers, Fixtures)	100% Demand	The total peak kW demand, regardless of when it occurs.
100% DC	100% Demand (Overhead and Underground Conduit)	100% Demand	The total peak kW demand, regardless of when it occurs.
100% DT	100% Demand (Transformers)	100% Demand	The total peak kW demand, regardless of when it occurs.
SERV	Services[15]	100% Customer	# customers weighted for the cost of installing and replacing services
CUSTM	Customers weighted for accounting / metering	100% Customer	# customers weighted for cost of installing, maintaining and reading meters, billing, and account management
DA1	Street Light Rate Base Assignment	100% Direct Assignment	Street lighting assets allocated directly to street light customer class of service
GPLT	Gross Plant	71.7% Demand, 21.1% Customer 7.2% Direct Assignment	Allocated on the Basis of Gross Plant (w/o General Plant & Intangible)
RBD-ST	Rate Base: Distribution Adjusted for Street Light Direct Assignments	61.8% Demand, 24.3% Customer 13.9% Direct Assignment	Classified and allocated to classes of service based on the value of all operational and shared services assets assigned to each class of service. Used for accumulated depreciation
RBD-NoDA	As Distribution Ratebase without DA Street Lighting	71.7% Demand, 28.3% Customer	Allocated as Distribution Rate Base without DA Street Lighting
RBD-NoDA Services	As Distribution Ratebase without DA Street Lighting or Services	97.8 Demand, 2.2% Customer	As Distribution Rate Base without DA Street Lighting or Services
RBGP	Rate Base - General Plant	71.7% Demand, 21.1% Customer, 7.20% Direct Assignment	On the Basis of General Plant Rate Base
RContr		50.7% Demand, 33.9% Energy 15.4% Customer	Based on Commodity and Distribution Split
OMWOP	O&M without Power Supply	51.6% Demand, 17.7% Energy,	Allocated based on O&M without Power Supply costs

[15] This is a technical term referring to the connection from the line transformer to the customer's electrical panel.

Factor Code	Factor Name	Classification	Allocation Basis
		27.7% Customer 3.0% Direct Assignment	
OMP	O&M: Purchase Power	9.3% Demand, 90.7% Energy	Allocated based on Purchased Power costs
OMPT	O&M: Purchased Transmission	100% Energy	Allocated based on Purchased Transmission costs
RBD	Rate Base: Distribution	71.7% Demand, 21.1% Customer 7.2% Direct Assignment	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.
Revenue Requirement Classification and Allocation Factors			
WEST	Western Base Resource allocation	16% Demand, 84% Energy	Western Base Resource costs. Classified according to the relative market value of the capacity and energy provided by the resource, and allocated to classes of service based on each class's energy consumption and coincident peak demand.
kWh	Energy consumption (kWh)	100% Energy	Energy consumption of each class of service in kWh
CP12	12-month Coincident Peak	100% Demand	Customer class of service's contribution to the utility's annual system peak demand
CALA	Calaveras Hydroelectric Resource allocation	7% Demand, 93% Energy	Calaveras hydroelectric resource costs. Classified according to the relative market value of the capacity and energy provided by the resource, and allocated to classes of service based on each class's energy consumption and coincident peak demand.
REN	Renewable Power Purchase Agreements	3% Demand, 97% Energy	Renewable Power Purchase Agreement costs. Classified according to the relative market value of the capacity and energy provided by the resource, and allocated to classes of service based on each class's energy consumption and coincident peak demand.
RBD	Distribution Rate Base	71.7% Demand, 21.1% Customer, 7.2% Direct Assignment	On the Basis of Distribution Rate Base
RBD-NoDA	Distribution Rate Base Excluding Street Lighting and Traffic Signals	71.7% Demand, 28.3% Customer	Used for allocation of most distribution system infrastructure O&M costs other than street light/traffic signal maintenance. 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, excluding street lighting and traffic signals.
RBD-NoDA Services	As Distribution Rate Base without DA Street Lighting or Services	97.8 Demand, 2.2% Customer	As Distribution Rate Base without Direct Assignment to Street Lighting and excluding Services (FERC 369)

Factor Code	Factor Name	Classification	Allocation Basis
DA1	Street Light and Traffic Signal Direct Assignment	100% Direct Assignment	Costs associated with operating and maintaining streetlight and traffic signal assets
GF	General Fund Allocator	4% Demand 95% Energy 1% Customer	Allocator for General fund Contributions based on Surplus Sales
RContr	Reserves Contribution	50.7% Demand, 33.9% Energy 15.4% Customer	Based on Commodity and Distribution split
RBOH	Rate Base (Overhead Lines)	100% Demand	Used for allocation of maintenance costs for overhead lines. Classified and allocated to classes of service based on the net book value of overhead lines assigned to each class of service.
RBUG	Rate Base (Underground Lines)	100% Demand	On the Basis of all Underground Rate Base
REV	Retail Revenues	100% Demand	Share of retail rate revenue
CUSTW	Customers weighted for accounting / metering	100% Customer	# customers weighted for cost of installing, maintaining and reading meters, billing, and account management
CUSTMR	Customers weighted for meter reading	100% Customer	# customers weighted for cost of reading meters
CREDIT	Credit and Collections	100% Customer	# customers weighted for credit and collections costs
CUST SERV	Customer Service	100% Customer	# customers weighted for customer service costs
CUST	Actual Customers	100% Customer	Actual (unweighted) customer count
OMAG	O&M omitting A&G and Power Supply	Shared Services	On the basis of all other O&M costs allocated to each class of service excluding A&G and Power Supply. Allocated to Power supply Function (12.6% Energy) and Distribution Function (48.7% Demand, 31.5% Customer, 7.2% Direct Assignment)
OM	All O&M	Shared Services	Allocated on the basis of all other O&M costs in the revenue requirement. Allocated to Power Supply Function (4.9% Demand, 12.6% Energy) and Distribution Function (48.7% Demand, 31.5% Customer, 7.2% Direct Assignment)
DSRE	Demand-Side Renewable Energy Allocator	Power Supply	Allocated based on PV Partners solar rebate budget allocation
DSMEE	DSM / EE Allocator	Power Supply	Based on historical residential / non-residential program expenditures. Residential direct assignment, non-residential based on annual kWh. No allocation to Street/Traffic Lights
NETPLT	Net Plant	78.4% Demand, 18.2% Customer, 3.4% Direct Assignment	Allocated on the basis of the net book value of all capital assets (initial cost less

Factor Code	Factor Name	Classification	Allocation Basis
			accumulated depreciation) assigned to each class of service.

4.5 COST OF SERVICE RESULTS

Given the key assumptions listed above, the COSA was completed. Schedules 3.4 and 4.3 in the appendix show the functionalized and classified rate base and revenue requirement allocated to each class of service. These schedules are calculated by multiplying the applicable classification and allocation factors to each cost in the revenue requirement or rate base.

Given the above assumptions regarding the COSA, the various costs were classified and allocated to the customer classes of service. Table 4-4 provides the COSA results. Summary data and additional detail is presented in Schedules 1.1 and 1.2.

TABLE 4-4: SUMMARY OF COST OF SERVICE ANALYSIS FOR FY 2024-25 TEST YEAR

	Projected Revenues under Current Rates	Net Revenue Requirement	Projected Surplus/ (Deficiency) in Revenue Based on Current Rates	Revenue Increase/ (Decrease) Needed[16]
Residential E-1	$27,309,759	$27,852,514	-$542,755	2.0%
Small Commercial E-2	$11,784,676	$11,067,556	$717,121	-6.1%
Medium Commercial E-4	$67,707,023	$65,186,601	$2,520,422	-3.7%
Large Commercial E-7	$59,295,683	$58,473,708	$821,975	-1.4%
Residential E-1	$2,224,184	$2,006,759	$217,425	-9.8%
TOTAL	**$168,321,326**	**$164,587,138**	**$3,734,187**	**-2.2%**

The results show that with present rates, the City would collect surplus revenues in FY 2024-25. As discussed previously in the report, the amount of additional revenue required varies by class of service. While customers on Rate Schedule E-7 are paying close to cost of service already, the E-1 rate class will need a rate increase. The varying cost requirements are a result of changes in customer usage characteristics since the last COSA and rate redesign. These changing consumption patterns affect use of the system and the way costs are allocated among customers.

As described throughout this section, costs are allocated to customers based on their consumption patterns, particularly energy consumption and peak demand. As customer consumption patterns change, some of the utility's costs change as well, but others are fixed over the short term. For example, some charges to the utility, like market energy purchases, are directly related to energy consumption. These costs decrease as customer energy consumption decreases, usually in real-time. If a customer class uses less energy, fewer of these costs will be allocated to them and their revenue requirement will decrease. Other costs only change slowly over time, such as the amount of distribution capacity the utility builds

[16] Projected FY 2024-25 revenue surplus/(deficiency) divided by projected FY 2024-25 revenue based on rates currently in effect.

and maintains. These costs are largely fixed and change over the long term with changes in peak demand or energy use. The majority of the City of Palo Alto's costs change slowly over the long term.

Rates for each customer class are set based on the energy and peak demand patterns over the study period. If energy use and peak demand decrease or increase after the rate study is completed, costs that change only over the long term might not change. When a subsequent COSA is performed, different revenue adjustments may need to be made for each customer class. The impacts to each class required as a result of the analysis done in the COSA are described below:

- Energy consumption and demand has increased for the E-1 (Residential)[17] class of service. The share of costs allocated to this customer class increased as a result. Revenues need to increase more than average for this class of service.
- Small Commercial (E-2) needs a larger rate decrease due to an updated assessment of the cost allocation factors for customer service costs for this customer class.
- The Medium Commercial (E-4) annual load factor has remained consistent with the previous COSA; however, energy usage and demand usage has decreased. This results in less cost allocation to E-4.
- Large Commercial (E-7) load factors[18] have increased. The share of costs allocated to this class decreased as a result.
- The streetlight and traffic signal class reflects lower maintenance costs and capital expenditures allocated to lighting.

Table 4-5 below compares usage data from this study (FY 2023-24) with the previous COSA (FY 2016-17). Note that E-18 (City Accounts) were combined with commercial classes in the last COSA (FY 2016-17). Rather than developing separate E-18 rates, the City included City Accounts in the appropriate commercial classes based on individual customer demand size as described in the retail rate schedules. Retail sales data and number of customers was provided by the City. Billed demand[19] for applicable classes was also provided by the City. Not all classes have meters that measure demand, therefore, for classes without billed demand, demands are calculated using load factor data calculated from an appropriate City feeder (i.e. a feeder[20] that is mostly serving residential customers is used to calculate monthly load factors).

[17] While this class of service is named "Residential Electric Service," it does not include 100% of residential use. Some master-metered multi-family residential buildings take service under other rate schedules.
[18] See previous footnote.

[19] Billed demand refers to the maximum measured kW in any given month. Billed demand is based on a customer's maximum demand regardless of the time of the utility system peak (non-coincident demand at the meter).

[20] A feeder is the part of the distribution system which connects the power supply to the area where power is to be distributed (and eventually to individual customers).

TABLE 4-5: COMPARISON OF LOAD CHARACTERISTICS

	Residential E-1	Small Comm. E-2	Medium Comm. E-4	Large Comm. E-7	City Accounts E-18	Street & Traffic Lights	Total
Retail Sales, MWh							
FY2016-17	153,030	70,451	320,995	394,322	29,231	1,897	969,926
Forecast FY2024-25	133,053	53,238	295,255	348,505	0	1,893	831,944
Peak Demand (12NCP, kW)[1]							
FY2016-17	304,102	190,983	773,606	747,738	76,890	5,371	2,098,690
Forecast FY2024-25	264,621	143,933	764,019	607,389	0	5,359	1,785,322
Load Factor[2]							
Average Monthly							
FY2016-17	69%	51%	54%	74%	53%	50%	
Forecast FY2024-25	69%	51%	49%	78%	NA	50%	
Customers							
FY2016-17	25,341	3,073	736	66	123	1	29,339
Forecast FY2024-25	26,100	3,183	837	71	0	2	30,193

When examining the results, it is important to note that the inter-class cost allocation is based on usage data estimates and usage pattern assumptions. Since these can vary from year to year, the results of applying this COSA may deviate from these allocations over time. To avoid these deviations, the COSA model can be updated when necessitated by significant changes to customer consumption patterns or the City's costs. This study utilizes the FY 2020-21 and FY2021-22 historic years and the City's forecasted load growth to estimate FY2024-25 loads. The historic data includes usage patterns that have continued since the pandemic. This data best reflects the near-term usage characteristics. It is recommended to revisit the load characteristics in future COSA studies.

5 Rate Design

The final step in the rate study process is to design rates for each class of service. It is important to note that the results of the revenue requirement and COSA study are dependent on forecasted usage data estimates and usage pattern assumptions. Actual electricity usage patterns may differ from forecast. For this study, rates are developed based on the forecasted usage and observed historical usage patterns for each rate class.

As part of the electric cost of service study, a rate design analysis is prepared to update the City's current and recommended rate schedules. The City's existing rate model and methodologies are largely preserved for each rate classes. In some cases, rate components for existing schedules have recommended updates. This section of the report summarizes the rate design analysis for FY 2024-25 electric rates. Table 5-1 summarizes the recommended rate adjustments by class. These rate adjustments are taken directly from the COSA results.

TABLE 5-1: RATE ADJUSTMENT RECOMENDATION OVERVIEW

	Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/ Traffic Lights
Current Rate Revenue	$168,321,326	$27,309,759	$11,784,676	$67,707,023	$59,295,683	$2,224,184
Rate Revenue Goal	$164,583,556	$27,852,396	$11,067,533	$65,184,561	$58,472,307	$2,006,759
Rate Adjustment	-2.2%	2.0%	-6.1%	-3.7%	-1.4%	-9.8%

Table 5-2 summarizes the current rate design for each rate schedule and recommended rate design updates.

TABLE 5-2: RATE DESIGN RECOMMENDATION OVERVIEW

Rate Schedule	Current Rate Design	Recommended Rate Design
Residential E-1	Energy Only Tiered Rate with 2 Inclining Blocks	• Add Customer Charge • Increase Tier 1 kWh to average summer usage
Small Commercial E-2	Seasonal Rates energy charge only	• Update Seasonal Costs • Add Customer Charge
Medium Commercial E-4	Seasonal with Energy and Demand Charges	• Update Seasonal Costs • Add Customer Charge • Adjust kW billing methodology
Medium Commercial E-4-TOU	6-period TOU Energy and Demand Rates	• Update TOU Periods • Commodity Rate Based on updated Marginal Cost • Add Customer Charge
Large Commercial E-7	Seasonal with Energy and Demand Charge	• Update Seasonal Costs • Add Customer Charge
Large Commercial E-7-TOU	6-period TOU with Energy and Demand Charge	• Update TOU Periods • Commodity Rate Based on updated Marginal Cost • Add Customer Charge • Adjust kW billing methodology

5.1 CUSTOMER CHARGE AND MINIMUM BILL

Table 5-2 recommends adding monthly customer charges to each rate schedule.[21] The recommended customer charges recover the cost of metering and billing in each class. Customer charge bill impacts to low-income customers are addressed in section 5.2 below.

5.2 RESIDENTIAL E-1

The current rate design is based on a 2-tier inclining block rate as described in Table 5-3. The costs allocated to Tier 1 include the cost of maintaining and replacing the distribution capacity used year-round, while the costs allocated to Tier 2 represent the cost of maintaining and replacing the distribution capacity used only in the winter, which is when residential consumption peaks. Local capacity costs (resource adequacy) are allocated to Tier 2 as well. The current break point between Tier 1 and Tier 2 is 330 kWh per month. A good estimate of the capacity that is used year-round by R-1 customers is the average summer residential consumption. That average consumption is 461 kWh per month (approximately 15 kWh per day). Therefore, we recommend that the Tier 2 threshold for each billing period be set at 15 kWh multiplied by the number of days in that billing period~~An analysis of residential consumption for CY 2020 shows the average summer residential consumption is 461 kWh per month. This is most representative of the current annual year-round usage; however, due to the City's billing system limitations. Therefore, the recommended rate design change is to increase the Tier 2 threshold to 461 450 kWh per month.~~

TABLE 5-3: RESIDENTIAL E-1 TIERED ENERGY RATE DESIGN

	Current Rates	Recommended Rate Design
Tier 1 kWh	330	450
Tier 2 kWh	Above 330	Above 450

It is recommended that the City implement a monthly customer charge.[21] This customer charge recovers customer-specific costs such as billing and meter reading. Additionally, a customer charge is a way to improve cost of service recovery within each class; low users pay their share of costs. Low-income programs would continue to be available to mitigate rate impacts to vulnerable customers.

Table 5-4 shows the recommended rates preserving the tiered rate structure.

[21] A monthly customer charge can be referred to as a facilities charge, fixed charge, basic charge, fixed delivery charge or other nomenclature. This study refers to the customer charge as fixed or facilities charge. All of these are essentially the same type of rate meant to recover a portion of fixed costs incurred just to serve a customer.

TABLE 5-4: RECOMMENDED E-1 RATES

	Commodity	Distribution	PBC	Total
Current Rates				
Tier 1 (up to 330 kWh), $/kWh	$0.09999	$0.06954	$0.00568	$0.17521
Tier 2 (> 330 kWh), $/kWh	$0.13873	$0.10225	$0.00568	$0.24666
Recommended Rate				
Tier 1 (up to ~~461~~ 450 kWh), $/kWh	$0.10270	$0.08642	$0.00549	$0.19461
Tier 2 (> ~~461~~ 450 kWh), $/kWh	$0.13240	$0.08079	$0.00549	$0.21868
Customer Charge, $/month				$4.64
COSA Rate Adjustment				**2.0%**

The above rates are based on the cost of service for each rate component. Table 5-5 summarizes the components for the recommended rate design.

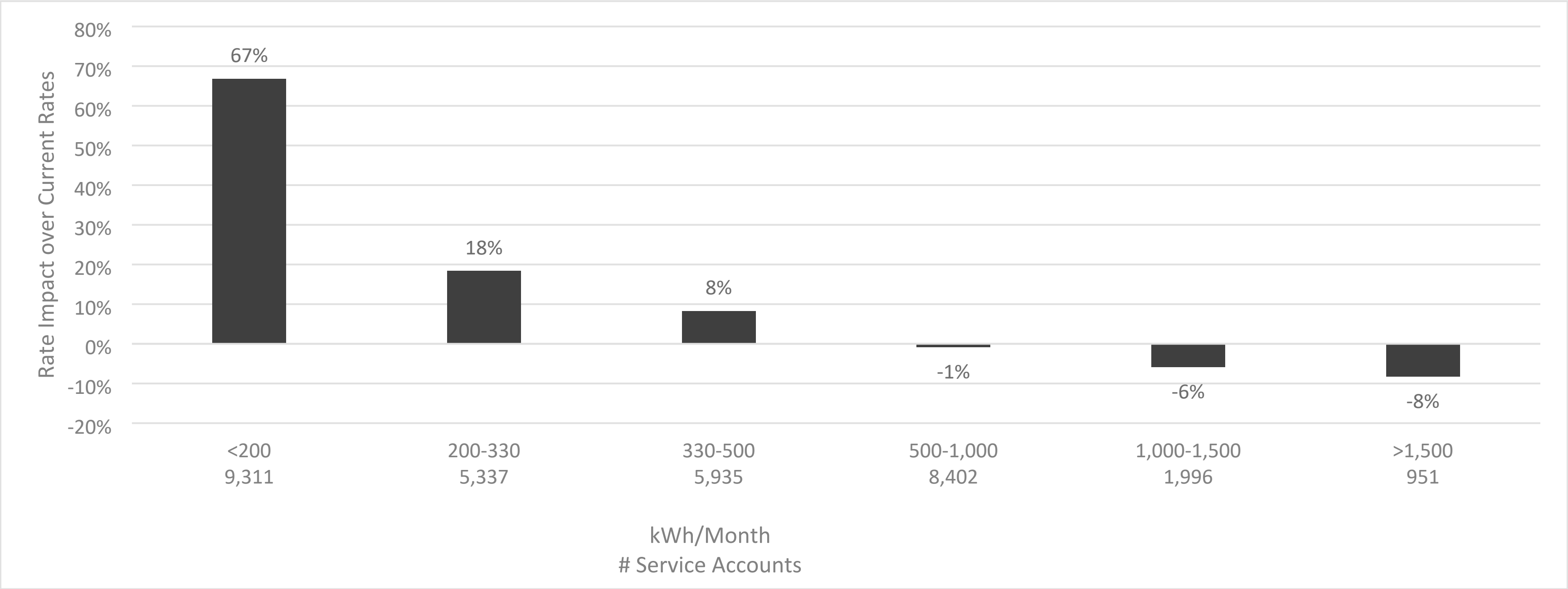
TABLE 5-5: COST BASIS FOR RECOMMENDED RATES

Rate Component	Cost-Basis	Reasoning
Commodity Tier 1	Average Energy Costs	Full cost recovery of energy-related power supply purchases
Commodity Tier 2	Average Energy Costs plus Local Capacity Costs	Higher-users contribute more to demand costs than customers in lower tiers. Customers in higher tiers use more energy in summer months which directly impact the utility's capacity costs
Distribution Tier 1	All Customer-Related Distribution Costs less Customer Charge Revenue plus Average demand-related distribution costs	Average demand-related costs are recovered even at lower usage levels.
Distribution Tier 2	Average and Excess Demand-Related Costs	Average demand-related costs plus Excess demand-related costs collected for usage over the Tier 1 kWh. Excess demand is related to higher usage levels.
Customer Charge	Recovers Fixed Customer Metering and Billing Costs	All customers should pay for their fixed costs independent of usage.

5.2.1 E-1 Bill Impacts

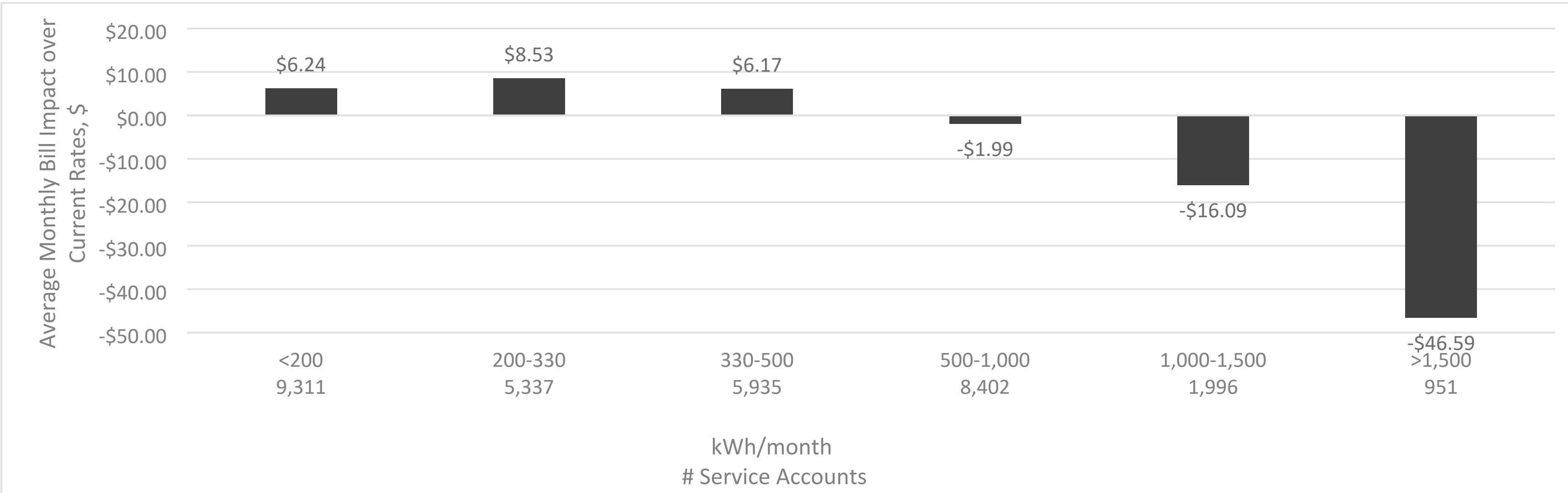
The figures below show impacts of the recommended rates. As expected, the customers in the lowest usage tier (<200 kWh/month) experience the greatest impact. Note that the bill impacts are calculated in reference to the current rate level and rate structure. The average customer using less than 200 kWh/month would experience a 67% bill increase.

FIGURE 5-1: BILL IMPACTS



While the monthly bills increase by a large percentage for the 200 kWh/month and less group, the actual dollar increase is smaller, averaging $6.24/month (Figure 5-4).

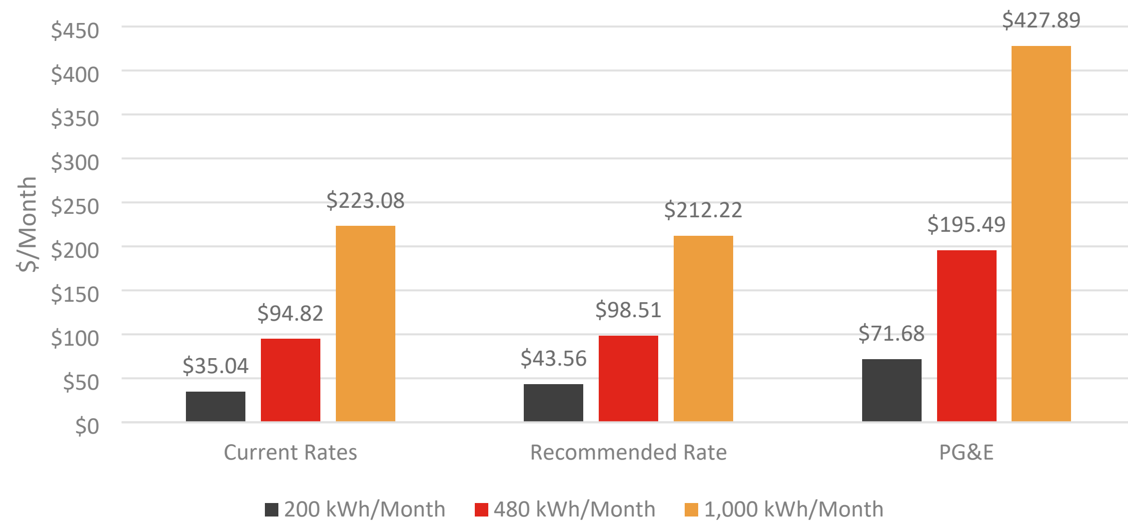
FIGURE 5-2: BILL IMPACTS, $/MONTH



5.2.2 Bill Comparison with PG&E

Figure 5-3 compares the current and recommended E-1 rates to PG&E current rates for a range of consumption levels: low, average, and high use. Regardless of usage, PG&E current rates are approximately twice the recommended rate level for Palo Alto E-1 rates.

FIGURE 5-3: E-1 BILL COMPARISON: PALO ALTO AND PG&E, AVERAGE BILL



Note that the PG&E baseline allowance for Tier 1 is 198 and 228 kWh/mo. (winter and summer respectively). PG&E current rates are 36 cents/kWh and 45 cents/kWh Tier 1 and Tier 2 respectively.

5.2.3 Rate Impacts for Low-Income E-1 (RAP)

One particular concern related to rate design change is the impact on low-income customers. This section presents bill impacts to customers currently participating in the City's Rate Assistance Program (RAP). The RAP program provides bill discounts of 25% to qualifying customers. Discounts are paid from the Public Benefits Charge (PBC) fund.[22] All customers pay into the PBC fund through the PBC charge, which is implemented via a variable rate (applied to kWh consumption).

As a group, participating RAP customers use less energy than non-RAP customers on average. Most RAP customers, (495 out of 817 or 61%), use 330 kWh or less per month and ~~78~~77% use less than 450~~61~~ kWh per month on average. As such, the inclusion of a minimum bill or monthly customer charge will disproportionately affect RAP customers. The charts below compare RAP bill impacts for current and recommended rates. Because these customers receive rate assistance, the bill impact (%) and the dollar per month impact are lower compared to the E-1 class as a whole (see previous figures).

[22] California Code, Public Utilities Code - PUC § 385

FIGURE 5-4: RAP CUSTOMER BILL IMPACTS

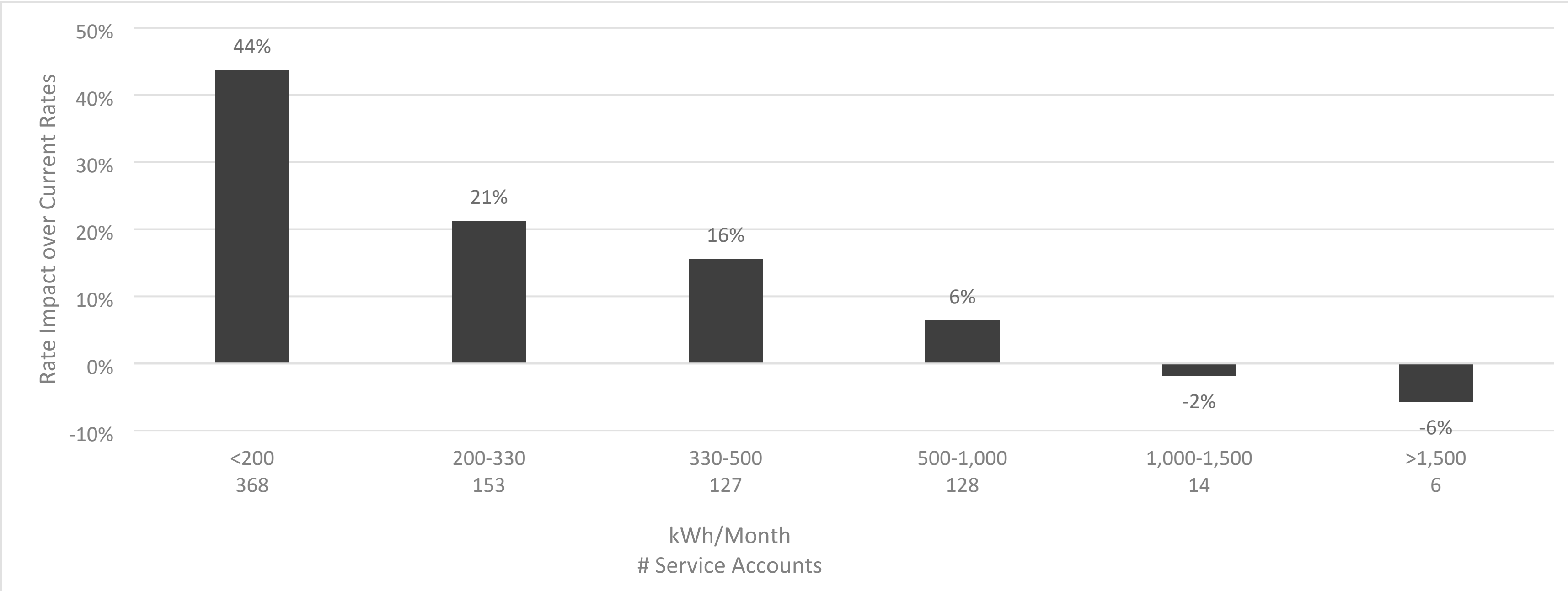


FIGURE 5-5: RAP CUSTOMER BILL IMPACTS, $/MONTH

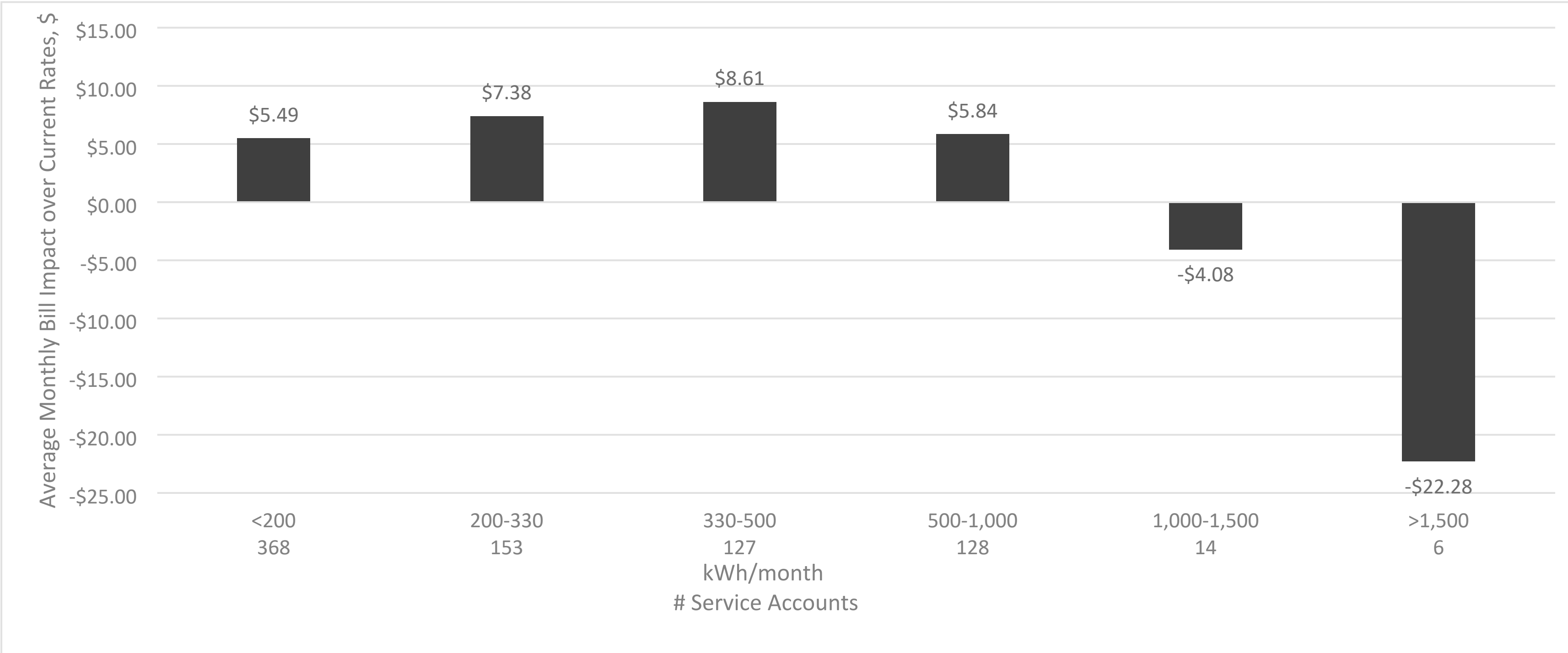


Table 5-6 below shows the average monthly bill increase and rate assistance needed to eliminate adverse bill impacts from the recommended rates. Also shown are the bill impact bookends: largest bill decrease and largest bill increase. For example, if the recommended tiered energy rate is implemented, it is estimated that the average monthly bill for a RAP customer is $6.06 higher compared with current rate levels and rate design. The customer with the largest bill decrease will see an average of $41.77 less on their monthly bills while the customer with the largest bill increase will see an increase of $11.18/month on average. If all RAP bill increases are mitigated with additional assistance, the City can expect to increase RAP funding by $58,000 per year. The City would fund this incremental increase to program spending with the PBC fund if necessary.

TABLE 5-6: LOW INCOME MONTHLY BILL IMPACT AND RATE ASSISTANCE NEED ESTIMATES

	Estimated Impacts
Average Bill Impact, $/month	$6.06
Largest Monthly Bill Decrease	-$41.77
Largest Monthly Bill Increase	$11.18
Estimated Rate Assistance Need	$58,000/year

5.3 SMALL COMMERCIAL E-2

The current E-2 rate is a seasonal rate with energy charges only. The seasonal Commodity component of the rate is based on actual seasonal Commodity costs. Distribution demand costs are split into summer and winter based on the average and excess method where summer receives a higher allocation consistent with higher summer peak demands. Distribution customer costs are shared equally across seasons. Table 5-7 shows the current and recommended rates.

TABLE 5-7: CURRENT AND RECOMMENDED E-2 RATES

	Commodity	Distribution	PBC	Total
Current Rates				
Summer, $/kWh	$0.14216	$0.11775	$0.00568	$0.26559
Winter, $/kWh	$0.10196	$0.07861	$0.00568	$0.18625
Recommended Rates				
Summer, $/kWh	$0.14926	$0.09735	$0.00549	$0.25210
Winter, $/kWh	$0.09242	$0.06623	$0.00549	$0.16414
Customer Charge, $/month				$5.60
COSA Rate Adjustment				-6.1%

Just as in the E-1 rate design, the recommended customer charge recovers customer billing and meter reading costs.

Figures 5-6 and 5-7 illustrate the monthly bill impact from a percent change perspective as well as dollar amount. While the lowest usage groups experience high bill impacts from a % change perspective, the dollar amount is less than $2 per month on average.

FIGURE 5-6: E-2 BILL IMPACTS

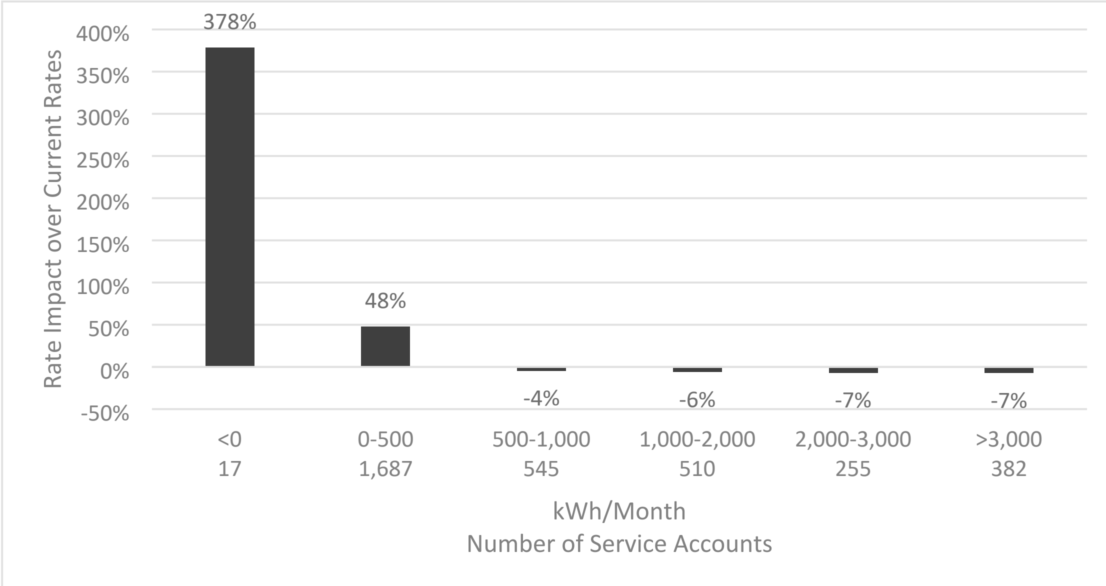
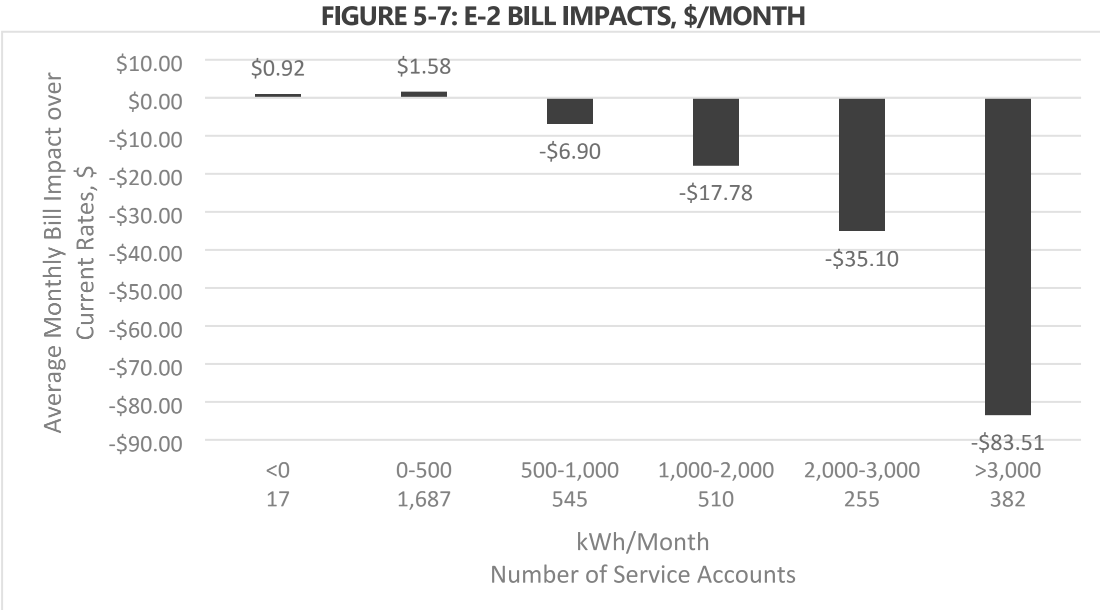


FIGURE 5-7: E-2 BILL IMPACTS, $/MONTH



5.4 MEDIUM COMMERCIAL E-4

The E-4 rate schedule, as shown in Table 5-8, is seasonal with a demand component. As mentioned previously, there is also an optional TOU option for E-4.

The default E-4 rate separates Commodity costs into summer and winter seasons based on actual seasonal costs. Local capacity costs (resource adequacy) are allocated to summer rates only. Other demand-related Commodity costs are allocated to both summer and winter based on kW. Distribution customer costs are the same across seasons. Billing and metering costs are collected through the customer charge. Distribution demand costs are allocated to each season based on average and excess where summer receives a larger allocation.

TABLE 5-8: CURRENT AND RECOMMENDED E-4 RATES

	Commodity	Distribution	PBC	Total
Current Rates				
Summer, $/kWh	$0.13157	$0.02638	$0.00568	$0.16363
Winter, $/kWh	$0.09461	$0.02638	$0.00568	$0.12667
Summer, $/kW-month	$5.28	$31.54		$36.82
Winter, $/kWh-month	$3.29	$20.87		$24.16
Recommended Rates				
Summer, $/kWh	$0.12318	$0.02520	$0.00549	$0.15387
Winter, $/kWh	$0.07949	$0.02520	$0.00549	$0.11018
Summer, $/kW-month	$10.98	$34.31		$45.29
Winter, $/kW-month	$2.57	$21.16		$23.73
Customer Charge, $/month				$113.73
COSA Rate Adjustment				**-1.9%**

Summer demand rates are increased significantly due to local capacity costs equaling a larger share of total power-related demand costs.

5.5 E-4 TOU

As solar has penetrated the market, daytime prices have become the lowest priced time to purchase energy. Table 5-9 compares the current and recommended TOU periods. The peak period is both the maximum priced energy period (for purchases of wholesale energy), and the City's system peak has occurred within this period in each month over the previous 3 years. Capacity requirements are set based on system peaks during this time period. The mid peak period represents mid-afternoon and or late evening periods when energy costs are lower. Off-peak periods represent all other hours and the lowest energy prices. All weekends and federal holidays are considered off-peak.

TABLE 5-9: PRESENT AND RECOMMENDED TOU PERIODS

Current TOU Periods			Recommended TOU Periods		
	Summer	Winter		Summer	Winter
Energy & Demand			**Energy**		
Peak	12 – 6 PM M-F	8 AM- 9 PM M-F	Peak	4-9 PM M-F	4-9 PM M-F
Mid-Peak	8 AM-12 PM, 6 PM- 9 PM M-F	None	Mid Peak	2-4 PM & 9-11 PM, M-F	9 AM-2 PM M-F
Off-Peak	9 PM- 8 AM M-F All Day Sat & Sun	All Other Hours	Off Peak	All Other Hours	All Other Hours
			Demand		
			Peak	4-9 PM M-F	4-9 PM M-F
			Max Peak	All Hours	All Hours

To illustrate why it is recommended to shift TOU periods, Table 5-10 compares the marginal cost of energy for the current and recommended TOU periods. These values are calculated by averaging hourly market prices over each period. These costs represent the value of energy if the City were to sell or purchase wholesale energy within these time periods. The recommended TOU periods maintain the current seasons where Summer is May 1- October 31. Table 5-10 shows that the current TOU periods do not have a pricing differential in winter months. Also, under the current structure, summer mid peak is the most expensive period.

TABLE 5-10: CURRENT AND RECOMMENDED TOU MARGINAL COSTS

	Marginal Cost, $/MWh
Current TOU Periods	
Summer Peak (noon -6 pm M-F)	$57.61
Summer Mid Peak (8 am - noon & 6 pm - 9 pm M-F	$73.81
Summer Off Peak (9pm - 8 am M-F, all day Sat & Sun)	$62.24
Winter Peak (8 am - 9 pm M-F)	$48.00
Winter Off Peak (all other times)	$48.00
Recommended TOU Periods	
Summer Peak (4-9 pm)	$81.29
Summer Mid Peak (2-4 pm and 9 am - 11 pm)	$66.99
Summer Off Peak (all other hours)	$50.36
Winter Peak (4-9 pm)	$63.51
Winter Mid Peak (9 am -2 pm)	$50.13
Winter Off Peak (all other hours)	$34.60

The recommended TOU rates adjust both the TOU periods and the demand billing methodology as shown in Table 5-11 below. The marginal costs from Table 5-10 (recommended TOU periods) are used to determine the commodity rate for each period.

The current method applies demand charges for each TOU period. This design choice will incentivize customers to reduce demand during both peak and mid peak periods. However, demand rates contain largely fixed costs. The recommended rate provides a simplification where customers are still able to reduce costs by shifting usage away from peak periods, and the City will collect a larger share of its fixed distribution costs with a non-TOU demand charge. Said another way, the peak demand charge recovers the associated commodity costs plus a share of distribution costs attributed to maximum demand in summer months. The non-TOU demand charge collects distribution demand costs for average demand consumption.

TABLE 5-11: CURRENT AND RECOMMENDED E-4 TOU RATES

	Commodity	Distribution	PBC	Total
Current Rates				
Summer Peak (noon -6 pm M-F)	$0.12020	$0.02636	$0.00568	$0.15224
Summer Mid Peak (8 am - noon & 6 pm - 9 pm M-F)	$0.15204	$0.02636	$0.00568	$0.18408
Summer Off Peak (9pm - 8 am M-F, all day Sat & Sun)	$0.09229	$0.02636	$0.00568	$0.12433
Winter Peak (8 am - 9 pm M-F)	$0.14744	$0.02636	$0.00568	$0.17948
Winter Off Peak (all other times)	$0.12619	$0.02636	$0.00568	$0.15823
Summer Peak Period Demand, $/kW-month	$3.22	$10.85		$14.07
Summer Mid Peak Period Demand, $/kW-month	$1.11	$10.85		$11.96
Summer Off Peak Demand, $/kW-month	$1.11	$10.85		$11.96
Winter Peak Period Demand, $/kW-month	$1.83	$11.63		$13.46
Winter Off-Peak Demand, $/kW-month	$1.83	$11.63		$13.46
Recommended Rates				
Customer Charge, $/month				$113.73
Summer Peak (4-9 pm)	$0.17038	$0.02538	$0.00549	$0.20125
Summer Mid Peak (2-4 pm and 9-11 pm)	$0.14041	$0.02538	$0.00549	$0.17128
Summer Off Peak (all other hours)	$0.10556	$0.02538	$0.00549	$0.13643
Winter Peak (4-9 pm)	$0.11976	$0.02500	$0.00549	$0.15025
Winter Mid Peak (9 am -2 pm)	$0.09452	$0.02500	$0.00549	$0.12501
Winter Off Peak (all other hours)	$0.06525	$0.02500	$0.00549	$0.09574
Summer Peak Period Demand, $/kW-month	$9.72	$17.18		$26.90
Summer Max Demand, $/kW-month	$1.29	$17.18		$18.47
Winter Peak Period Demand, $/kW-month	$1.30	$10.73		$12.03
Winter Max Demand, $/kW-month	$1.30	$10.73		$12.03

Since the majority of commodity-related demand costs are from local resource adequacy purchases (capacity), the commodity portion is low in winter months and off-peak summer periods. High summer peak period demand charges reflect the marginal costs for demand requirements during the most expensive periods. The local RA cost is based on the City's system peak demand, which occurs during the 4 pm to 9 pm peak period in the summer.

The TOU rate designs allocate costs seasonally using the same methodology as the underlying non-TOU rate designs, but they also take into account hourly variations in energy prices. Most generating capacity costs are allocated to the summer peak periods, since the City's system peak demand occurs during that time. Most of the City's resource adequacy (generating capacity) costs result from requirements imposed by the CAISO based on the City's annual system peak demand. Resource Adequacy costs are allocated to the peak periods based on the impact peak demand has on those costs.

5.6 LARGE COMMERCIAL E-7

The E-7 rate schedule is seasonal with a demand component, as shown in Table 5-12. The E-7 rate separates Commodity costs into summer and winter seasons based on actual seasonal costs. Local RA (capacity costs) are allocated to summer rates only. Other power-demand costs are allocated to both summer and winter based on kW. Billing and metering costs are recovered through the recommended customer charge. Other Distribution customer costs are the same across seasons. Distribution demand costs are allocated to each season based on average and excess where summer receives a larger allocation consistent with higher summer usage which drives distribution system costs. Note that distribution demand costs are spread more evenly across seasons due to flatter seasonal load profiles for E-7 customers.

TABLE 5-12: CURRENT AND RECOMMENDED E-7 RATES

	Commodity	Distribution	PBC	Total
Current Rates				
Summer, $/kWh	$0.13917	$0.00075	$0.00568	$0.14560
Winter, $/kWh	$0.09212	$0.00075	$0.00568	$0.09855
Summer, $/kW-month	$6.03	$33.05		$39.08
Winter, $/kWh-month	$3.46	$18.25		$21.71
Recommended Rates				
Summer, $/kWh	$0.12659	$0.00362	$0.00549	$0.13570
Winter, $/kWh	$0.07894	$0.00354	$0.00549	$0.08797
Summer, $/kW-month	$11.95	$28.41		$40.36
Winter, $/kW-month	$2.79	$25.00		$27.79
Customer Charge, $/month				$520.80
COSA Rate Adjustment				-1.4%

5.6.1 E-7 TOU

The recommended TOU rates adjust both the TOU periods and the demand billing methodology in the same manner as the recommended E-4 TOU rate.

TABLE 5-13: CURRENT AND RECOMMENDED E-7 TOU RATES

	Commodity	Distribution	PBC	Total
Current Rates				
Summer Peak (noon -6 pm M-F)	$0.14457	$0.00075	$0.00568	$0.15100
Summer Mid Peak (8 am - noon & 6 pm - 9 pm M-F)	$0.18205	$0.00075	$0.00568	$0.18848
Summer Off Peak (9pm - 8 am M-F, all day Sat & Sun)	$0.11171	$0.00075	$0.00568	$0.11814
Winter Peak (8 am - 9 pm M-F)	$0.09697	$0.00075	$0.00568	$0.10340
Winter Off Peak (all other times)	$0.08323	$0.00075	$0.00568	$0.08966
Summer Peak Period Demand, $/kW-month	$3.86	$11.08		$14.94
Summer Mid-Peak Period Demand, $/kW-month	$1.13	$11.08		$12.21
Summer Off-Peak Demand, $/kW-month	$1.13	$11.08		$12.21
Winter Peak Period Demand, $/kW-month	$1.78	$9.22		$11.00
Winter Off-Peak Demand, $/kW-month	$1.78	$9.22		$11.00
Recommended Rates				
Customer Charge, $/month				$520.80
Summer Peak (4-9 pm)	$0.18019	$0.00362	$0.00549	$0.18930
Summer Mid Peak (2-4 pm and 9-11 pm)	$0.14850	$0.00362	$0.00549	$0.15761
Summer Off Peak (all other hours)	$0.11164	$0.00362	$0.00549	$0.12075
Winter Peak (4-9 pm)	$0.12104	$0.00354	$0.00549	$0.13007
Winter Mid Peak (9 am -2 pm)	$0.09552	$0.00354	$0.00549	$0.10455
Winter Off Peak (all other hours)	$0.06594	$0.00354	$0.00549	$0.07497
Summer Peak Period Demand, $/kW-month	$11.28	$14.71		$25.99
Summer Max Demand, $/kW-month	$1.45	$14.71		$16.16
Winter Peak Period Demand, $/kW-month	$1.45	$12.99		$14.44
Winter Max Demand, $/kW-month	$1.45	$12.99		$14.44

The ratio of distribution demand costs collected through the Peak Period Demand charge to those collected through the Max Demand charge is determined based on load profile data. The Max Demand charge collects costs that were allocated based on the non-coincident peak (NCP) of the customer class. Just over half (52%) of all costs allocated under the recommended rate design are based on customer maximum peak (NCP). Therefore, 52% of demand-related distribution costs are collected through the Max Demand charge. The remaining 48% are collected through the Peak Demand charge. For summer demand charges these calculations coincidentally resulted in an identical distribution demand charge for both the Peak and Max Demand charge. Table 5-14 illustrates the demand billing determinants assuming the entire E-7 class is on the TOU schedule.

TABLE 5-14: TOU E-7 BILLED DEMAND ASSUMPTIONS

	Share of Total Billed Demand		Estimated Class Billing Determinant, kW	
	Summer	Winter	Summer	Winter
Peak Demand	48.2%	48.0%	283,362	280,165
Max Peak Demand (NCP)	51.8%	52.0%	304,237	303,152

5.7 STANDBY CHARGE

A standby rate is paid by customers who have on-site generation and where loads are partially served by the utility. Because the utility provides standby service for up to the full customer load, in the event of generation outages (planned or unplanned), the utility must have in place the infrastructure needed to serve the full (gross) customer load. Utility rate schedules are developed based on cost of service which include expected loads. Expected loads are net of expected on-site generation. As such, customers with on-site generation do not fully pay for the level of services provided when billed at the otherwise applicable rate. When this is the case, a standby rate is needed so that the utility can recover the cost to serve, which includes facilities that are sized for gross customer loads and local resource adequacy purchases. The recommended standby charges for E-4 and E-7 rates are based on the distribution demand charges plus a share of commodity demand charges.

TABLE 5-15: E-4 STANDBY CHARGES, $/KW-MO RESERVED CAPACITY

	Commodity	Distribution	Total $/kW-mo
E-4			
Summer	$8.41	$34.31	$42.72
Winter	$0.00	$21.16	$21.16
E-7			
Summer	$9.16	$28.41	$37.57
Winter	$0.00	$25.00	$25.00

5.8 PRIMARY VOLTAGE DISCOUNT

The cost -based rates recommended in this study apply to customers taking service at secondary voltage. These would apply to the majority of the City's customers. However, there are a few customers receiving service at primary voltage. This service level has a lower cost to serve because delivered energy is measured at the primary voltage level which avoids secondary voltage line losses. The City estimates that secondary voltage line losses are 2.85%. Meaning, the step-down from primary to secondary voltage results in a loss of 2.85% of usable energy. Customers who are primary metered should then receive a discount on rates paid. Because the discount applies to only energy and demand-related costs, the line loss percentage is adjusted based on the share of energy and demand-related costs compared with fixed costs (customer-related and direct assignments). This resulting discounts are calculated at 2.5% for E-4 and 2.8% for E-7.

~~5.7~~5.9 PUBLIC BENEFITS CHARGE

Public Utilities Code Section 385 requires all POUs to have a public benefits charge built into their rates. The rate must recover revenue equal to a set percentage of all other sales revenue based on a formula in that law. Most California POUs have interpreted this formula to require collection of an additional 2.85% of sales revenue for this purpose, as has the City. The revenue collected must be spent on a specified set of energy efficiency and other demand-side measures, including: 1) demand side-management services to promote efficiency and conservation, 2) new investment in renewable energy and technologies, 3) research and development programs for the public interest, and 4) services and discounts for low income electricity customers.

The public benefits charge is collected as a flat charge assessed on every kWh that results in the revenue level described above. The FY 2024-25 Public Benefits Charge is calculated at $0.00549/kWh.

~~5.8~~5.10 STREET LIGHTING AND TRAFFIC SIGNALS

The City's electric utility also provides lighting and traffic signal maintenance services, which are captured in the E-14 Street Lights schedule. These services are primarily provided to the City itself, but also to a few other governmental agencies. Table 5-~~17~~ 16 shows the updated lighting rates based on current rates adjusted by the 9.8% rate reduction. Maintenance Class A indicates that the City provides electricity and switching service only. Maintenance Class C indicates that the City supplies electricity, switching, and maintains the lighting system including lamps and glassware.

TABLE 5-~~17~~16: SCHEDULE E-14 RECOMMENDED RATES

Maintenance Class	Lamp Rating	Current Rate $/mo.	Recommended Rate $/mo.
A	HPS 100W	$6.21	$28.87
A	HPS 200W	$11.46	$53.29
A	HPS 250W	$14.08	$65.50
A	HPS 310W	$17.42	$81.05
A	HPS 400W	$22.43	$104.36
C	Mercury-Vapor 400W	$35.83	$43.84
C	HPS 70W	$32.97	$30.52
C	HPS 100W	$34.55	$37.84
C	HPS 150W	$37.17	$50.06
C	HPS 250W	$42.42	$74.48
C	LED 70W-EQ	$29.48	$14.31
C	LED 100W-EQ	$30.68	$19.86
C	LED 150W-EQ	$31.77	$24.96
C	LED 250W-EQ	$34.78	$38.95

6 Technical Appendix