PREPARED BY EES CONSULTING

City of Healdsburg

Electric Cost of Service Study
Draft Report

May 25, 2023

EES Consulting
a GDS Associates Company

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May 25, 2023

Mr. Terry Crowley
City of Healdsburg
401 Grove Street
Healdsburg, California 95448

SUBJECT: Cost of Service Analysis– Draft Report

Dear Mr. Crowley:

It is with pleasure that EES Consulting (EES), a GDS Associates Company, submits this Cost of Service Analysis Report for the City of Healdsburg electric utility (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

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Georgia ▪ Texas ▪ Alabama ▪ New Hampshire ▪ Wisconsin ▪ Florida ▪ Maine ▪ Washington ▪ California

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1 Executive Summary

The City of Healdsburg, (City) retained EES Consulting (EES) to update its most recent Cost of Service study as part of its ongoing efforts to maintain fiscally prudent and fair 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 revenue requirement, cost of service and rate design. This report details the revenue requirement and cost of service studies.

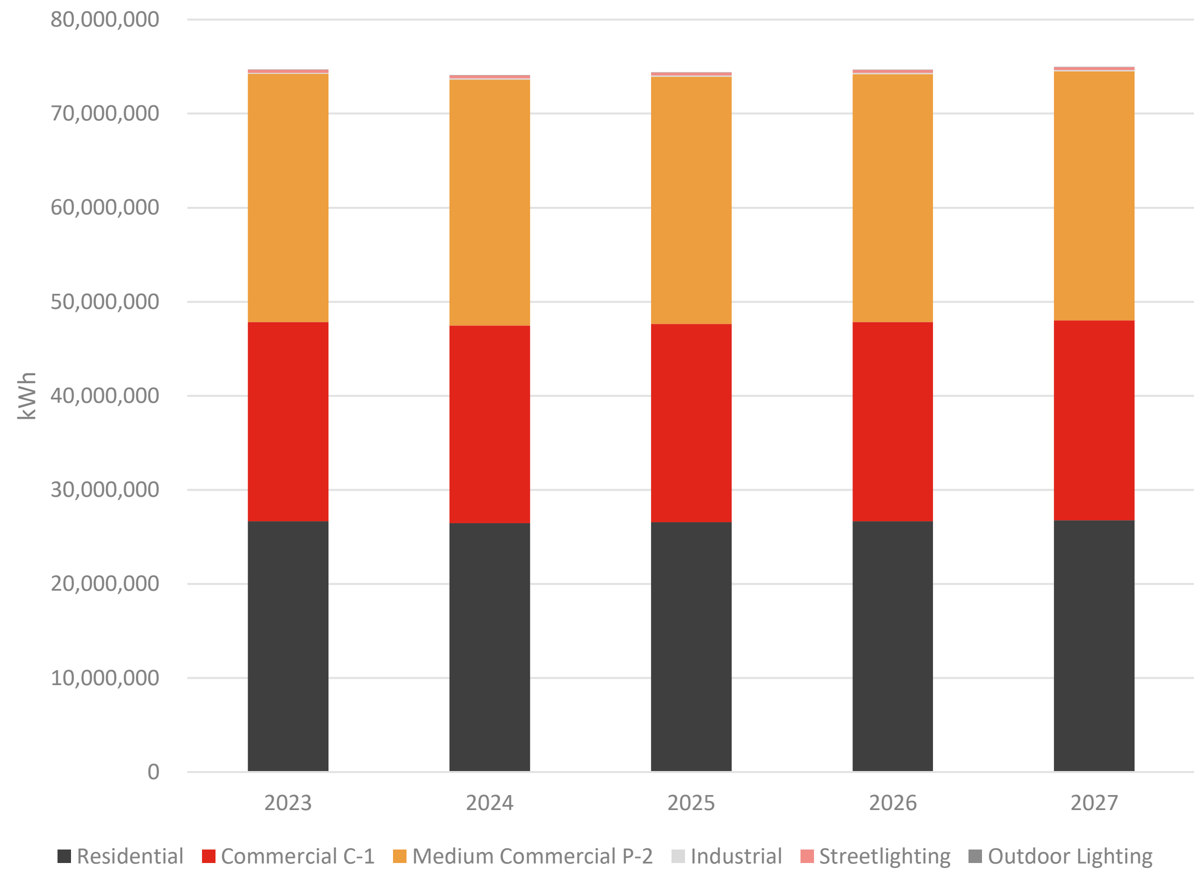
1.1 REVENUE REQUIREMENT

A revenue requirement analysis compares the overall revenues of the utility to its expenses and helps determine the overall adjustment to rate levels that is required. For this analysis, a "cash basis" method was used for determining the City's revenue requirement. Projected fiscal years (FY) 2023 and FY 2024 operating expenses used to determine the revenue requirement in the COSA were provided by the City.

A base case was defined to develop the COSA. This base case assumed the following:

- Historic year is FY 2022 (July 2021 – June 2022).
- Test year/allocation year is FY 2024.
- The customer classes included in the COSA are: Residential, Small Commercial (C-1), Large Commercial (P-2, E-19), Public Lighting (city owned), and Outdoor Lighting (OL).
- The FY 2022 loads, including monthly energy consumption, number of customers and demand, was provided by the City. The FY 2024 load forecast includes projected load growth of -0.8% for all customer classes in FY 2024 and then 0.4% annually for FY 2025 through FY 2027. Historic and projected loads for FY 2022-FY 2027 are shown below in Figure 1-1.

FIGURE 1-1: CITY OF HEALDSBURG ELECTRIC RETAIL SALES PROJECTIONS BY CUSTOMER CLASS



- Projected retail revenues for the forecast period were calculated based on projected loads and the City's current electric retail rates.
- Projected and historic non-power costs were provided by the City for FY 2022 through 2024. Expenses were escalated at 3% after 2024 unless specific cost categories were known to have differing rates of inflation (e.g. equipment, power, transmission costs, etc.).
- Projected power supply costs are based on a power supply cost forecast provided by NCPA for the period 2024 through 2027. On a dollar per megawatt-hour basis power supply costs (energy, transmission) are projected to range between \$105/MWh to \$116/MWh over the study period. Table 1-1 below shows the projected power supply costs included in the COSA.

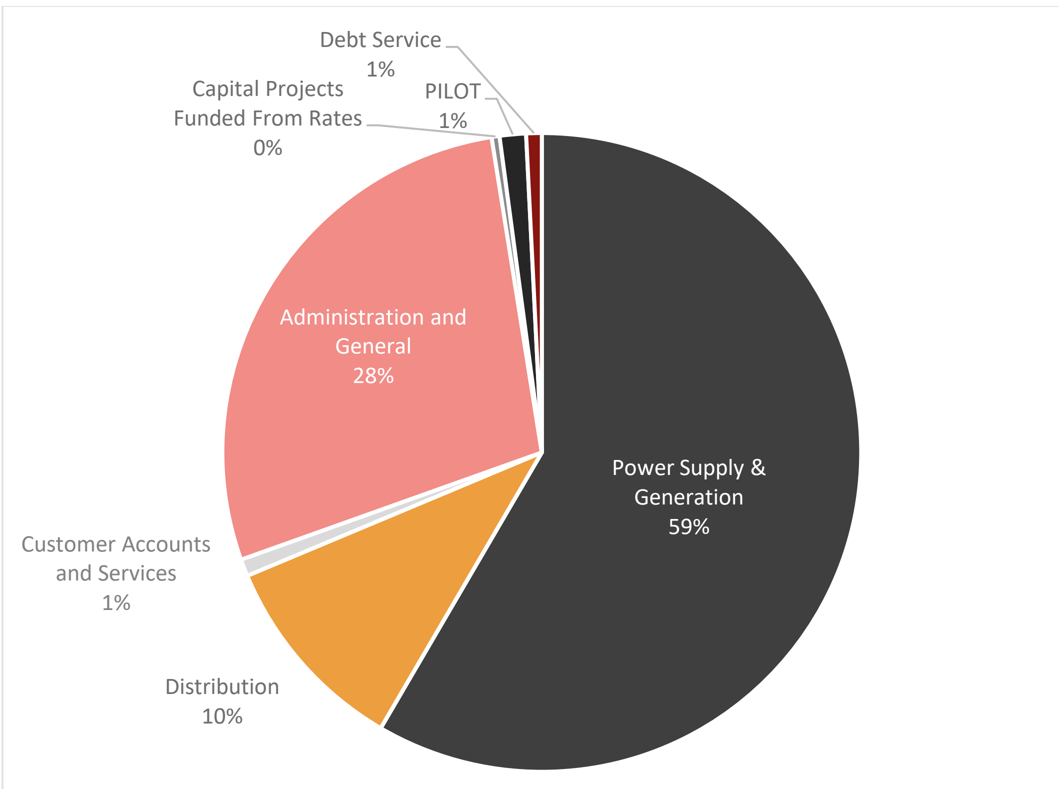
TABLE 1-1: PROJECTED POWER SUPPLY COSTS

	FY22	FY23	FY24	FY25	FY26	FY27
NCPA Plants	-$322,442	-$727,672	$2,548,379	$2,390,205	$2,377,303	$2,220,999
NCPA Western	-$70,534	$107,045	$344,155	$372,584	$388,312	$396,983
Market Power Purchases	$5,585,112	$6,952,867	$8,074,203	$7,175,224	$7,109,817	$6,457,119
Gas Power Generation	$0	$554,293	$2,826,159	$2,702,590	$2,842,289	$2,647,136
NCPA Transmission	$2,181,787	$2,459,790	$2,585,923	$2,634,581	$2,721,821	$2,832,103
Management Services	$367,357	$455,342	$425,511	$436,288	$445,489	$454,532
Solar Rebates	$56,703	$60,000	$60,000	$66,000	$71,280	$75,557
Power Sales Revenue	-$44,375	-$391,615	-$7,690,527	-$6,792,606	-$7,194,698	-$6,274,354
Total Purchased Power	**$7,753,609**	**$9,470,050**	**$9,173,804**	**$8,984,866**	**$8,761,614**	**$8,810,075**

Table 1: shows the actual FY2022 costs and forecasted costs for FY2023 through FY2027. Note that NCPA's forecast includes the net cost or revenue from NCPA generating resources optimized in the CAISO market.

As shown below, power supply costs are 54% of projected FY 2024 total expenses. Figure 1-2 below shows a breakdown of the projected $14 million in FY 2024 total expenses.

FIGURE 1-2: PROJECTED FY 2024 EXPENSES



Total FY 2023 revenues, including other revenue (non-retail rate revenue) of $0.2 million, are projected to be $12 million. An increase in retail rate revenue is required in FY 2024. Other revenues include miscellaneous service revenues, pole rental fees, dividends and interest, and line extension revenues.

A summary of the FY 2023- FY 2027 revenue requirements are shown below in Table 1-2.

TABLE 1-2: SUMMARY OF THE REVENUE REQUIREMENT

Fiscal Year:	2023	2024	2025	2026	2027
Planned Rate Adjustment		16.0%	14.0%	8.0%	7.0%
Rate Revenue with Rate Adjustment	$12,150,672	$13,995,172	$16,010,818	$17,352,755	$18,633,055
Other Revenue	$232,519	$238,519	$245,675	$253,045	$260,636
Total Revenue	**$12,383,191**	**$14,233,691**	**$16,256,493**	**$17,605,800**	**$18,893,691**
Purchased Power	$9,470,050	$9,173,804	$8,984,866	$8,761,614	$8,810,075
O&M plus A&G	$5,944,027	$6,101,875	$6,328,791	$6,108,426	$5,844,973
PILOT	$186,777	$191,447	$197,190	$203,106	$209,199
Principal & Interest Payment	$253,143	$122,918	$122,918	$122,918	$122,918
Capital Improvement Program from Rates	$35,000	$62,500	$1,410,000	$4,488,750	$900,000
Total Expenses	**$15,888,997**	**$15,652,544**	**$17,043,765**	**$19,684,814**	**$15,887,164**
Change in Working Capital	($3,505,806)	($1,418,853)	($787,272)	($2,079,014)	$3,006,527

Given the assumptions detailed above, the results show that, under current retail rates, the City is not collecting sufficient revenue to meet projected expenses in FY2023-FY2027. To balance the needed rate increases across the four-year period, the proposed rate adjustment utilizes approximately $4.2 million in reserves. It is estimated that by the end of FY 2027, $3 million of this amount will be transferred back to the reserve fund. By the end of the study period, the electric utility meets the 50% reserve requirement authorized by Resolution 112-2019.

1.2 COST OF SERVICE STUDY

A cost of service study is concerned with the equitable allocation of the revenue requirement to the various customer classes of service. As is standard procedure for cost of service analyses, the revenue requirement for the City was functionalized, classified and allocated.

A COSA can be performed using embedded costs or marginal costs. Embedded costs generally reflect the actual costs incurred by the utility and closely track the costs kept in its accounting records. Marginal costs reflect the cost associated with adding a new customer and are based on costs of facilities and services if incurred at the present time. This study uses an embedded COSA as its standard methodology.

Generally, there are two methodologies that can be used to classify distribution costs: 100 percent demand and minimum system. The 100 percent demand methodology assumes that the distribution system is built to meet the non-coincident peak. Therefore, distribution costs using this method are classified as 100 percent demand-related.

Specific distribution costs are sometimes split between demand and customer according to a minimum system approach. This approach reflects the philosophy that the system is in place in part because there are customers to serve throughout the service territory, and that a minimally sized distribution system is needed to serve these customers even if they only use 1 kilowatt-hour (kWh) of energy per year.

The concept follows that any costs associated with a system larger than this minimal size are due to the fact that customers "demand" a delivery quantity greater than the minimum unit of electricity and that therefore, those costs should be treated as demand-related.

Because the residential class tends to have a higher share of the number of customers compared to its share of non-coincident peaks, the minimum system methodology tends to allocate more costs to the residential customer class and customer charges tend to be higher than with the 100 percent demand methodology. Demand and customer allocation factors were derived for the minimum system case using data from other public utilities. The study assumes that 60% of the system is in place due to customer demand while 40% of the distribution system plant value is in place due to the need to serve the number of customers. Greater detailed plant asset data would be needed in order to develop a minimum system analysis specific to the City.

This analysis utilizes the minimum system approach for cost allocation. This methodology is typical for utilities in California reflecting a trend toward improving the recovery of fixed costs through monthly charges to gain financially prudent cost recovery across all customer types.

TABLE 1-3: SUMMARY OF COST OF SERVICE ANALYSIS FY 2024

	Present Rate Revenues	Net Revenue Requirement	Surplus/(Deficiency) in Present Rates	Rate Increase (Decrease)
Residential D-1, D-4 & E-7	$4,867,033	$5,195,574	($328,541)	7%
Small Commercial, C-1 & A-6	$3,512,553	$3,946,937	($434,384)	12%
Large Commercial P-2, E-19	$3,630,294	$4,673,709	($1,043,415)	29%
Outdoor Lighting	$54,923	$176,857	($121,934)	222%
TOTAL	$12,064,804	$13,993,077	($1,928,274)	16%

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TOTAL	$12,064,804	$13,993,077	($1,928,274)	16%

The City pays for all City Facility electric usage based on current established rates. The City currently funds street and area lighting through electric retail revenue. This study includes the cost of repair and replacement in the Outdoor Lighting class and assumes city owned and maintained street and area lighting will be paid for by the City at the same rate as outdoor lighting charged to customers. The revenue requirement for this class is estimated at $176,857 in fiscal year 2024.

When examining the results shown above in Tables 1-3, it is important to note that the inter-class cost allocations are based on load data estimates and usage pattern assumptions. Therefore, utilities often elect not to make rate modifications when deviations are within 10 percent.

1.3 RECOMMENDATIONS

Based on the projected revenue requirement and COSA analysis, the following recommendations are made:

- Using current rates, the City is not collecting sufficient revenues compared to the projected FY 2024 revenue requirement and, as such, an increase in total retail revenue is required.
- This study developed a rate adjustment plan over a 4-year forecast period. During this time, rates are adjusted so that the City can mitigate impacts through use of reserves as well as recover the reserves by the end of the planning period
- Use the minimum system methodology for distribution system cost allocation to improve recovery of fixed costs
- Several customer classes are outside of the +/- 10% band from their cost of service. It is recommended that the rate adjustment by class gradually move each customer class to within 10% of its cost of service.
- This study shows that fixed monthly costs should be increased slowly over time so that the electric utility is able to recover fixed costs while mitigating potential cost shifts of low users.

2 Overview of Rate Setting Principles

EES was retained by the City of Healdsburg to perform a comprehensive electric cost of service and rate study. Performing an electric rate study is necessary to assure that the City's electric rates continue to recover the cost of operations, fund planned capital projects, and are structured to be fair, equitable and competitive.

In conducting this study, three inter-related analyses were performed. The first analysis performed was a revenue requirement analysis. This analysis examines the various sources and applications of funds for the utility and determines the overall revenue (retail rate) adjustment required of the utility. The next analysis developed is a cost of service analysis. The cost of service analysis is used to determine the fair and equitable allocation of the total revenue requirement to the various customer classes of service. The cost of service results in unit costs that will assist with a rate design analysis.

2.1 OVERVIEW AND ORGANIZATION OF REPORT

In developing electric rates for the City, a major goal of the study is to develop cost-based rates that meet the City's electric utility revenue requirement. It is important to understand that revenue requirement consists of both operational expenses and capital costs. Failure to collect the full revenue requirement may lead to a system that is more expensive to operate in the long run, and more susceptible to periodic outages and failures.

This report is organized such that it follows the steps taken in analyzing and developing the City's electric utility cost of service. Contained in this 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's electric utility. The next section discusses the cost of service study and the results of that process.

The setting of electric utility rates that are "fair and equitable" is a complex process. This process is directed, however, by "generally accepted methodologies" that can be used as a guide in developing the City's electric rates. At the same time, there are often a number of financial principles or guidelines that must be taken into consideration during this process. Therefore, the setting of electric rates that are "fair and equitable" is an integration of these generally accepted methodologies and any related financial policies or specific considerations from the City.

The purpose of this section of the report is to provide a brief overview of the basic 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 review of the City's electric utility allocated costs.

2.2 OVERVIEW OF THE ANALYSES

As discussed previously, there are a number of "generally accepted methodologies" for allocating costs for ratemaking purposes. However, all of these methodologies share the same basic framework. That is, in allocating electric costs two separate yet interrelated analyses are generally performed. It is within these two separate analyses that different methodologies exist. The two analyses contained within the basic framework for allocating electric costs are revenue requirement analysis and cost of service analysis.

The revenue requirement analysis reviews the various sources of funds and applications of funds for the utility.

Within the next step of the study, the cost of service analysis takes the results of the revenue requirement analysis and attempts to equitably allocate those costs to the various customer classes of service (e.g., residential, commercial, etc.). This analysis provides a determination of the level of revenue responsibility of each class of service and the adjustments required to meet the cost of service.

2.3 TYPES OF UTILITIES

As noted above, there are different methodologies that exist for setting electric rates. The first distinction often made in developing a methodology is the type of utility that is attempting to set the rates. Utilities are generally divided into two types by ownership—public and private utilities.

Public utilities are generally owned by a municipality, cooperative, county or special district, and are operated on a not-for-profit basis. Public utilities are generally capitalized by issuing debt and soliciting funds from customers through direct capital contributions or user rates. Through statute and/or the lack of profit motive, public utilities do not pay state and federal income taxes. Finally, a public utility is usually regulated by a publicly elected or appointed City Council, Board of Commissioners or Board of Trustees. As a point of reference, the City is a municipal utility regulated by the City Council.

In contrast, private electric utilities are capitalized by issuing debt or equity (stock) to the general public. The owners of the private utility are its equity contributors, or shareholders. Private utilities are taxable entities, and finally, they are generally regulated by state public utility commissions. PG&E is an example of a private electric utility.

These differences in ownership and other characteristics often lead to two different methods for reviewing revenue requirement needs. A more detailed discussion of the different methodologies that may be used is provided below.

2.4 OVERVIEW OF REVENUE REQUIREMENT METHODOLOGIES

By virtue of differences noted above for public versus private utilities, revenue requirements are based upon different elements or methodologies. Most private utilities use what is known as a "utility" or "accrual" basis of determining revenue requirement or setting rate levels. This convention calculates a utility's annual revenue requirement by aggregating a period's operation and maintenance (O&M) expenses, taxes, depreciation expense and a "fair" return on investment. Operating expenses include the labor, materials, supplies, etc., that are needed to keep the utility functioning. Private utilities must also pay state and federal income taxes, along with any applicable property, franchise, sales or other forms of taxes. Next, depreciation expense is a means of recouping the cost of capital facilities over the useful lives of those facilities as well as generating internal cash. Finally, a return on the capital invested pays for the utility's interest expense on indebtedness, provides funds for a return to the utility's equity holders in the form of dividends and leaves a balance for retained earnings and cash flow purposes.

In contrast to the "utility" or "accrual" method of developing revenue requirement for private utilities, a different method of determining annual revenue requirement is often used for public utilities. The convention used by most public utilities is called the "cash basis" of cost accounting. As the name implies, a public utility aggregates its cash expenditures to determine its total revenue requirement for a specified period of time. This methodology conforms nicely to most public utility budgetary processes and is a very straightforward and easily understood calculation.

Under the "cash basis" approach, there are four component costs. They are operation and maintenance expenses, taxes, debt service, and capital improvements funded from rates. The operating portion of the revenue requirement, i.e., O&M and taxes, are similar under either methodology. The major difference between the two methodologies is the way in which capital costs are viewed and handled. Capital costs under the cash basis approach are calculated by adding debt service to capital improvements financed with rate revenues. A utility's depreciation expense is often used as a measure of the reasonable level of funding required from rates for capital improvement activities. Depreciation expense represents the current investment of the utility and that portion that has become worn out or obsolete and must be renewed or replaced. It should further be noted that the two portions of the capital expense component (principal and interest) are necessary under the cash basis approach because utilities often cannot finance all capital facilities with long-term debt.

Table 2-1 compares the cash and utility accounting conventions.

TABLE 2-1: CASH VS. UTILITY BASIS COMPARISON

	Cash Basis		Utility (Accrual) Basis
+	O&M Expense	+	O&M Expense
+	Taxes or Payment in Lieu of Taxes	+	Taxes
+	Capital Improvements Financed with Operating Revenues (Depreciation Expense)	+	Depreciation Expense
+	Debt Service (Principal & Interest)	+	Interest Expense
		+	Margin
Σ =	**Revenue Requirement**	Σ =	**Revenue Requirement**

For this study, a cash basis was used to determine the utility's revenue requirement.

2.5 OVERVIEW OF COST ALLOCATION PROCEDURES

After the total revenue requirement has been determined, it is allocated to the various customer classes of service based upon a fair and equitable methodology that reflects the cost-causal relationships for the production and delivery of the services. This analytical exercise usually takes the form of a "cost-of-service" study. A cost of service study begins by "functionalizing" a utility's revenue requirement as power supply, transmission, distribution and customer. Next, the functionalized costs are "classified" to demand-, energy- and customer-related component costs. Demand-related costs are those that the utility incurs to meet a customer's maximum instantaneous usage requirement and is usually measured in kilowatts (kW). Energy-related costs are those that vary directly with longer periods of consumption and are usually measured in kWh. Customer-related costs are those that vary with the number and type of customers served. These three component costs are then "allocated" to each class of service based upon the most equitable method available for each specific cost. At that point, the revenue requirement has been allocated to each class of service and a determination of the necessary revenue adjustments between classes of service can be made.

3 Development of the Revenue Requirement

This section of the report presents the development of the electric revenue requirement for the City's electric utility. 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 OF HEALDSBURG ELECTRIC UTILITY REVENUE REQUIREMENT METHODOLOGY

In developing the revenue requirement, a number of decisions must be made regarding the basic methodology to be used. As discussed in the previous section of the report, the first decision the City's electric utility must make is the method of accumulating costs. The City utilized the "cash basis" approach for determining revenue requirement. In summary form, components to 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 & Service Expense
		✓ Administrative and General Expense
	+	Debt Service Costs (Principal + Interest)
	+	Rate Funded Capital
	+	PILOT
	=	Total Revenue Requirement
	–	Other Revenue Sources
Σ	=	**Net Revenues Required from Rates**

From this basic analytical framework, the next step in determining the revenue requirement methodology is to select a time period over which to review revenue and expenses. In the case of the City of Healdsburg, a fiscal year test period was utilized (July through June). FY 2022 was chosen as the test period for the cost of service study. The City provided projected FY 2023-2024 costs. Revenues from retail rates and purchased power costs were forecast based on forecast FY 2024 customer usage.

3.2 DEVELOPMENT OF THE PROJECTED LOAD FORECAST AND FORECAST REVENUES

The FY 2024 load forecast, including monthly energy consumption, number of customers and billed demand, was provided by the City. The FY 2024 load forecast includes projected load growth of 0.4% for all classes compared with FY 2023 projections. While Healdsburg continues to develop, new solar projects and efficiency programs reduce or eliminate increases in overall kilowatt-hour sales.

The load forecast is a key component of a cost of service study as it is used to allocate costs to the customer classes and provides the units of consumption used to design final rates. Line losses were calculated using total FY 2022 system purchases and total FY 2022 customer sales. For FY 2022, line losses on the secondary system were assumed to be 2% while line losses on the primary system were assumed to be 3%. For non-demand metered classes, load factors and coincident factors were determined using PG&E load profile data for each customer class.

Forecasted retail revenues were calculated for FY 2024 and beyond using current retail rate schedules and forecast loads.

3.3 DEVELOPMENT OF POWER SUPPLY COSTS

The City purchases wholesale power as a member of NCPA. Projected power and transmission costs were provided by NCPA through FY 2027. As with most electric utilities, power supply is the City's electric utility's largest operating expense. Approximately $9.2 million, or 54 percent of the FY 2024 total revenue requirement are power supply and transmission costs as shown in Table 3-2.

TABLE 3-2: PROJECTED POWER SUPPLY COSTS

	FY22	FY23	FY24	FY25	FY26	FY27
NCPA Plants	-$322,442	-$727,672	$2,548,379	$2,390,205	$2,377,303	$2,220,999
NCPA Western	-$70,534	$107,045	$344,155	$372,584	$388,312	$396,983
Market Power Purchases	$5,585,112	$6,952,867	$8,074,203	$7,175,224	$7,109,817	$6,457,119
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Power Sales Revenue	-$44,375	-$391,615	-$7,690,527	-$6,792,606	-$7,194,698	-$6,274,354
Total Purchased Power	**$7,753,609**	**$9,470,050**	**$9,173,804**	**$8,984,866**	**$8,761,614**	**$8,810,075**

3.4 OTHER OPERATIONS AND MAINTENANCE EXPENSES

Projected FY 2023-2024 expenses were provided by the City based on approved budgets and forecasts. Projected operating costs were provided for distribution, customer service and accounting and administrative and general expenses categories. Table 3-3 shows the forecast for non-power operation and maintenance expenses (O&M). Overall, these expenses are forecast to remain fairly stable over the study period.

TABLE 3-3: PROJECTED NON-POWER O&M (MILLIONS)

	FY23	FY24	FY25	FY26	FY27
Distribution	$1,519,763	$1,604,222	$1,677,446	$1,298,029	$869,971
Customer Accounts and Services	$129,763	$134,586	$139,910	$145,446	$151,201
Administration and General	$4,294,501	$4,363,067	$4,511,434	$4,664,951	$4,823,801
Total	**$5,944,027**	**$6,101,875**	**$6,328,791**	**$6,108,426**	**$5,844,973**

3.5 PAYMENT IN LIUE OF TAXES

FY 2024 PILOT, approved under Council resolution 72-1982 and exempt from Proposition 26, is projected at $191,447 based on 1% of the net plant value attributed to the electric utility (including general plant).

3.6 INTEREST AND DEBT SERVICE

Total interest and debt service expenses are projected at $122,918 in each of the forecast years.

3.7 RATE FUNDED CAPITAL EXPENSES

The City provided the CIP plan for the next 5 years. The CIP includes only distribution system projects including undergrounding projects and routine repair and replacement expense. Table 3-4 shows the portion of CIP funded directly through rates. The rate adjustment plan smooths out these capital expenses through the use of reserves, especially in FY 2026 where capital projects are nearly $5 million.

TABLE 3-4: RATE FUNDED CAPITAL PROJECTS

	FY23	FY24	FY25	FY26	FY27
Distribution CIP	$35,000	$62,500	$1,410,000	$4,488,750	$900,000

3.8 OTHER REVENUES

Other revenues include customer contributions, miscellaneous service revenue, dividends and interest, line extension revenue, and utility pole attachment fees. Projected other revenues are provided in Table 3-5 below.

TABLE 3-5: PROJECTED OTHER REVENUES

	FY23	FY24	FY25	FY26	FY27
Pole Attachment Fees	$84,000	$90,000	$92,700	$95,481	$98,345
Misc. Revenue	$148,519	$148,519	$152,975	$157,564	$162,291
Total Other Revenues	**$232,519**	**$238,519**	**$245,675**	**$253,045**	**$260,636**

3.9 OTHER CONTRIBUTIONS

Finally, reserve fund transfers and contributions are based on the fund use needed to meet the rate adjustment plan.

TABLE 3-6: CONTRIBUTIONS

	FY23	FY24	FY25	FY26	FY27
Rate Reserve Fund (Transfers from) or Contributions	($3,505,806)	($1,418,853)	($787,272)	($2,079,014)	$3,006,527

3.10 SUMMARY OF REVENUE REQUIREMENT

Once all of the components of the cash basis revenue requirement have been forecast, the parts can be summed to equal the total revenue requirement. Since the City uses a "cash basis" approach for rate setting, the basic revenue requirement is presented in that format. A summary of the City's electric utility revenue requirement for the forecast period is summarized below in Table 3-7.

TABLE 3-7: SUMMARY OF THE FORECAST REVENUE REQUIREMENT

Fiscal Year:	2023	2024	2025	2026	2027
Planned Rate Adjustment		16.0%	14.0%	8.0%	7.0%
Rate Revenue with Rate Adjustment	$12,150,672	$13,995,172	$16,010,818	$17,352,755	$18,633,055
Other Revenue	$232,519	$238,519	$245,675	$253,045	$260,636
Total Revenue	**$12,383,191**	**$14,233,691**	**$16,256,493**	**$17,605,800**	**$18,893,691**
Purchased Power	$9,470,050	$9,173,804	$8,984,866	$8,761,614	$8,810,075
O&M plus A&G	$5,944,027	$6,101,875	$6,328,791	$6,108,426	$5,844,973
PILOT	$186,777	$191,447	$197,190	$203,106	$209,199
Principal & Interest Payment	$253,143	$122,918	$122,918	$122,918	$122,918
Capital Improvement Program from Rates	$35,000	$62,500	$1,410,000	$4,488,750	$900,000
Total Expenses	**$15,888,997**	**$15,652,544**	**$17,043,765**	**$19,684,814**	**$15,887,164**
Change in Working Capital	($3,505,806)	($1,418,853)	($787,272)	($2,079,014)	$3,006,527

Table 3-7 shows that, based on the assumptions detailed above and current retail rates, the City's electric utility is not collecting sufficient revenue to meet projected expenses. The annual rate increases shown in Table 3-7 are recommended.

3.11 RECOMMENDATION

The City's electric utility projected revenues are not sufficient to cover its projected revenue requirement in FY 2023-FY 2027. Table 3-7 shows that a significant rate increase is needed beginning in FY 2024 with additional adjustments through FY 2027. Both short- and long-term supply and operating cost considerations need to be evaluated and analyzed as the City Council works with the electric utility's management to reach its operating objectives.

4 Cost of Service Analysis

The objective of the COSA is to analyze costs and equitably assign those costs to customers commensurate with the cost of serving those customers. The founding principal of cost allocation is the concept of cost-causation. Cost-causation evaluates which customer or group of customers causes the utility to incur certain costs by linking system facility investments and operating costs to serve certain facilities to the services used by different customers. This section of the report will discuss the general approach used to apportion the utility's cost of service and provide a summary of the results.

4.1 COSA DEFINITION AND GENERAL PRINCIPLES

A COSA study allocates the costs of providing utility service to the various customer classes served by the utility based upon the cost-causal relationship associated with specific expense items. This approach is taken to develop a fair and equitable designation of costs to each customer class, where customers pay for the costs that they incur. Because the majority of costs are not incurred by any one type of customer, the COSA becomes an exercise in spreading 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 service rates. The first step is the development of the test period revenue requirement for the utility, which is the starting input for the COSA. The COSA then spreads the revenue requirement across the various customer classes, creating per unit costs by class. In the third step, rates are designed for each customer class, with per unit costs being one consideration in setting the appropriate rate levels.

A COSA study can be performed using embedded costs or marginal costs. Embedded costs generally reflect the actual costs incurred by the utility and closely track the costs kept in its accounting records. Marginal costs reflect the cost associated with adding a new customer and are based on costs of facilities and services if incurred at the present time. While marginal costs can be valuable for designing rates in certain instances, marginal costs are generally higher than embedded costs. Therefore, the use of a marginal COSA study usually requires that all costs be scaled back to a level equal to the embedded cost revenue requirement established using actual or projected costs from an "accounting" perspective.

This study uses an embedded COSA as its standard methodology. Therefore, the City's electric utility embedded cost revenue requirement and existing rate base investment are used in developing the COSA results.

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

- Functionalization
- Classification
- Allocation

Functionalization separates costs into major categories that reflect the utility's plant investment and different services provided to customers. The primary functional categories are production, transmission, distribution and general.

Classification determines the portion of the cost that is related to specific cost-causal factors, such as those that are demand-related, energy-related or customer-related. Production costs are related to supplying and transporting power to customers on the system. Transmission costs are related to the bulk transfer of power throughout the system, which is designed to meet the peak demand requirement. The distribution system is designed to extend service to all customers attached to the system and to meet the peak load capacity requirement of each customer. Additionally, costs can be classified based on system revenues or directly assigned to a customer or group of customers.

Allocation of costs to specific customer classes is based on the customer's contribution to the specific classifier selected. For instance, demand-related costs are allocated to a customer group using that customer group's contribution to the particular measurement of system demand, whether coincident peak, non-coincident peak or some variation determined to be appropriate for the particular cost item. An analysis of customer requirement, loads and usage characteristics is completed to develop allocation factors reflecting each of the classifiers employed within the COSA. The analysis may include an evaluation of the system design and operations, its accounting and physical asset records, customer load data and special studies.

4.2 GENERAL RATEMAKING PRINCIPLES

While this section does not address the design of rates, it is important to note that the COSA results will be one of the considerations when the process of designing rates for various customer classes begins. The basic goals of rate design include:

- The utility has an ability to collect the appropriate revenue requirement
- Utility revenues and customer rates are stable and predictable
- Proper price signals are sent to create efficiency of resources
- Rates are fair and equitable among customers and avoid undue discrimination
- Rates are simple, easy to understand and feasible for the utility to implement

The COSA is generally used to assist in meeting the second and fourth goals of rate design. Price signals are best if they reflect the specific costs incurred. Rates are generally considered fair and equitable if customers are deemed to pay their share of the costs incurred by the utility. Additionally, the first goal is met as long as the COSA is based on the appropriate revenue requirement, and the use of a consistent COSA methodology contributes towards the second goal. Rates are more stable through time if the COSA methodology is not significantly changed every time a rate application is made.

4.3 FUNCTIONALIZATION OF COSTS

The first step in the COSA process following finalization of the revenue requirement is to functionalize the revenue requirement. Functionalization is the separation of cost data into the functional activities performed in the operation of a utility system (i.e., power supply, transmission, distribution and customer service). Functionalization was accomplished using the City's system of accounts, which largely segregates costs in this manner.

In addition to the functionalized costs, certain joint costs are spread to each functional category based on the relationship of the joint cost to the business function. These joint costs include such items as administrative and general costs.

4.3.1 Standard Functionalization

Plant investment costs or rate base are generally functionalized into production, transmission, distribution and general cost categories. The functionalization of rate base typically is very straightforward as costs for the different functions are readily identifiable and rate base accounts are maintained by functional categories.

Expense accounts are also typically kept according to these basic functional categories, with expense items associated with certain types of plant being treated in the same manner as the corresponding plant account.

The two areas where there generally are differences in functionalization among utilities are in the treatment of general plant and A&G expenses. Typically, general plant is considered a separate functional category. Some utilities, when their internal accounting systems can support such an assignment process, will record general plant investment by loading the costs into the other functional categories, much like an overhead assignment or a form of activity-based accounting.

On the expense side, A&G costs can be treated in much the same way. Generally, they are treated as a separate expense category that can be spread to functions based upon all other O&M expenses. However, they can also be spread to functions on the basis of total net plant, labor ratios or, in some cases, directly assigned as part of the activity-based accounting approach.

4.3.2 City of Healdsburg Functionalization Method

The specific functions used for the City's electric COSA are defined below. The functions generally follow standard cost of service approaches.

- ***Production/Power Supply.*** The power supply function category includes all power-related services that are obtained by the utility through generation/production and direct purchase. The purchase activity represents a form of supply acquisition activity.
- ***Transmission*****.** The transmission services that the utility must acquire to deliver the purchased power supply to the service area are included in purchased power costs. The costs associated with the distribution system's transmission service include only those costs for operating and maintaining the transmission lines, poles, towers, substations, etc., used to deliver power to the distribution network.
- ***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.
- ***Customer*****.** Customer-related services include all services related to the presence of customers on the system, not to customer usage. These services include meter reading, billing, collections, advertising, etc.

4.4 CLASSIFICATION OF COSTS

The second step in performing a cost of service study is to classify the functionalized expenses to traditional cost causation categories. These cost causation categories can be directly related to specific consumption behavior or system configuration measurements such as coincident peak (CP) or non-coincident peak (NCP) demand, energy or number of customers. Each classification category will have a specific allocator that, when applied, will distribute those costs among the appropriate customer classes during the allocation phase of the analysis.

Functionalized power purchases, generation and transmission system costs are classified as demand-related and/or energy-related and in some instances directly assigned, while distribution costs are classified as demand- or customer-related, or directly assigned to specific customer classes of service.

4.4.1 Standard Classification

The three most general classification categories are demand-related, energy/commodity-related and customer-related. Within these three categories there are multiple ways of defining each option as well as varying ways to split costs between two or more classifiers. For example, demand- and energy-related costs can be separated by seasonal distinctions as well as to reflect peak/off peak consumption periods. Customer-related costs could be separated by demand and customer categories, while customer categories can distinguish between actual customer and weighted customer characteristics. Other classifiers sometimes used in the process include revenue-related and direct assignment. In addition, there are many instances where costs are not specifically classified to a particular category but rather in the same manner as an individual cost account or subtotal of specific cost accounts.

Generally, power production and purchased power costs are classified by a combination of demand and energy. Transmission costs are generally classified as peak demand, while distribution costs are generally split between demand and customer.

There are two methodologies that can be used to classify distribution costs: 100% demand and minimum system. The 100% demand methodology assumes that the distribution system is built to meet the non-coincident peak. Therefore, distribution costs are classified as 100% demand-related. Specific distribution costs are sometimes split between demand and customer according to a minimum system approach. This approach reflects the philosophy that the system is in place in part because there are customers to serve throughout the service territory expanse, and that a minimally sized distribution system is needed to serve these customers even if they only use 1 kWh of energy per year. The concept follows that any costs associated with a system larger than this minimal size are due to the fact that customers “demand” a delivery quantity greater than the minimum unit of electricity and that therefore, those costs should be treated as demand-related. Because the residential class tends to have a higher share of the number of customers as compared to the share of non-coincident peak, the minimum system methodology tends to allocate more costs to the residential customer class and customer charges tend to be higher than with the 100% demand methodology.

The process of cost classification is the area within the COSA that can create considerable cost variability between customer classes due to differences in system configurations, demand measurements and assignment philosophy. The complexity of the entire COSA process is further compounded since, in some cases, the classification category is clear, but the specific allocator is not. For example, a particular cost item may clearly be peak demand-related but that demand can be measured as either a single coincident peak for the year, a 2 CP approach to reflect seasonal considerations, the sum of 12 monthly coincident peaks or through some other approach such as “Average & Excess.”

4.4.2 City of Healdsburg Classification Method

The following are the specific classifiers used in the City’s electric COSA within each of the four functions:

- Power Supply

Classifying power supply costs to demand and energy (commodity) components requires the evaluation of a number of complex, interrelated factors. Consideration must be given to what or who caused the power supply purchase to be made, and to the uses to which it will be put (i.e., meeting demand and energy requirement). Within this study, power supply costs are classified to demand and energy based on the City's power cost forecast for the test period. The specific classifiers used for the power supply function include:

- Energy
- Demand

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 as well. Energy costs are the costs of consumption over a specified period of time, such as a month or year.

Demand-related costs are those that vary with the maximum demand or the maximum rates of power supply to customer classes. Customer and system demand for this analysis were 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.

All of the City's power supply costs are purchases related to energy including transmission purchases. Transmission purchases through NCPA are included in this section of the revenue requirement.

- Transmission (Utility-Owned)

  The transmission function includes the utility's own transmission assets associated with providing power to the City's distribution system. Transmission services that the City purchases in order to facilitate the delivery of wholesale power purchases to the City's service area are included in power supply costs. The costs associated with the local utility's transmission service include only those costs for operating and maintaining the transmission lines, poles, towers, substations, etc. used to deliver power to the distribution network. The cost of providing transmission service to a customer is considered to be directly proportional to the demand that customer imposes on the system. The City does not own transmission equipment; therefore, these line items are not included in the analysis.

- Distribution

  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. Classifying distribution costs requires a special analysis of the nature of the costs. Most distribution costs are split between demand and customer components. The demand component is the cost of facilities built to serve a particular load, such as distribution substations. 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 distribution function:

  - Non-coincident peak demand (NCP) on Primary System
  - NCP on Secondary System
  - Actual Customer
  - Customers Weighted for Meters and Services
  - Direct Assignment

The minimum system analysis is used to determine the lowest level of plant investment required to serve a utility's customers compared to the actual facilities in place to meet varying customer demands. This study uses data from other municipal utilities to develop the demand and customer share of the distribution system. Generally, 60% of the system is functionalized and classified as demand related and the remaining 40% is customer related.

- Customer

  Customer-related services include all services related to the presence of customers on the system, not to customer usage. These services include meter reading, billing, collections, advertising, etc. Customer-related costs vary with the number and type of customers. They do not vary with system supply levels. These costs are sometimes referred to as "readiness to serve" or "availability" charges. Customer costs are incurred by the utility to have electricity supply readily available for a customer whether it is utilized or not.

  There are two types of customer-related cost classification categories—actual and weighted. Actual customer costs vary proportionally with the addition or deletion of a customer, regardless of the size or usage characteristics of the customer. An example of an actual customer-related cost is postage on customer bills. The cost of postage does not vary regardless of the type or size of customer or usage levels. In contrast, a weighted customer cost reflects a disproportionate cost attributable to the addition or deletion of a customer. An example of weighted customer costs is meter-reading expenses. In some cases, it takes less time and effort to read a residential energy meter than it does to serve a large commercial customer that also has a demand meter. This type of difference is accounted for in the weighted customer allocation factors.

- Direct Assignment

  Some costs can be directly assigned to certain customer classes without being classified as demand-, energy-, or customer-related. These are generally costs associated with specific services, such as dedicated capital facilities, or with specific customer classes, such as lighting customers. Direct assignments include costs incurred to maintain and serve city-owned streetlights.

4.5 ALLOCATION OF COSTS

The third step in performing a cost of service study is the allocation of the utility's total functionalized and classified revenue requirement to the customer classes of service. This is performed through the application of an appropriate allocation methodology.

4.5.1 City of Healdsburg Allocation Methodology

The following are the specific allocation methods used in the City's electric COSA.

- Demand Allocation Factors. For purposes of this study, five types of demand allocation factors were developed.
  - *Non-coincident peak demand allocation factor (NCP).* First, a non-coincident peak demand allocation factor was developed for each customer class. Expenses classified and allocated by the non-coincident peak demand allocation factor included those predicated on maximum demands

such as distribution substations, and a portion of poles and lines, mains, meters and services. The NCP demand method allocates costs to each class of service based upon their highest individual non-coincident peak demand regardless of the time of occurrence. The NCP allocation factor is used to allocate distribution.

- *1 Coincident peak (1 CP).* For each class of service, a contribution to a single annual system coincident peak was derived from the non-coincident peak by use of a coincidence factor. This coincident peak demand allocation method is referred to as the single coincident peak (1 CP) method. The 1 CP method allocates demand costs on the basis of a single demand value at the time of the system peak demand by each class. Expenses allocated on the 1 CP allocation factor include those related to the utility's transmission system. The 1 CP allocation method is not used in this study.
- *Sum of the two months coincident peaks (2 CP).* For each class of service, a contribution to a seasonal system coincident peak was also derived from the non-coincident peak by use of a coincidence factor. The coincident peak demand allocation method used was the sum of the summer and winter coincident peaks (2 CP) method. The 2 CP method allocates demand costs on the basis of the sum of the contributions to seasonal system peak demands by each class. The 2 CP method was not used in this study.
- *Sum of monthly coincident peak (12 CP).* As with the 1 CP calculation, a contribution to monthly system coincident peaks was derived from the non-coincident peak by use of a coincidence factor. This coincident peak demand allocation method is referred to as the sum of the monthly coincident peak (12 CP) method. The 12 CP method allocates demand costs on the basis of demand value at the time of the system peak demand in each month by each class. As discussed previously, the 12 CP method is used for power supply costs and transmission costs.
- *Average and excess method (A&E).* The average and excess method represents an alternative approach to CP-related cost allocation. The A&E method compares each customer class's average demand against its maximum NCP demand in order to reflect its *potential* peak demand volatility, and therefore its inherent ability to increase system peak requirement. The A&E method was not used in this study.

- Energy Allocation Factors. Energy costs vary directly with consumption. Accordingly, energy allocation factors were based upon electricity sales for each class. Energy allocation factors were used to allocate power supply costs, green-energy related costs and revenues and surplus sales revenue.
- Customer Allocation Factors. Two basic types of customer costs were identified—actual and weighted. The allocation factor for actual customers was derived from the actual number of customers served in each class of service. Two weighted customer allocation factors were also developed. The first weighted customer allocation factor considered the relative differences among the various customer classes of meter costs. The second weighted customer allocation factor considered the cost of customer accounting and meter reading by each rate class. Customer allocation factors were used to allocate some distribution costs such as meters and meter installations, and costs associated with customer service, accounts and sales.
- Rate Base Allocation. The value of the City's electric system was estimated as of FY 2022 and is functionalized, classified and then allocated to customer classes. The resulting functionalized, classified and allocated rate base is then used to develop rate base allocation factors. These allocation factors (i.e., general plant, net plant, distribution rate base, etc.) are then used to allocate revenue requirement expenses. For example, maintenance of station equipment can be allocated using station equipment rate base, or property taxes might be allocated using net plant.

- Other Cost Allocation. Other costs are allocated based on specific rate base items, O&M function totals, revenues, labor ratios and other allocation factors. These other allocation factors were used to allocate administrative and general expense items, as well as some other revenues such as dividend income or non-operating rental income.
- Administrative and General (A&G). All costs that are related to general overhead are classified to this area. Costs are allocated to customers based on their percentage of all other O&M expenses without power supply.
- Miscellaneous/Other Revenues. Miscellaneous/other revenues are generally allocated to customers based on allocation of all other O&M expenses.

4.6 REVIEW OF CUSTOMER CLASSES OF SERVICE

Customer classes of service refer to the arrangement of customers into groups that reflect common usage characteristics or facility requirement. The classes of service used within this study were as follows:

- Residential (D-1, D-4, & E-7)
- Small Commercial (C-1 & A-6)
- Large Commercial (P-2, E-19)
- Outdoor Lighting (OL)

4.7 MAJOR ASSUMPTIONS OF THE COST OF SERVICE STUDY

Major assumptions used in conducting the cost of service study for the City are as follows:

- Forecast calendar year 2024 was selected as the period for the allocation of costs within the cost of service study.
- The revenue requirement as outlined in Section 2 was used for the cost of service study.
- Power purchased is assigned to energy as detailed in the previous section.
- Distribution plant was classified based both on a “minimum system” approach.
- City-owned and maintained streetlights do not receive an allocation of capital projects funded through rates.
- Projected loads were based on data provided by the City.

Given these key assumptions, the cost of service analysis results are provided in the next subsection.

4.8 COST OF SERVICE RESULTS

Given the above assumptions regarding the cost of service analysis, the various costs were classified and allocated to the customer classes of service. Table 4-1 shows the results of this analysis by function for FY 2024.

TABLE 4-1: SUMMARY OF FUNCTIONALIZATION FY 2024

	Production Related	Distribution Related	Customer Related	Net Revenue Requirement
Residential D-1, D-4 & E-7	$3,942,970	$405,606	$846,998	$5,195,574
Small Commercial, C-1 & A-6	$3,285,434	$265,587	$395,916	$3,946,937
Large Commercial P-2, E-19	$4,255,970	$353,515	$64,224	$4,673,709
Outdoor Lighting	$58,712	$6,565	$111,579	$176,857
TOTAL	$11,543,087	$1,031,273	$1,418,717	$13,993,077

The overall COSA results are summarized in Table 4-2.

TABLE 4-3: SUMMARY OF COST OF SERVICE ANALYSIS FY 2024

	Present Rate Revenues	Net Revenue Requirement	Surplus/(Deficiency) in Present Rates	Rate Increase (Decrease)
Residential D-1, D-4 & E-7	$4,867,033	$5,195,574	($328,541)	7%
Small Commercial, C-1 & A-6	$3,512,553	$3,946,937	($434,384)	12%
Large Commercial P-2, E-19	$3,630,294	$4,673,709	($1,043,415)	29%
Outdoor Lighting	$54,923	$176,857	($121,934)	222%
TOTAL	$12,064,804	$13,993,077	($1,928,274)	16%

The results show that under present retail rates, the City's electric utility is not collecting sufficient revenues to meet projected revenue requirements.

When examining the results shown above, it is important to note that the inter-class cost allocations are based on load data estimates and usage pattern assumptions. Therefore, utilities often elect not to make rate modifications when deviations from the total system rate change are within 10 percent. Some of the City's rate classes are outside of the +/-10% margin of error. Proposed rate adjustments by class are recommended to gradually move each class closer to its cost of service rather than make large and sudden corrections.

5 COSA Unit Costs

This section provides the table comparisons for current rates and the COSA unit costs for FY 2024. For classes without demand rates, demand-related costs are included in the energy charge. In practice, a share of these costs may be included in both the basic charge and kWh charge.

TABLE 5-1: COSA UNIT COSTS FY 2024: RESIDENTIAL

	Present Rates D-1 & D-4	COSA Unit Costs D-1, D-4, E-7
Basic Charge ($/month)	$6.38	$14.84
Energy Charge Tier 1, ($/kWh)	**$0.1360**	
Energy Charge Tier 2, ($/kWh)	**$0.1711**	
Energy Charge Tier 3, ($/kWh)	**$0.2958**	
Energy Charge all kWh ($/kWh)	*Avg = $0.1697*	$0.1716
Rate Change over Present		11.4%

TABLE 5-2: COSA UNIT COSTS FY 2024: SMALL COMMERCIAL

	Present Rates C-1	COSA Unit Costs C-1, A-6
Basic Charge ($/month)	**$17.94**	**$29.74**
Energy Charge Summer, ($/kWh)	**$0.1728**	
Energy Charge Winter, ($/kWh)	**$0.1375**	
Energy Charge all kWh ($/kWh)	*Avg = $0.1558*	$0.1682
Rate Change over Present		11.8%

TABLE 5-3: COSA UNIT COSTS FY 2024: LARGE COMMERCIAL P-2, E-19

	Present Rates P-2	COSA Unit Costs P-2, E-19
Basic Charge ($/month)	**$87.92**	**$77.96**
Energy Charge Summer, ($/kWh)	**$0.1179**	
Energy Charge Winter, ($/kWh)	**$0.1021**	
Energy Charge all kWh ($/kWh)	*Avg = $0.1103*	**$0.1556**
Demand Charge Summer, ($/kWh-mo)	**$8.77**	
Demand Charge Winter, ($/kW-mo)	**$5.37**	
Demand Charge, ($/kW-mo)	*Avg = $7.16*	**$3.74**
Rate Change over Present		**23.8%**