Finance Committee
Staff Report

From: City Manager
Report Type: ACTION ITEMS
Lead Department: Utilities

Meeting Date: April 15, 2025
Report #: 2412-3870

TITLE
Recommendation to the City Council to Adopt a Resolution Approving the FY 2026 Electric Financial Forecast, including Transfers, Amending Rate Schedules E-1 (Residential Electric Service), E-2 (Residential Master-Metered and Small Non-Residential Electric Service), E-2-G (Residential Master-Metered and Small Non-Residential Green Power Electric Service), E-4 (Medium Non-Residential Electric Service), E-4-G (Medium Non-Residential Green Power Electric Service), E-4 TOU (Medium Non-Residential Time of Use Electric Service), E-7 (Large Non-Residential Electric Service), E-7-G (Large Non-Residential Green Power Electric Service), E-7 TOU (Large Non-Residential Time of Use Electric Service), E-14 (Street Lights), E-16 (Unmetered Electric Service), E-EEC-1 (Export Electricity Compensation), and E-NSE-1 (Net Metering Surplus Electricity Compensation)

RECOMMENDATION
The Utilities Advisory Commission and Staff request that the Finance Committee recommend that the City Council adopt a resolution (Attachment A):

1. Approving the Fiscal Year 2026 Electric Utility Financial Forecast shown in this staff report and attachments; and
2. Approving the transfer at the end of FY 2025 of up to $5 million from the Electric Utility Supply Operations Reserve to the Distribution Operations Reserve;
3. Amending Rate Schedules (Attachment B) effective July 1, 2025 (FY 2026):
    a. E-1 (Residential Electric Service)
    b. E-2 (Small Non-Residential Electric Service)
    c. E-2-G (Residential Master-Metered and Small Non-Residential Green Power Electric Service
    d. E-4 (Medium Non-Residential Electric Service)
    e. E-4-G (Medium Non-Residential Green Power Electric Service)
    f. E-4 TOU (Medium Non-Residential Time of Use Electric Service)
    g. E-7 (Large Non-Residential Electric Service)
    h. E-7-G (Large Non-Residential Green Power Electric Service)
    i. E-7 TOU (Large Non-Residential Time of Use Electric Service)

j. E-14 (Street Lights)
k. E-16 (Unmetered Electric Service) to recover capital and maintenance costs for utility pole attachments and telecom conduit
l. E-EEC-1 (Export Electricity Compensation) to reflect 2024 avoided cost, and
m. E-NSE-1 (Net Surplus Electricity Compensation) to reflect current projections of FY 2026 avoided cost.

EXECUTIVE SUMMARY

The City of Palo Alto Utilities (CPAU) provides electricity, water, wastewater, natural gas, and fiber optic services to the Palo Alto community. The Public Works Department also provides refuse collection and processing for recycling, compost and garbage, wastewater treatment and stormwater management. The City's primary goals are to manage these services in a way that ensures continued safe, reliable, environmentally sustainable, and cost-effective operations. The City is proposing rate increases this year for electric, natural gas, wastewater and water services. As a locally owned municipal utility, CPAU's rates are designed to recover the costs of purchasing and delivering these utility services to customers. The City strives to be transparent with utilities customers about the reason for rate changes, including explaining the cost drivers, benefits to customers, what the City is doing to keep costs low for ratepayers, and the services and programs provided by the City to help customers keep utility bill costs low. Attachment E outlines CPAU's plan for communicating rate changes to customers. Staff are presenting an overview of the financial forecast and rate change proposal for each utility service to the Utilities Advisory Commission (UAC) and Finance Committee prior to City Council review and approval in June 2025.

The Electric Utility rate forecast proposes a 5.1% rate increase for FY 2026. Last year's forecast projected 5% annual rate increases from FY 2027 to FY 2029. The updated forecast now projects a 6% increase in FY 2027, 8% increases in FY 2028 and FY 2029, and a 6% increase in FY 2030. Table 1 shows the proposed rate increases for FY 2026 through FY 2030. The drivers for this increase relative to last year's forecast include a new warehouse and laydown yard for grid modernization, replacement of emergency generators, and an update to the General Fund Transfer forecast from $15.6 million to $17.4 million beginning in FY 2026. The General Fund Transfer increase is a result of the estimated grid modernization asset value increase (capital assets are an input to the Council-adopted General Fund Transfer methodology and when capital assets increase, General Fund Transfer also increases). Although the General Fund Transfer is funded by non-rate revenue, less non-rate revenue is projected to be available to pay for other costs with a larger General Fund Transfer and so a larger rate increase is necessary. The rate increases in the outer years of the forecast could change as the Council finalizes plans for debt financing grid modernization costs.

In the current year, FY 2025, power supply costs are expected to be slightly lower than forecasted a year ago; the main driver for this shift is extremely high market prices for resource adequacy capacity and renewable energy credits, which have yielded higher wholesale revenues for the

City. The City's load (consumption) for the current year is projected to be about 10% higher than previously forecasted, but is then expected to be relatively flat over the next several years. Meanwhile, output from the City's hydroelectric resources is projected to be roughly equal to long-term average levels over the next few years. Hydroelectric revenue continues to be a large source of uncertainty in the City's supply cost projections. In the next five years, staff expects increasing transmission access charges, rising renewable portfolio standard requirements, and tightening resource adequacy requirements to steadily increase electric supply costs. Capital spending and distribution system maintenance spending is rising due to grid modernization, fiber-related investments and an upgrade to the Hanover Substation which will benefit all electric rate payers. Staff expects grid modernization and related capital costs to be offset with a series of debt financing with the first bond issuance in FY 2026.

The Hydroelectric Rate Stabilization Reserve has a balance of $17.4 million, approaching the reserve's target level of $19 million. This level will allow the City to avoid activating the hydroelectric rate adjuster if an upcoming winter is drier than average. In FY 2025, this forecast anticipates the Electric Special Projects Reserve will also be repaid $7.5 million from the Electric Supply Operations Reserve, bringing the balance in the Electric Special Projects Reserve from $22.6 million to $30.1 million. This will fully repay the monies borrowed from the Electric Special Projects Reserve to the Electric Supply Operations Reserve to cover higher costs during the pandemic, the drought, and high winter energy prices during 2022-2023.

Table 1: Current Year (FY 2025) and Projected Overall Rate Trajectory from FY 2026 to FY 2030

Fiscal Year	2025	2026	2027	2028	2029	2030
Proposal	**9%**	**5.1%**	**6%**	**8%**	**8%**	**6%**
FY 2025 Plan (prior year)	9%	5%	5%	5%	5%	-

BACKGROUND

This staff report provides the Finance Committee with a financial forecast for the Electric Utility and provides an overview of the utility's operations costs, capital costs, and debt and includes recommended rate adjustments required to maintain the utility's financial health. This work is done annually as part of the budget and rate-setting cycle. Attachment A contains a draft Council Resolution. Attachment B contains a redline of the proposed changes to the Electric Utility rate schedules. Attachment C contains a summary of the financial details and CIP budgets underlying the forecast. Attachment D contains a set of Reserves Management Practices describing the reserves. Attachment E contains a summary of the Electric Utility communications strategy and samples. Attachment F contains a technical memo summarizing the methodology and assumptions used to develop the rates for the Unmetered Electric Service Rate Schedule (E-16).

ANALYSIS

Past Trends

Annual expenses for the Electric Utility increased significantly from FY 2019 to FY 2024. Electric supply costs increased as new renewable projects came online, and transmission access charges have continued to rise as improvements are made to the California grid. Capital improvement and operational expenses have increased due to construction inflation, increased investment in the electric system, and the cost of contract field crews to cover operational work due to challenges with filling vacancies and multi-year construction projects such as Foothills undergrounding and grid modernization.

In FY 2024, supply costs were significantly lower than budgeted, driven primarily by favorable hydrological conditions and high resource adequacy (RA) market prices. The record levels of precipitation the state received during FY 2023 led to reservoirs being nearly full in FY 2024, producing high levels of hydroelectric generation and enabling the City to sell significant quantities of surplus generation to other utilities. In addition, the City is a net seller of RA capacity, and record-high RA prices during FY 2024 enabled the City to realize significant RA sales revenue. This trend continued in FY 2025, which is one of the main drivers of the lower than projected overall supply costs.

The capital costs for FY 2025 in Figure 1 are unusual due to the timing of various capital investments and related debt issuances in FY 2025 and FY 2026. In FY 2025 the Electric Utility's reserves will fund the capital investment, including grid modernization, while in FY 2026 CPAU plans to issue the first grid modernization bond which will offset the capital costs paid for by customer revenues or Electric Utility reserves in that year. Electric supply purchase costs increased 2% per year on average from FY 2019 through FY 2024, and other operational costs increased 4% per year on average over the same time period. For capital costs, grid modernization investments are expected to be substantial beginning in FY 2025 through FY 2030 with bond financing occurring in FY 2026. In the longer term, debt service costs will grow as a result of the repayment of principal and interest on the grid modernization bonds. However, the capital and debt service costs combined are expected to be relatively steady from year to year.

Table 2: FY 2024 Actuals vs. Prior Year's Forecast ($000)

	Net Cost/(Benefit) Variance	Type of change
Higher revenues from higher load	(5,083)	Revenue increase
Lower electric supply costs	(7,897)	Cost decrease
Higher operational costs	8,799	Cost increase
Lower than forecasted capital investment	(28,074)	Cost decrease
Net Cost / (Benefit) of Variances	**(33,156)**	

Projections

Overview

In FY 2025, total revenues are expected to be similar to FY 2024 actuals, sales revenues increased by $4.2 million or 2% from FY 2024 actuals primarily due to increased retail sales from higher than anticipated electricity load. However, this was offset by decreases in other revenues and transfers and wholesale revenues. The decline in wholesale revenues compared with FY 2024 is attributed to lower surplus energy revenues, partially offset by higher Renewable Energy Credit (REC) sales revenue. Purchase costs are currently projected to be $1.3 million, or 1%, lower than last year's forecast.

Operations costs in FY 2025, other than public benefits and Low Carbon Fuel Standards (LCFS) expenses, are projected to be $5 million, or 7% higher than FY 2024 actuals. Allocated charges from other City departments are projected to increase 9% based on adopted FY 2025 budget numbers.

The FY 2025 estimate for the Capital Improvement Program (CIP) budget is $81 million, including $31 million for grid modernization and $14.8 million for a rebuild of the Hanover Substation.

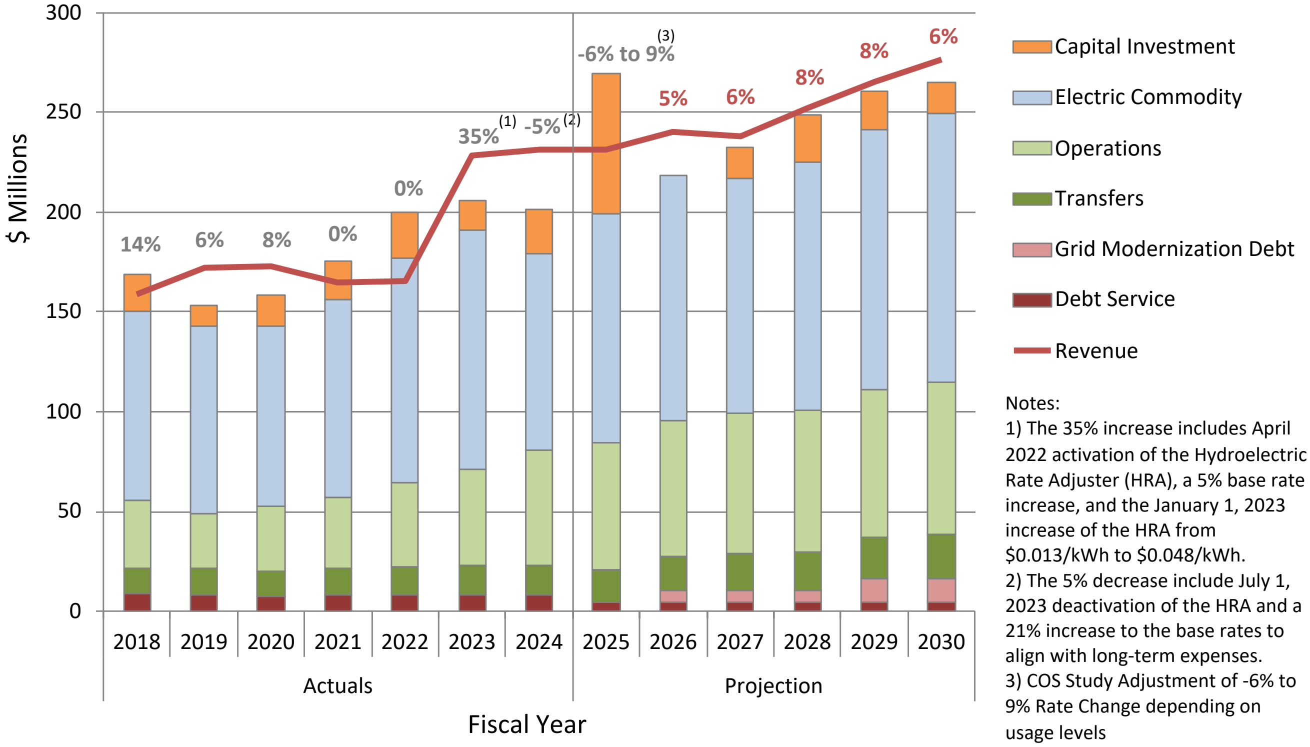
From FY 2025 through FY 2030, total revenues and total supply purchases and operating expenses are expected to increase by 4% on average annually. Capital investment and debt service costs are rising due to the grid modernization project. Rates need to increase 5.1% in FY 2026 to cover rising costs, grid modernization CIP, and reserve targets.

This financial forecast includes repayment of all internal loans from the Electric Special Projects Reserve by the end of FY 2025. Additionally, this forecast includes a transfer in FY 2025 of $5 million from the Electric Utility Supply Operations Reserve to the Electric Utility Distribution Operations Reserve to manage the impact of the startup capital expenditures of the grid modernization project.

Figure 1 shows the electric utility revenues, expenses, and proposed rate changes for the recorded years 2018 through 2024, the current year, and the projections for the next five years. Staff proposes a 5.1% rate increase for FY 2026 and projects rate increases of 6% in FY 2027, 8% in FY 2028 and FY 2029, and 6% in FY 2030 to keep revenues in line with expenses.

The FY 2026 CIP cost bars in Figure 1 reflect a one-time timing issue with the startup of the grid modernization project. The first year of spending was budgeted in FY 2024, but the first debt issuance will not take place until FY 2026 (this was to allow time for the City to apply for a grant, which it did not receive). It also reflects a one-time transfer in FY 2024 related to new customer investments.

Figure 1: Electric Utility Revenues, Expenses, and Rate Changes: Actual Costs through FY 2024 and Projections through FY 2030



Notes:
1) The 35% increase includes April 2022 activation of the Hydroelectric Rate Adjuster (HRA), a 5% base rate increase, and the January 1, 2023 increase of the HRA from $0.013/kWh to $0.048/kWh.
2) The 5% decrease include July 1, 2023 deactivation of the HRA and a 21% increase to the base rates to align with long-term expenses.
3) COS Study Adjustment of -6% to 9% Rate Change depending on usage levels

Load Forecast

Staff conducted an updated load forecast for FY 2026, with forecast methodologies that incorporated weather patterns, economic factors, and historical trends. This forecast projected energy demand at 893,052 MWh and a peak load of 163 MW in FY 2026. This forecast also included a revised FY 2025 energy demand about 8% higher than last year's forecast, at 902,133 MWh and 164 MW, driven largely by higher-than-expected sales in FY 2024. The main contributors of the increased demand include 10% growth in the E-7 rate class, driven primarily by a customer's data center expansion, which added nearly 30 GWh to the load. This customer's formalized capacity reservation agreement further adds 60 GWh annually and is included in this forecast. However, long-term trends show a gradual 1% annual decline over the last 20 years in load due to energy efficiency measures, rooftop solar adoption, and the loss of industrial users, partially offset by growth in building electrification and EV charging.

Figure 2 shows the forecast of electricity consumption through FY 2044. Electricity consumption, which was depressed due to the economic effects of the pandemic, is assumed to recover to a level slightly above the long-term trend line (shown in the FY 2026 Forecast line). Potential factors that may offset declining sales include another potential data center project and Figure 2 shows a range of forecasts up to the FY 26 Forecast (high range) line. Building and vehicle electrification at a business-as-usual level is included in the FY 2026 forecast, but large increases in the pace of building and vehicle electrification could increase sales further as well. Demand forecasts are updated every year taking into account fundamental changes. Staff updates the forecast annually based on the most updated information for financial forecast purposes.

Figure 2: Forecasted Electricity Consumption

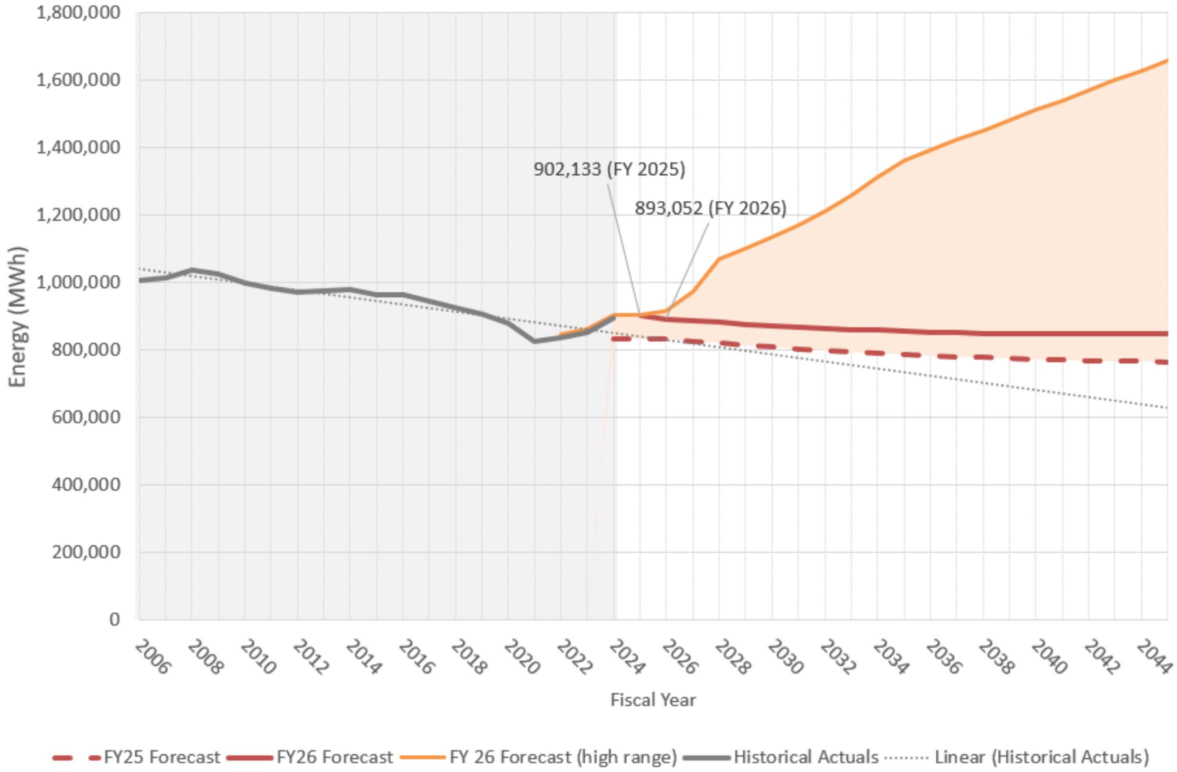
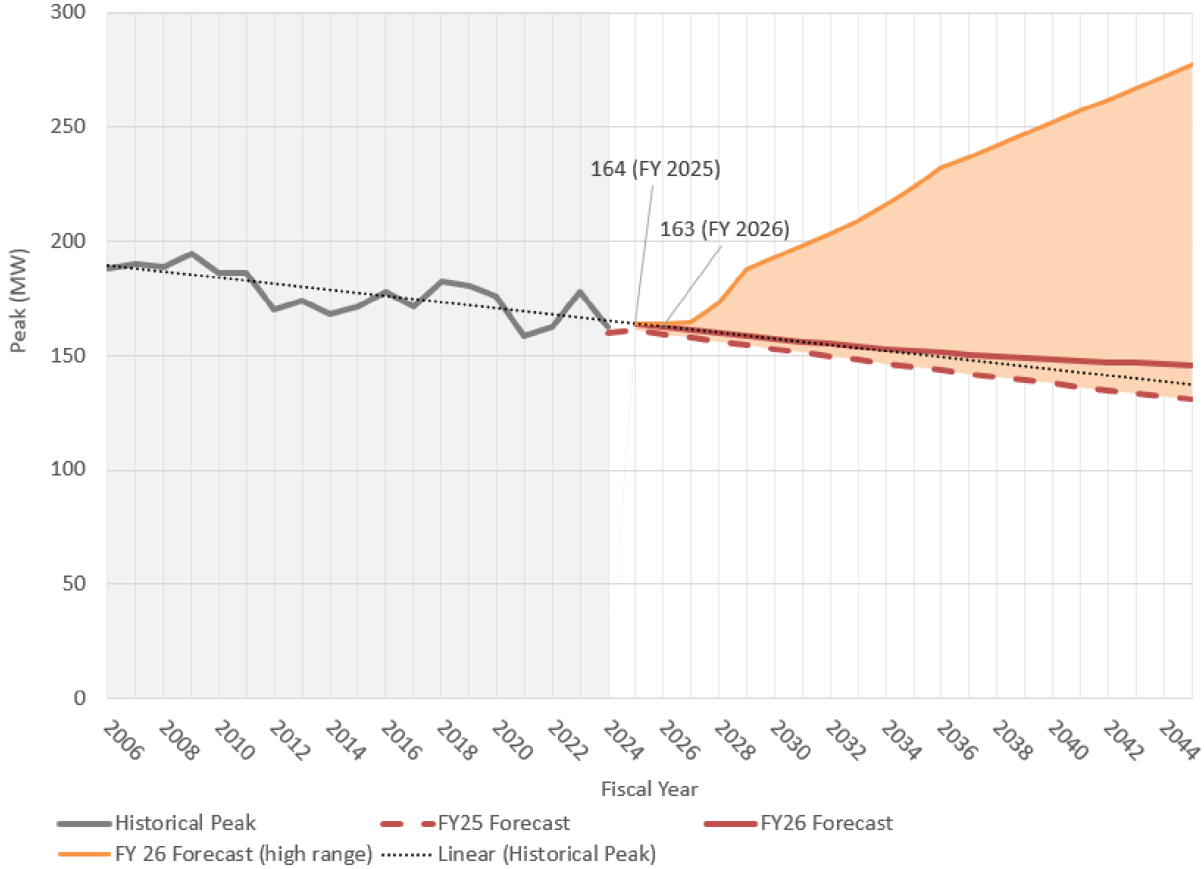


Figure 3 shows forecasted electricity peak demand through FY 2044. Figure 3 highlights the uncertainties around future electricity peak demand. This is because of the growing influence of data centers and electrification initiatives in shaping Palo Alto's energy landscape. The FY 26 Forecast (high range) line captures a range of uncertainty in the forecast.

Figure 3: Forecasted Electricity Peak Demand



Revenues

The Electric Utility receives most of its revenues from sales of electricity to Palo Alto customers, but about 20 to 25% comes from other non-rate revenue sources. Of these non-rate revenue sources, about 50% to 75% represents wholesale revenues – from surplus energy sales, surplus RA sales, and sales of RECs that are in excess of the City's renewable portfolio standard (RPS) requirements. These revenues may offset electric supply purchase costs, smooth rate increases, or fund reserves or costs including the Electric General Fund Transfer and local decarbonization programs of the remaining revenues, the largest sources are interest income, customer connection fees for new or replacement electric services, and carbon allowance sales revenues associated with the State's cap-and-trade program.

Staff expects Cap-and-Trade allowance revenues to stabilize through the forecast period, but this revenue source is uncertain as the current regulations are set to sunset in 2030 unless reauthorized by the State. The California Air Resources Board (CARB) is in the process of updating Cap-and-Trade regulations to increase the stringency of the program and allowable uses by lowering the target emissions levels. A revised regulation is expected to be adopted in 2025, with implementation anticipated in 2026. Staff will update Cap-and-Trade related revenues projections when more information becomes available.

The forecast for interest income assumes current interest rates continue, and there are no major reserve reductions aside from what is anticipated in this forecast. If interest rates rise, interest income could increase, and if reserves decrease (due to drought or a withdrawal from the Electric Special Projects (ESP) reserve for a major project), interest income would decrease.

The load forecast and the rate changes proposed in this staff report provide the basis for sales revenue projections.

Expenses

As shown in Figure 1 above, from FY 2026 through FY 2030, increasing power supply costs combined with rising capital investment and debt service costs due to the grid modernization project are projected to require a 5.1% rate increase in FY 2026, 6% in FY 2027, 8% increases per year in FY 2028 and FY 2029, and a 6% increase in FY 2030. These rate increases are necessary to keep revenues in line with expenses.

Although total load for FY 2025 is expected to be 10% higher than forecasted a year ago, overall power supply costs are expected to be slightly lower than originally projected. The main factors driving this favorable supply cost shift include executing several sales of excess RA and REC supplies at higher than anticipated prices, and projected hydroelectric output being 11% greater than forecasted a year ago. Hydroelectric generation revenue continues to be a very large source of uncertainty in the City's supply cost projections, and is expected to decrease over time due to climate change. To reduce the downside risk associated with hydroelectric uncertainty in the future, staff is now making its rate projections assuming that long-term "normal" production from the City's hydroelectric resources will be about 80% of historical average levels for purposes of estimating future hydroelectric resource costs. Over the longer term, increasing transmission costs, rising renewable energy procurement requirements, and tightening resource adequacy regulations are also expected to steadily increase electric supply costs.

<u>Supply Purchases</u>

As shown in Figure 4 below, the utility is projected to get roughly 43% of its energy from hydroelectric projects in a normal year, but received over 50% during FY 2024 due to the favorable hydroelectric generation conditions resulting from the rains of the 2022/2023 winter. In the longer term, contracts with renewable sources make up approximately 56% to 64% of the portfolio. If hydroelectric output is lower than forecasted (as was the case in FY 2023) or if loads increase, some additional power purchases may come from unspecified market sources. Under the City's Carbon Neutral Plan, CPAU purchases additional RECs corresponding to the net amount of market energy it purchases.

Figure 4: Electricity Supply by Source

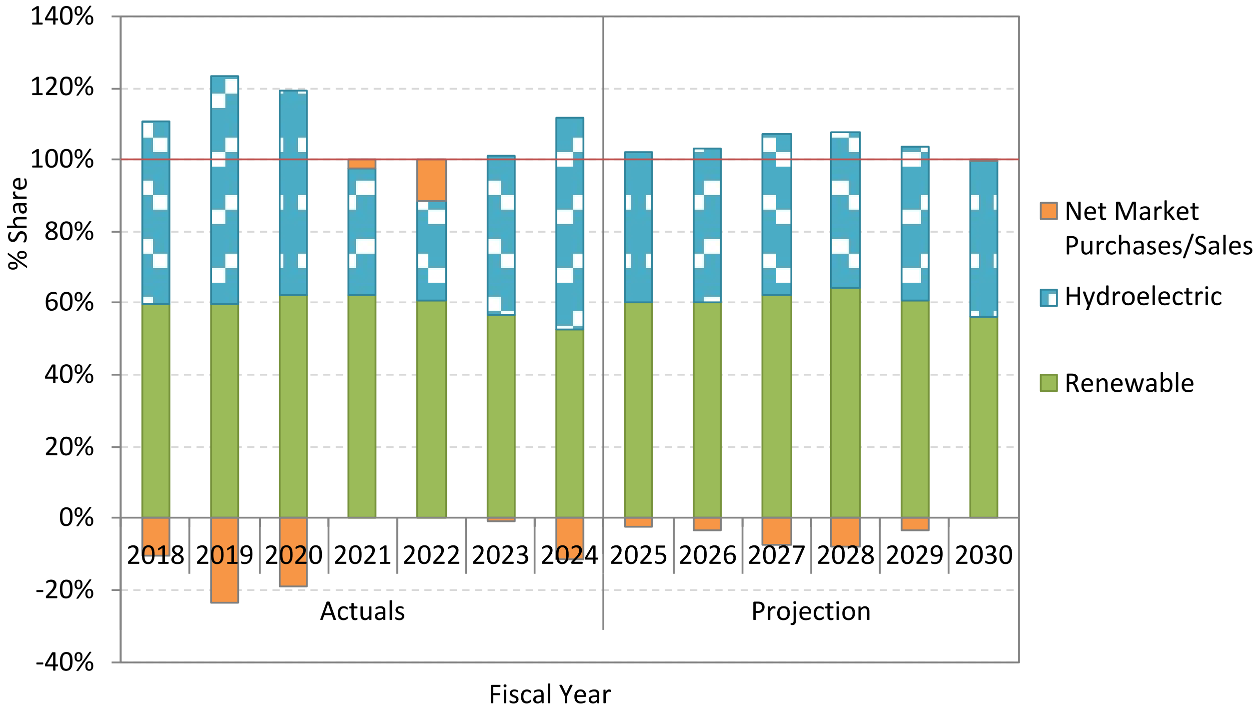


Figure 5 and Table 3 show the actual and projected costs for the electric supply portfolio,[1] and Figure 5 also shows average and actual hydroelectric generation.[2] FY 2021 and FY 2022 had lower than average hydroelectric generation, while FY2024 had higher than forecasted generation. Starting in FY 2023 (in the FY 2024 Electric Utility Financial Plan) staff lowered its projection of an average hydroelectric year to more closely align with the past 10 years of historical averages.

Renewable energy costs have stayed relatively flat as one renewable energy contract ended while another renewable project came online to fulfill the City's carbon neutral and RPS goals. The current market outlook is uncertain for newer renewables projects because of headwinds from supply chain issues and interconnection delays, along with the potential for new trade tariffs and reduced federal subsidies. CAISO transmission access charges are projected to continue to increase as transmission lines are built throughout California to accommodate new renewable projects. In total, staff projects net electric supply costs to increase from an average of about $86 million from FY 2022 through FY 2025 to about $117 million by FY 2030.

[1] Costs are shown net of wholesale revenues and cannot be directly compared with the electric supply purchase figures shown in Attachment C: Electric Utility Financial Forecast Table.
[2] Average hydroelectric generation based on the currently inactive E-HRA rate schedule.

Figure 5: Electric Supply Portfolio Costs

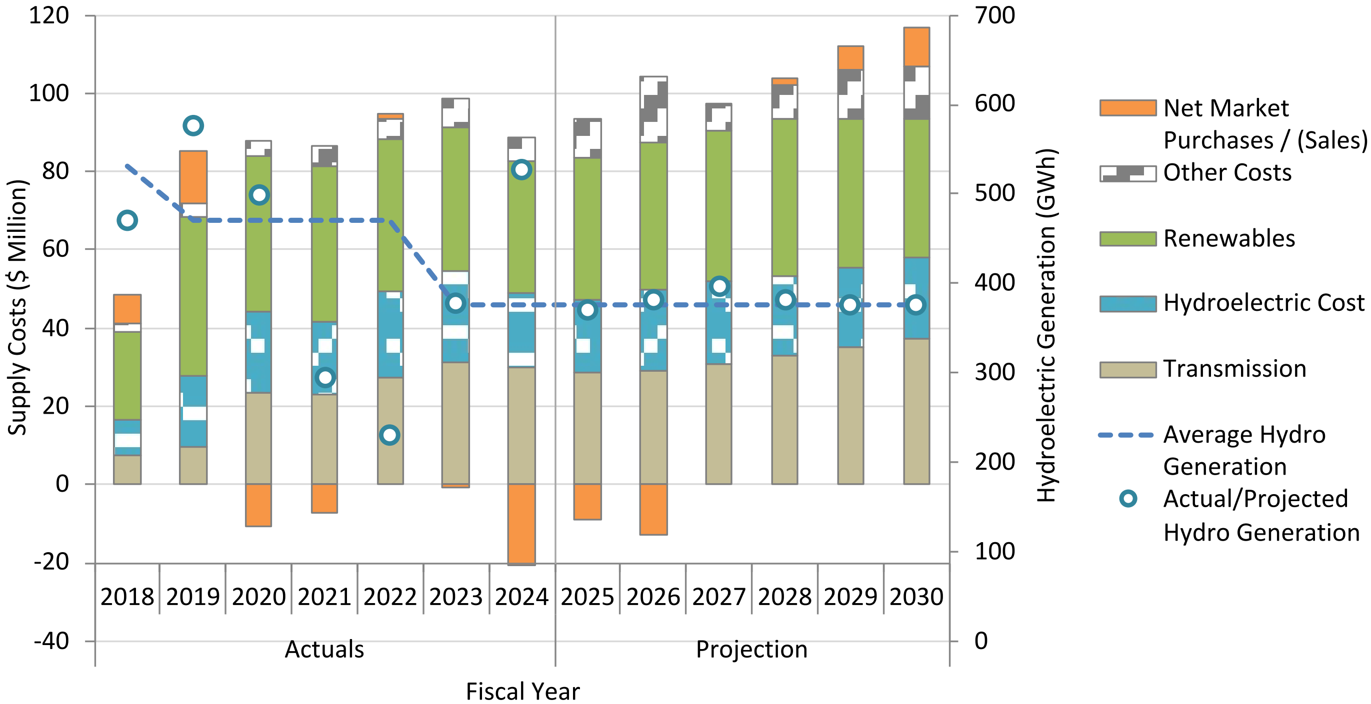


Table 3: Electric Supply Portfolio Costs ($000)

Expenses	Actual	Projection					
	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030
Net Market Purchases / (Sales)	(20,417)	(9,146)	(12,684)	410	1,632	6,116	10,141
Renewables	33,794	36,196	37,489	38,805	40,283	38,078	35,402
Hydroelectric Costs	18,690	18,819	20,686	21,089	20,434	20,208	20,818
Transmission	30,093	28,559	29,120	30,768	32,844	35,042	37,137
Other Costs	6,349	10,000	17,070	6,111	8,668	12,518	13,529
Net Supply Costs	68,509	84,430	91,682	97,182	103,861	111,961	117,028

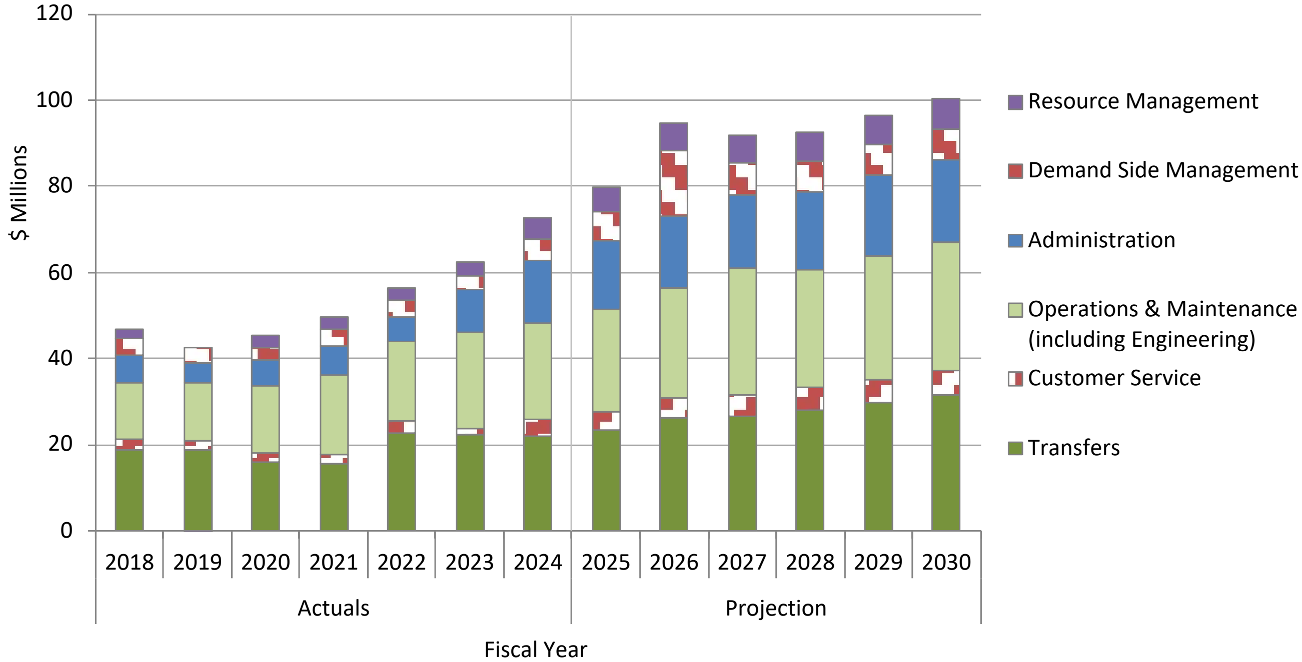
Operations

CPAU's Electric Utility operations include the following activities:

- Administration, including financial management of charges allocated to the Electric Utility for administrative services provided by the General Fund and for Utilities Department administration, as well as debt service and other transfers (for example, transfers to General Fund to pay for communications dispatch, fire training, graffiti removal from poles and boxes, and Office of Emergency Services emergency response). Additional detail on Electric Utility debt service is provided in the Debt Service section below
- Customer Service
- Engineering work for maintenance activities (as opposed to capital activities)
- Operations and Maintenance of the distribution system;
- Resource Management and Demand Side Management; and
- Transfers including the General Fund Transfer, transfers to the City's capital project fund, and technology fund.

Figure 6 shows the Electric Utility operational costs from FY 2018 through FY 2030. Overall operations costs are expected to rise annually by about 4% on average from FY 2025 to FY 2030. This is primarily driven by increased operations and maintenance and administrative overhead allocations. Operations and maintenance costs are increasing primarily due to inflation driven by the tight labor market and the cost of using contract field crews for multi-year CIPs and to backfill for vacant positions. These costs may be reduced depending on how much work is needed and may be phased out as longer-term employees are gained. Administration costs are rising primarily due to increasing support and labor from other City departments and Utilities Administration costs resulting from filling vacancies, merit increases and cost of living increases.

Figure 6: Electric Utility Operational Costs



Capital Improvement Program

Staff anticipates CIP spending for FY 2025 through FY 2030 to focus primarily on grid modernization (~$228 million). Other significant one-time projects include a rebuild of Hanover Substation, undergrounding of power lines in the Foothills, and completion of the Smart Grid (Advanced Metering Infrastructure) project. Ongoing projects include replacement of deteriorated wood poles, substation physical security upgrades, and ongoing capital investment in smaller projects on the electric distribution system to maintain/improve reliability. Total spending over the forecast period, including the FY 2025 current year budget, is approximately $340 million. Of this, about $186 million (55%) is planned to be financed through debt while $115 million (34%) is scheduled to be funded by utility rates. This forecast assumes the remaining $38 million (11%) is primarily funded through future debt issuances beyond the 5-year forecast, and less significantly, through other sources including connection fees (for Customer Connections), phone and cable companies (primarily for undergrounding), and other funds (such as funds from the Electric Special Projects Reserve for Smart Grid). Table 4 shows the latest projected budget and the five year CIP spending plan, although these figures are preliminary pending budget discussions starting in May.

Table 4: Electric Utility CIP Spending ($000)

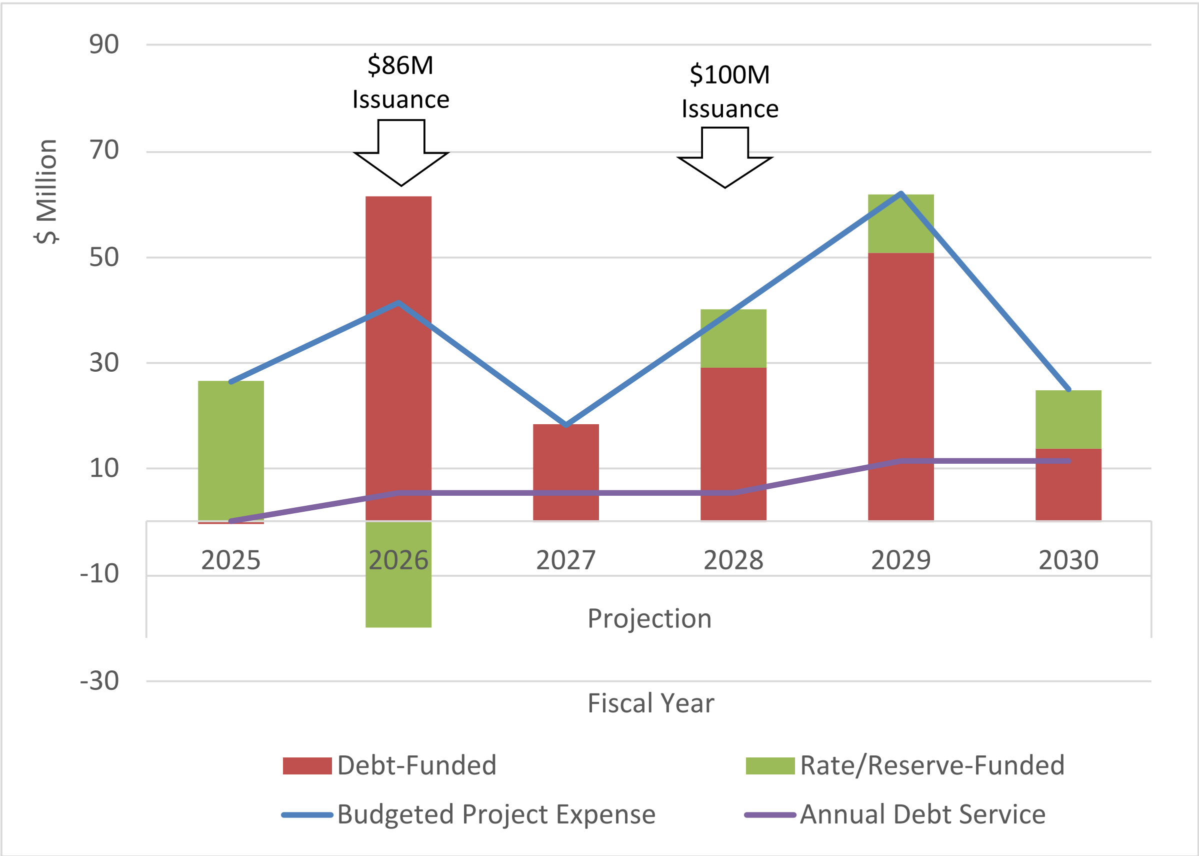
Project Category	2025*	2026	2027	2028	2029	2030
One Time	23,579,421	10,652,009	2,850,000	750,000	750,000	825,000
Reliability	1,654,188	3,275,028	900,000	553,150	544,870	412,412
Undergrounding	-	-	-	-	-	-
Underground Rebuild	-	-	-	-	-	-
Ongoing	16,259,756	6,975,097	4,575,670	4,350,650	4,476,280	4,688,244
Customer Connections	1,700,000	2,700,000	2,700,000	2,700,000	2,781,000	3,059,100
Smart Grid	7,065,270	-	-	-	-	-
Grid Modernization	31,000,000	52,500,000	18,357,000	40,000,000	62,000,000	25,000,000
Total	81,258,635	76,102,134	29,382,670	48,353,800	70,552,150	33,984,756
*Includes unspent funds from previous years carried forward or reappropriated into the current fiscal year						

Apart from the grid modernization capital work, the system would need to invest approximately $15 to $20 million per year for existing capital asset replacement. So, over the next 6 years (FY 2025 – 2030), the Electric Utility would spend a baseline amount of $90 to $120 million. The additional spending for grid modernization is $109 million to $139 million, depending on the full cost of grid modernization (~$229 million estimated in this forecast for FY 2025 - 2030).

Debt Service

The Electric Utility currently has no debt service expenses related to its own distribution system (though it does have debt service expenses related to the Calaveras Dam, a power supply expense). However, staff expects to issue substantial amounts of debt to fund grid modernization expenses through FY 2030. A tentative estimate of how much of the cost of that project will be debt funded vs. rate funded is shown in Figure 7 below. The timing and amount of the debt issuances will likely change as the grid modernization project progresses. Note that the debt issuance in FY 2026 will be used to reimburse FY 2025 expenses, resulting in the use of rate/reserve funding in FY 2025 and a refund to the reserves in FY 2026 as the bond proceeds are applied to those FY 2025 actual capital costs for grid modernization and related projects (see Council staff report 2411-3805,[3] December 16, 2024 for a detailed discussion and accompanying Resolution 10209[4]).

Figure 7: Projected Funding Plan for Grid Modernization Project



The Electric Utility has previously pledged reserves and net revenue as security for non-electric bond issuances listed in Table 5 even though the Electric Utility is not responsible for the debt service payments. The Electric Utility's reserves or net revenues would only be called upon if the responsible utilities are unable to make their debt service payments. Staff does not anticipate that this will occur. These pledges have not impacted electric rates. Staff projects that the Electric Utility's net revenues in each future year will exceed 125% of debt service (see Attachment C, Utility Financial Table, line 71).

[3] Staff report 2411-3805 "Adoption of a Resolution of Intention to Reimburse Expenditures for the Grid Modernization and Related Projects of the Electric Utility System Infrastructure from the Proceeds of the Tax-Exempt Utility Revenue Bonds." https://portal.laserfiche.com/Portal/DocView.aspx?id=117749&repo=r-704298fc
[4] Council Resolution 10209 (Dec. 16, 2024) https://portal.laserfiche.com/Portal/DocView.aspx?id=126359&repo=r-704298fc

Table 5: Other Issuances Secured by Electric Utility's Revenues or Reserves

Bond Issuance	Responsible Utilities	Annual Debt Service ($000)	Secured by Electric Utility's:	
			Net Revenues	Reserves
2009 Water Revenue Bonds (Build America Bonds)	Water	$1,977*	No	Yes
2011 Utility Revenue Refunding Bonds, Series A	Gas Water	$1,457	No	Yes
*Net of Federal interest subsidy				

Reserves

The Electric Utility currently has two primary contingency reserves, the Supply Operations Reserve and the Distribution Operations Reserve. In addition, the Electric Utility has a Hydro Stabilization Reserve, an Electric Special Projects (ESP) Reserve, and a Capital Reserve. Reserve funds may be utilized with Council approval.

There are a variety of risks associated with the Supply Fund related to resource generation variability, market price volatility, transmission cost increases, and regulatory changes to market rules. Because of the high range of uncertainty in energy price predictions more than three years into the future, this risk assessment is only performed for the first two fiscal years of the forecast period. It is important to note that the likelihood of all these adverse scenarios occurring simultaneously, and to the degree described in Table 6, is very low.

Table 6: Electric Supply Fund Risk Assessment

Categories of Electric Supply Cost Uncertainties	Estimates of Adverse Outcomes (M$)	Estimates of Adverse Outcomes (M$)
	FY 2026	FY 2027
1. Load Net Revenue	3.8	4.4
2. Hydro Production: Western & Calaveras	5.6	7.6
3. Renewable Production: Landfill, Wind, Solar, Geothermal	1.1	1.9
4. REC Purchases	0.5	0.5
5. REC Sales	2.3	1.9
6. Market Price	2.1	-0.1
7. Resource Adequacy	5.0	1.4
8. Transmission/CAISO	5.0	5.2
9. Plant Outage	1.0	1.0
10. Western Cost	1.7	1.6
11. Legislative & Regulatory	0.0	0.0
12. Supplier Default+	0.2	0.2
Electric Supply Fund Risks	**28.4**	**25.6**

Of the risks faced by the Electric Utility's Supply Fund for FY 2027, the largest risk would be facing a dry year with very low hydroelectric output, accounting for one third ($7.6 million) of all the adverse cost uncertainty. Since the utility's costs for its hydroelectric resources are almost entirely fixed, costs do not decline when the output of those resources are low, but the utility needs to buy power to replace the lost output. The converse happens when hydroelectric output is higher than average.

Of the remaining risks for FY 2027, $5.2 million or 20% is related to potential transmission cost increases above staff's current forecast. $4.4 million or 17% is related to the potential that total load (and the associated retail sales revenue) may be lower than projected. Other risks are related to production from the City's renewable contracts and market prices for purchases and sales of energy and resource adequacy (Items 3, 4, 5, 6, and 7 above), totaling $5.6 million or 22%.

As shown in Figure 8, staff anticipates the Supply Operations Reserve will remain within guideline levels throughout the five year forecast period. Note that the high reserve level in FY

2023 is related to one-time revenues including a $24M refund from the successful litigation against the Bureau of Reclamation for overcharges related to power purchases from the Central Valley Project. These funds were redistributed to other purposes in FY 2024, with those transfers resulting in a reduction in the Supply Operations Reserve.

Figure 8: Electric Supply Operations Reserve Adequacy

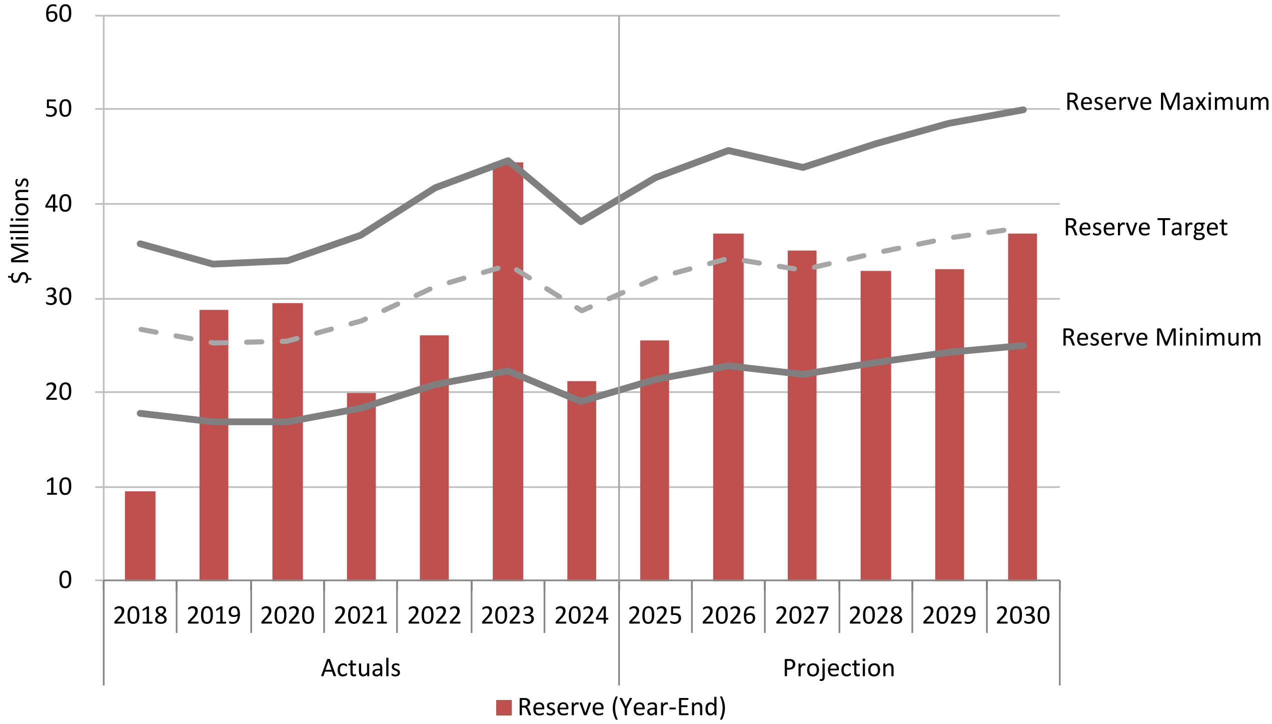


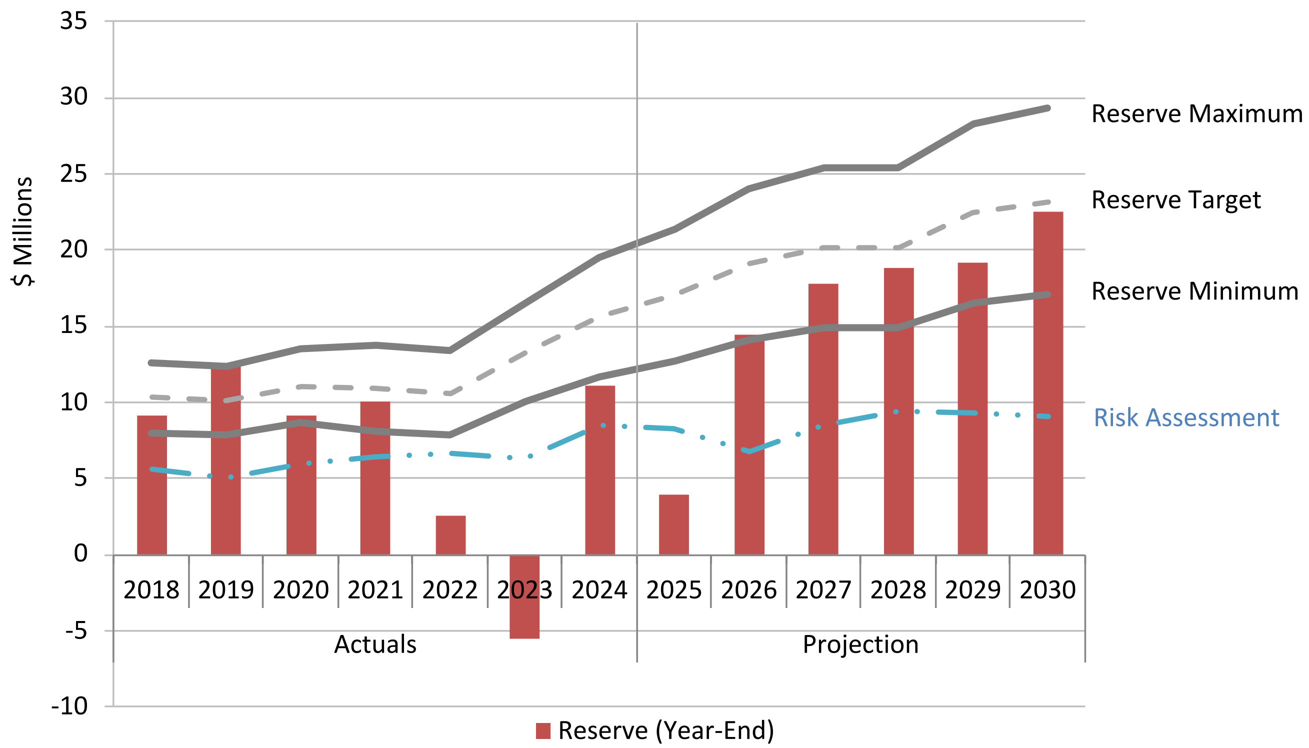
Table 7 summarizes the risk assessment calculation for the Distribution Operations Reserve through FY 2030. As shown in Figure 9, the Distribution Operations Reserve is projected to drop below the minimum reserve guideline range in FY 2025, and is also projected to drop below the risk assessment level. This Financial Forecast recommends a $5 million transfer from the Supply Operations Reserve to the Distribution Operations Reserve in FY 2025 to bring the Distribution Operations Reserve above zero. The Distribution Operations reserve is projected to recover to target levels over the course of the forecast period. The risk assessment includes the revenue shortfall that could accrue due to:

1. Lower than forecasted sales revenue; and
2. An increase of 10% of planned system improvement CIP expenditures for the budget year.

Table 7: Electric Distribution Fund Risk Assessment ($000)

Fiscal Year	2025	2026	2027	2028	2029	2030
Total non-commodity revenue	77,592	85,849	88,142	88,744	92,892	94,459
Max. revenue variance, previous 10 yrs	8%	8%	8%	8%	8%	8%
Risk of revenue loss	6,124	6,776	6,957	7,004	7,331	7,455
CIP Budget	21,066	-	15,297	23,796	19,172	15,804
CIP Contingency @10%	2,107	-	1,530	2,380	1,917	1,580
Total Risk Assessment value	8,231	6,776	8,486	9,384	9,249	9,036

Figure 9: Electric Distribution Operations Reserve Adequacy



Reserve Transfers

In last year's Financial Plan, staff proposed various reserve transfers to manage a one-year cash flow issue related to the grid modernization project. Council approved certain transfers recommended in last year's Financial Plan in FY 2024 and FY 2025. At year end FY 2024, staff evaluated the reserve levels based upon actual FY 2024 results and completed necessary transfers within the Council approved levels. Following is a list of each of the transfers Council approved for FY 2024 followed by a discussion of the actual transfers completed in FY 2024.

1) **Up to $20 million from the Electric Special Projects Reserve to the Supply Operations Reserve**

No transfer was necessary from the Electric Special Projects Reserves to the Supply Operations Reserve. Furthermore, the Electric Utility Supply Operations Reserve was able to repay $2.5

million of an earlier $10 million loan from the Electric Special Projects Reserve in FY 2024. The current balance of the Electric Special Projects Reserve is $22.6 million. This Financial Forecast proposes the Electric Utility Supply Operations Reserve to repay the Electric Special Projects Reserve the remaining $7.5 million of the internal loan in FY 2025. Council also approved a transfer of up to $30 million from the Supply Operations Reserve to the Electric Special Projects Reserve in FY 2025 so no further Council action is necessary for staff to complete this transfer (Resolution 10178[5]). Additionally, this forecast reflects repayments of $1 million per year from FY 2026 through FY 2030 to the Electric Special Projects Reserve for loans to the water and gas utilities for AMI investments.

2) **Up to $17 million from the Supply Operations Reserve to the Hydroelectric Stabilization Reserve**

Staff completed the $17 million transfer from the Supply Operations Reserve to the Hydroelectric Stabilization Reserve in FY 2024. The Hydroelectric Stabilization Reserve balance is $17.4 million, approaching the reserve's target level of $19 million. This level will allow the City to avoid activating the hydroelectric rate adjuster if upcoming winters are drier than average. The Electric Utility was in a position to make this transfer because of one-time sales revenues and supply cost savings in FY 2024 related to high hydroelectric generation resulting from the rainy winter of 2022/2023. In addition, market conditions enabled the utility to realize higher than usual sales revenue related to favorable hydrological conditions and high resource adequacy market prices.

3) **Up to $58 million from the Supply Operations Reserve to the Distribution Operations Reserve**

Staff completed a $42 million transfer from the Supply Operations Reserve to the Distribution Operations Reserve. Attachment C, Electric Utility Financial Details table shows the FY 2024 year-end Electric Operations Reserve (Supply and Distribution combined) is $32.2 million, which is approximately equal to the minimum guideline range. Figures 8 and 9 show the actual and projected reserve balances for each of these reserves. In FY 2025, staff proposes a transfer of up to $5 million from the Supply Operations Reserve to the Distribution Operations Reserve. The purpose of this transfer is to manage the Distribution Operations Reserve level given the short-term cash flow issue related to the grid modernization project. The debt issuance is not scheduled until FY 2026 while some of the CIP work will occur in FY 2025 and will temporarily be funded by the Electric Utility Distribution Operations Reserve.

Additionally, in accordance with the Electric Utility Reserve Management Practices (Attachment D), staff transferred $1.9 million from the Supply Operations Reserve to the Cap and Trade Reserve based upon actual Cap and Trade costs and revenues. The City maintains a Cap and Trade Program Reserve within the Electric fund to hold any revenues from the sale of carbon allowances freely allocated by CARB to the Electric Utility that are not spent within the fiscal year. Cap and Trade Program revenues are provided to the Electric Utility to support a wide variety of carbon reducing activities. Until the establishment of the REC Exchange program, adopted by Council in

[5] Resolution 10178, June 17, 2024, https://portal.laserfiche.com/Portal/DocView.aspx?id=83862&repo=r-704298fc

August 2020 (Staff Report #11556),[6] all of this Cap and Trade Program revenue was spent on purchasing renewable energy and none was held in reserve.

In accordance with Council's August 2020 direction, the City began selling City-owned renewable energy (Category 1 RECs, which mostly represent in-state renewable energy) and replacing them with purchased Category 3 RECs, which represent mostly out-of-state electricity. This exchange takes advantage of market conditions to reduce supply costs, fund electric utility programs and capital investment, and raise funds for local emissions reduction. On December 12, 2022[7] Council approved continuation of the program with 100% of revenue going to local emissions reduction. In accordance with Council policy, staff will fund the Cap and Trade Program Reserve with unspent revenues from the sale of carbon allowances freely allocated to the electric utility in an amount equal to 100% of each FY's Renewable Energy Credit (REC) Exchange program revenues, currently estimated to be between $0.7 million and $1.7 million going forward, for future local decarbonization projects.

Last year's financial plan amended the Electric Utility Reserve Management Practices to direct staff to transfer any unspent CIP budget that is not reappropriated or encumbered at the end of each fiscal year to the CIP Reserve. These represent ratepayer funds already collected for the purpose of CIP investment, and retaining them in the CIP Reserve allows the City to use them to fund future unanticipated CIP expenses (such as mid-year budget adjustments due to increased costs for specific projects) that were not included in a financial forecast. Last year's financial plan also recommended, and Council approved, a transfer of up to $5 million from the Electric Distribution Operations Reserve to the CIP Reserve in FY 2025. The Capital Reserve balance is $0.9 million, which is below the minimum guideline range. Staff will evaluate the year-end results in FY 2025 and complete a transfer to the Capital Reserve to bring it up to the minimum guideline if this is feasible.

Reserve Balance

The Electric Utility also has a CIP Reserve for short term capital contingencies and as a place to set aside funds for large, one-time projects that the Utilities would otherwise need to debt-fund. Figure 10 below reflects the maximum and minimum CIP Reserve guideline levels, starting in FY 2018 through FY 2030. Because of the fluctuating annual dollar amounts and timing of CIP projects budgeted to occur during the forecast period, as well as the potential for new ongoing projects to be included in the CIP plan in later years, four years of budgeted CIP are used to calculate the reserve maximum levels. The minimum CIP Reserve level is 20% of the maximum CIP Reserve guideline level.

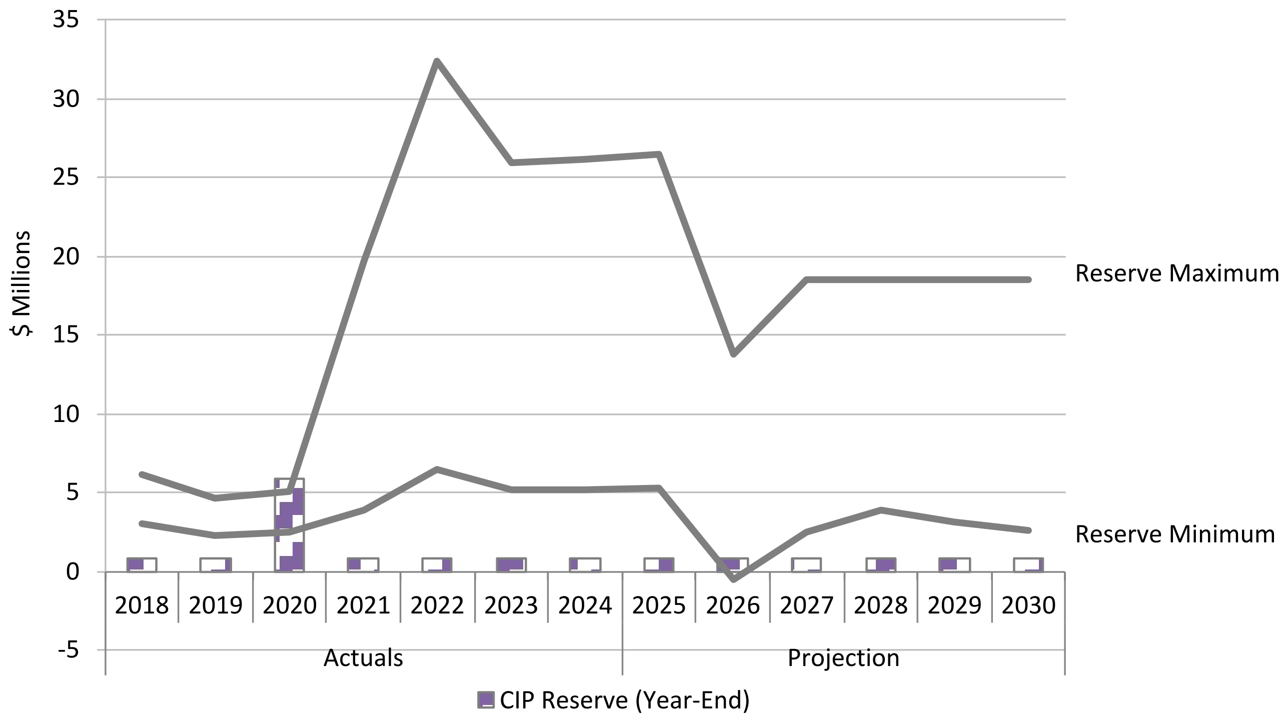
Last year's Financial Plan recommended to fund the CIP Reserve to its minimum level by the end of FY 2025, and Council approved a $5 million transfer in FY 2025 for this purpose. Staff will

[6] Staff Report 11556 https://www.cityofpaloalto.org/civicax/filebank/documents/78046
[7] December 12, 2022 Staff Report #14375 https://portal.laserfiche.com/Portal/DocView.aspx?id=59015&repo=r-704298fc

complete the transfer based on FY 2025 actual results, however, this forecast does not include funds for this transfer based upon current projections.

Figure 10 shows that the CIP reserve is not projected to be above the minimum guideline by the end of FY 2025. Per the Reserves Management Practices (Attachment D), Section 10, any rate plan that does not return CIP reserves to minimum levels within one year requires Council approval. Currently, reserves are being used to fund grid modernization spending as well as non-grid modernization Electric CIP spending in the current year. This will allow the Electric Utility to delay the first bond issuance for grid modernization to FY 2026. At this time, staff does not anticipate sufficient rate funding available to bring the CIP Reserve up to within guideline levels during the five year forecast period. Staff will revisit this next year, considering whether the $5 million was transferred to the CIP Reserve in FY 2025, along with the actual grid modernization expenditures and revenue bond issuance.

Figure 10: Electric CIP Reserve Adequacy



Reserves balances based on these revenue projections are shown in Figure 11 (for Supply Fund Reserves) and Figure 12 (for Distribution Fund Reserves), below.

The reserves charts below show significant increases in the Cap and Trade Program Reserve over the forecast period. Staff expects significant utilization of those funds for electrification programs.

Figure 11: Electric Utility Reserves (Supply Fund): Actual Reserve Levels through FY 2024 and Projections through FY 2030

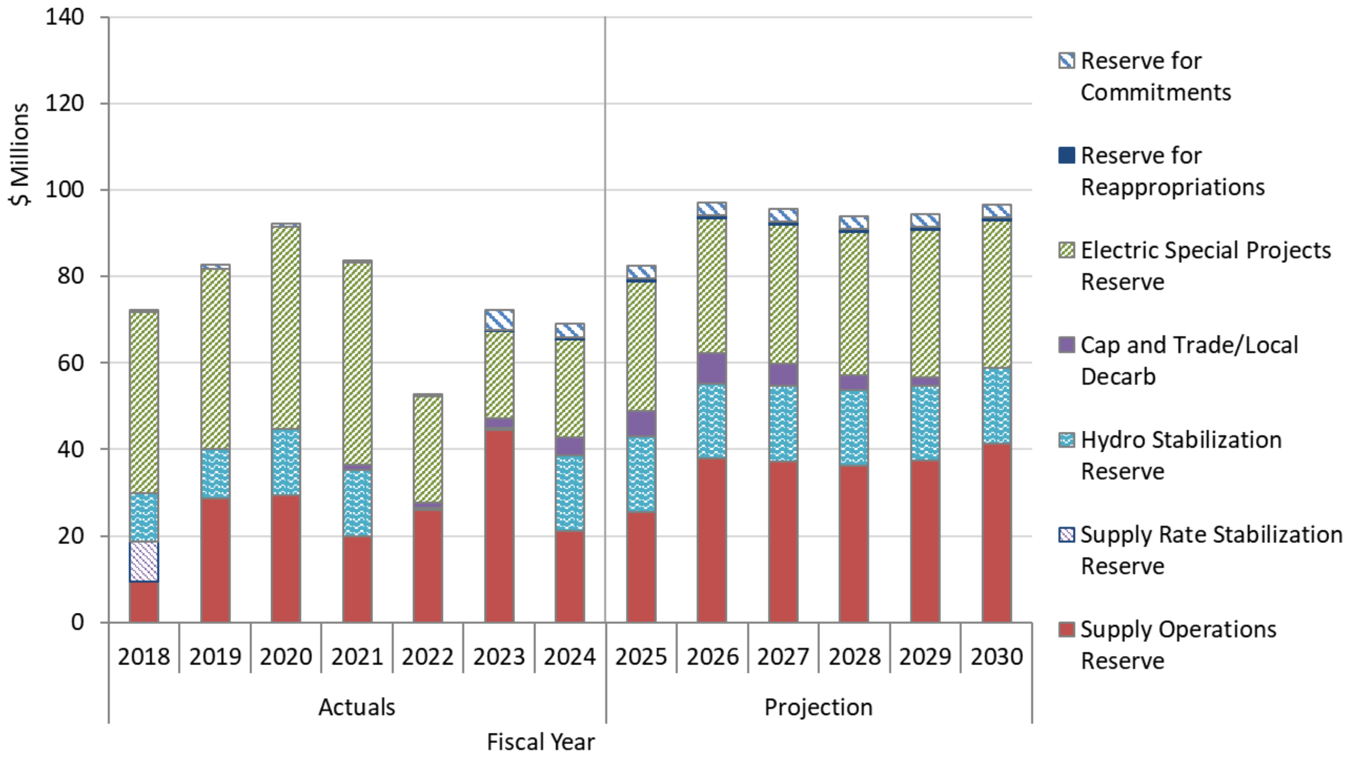


Figure 12: Electric Utility Reserves (Distribution Fund): Actual Reserve Levels through FY 2024 and Projections through FY 2030

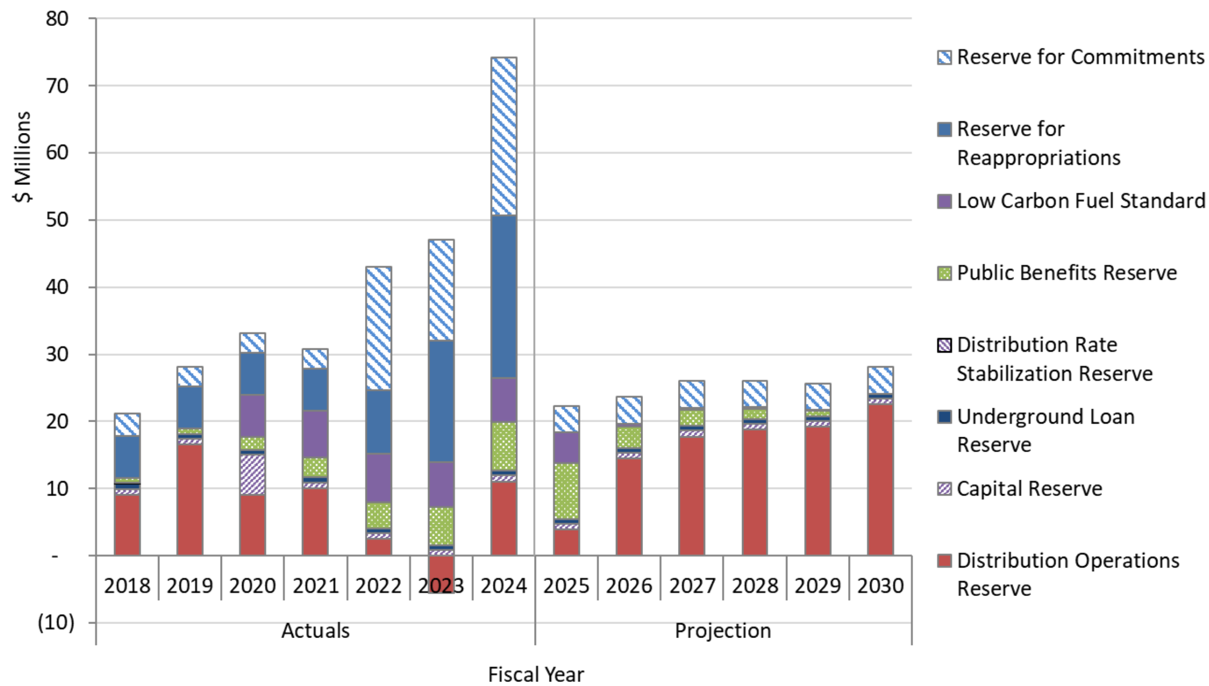


Table 13 shows the projected balance of each of the Electric Utility reserves for the period covered by this Financial Forecast. See also: Attachment C: Electric Utility Financial Table

Table 12: Electric Utility Reserves Starting and Ending Balances, Revenues, Transfers To/(From) Reserves, and Reserve Guideline Levels for FY 2025 to FY 2030 ($000)

	Fiscal Year	2025	2026	2027	2028	2029	2030
	Starting Reserve Balances						
1	Supply Operations	21,183	25,526	37,844	37,179	36,206	37,386
2	Distribution Operation	11,036	3,886	14,465	17,747	18,762	19,167
3	CIP Reserve	880	880	880	880	880	880
4	Electric Special Projects	22,649	30,149	31,169	32,189	33,209	34,229
5	Hydro Stabilization	17,400	17,400	17,400	17,400	17,400	17,400
6	Cap and Trade Program	4,122	5,832	7,042	5,282	3,521	1,761
7	Public Benefits	7,268	8,331	3,109	2,332	1,554	777
8	Low Carbon Fuel Standard (LCFS)	6,534	4,589	499	374	250	125
9	Electrification Reserve	4,500	4,500	4,500	4,500	4,500	4,500
	Revenues						
10	Supply	145,564	148,900	143,412	156,773	166,721	174,841
11	Distribution	76,623	82,546	85,587	85,989	89,109	90,961
12	Cap and Trade Revenues	2,992	2,999	3,024	3,013	3,039	3,039
13	Public Benefits Revenues	5,063	4,920	4,893	4,864	4,835	4,810
14	LCFS Revenues	1,120	1,232	1,355	1,400	1,400	1,400
15	Electrification Reserve Repayments	-	-	-	-	-	-
	Transfers from Supply Operations Reserve to Other Reserves or to Distribution Fund						
16	Distribution Operation	(5,000)	19,000	7,000	2,000	2,000	2,000
17	Electric Special Projects	(7,500)	(1,020)	(1,020)	(1,020)	(1,020)	(1,020)
18	Hydro Stabilization	-	-	-	-	-	-
19	Cap and Trade	-	-	-	-	-	-
16+17+18+19=20	Supply Operations Total	(12,500)	17,980	5,980	980	980	980
	Transfers from Distribution Operations Reserve to Other Reserves or to Supply Fund						
21	Supply Operations	5,000	(19,000)	(7,000)	(2,000)	(2,000)	(2,000)
22	CIP Reserve	-	-	-	-	-	-
23	LCFS	-	-	-	-	-	-
21+22+23=24	Distribution Operations Total	5,000	(19,000)	(7,000)	(2,000)	(2,000)	(2,000)
	Expenses						
25	Supply Funded Expenses	(128,721)	(154,561)	(150,058)	(158,726)	(166,521)	(171,839)
26	Distribution Non-CIP Expenses	(62,581)	(56,116)	(60,008)	(59,179)	(67,533)	(69,773)
27	Distribution Planned CIP Expense	(70,086)	3,149	(15,297)	(23,796)	(19,172)	(15,804)
28	Cap and Trade Expenses	(1,282)	(1,789)	(4,784)	(4,774)	(4,799)	(4,799)
29	Public Benefits Expenses	(4,000)	(10,143)	(5,670)	(5,641)	(5,612)	(5,587)
30	LCFS Expenses	(3,065)	(5,322)	(1,480)	(1,525)	(1,525)	(1,525)
31	Electrification Reserve Expenditures	-	-	-	-	-	-
	Ending Reserve Balance						
1+10+20+25=32	Supply Operations	25,526	37,844	37,179	36,206	37,386	41,368
2+11+24+26+27=33	Distribution Operation*	3,886	14,465	17,747	18,762	19,167	22,551
3+22=34	CIP Reserve	880	880	880	880	880	880
4-17=35	Electric Special Projects	30,149	31,169	32,189	33,209	34,229	35,249
5+18=36	Hydro Stabilization	17,400	17,400	17,400	17,400	17,400	17,400
6+12+19+28=37	Cap and Trade Program	5,832	7,042	5,282	3,521	1,761	-
7+13+29=38	Public Benefits	8,331	3,109	2,332	1,554	777	-
8+14+23+30=39	Low Carbon Fuel Standard	4,589	499	374	250	125	-
9+15+31=40	Electrification Reserve	4,500	4,500	4,500	4,500	4,500	4,500
	Operations Reserve Guidelines (Supply)						
	Minimum	21,370	22,840	21,947	23,210	24,281	24,934
	Maximum	42,741	45,680	43,894	46,421	48,562	49,869
	Operations Reserve Guidelines (Distribution)						
	Minimum	12,657	14,084	14,843	14,900	16,467	17,037
	Maximum	21,367	24,061	25,415	25,359	28,315	29,270
	CIP Reserve Guidelines						
	Minimum	5,301	(518)	2,515	3,912	3,151	2,598
	Maximum	26,507	13,779	18,517	18,517	18,517	18,517

**Includes funds of $43.895 million from the CIP Reappropriations and Commitments Reserves*

Cost of Service Supplement - Unmetered Electric Service (E-16) Rate

The City offers an E-16 rate for unmetered electric service for wireless communication facilities and related equipment on wood utility poles and streetlight poles. The E-16 unmetered service rate aligns closely with the E-2 rate for small commercial electric service and excludes costs related to meter reading and is determined based on the energy requirement of equipment specifications. The E-16 rate also includes miscellaneous electric utility charges such as licensing fees for City-owned spare conduit, usable space for utility pole attachments, and mounting communication equipment on utility poles and streetlight poles.

Wireless communication companies are experiencing increasing demand for fifth generation ("5G") wireless communication services and are expanding their wireless small cell network to improve their broadband facilities' capacity and coverage. CPAU engaged the services of EES Consulting (EES) to perform a cost of service analysis of the E-16 rate and update the rate schedule to ensure the City is recovering the actual costs of delivering these services (Attachment F). Since E-16 is limitedly applied, the last significant update was performed in when California Assembly Bill 1027 was enacted (now codified at Public Utilities Code sections 9510-9519). PUC 9510 et seq. limited local fees cities could charge authorized third party telecommunications providers to attach antennas to city-owned poles. In 2012, the annual licensing fee for mounting communication equipment on City-owned poles was reduced from $1,500 per pole to $270 per pole (Staff Report #3133[8]). EES recommends increasing this fee (also adopted by the Federal Communications Commission as a "safe harbor" rate in 2018) by the annual Consumer Price Index for All Urban Consumers in the San Francisco-Oakland-Hayward area since 2018. The recommended updated license fee is $329.44 per year per pole.

Table 13 compares the FY 2025 Current Rates and FY 2026 Proposed Rates for E-16, and incorporates updates to the other components of the E-16 rate schedule. The proposed customer charge of $10.96 reflects actual staff costs to administer the bills for unmetered customers. This charge will be updated annually based on the City's labor agreement salary schedule. The proposed pole attachment fee of $47.60 is based on the net book value of the poles plus annual operating costs. Since CPAU is planning for significant pole replacements in the next 5 years for grid modernization, CPAU will revisit this calculation with updates, as the net book value of the poles is expected to increase over time with the capital expenses planned. The proposed processing fee of $152 represents one hour of review by Engineering and Operations and is aligned to the C-1 hourly rate for utility miscellaneous charges.

[8] Staff Report #3133 https://www.cityofpaloalto.org/files/assets/public/v/1/agendas-minutes-reports/reports/city-manager-reports-cmrs/year-archive/2012/final-staff-report-id-3133_amendments-to-util-rate-schedule-e-16.pdf

TABLE 13: PROPOSED E-16 RATES

Service	Current Rate FY 2025	Proposed Rate FY 2026
C. Unmetered Electric Service		
1. Customer Charge, $/month	$9.00	$10.96
2. Energy Charge, $/kWh	Same as E-2	Same as E-2
E. Misc Rates		
1. Conduit License Fee, $/foot/year	$1.94	$1.94
2. Processing Fee for Electric Conduit Usage	Actual Cost	Actual Cost
3. Pole Attachment License Fee, $/Foot/Year	$29.51[1]	$47.60
4. Processing Fee for Utility Pole Attachments, $/pole	$55.00	$152.00
5. License Fee for mounting communication equipment including distributed antenna systems on utility poles, $/pole	$270.00	$329.44

1. The current rate includes a small incremental increase of $2.80/year for each additional foot of leased space up to 4 feet.

Proposed Rates

Bill Impacts

The City adopted its current electric rates effective July 1, 2024. At that time, the City did not increase the overall revenue but did implement a series of rate adjustments by customer class in accordance with the City of Palo Alto Electric Cost of Service and Rate Study, completed by EES Consulting in April 2024.[9] The current and proposed FY 2026 rates are reflected in Table 14 below:

[9] Palo Alto Electric Cost of Service and Rate Study https://www.cityofpaloalto.org/files/assets/public/v/3/agendas-minutes-reports/reports/city-manager-reports-cmrs/attachments/2024-rates/electric-cosa.pdf

Table 14: Current and Proposed Electric Rates

Rate Schedule	Current Rates (as of 7/1/24)	Proposed Rates (effective of 7/1/25)	Change	Change (%)
E-1 *(Residential)*				
Tier 1 Energy ($/kWh)	0.19461	0.20570	0.01109	5.7%
Tier 2 Energy ($/kWh)	0.21868	0.22944	0.01076	4.9%
Customer Charge ($/month)	4.64	5.15	0.51	11.0%
E-2 & E-2-G *(Small Non-Residential)*				
Summer Energy ($/kWh)	0.25210	0.26485	0.01275	5.1%
Winter Energy ($/kWh)	0.16414	0.17290	0.00876	5.3%
Customer Charge ($/month)	5.60	6.22	0.62	11.1%
E-4 & E-4-G *(Medium Non-Residential)*				
Summer Energy ($/kWh)	0.15387	0.16171	0.00784	5.1%
Winter Energy ($/kWh)	0.11018	0.11579	0.00561	5.1%
Summer Demand ($/kW)	45.29	47.59	2.30	5.1%
Winter Demand ($/kW)	23.73	24.94	1.21	5.1%
Customer Charge ($/month)	113.73	119.53	5.80	5.1%
E-7 & E-7-G *(Large Non-Residential)*				
Summer Energy ($/kWh)	0.13570	0.14262	0.00692	5.1%
Winter Energy ($/kWh)	0.08797	0.09245	0.00448	5.1%
Summer Demand ($/kW)	40.36	42.41	2.05	5.1%
Winter Demand ($/kW)	27.79	29.20	1.41	5.1%
Customer Charge ($/month)	520.80	547.36	26.56	5.1%

Table 15 shows the impact of the proposed July 1, 2025 rate changes on the residential and non-residential bills for various consumption levels. The increase for all rate classes is about 5.1%.

Table 15: Impact of Proposed Electric Rate Changes on Customer Bills in FY 2026

Rate Schedule	Usage (kWh/mo)	Peak Demand (kW-mo)	Bill under Current Rates ($/mo)	Bill Under Rates Proposed Rates ($/mo)	Change ($)	Change (%)
E-1 (Residential)	300	N/A	63.02	66.86	3.84	6.1%
	(Summer Median) 365	N/A	75.67	80.23	4.56	6.0%
	(Winter Median) 450	N/A	92.21	97.72	5.50	6.0%
	650	N/A	135.95	143.60	7.65	5.6%
	1,200	N/A	256.22	269.80	13.57	5.3%
E-2 (Small Non-Residential)	1,000	N/A	213.72	225.10	11.38	5.3%
E-4 (Medium Non-Residential)	160,000	274	30,693.47	32,253.66	1,560.19	5.1%
	500,000	856	95,666.79	100,515.02	4,848.23	5.1%
E-7 (Large Non-Residential	2,000,000	3,424	340,863.60	355,194.24	14,330.64	4.2%

Net Energy Metering Compensation Rates

The City operates two Net Energy Metering (NEM) programs. Solar customers served by the City of Palo Alto's (CPAU) original NEM program, also called NEM 1, are compensated at retail rates for electricity they export to the grid, and solar customers served by the NEM successor program, or NEM 2 (effective after the City reached its NEM 1 cap at the end of 2017), are compensated at the Export Electricity Compensation (EEC) rate for exported electricity.

Customers on the NEM 1 program who have chosen to have the value of any annual net generation they produced over the past 12 months credited back to their account do so under the Net Metering Net Surplus Electricity Compensation (E-NSE-1) rate. The Net Surplus Electricity Compensation rate represents the value of the City's avoided cost or value of customer-generated electricity in Palo Alto, including compensation for the energy, avoided capacity charges, avoided transmission and ancillary service charges, avoided transmission and distribution (T&D) losses, and renewable energy credits (RECs), or environmental attributes. Staff proposes decreasing the E-NSE-1 rate to $0.1012/kWh based on updated avoided cost calculations reflecting declines in long-term electricity market prices expected to continue into the future.

Under the City's NEM successor program, participating solar customers in Palo Alto are billed at the current retail rate for electricity drawn from the grid, and receive a credit for electricity they export to the grid at the EEC rate. This compensation rate also reflects the avoided cost or value of customer-generated electricity in Palo Alto, calculated on a forward-looking basis for the upcoming fiscal year. As shown in the table below, the current avoided cost for solar generation in Palo Alto is $0.1420/kWh, which is higher than the City's projected avoided cost, which requires the proposed NEM compensation rate (E-EEC-1) to decrease to $0.1206/kWh. This decrease in the overall avoided cost is driven by changes in electricity market prices. Table 16 shows the current and proposed NEM Buyback rates effective July 1, 2025.

Table 16: NEM Buyback Rates – Current vs. Proposed

Rate	Current $/kWh	Proposed $/kWh
Net Surplus Electricity (E-NSE-1)	$0.1427	$0.1012
Export Electricity (E-EEC-1)	$0.1420	$0.1206

Palo Alto Green (PAG) Program

The Palo Alto Green (PAG) program provides CPAU's commercial customers an opportunity to voluntarily pay a premium to receive renewable electricity credits to match their energy usage. Under this program, CPAU staff purchase and retire Green-e certified renewable energy certificates (RECs) in the wholesale market on behalf of PAG customers. This enables participating commercial customers to claim credit for the REC purchases in order to satisfy their corporate sustainability goals and meet federal "green certification" requirements.

The PAG charge is a pass-through charge; the revenue collected through the PAG rate premium is intended to fully recover the costs of administering the program. The PAG program has very low overhead costs (e.g., the cost of hiring an auditor to carry out an annual Green-e verification process for the program), so most of the program cost is the purchase cost of the RECs. In the past year the wholesale cost of Green-e certified RECs in the Western US market has remained relatively flat at around $7.75/REC. As such, the PAG rate premium should remain at $7.5 per 1,000 kWh block (.75 cents/kWh), enough to cover the cost of the RECs and overhead. The PAG rate premium is reflected on the Residential Master-Metered and Small Non-Residential Green Power Electric Service (E-2-G), the Medium Non-Residential Green Power Electric Service (E-4-G), and the Large Non-Residential Green Power Electric Service (E-7-G) rate schedules.

Bill Comparisons/Competitiveness

For the median consumption level, the CPAU residential electric monthly bill is about $83.94. This is about 50% lower than the monthly bill for a PG&E customer and about 22% higher than the bill for a City of Santa Clara (Silicon Valley Power) customer with the same consumption level, based on rates as of March 1, 2025. PG&E bill calculations are based on the "average" bundled total rates, including the annual climate credit, and Climate Zone X, which includes most nearby comparison communities.

Santa Clara's electrical system benefits from a higher load factor with a significantly larger commercial load compared to Palo Alto's, resulting in a more efficient distribution system and lower rates. However, unlike Palo Alto, Santa Clara's system is not 100% carbon neutral, as part of its electricity is generated from natural gas.

Table 17 provides sample residential bills for Palo Alto, PG&E, and the City of Santa Clara at various usage levels, calculated using rates as of March 1, 2025.

Table 17: Residential Monthly Electric Bill Comparison (Effective 3/1/2025, $/mo.)

Usage (kWh)	Palo Alto	PG&E	Santa Clara
300	63.02	113.11	51.23
(Median) 408	83.94	167.97	69.02
650	135.95	291.72	112.06
1200	256.22	572.39	209.68

For commercial customers, the CPAU electric monthly bill is about 46% to 57% lower than the bill for a PG&E customer, depending on usage levels. Compared to the City of Santa Clara, CPAU commercial bills are approximately 19% lower to 6% higher, depending on usage levels, based on rates as of March 1, 2025.

Table 18 presents sample commercial bills for Palo Alto, PG&E, and the City of Santa Clara at various usage levels, calculated using rates as of March 1, 2025.

Table 18: Commercial Monthly Electric Bill Comparison (Effective 3/1/2025, $/mo.)

Usage (kWh)	Palo Alto	PG&E	Santa Clara
1000	213.72	442.49	263.86
160,000	30,693.47	70,797.66	28,924.47
500,000	95,666.79	195,910.00	90,174.88
2,000,000	340,863.60	632,699.19	360,401.49

General Fund Transfer

The City calculates the General Fund Transfer from its Electric Utility based on a methodology adopted by Council in 2009, which has remained unchanged since then.[10] Each year it is calculated according to the 2009 Council-adopted methodology and does not require additional Council action.

[10] For more detail on the ordinance adopting the 2009 transfer methodology, see CMR 280:09, Budget Adoption Ordinance for Fiscal Years 2009 and 2010; and CMR 260:09, Finance Committee Report explaining proposed changes to the General Fund Transfer methodology.

Next Steps

Staff will incorporate the Finance Committee's recommendations into the draft financial forecast and attachments and bring those to the City Council in June. The City Council will consider the proposed financial forecast and rate schedules with the FY 2026 budget review and adoption process in June 2025. If Council approves the proposed rate changes, the rates will become effective July 1, 2025.

FISCAL/RESOURCE IMPACT

FY 2026 revenues are projected to increase 5% or $9.34 million from FY 2025 projected levels if Council adopts this financial forecast's recommendations. The City is a non-residential utility customer and can expect an increase to General Fund expenses (due to the rate increases) and revenues (due to the General Fund Transfer). Street light expenses (which are paid from the General Fund) are projected to increase by 11% or $0.22 million. The General Fund revenues from the General Fund Transfer would increase from an estimate of $15.985 million in FY 2025 to an estimated $17.407 million in FY 2026, an increase of $1.422 million.

POLICY IMPLICATIONS

The proposed electric rate adjustments are consistent with Council-adopted Reserve Management Practices that are part of the Financial Forecast and were developed using a cost-of-service study and methodology consistent with the California Constitution and industry-accepted cost of service principles.

STAKEHOLDER ENGAGEMENT

On December 3, 2024, staff discussed the preliminary rate proposals at the Finance Committee meeting. Finance Committee members made suggestions to separate the electric grid modernization costs in two categories to show: 1) costs that would have been needed in the next 10 years anyway, and 2) costs that are necessary for grid modernization and electrification. Committee members expressed interest in the portion of the electric rate increase attributable to grid modernization and interest in seeing non-residential bill comparisons and information about future rate changes, if available. The Finance Committee did not take any action on this item. The video of the meeting is available on the City's website at the following link: https://youtube.com/watch?v=-tshOdaDA3A?feature=share

On December 4, 2024, staff discussed the preliminary rate proposals at the UAC meeting. The UAC took no action. The transcript from the meeting is available on the City's website: https://cityofpaloalto.primegov.com/Public/CompiledDocument?meetingTemplateId=15106&compileOutputType=1 This proposal will be presented to City Council in June 2025 during the budget adoption process.

On April 2, 2025, staff presented rate proposals to the UAC. The UAC unanimously recommended approval of this proposal. The video of the meeting is available on the City's website at the following link: https://www.youtube.com/watch?v=021zJQHLADI

Attachment E contains examples of CPAU's communication and outreach methods including the use of the utilities website, utility bill inserts, messaging on utility bills and MyCPAU online account management platform, email newsletters, print and digital ads in local publications, social media, and business and neighborhood customer presentations.

ENVIRONMENTAL REVIEW

The Finance Committee's review and recommendation to the Council on the FY 2026 Electric Financial Forecast and rate adjustments does not meet the California Environmental Quality Act's definition of a project, pursuant to Public Resources Code Section 21065, thus no environmental review is required.

ATTACHMENTS

Attachment A: FY26 Electric Resolution
Attachment B: FY26 Electric Rate Schedules
Attachment C: FY26 Electric Utility and CIP Financial Details
Attachment D: FY26 Electric Reserves Management Practices
Attachment E: FY26 Electric Communications Plan and Samples
Attachment F: COSA Supplement - Unmetered Electric Service (E-16) Rate

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