CITY OF PALO ALTO

Finance Committee Staff Report

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

Meeting Date: April 23, 2024
Staff Report: 2401-2497

TITLE
Finance Committee to Review and Recommend to the City Council to Adopt a Resolution: 1) Approving the Fiscal Year (FY) 2025 Electric Financial Plan and Accepting the 2024 City of Palo Alto Electric Cost of Service and Rate Study, and 2) Amending 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-NSE (Net Metering Net Surplus Electricity Compensation), and E-EEC (Export Electricity Compensation) as Recommended by the Utilities Advisory Commission

RECOMMENDATION
Staff recommends that the Finance Committee review the Utilities Advisory Commission (UAC) recommendation and recommend the City Council Adopt a Resolution (Attachment A):

1. Accepting the 2024 City of Palo Alto Electric Cost of Service and Rate Study (Exhibit 1)
2. Approving the FY 2025 Electric Financial Plan (Exhibit 2), which includes the following actions:
    a. Amending the Electric Utility Reserves Management Practices (Attachment B), to direct staff to transfer to the CIP reserve, at the end of each fiscal year, any budgeted capital investment that remains unspent, uncommitted, and which is not proposed for reappropriation to the following fiscal year and to clarify how the Cap and Trade Program Reserve is adjusted each year.
    b. Approving the following transfers at the end of FY 2024:
        i. Up to $20 million from the Electric Special Projects Reserve to the Supply Operations Reserve;
        ii. Up to $17 million from the Supply Operations Reserve to the Hydroelectric Stabilization Reserve;
        iii. Up to $58 million from the Supply Operations Reserve to the Distribution

Operations Reserve; and

   c. Approving the following transfers in FY 2025:
      i. Up to $26 million from the Distribution Operations Reserve to the Supply Operations Reserve;
      ii. Up to $30 million from the Supply Operations Reserve to the Electric Special Projects Reserve; and
      iii. Up to $5 million from the Distribution Operations Reserve to the CIP Reserve;

3. Amending the following rate schedules effective July 1, 2024 (FY 2025), (Exhibit 3):
   a. Changing retail electric rates E-1 (Residential Electric Service), E-2 (Small Non-Residential Electric Service), E-4 (Medium Non-Residential Electric Service), E-4 TOU (Medium Non-Residential Time of Use Electric Service), E-7 (Large Non-Residential Electric Service), and E-7 TOU (Large Non-Residential Time of Use Electric Service) by varying percentages depending on rate schedule and consumption with an overall revenue increase of 0.5% effective July 1, 2024;
   b. Decreasing the Net Surplus Electricity Compensation (E-NSE-1) rate to reflect 2023 avoided cost, effective July 1, 2024; and
   c. Decreasing the Export Electricity Compensation (E-EEC-1) rate to reflect current projections of FY 2025 avoided cost, effective July 1, 2024;
   d. Updating 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 to reflect modified distribution and commodity components, effective July 1, 2024.

EXECUTIVE SUMMARY

The FY 2025 Electric Utility Financial Plan includes projections of the utility’s costs and revenues through FY 2028. Rate changes are recommended that vary significantly by customer class but that in aggregate result in little change (around an 0.5% increase) to total electric utility revenue in FY 2025. To ensure that electric rates continue to represent the Utility’s cost to serve customers, the City engaged the services of a consultant to prepare a cost of service analysis (COSA), which was completed in February 2024 (Attachment A, Exhibit 2) The COSA showed the need for different changes by customer class ranging from a 6% decrease for small non-residential customers (E-2) to a 2% increase for the residential class as a whole. However, recommended changes to the tier structure and the addition of a fixed charge result in a range of changes for residential customers depending on usage, with the median residential customer seeing a 9% increase. Palo Alto residential electric bills are approximately 50% lower than neighboring communities served by PG&E.

As of the drafting of this report, precipitation for the 2023/2024 water year was still below average. However, reservoir conditions are good as a result of last year’s rains, so staff is forecasting hydroelectric generation for FY 2025 and FY 2026 that is slightly higher than the baseline level assumed in its long-term projections. High one-time energy supply cost savings and surplus energy sales for FY 2024 are projected related to higher late summer 2023 hydroelectric generation resulting from the 2022/2023 winter rains. Other one-time revenues include higher than average sales revenue for resource adequacy and renewable energy credits (RECs) in FY 2024 through FY 2026 due to favorable market conditions. Some of these revenues are being used to replenish the hydroelectric stabilization reserve, reducing the chance that the City would need to activate the hydroelectric rate adjuster in the next few years, even if there is less snow and rain.

These one-time revenues are offset by significant capital investment costs associated with grid modernization ($50 million in FY 2024 and FY 2025), a rebuild of the Hanover substation ($15 million in FY 2024), and a new dark fiber backbone for the electric utility that will require some contribution from the electric utility ($13 million in FY 2026). Current plans anticipate offsetting these capital investments by issuing municipal bonds. However, reserves will need to absorb some of the costs in FY 2024 until the first bonds can be issued in FY 2025. This is leading to large reserve transfers in FY 2024 and FY 2025 to manage this short-term cash flow issue.

Total costs for the Electric Utility are projected to increase steadily through the forecast period. The largest contributors to these cost increases are increasing transmission costs, reduced sales revenue from surplus RECs and resource adequacy rights, and increasing debt service associated with grid modernization. Projecting the need for 5% per year rate increases through the forecast period. However, the electricity consumption projections in this report are conservative and increased load from electrification and any new large customer loads could reduce these projections. On the other hand, if the costs for grid modernization or other capital investment end up being higher than forecasted, as often occurs, those costs could offset the benefit of new customer loads.

BACKGROUND

Every year staff presents the Utilities Advisory Commission (UAC) and Finance Committee with Financial Plans for its Electric, Gas, Water, and Wastewater Collection Utilities and recommends any rate adjustments required to maintain their financial health. These Financial Plans include a comprehensive overview of the utility's operations, both retrospective and prospective, and are intended to be a reference for UAC and Council members as they review the budget and rate recommendations. Each Financial Plan also contains a set of Reserves Management Practices describing the reserves for each utility and the management practices for those reserves.

ANALYSIS

An annual assessment of the financial position of the City's Electric Utility is completed in compliance with cost of service requirements set forth in the California Constitution and applicable statutory law. The assessment includes making long-term projections of market conditions, of costs associated with the physical condition of infrastructure, and of other factors that could affect utility costs. Rates are then proposed that will move towards adequate cost recovery. This year's proposed rates are based on the models developed in the attached March 1, 2024 City of Palo Alto Electric Cost of Service and Rate Study by EES Consulting (Exhibit 2 to the attached resolution).

<u>Proposed Actions for FY 2024 and FY 2025</u>:

The FY 2025 Electric Utility Financial Plan (Exhibit 1 to the attached resolution) includes the following proposed actions:

1. Amending the Electric Utility Reserves Management Practices (Appendix B to the Financial Plan) to transfer to the CIP reserve, at the end of each fiscal year, any budgeted capital investment that remains unspent, uncommitted, and which is not proposed for reappropriation to the following fiscal year, and to clarify how the Cap and Trade Program Reserve is adjusted each year.
2. Approval of the following reserve transfers for the Electric Utility for FY 2024:
    a. Up to $20 million from the Electric Special Projects Reserve to the Supply Operations Reserve;
    b. Up to $17 million from the Supply Operations Reserve to the Hydroelectric Stabilization Reserve;
    c. Up to $58 million from the Supply Operations Reserve to the Distribution Operations Reserve; and
3. Approval of the following reserve transfers for the Electric Utility for FY 2025:
    a. Up to $26 million from the Distribution Operations Reserve to the Supply Operations Reserve
    b. Up to $30 million from the Supply Operations Reserve to the Electric Special Projects Reserve, and
    c. Up to $5 million from the Distribution Operations Reserve to the CIP Reserve
4. Approval of the following rate actions effective July 1, 2024 (FY 2025):
    a. Changing retail electric rates E-1 (Residential Electric Service), E-2 (Small Non-Residential Electric Service), E-4 (Medium Non-Residential Electric Service), E-4 TOU (Medium Non-Residential Time of Use Electric Service), E-7 (Large Non-Residential Electric Service), and E-7 TOU (Large Non-Residential Time of Use Electric Service) by varying percentages depending on rate schedule and consumption resulting in an overall revenue increase of 0.5% effective July 1, 2024;
    b. An increase to the Export Electricity Compensation (E-EEC-1) rate to reflect 2023 avoided cost, effective July 1, 2024;
    c. An increase to the Net Surplus Electricity Compensation (E-NSE-1) rate to reflect current projections of FY 2024 avoided cost, effective July 1, 2024; and
    d. An update to 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 to reflect modified distribution and commodity components, effective July 1, 2024.

The Hydroelectric Stabilization Reserve will receive a $17 million transfer, increasing its current balance from $400,000 to $17.4 million, approaching the reserve's target level of $19 million. This transfer is possible due to one-time revenues related to high hydroelectric generation in FY 2024, receipt of a $24 million judgment in a lawsuit related to Federal hydropower, and unusually high sales revenue from sales of surplus resource adequacy rights and RECs.

The $58 million interfund transfer from the Supply Operations Reserve to the Distribution Operations Reserve in FY 2024, followed by the return of $26 million in FY 2025 is related to the timing of debt issuance associated with major capital expenses, as described in the Executive Summary and in Section 3D (Proposed Reserve Transfers) of the attached FY 2025 Electric Utility Financial Plan. This will require a one-year $20 million additional loan from the Electric Special Projects Reserve in FY 2024 rather than the $10 million repayment of a previous loan that was approved in the FY 2024 Electric Utility Financial Plan. However, this Financial Plan includes repayment of the total $30 million in outstanding Electric Special Projects Reserve loans in FY 2025.

The amendments to the Electric Utility Reserves Management Practices (Appendix B to the Financial Plan) will simplify the administration of the CIP Reserve and Cap and Trade Program Reserves.

Table 1 below shows the effects of the proposed Council-approved transfers above on reserve funds as well as other planned or projected reserve transfers per the Council-approved Electric Utility Reserves Management Practices.

Table 1: Reserves Starting and Ending Balances, Revenues, Expenses, Transfers To/(From) Reserves, Operations and Capital (CIP) Reserve Guideline Levels for FY 2024 to FY 2029 ($000)

			FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
	Starting Reserve Balances							
1		Supply Operations	44,463	15,601	27,652	26,757	26,337	25,855
2		Distribution Operation	(5,581)	6,921	12,020	14,317	14,429	15,362
3		CIP Reserve	880	880	5,880	5,880	5,880	5,880
4		Electric Special Projects	20,149	149	30,149	32,149	34,149	36,149
5		Hydro Stabilization	400	17,400	17,400	17,400	17,400	17,400
6		Cap and Trade Program	2,231	3,231	4,941	6,151	7,231	8,141
7		Public Benefits	5,673	7,431	9,033	10,569	12,032	13,422
8		Low Carbon Fuel Standard (LCFS)	6,713	4,053	1,486	-	-	-
9		Electrification Reserve	4,500	4,500	4,500	4,500	4,500	4,500
	Revenues							
10		Supply	145,323	142,902	133,822	133,976	136,567	139,122
11		Distribution	71,803	69,511	75,545	82,068	88,469	92,046
12		Cap and Trade Revenues	3,016	2,992	2,999	3,024	3,013	3,039
13		Public Benefits Revenues	4,780	4,690	4,584	4,551	4,520	4,488
14		LCFS Revenues	1,100	1,120	1,232	1,355	1,400	1,400
15		Electrification Reserve Repayments	-	-	-	-	-	-
	Transfers from Supply Operations Reserve to Other Reserves or to Distribution Fund							
16	From/(To)	Distribution Operation	(58,000)	26,000	-	2,000	2,000	2,000
17	From/(To)	Electric Special Projects	20,000	(30,000)	(2,000)	(2,000)	(2,000)	(2,000)
18	From/(To)	Hydro Stabilization	(17,000)	-	-	-	-	-
19	From/(To)	Cap and Trade	-	-	-	-	-	-
20: =16+17+18+19		Supply Operations Total	(55,000)	(4,000)	(2,000)	-	-	-
	Transfers from Distribution Operations Reserve to Other Reserves or to Supply Fund							
21	From/(To)	Supply Operations	58,000	(26,000)	-	(2,000)	(2,000)	(2,000)
22	From/(To)	CIP Reserve	-	(5,000)	-	-	-	-
23	From/(To)	LCFS	-	-	-	-	-	-
24: =21+22+23		Distribution Operations Total	58,000	(31,000)	-	(2,000)	(2,000)	(2,000)
	Expenses							
25		Supply Funded Expenses	(119,185)	(126,851)	(132,717)	(134,396)	(137,049)	(139,289)
26		Distribution Non-CIP Expenses	(50,482)	(52,153)	(58,105)	(65,285)	(72,848)	(74,969)
27		Distribution Planned CIP Expense	(66,884)	18,655	(15,143)	(14,671)	(12,688)	(13,089)
28		Cap and Trade Expenses	(2,016)	(1,282)	(1,789)	(1,944)	(2,103)	(2,309)
29		Public Benefits Expenses	(2,956)	(3,003)	(3,049)	(3,088)	(3,130)	(3,177)
30		LCFS Expenses	(3,759)	(3,687)	(2,718)	(1,355)	(1,400)	(1,400)
31		Electrification Reserve Expenditures	-	-	-	-	-	-
	Ending Reserve Balance							
32: =1+10+20+25		Supply Operations	15,601	27,652	26,757	26,337	25,855	25,687
33: =2+11+24+26+27		Distribution Operation	6,856	11,934	14,317	14,429	15,362	17,350
34: =3+22		CIP Reserve	880	5,880	5,880	5,880	5,880	5,880
35: =4+17		Electric Special Projects	149	30,149	32,149	34,149	36,149	38,149
36: =5+18		Hydro Stabilization	17,400	17,400	17,400	17,400	17,400	17,400
37: =6+12+19+28		Cap and Trade Program	3,231	4,941	6,151	7,231	8,141	8,871
38: =7+13+29		Public Benefits	7,497	9,119	10,569	12,032	13,422	14,733
39: =8+14+23+30		Low Carbon Fuel Standard	4,053	1,486	-	-	-	-
40: =9+15+31		Electrification Reserve	4,500	4,500	4,500	4,500	4,500	4,500
	Operations Reserve Guidelines (Supply)							
		Minimum	21,063	22,111	22,412	22,874	23,149	23,601
		Maximum	42,126	44,221	44,824	45,749	46,297	47,202
	Operations Reserve Guidelines (Distribution)							
		Minimum	10,800	11,701	12,742	14,084	14,526	14,763
		Maximum	17,736	19,382	21,303	23,821	24,530	24,824
	CIP Reserve Guidelines							
		Minimum	1,192	2,489	2,412	2,086	2,152	2,223
		Maximum	5,962	13,898	13,494	13,494	13,494	13,494

Table 2 shows the proposed and projected electric rates for FY 2025 through FY 2029. As noted above a set of rate changes are recommended consistent with the attached March 1, 2024 City of Palo Alto Electric Cost of Service and Rate Study by EES Consulting (GDS Associates) that result in an approximately 0.5% increase in revenue for FY 2025. The rate changes by customer class and customer usage are discussed further in this report.

Table 1: Projected Electric Rates, FY 2024 to FY 2029

Projection	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Current	-6% to +9%[1]	5%	5%	5%	5%
Last Year	5%	5%	5%	5%	N/A

FY 2025 Financial Plan Projected Rate Adjustments for the Next Five Fiscal Years

Table 3 shows the impact on the annual median residential electric bill (453 kwh per month in winter, 365 kwh per month in summer). Customers experienced a rate reduction in FY 2024 as the hydroelectric rate adjuster was deactivated. The proposed rate changes in FY 2025 are expected to increase the median residential bill by 5%. Future year increases of 5% per year are also projected.

Table 3: Actual/Proposed/Projected Residential Bill Impacts, FY 2023 to FY 2029

	Mid-year FY 2023	Current	Proposed	Projected			
		FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Estimated Bill Impact ($/mo) *							
Base Bill Only	$63.73	$76.82	$84.27	$88.82	$93.64	$98.72	$104.09
With Hydro Rate Adjuster	$83.37	$76.82	No Hydro Rate Adjuster forecasted				

* Estimated impact on median monthly residential electric bill

Figure 1 shows the overall Electric Utility's costs (net of surplus sales revenues) in FY 2020, FY 2025, and FY 2029. Since FY 2025 is projected to have lower than usual electric supply costs, the rate of increase for the electric supply portfolio from FY 2020 to FY 2025 is minimal. Both FY 2024 and FY 2025 have unusually low electric supply costs, but if the comparison were done to FY 2023 or FY 2026 it would show a significant increase from FY 2020 levels, on the order of 4% to 5% per year on average, and a similar rate of increase is expected through FY 2029 as transmission and related electric supply costs continue to increase.

The distribution costs for FY 2025 in Figure 1 are also unusual due to the timing of various capital investments and related debt issuances in FY 2024 and FY 2025. If a more representative year were shown (such as FY 2026) it would show operational and capital investment costs increasing at a rate of 5% to 6% per year from FY 2020 through today with a similar rate forecasted for the next five years. The forecasted increases in distribution cost relate primarily to debt service for the grid modernization project as well as continuing construction inflation and other inflation.

[1] Rates for individual customers may vary significantly from this projection based on their consumption patterns.

Combined, the utility's costs 4% to 5% per year on average for the last few years (after adjusting for the unusually low FY 2025 expenses) and are forecasted to increase at a similar rate for the next five years, necessitating ongoing 5% per year rate increases.

Figure 1: Electric Utility Costs, FY 2020 Actual vs. FY 2025 and FY 2029 Projections

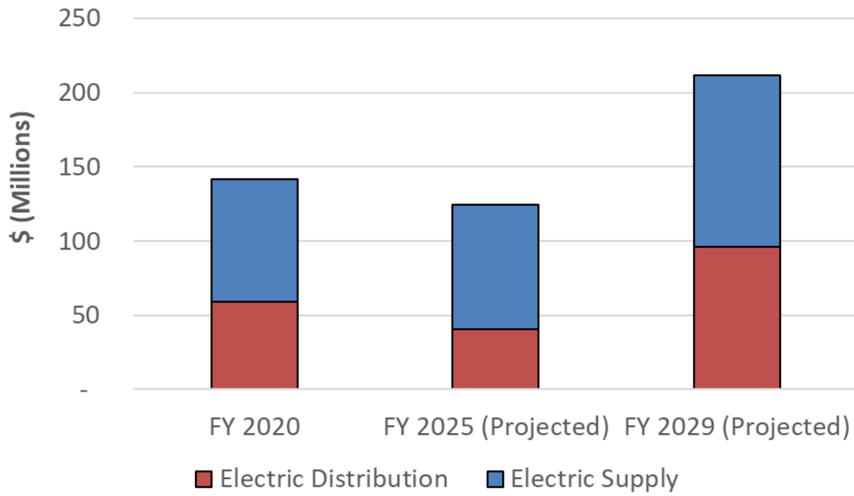


Figure 2 shows distribution costs. Operational costs increased about 6% per year from FY 2020 to FY 2025. Due to higher than anticipated staff vacancies, more expensive external contracts have been needed to complete necessary electric system maintenance. Salary and benefit costs have increased, and inflation has increased operating costs. There is greater spending on sustainability and energy efficiency initiatives to achieve S/CAP goals, though much of this is funded by dedicated funding sources not reflected in the chart below. Operational costs are projected to increase at a lower rate, 3% to 4% per year, over the forecast period.

Capital costs for FY 2025 are unusual, showing a net refund as planned bond issuance debt proceeds are used to fund significant capital expenses, allowing the utility to replenish reserves. Future capital investment rates are expected to stay fairly stable as most of the electric utility capital investment activity is focused on grid modernization. The projected debt service for this effort is shown in Figure 2. With growth in debt service included capital-related expenses are expected to grow 7% per year on average, leading to an overall growth rate for distribution costs of 5% to 6% per year.

Figure 2: Electric Distribution Costs, FY 2020 vs. FY 2025 and FY 2029 Projections

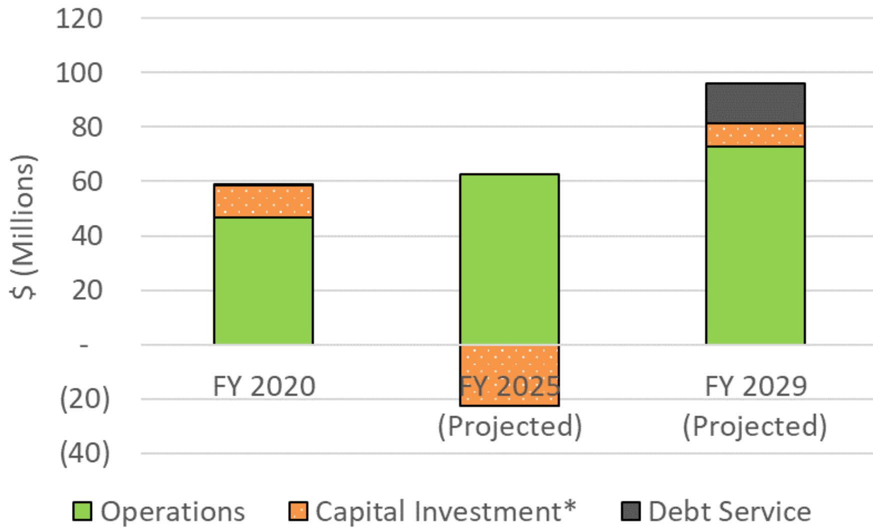
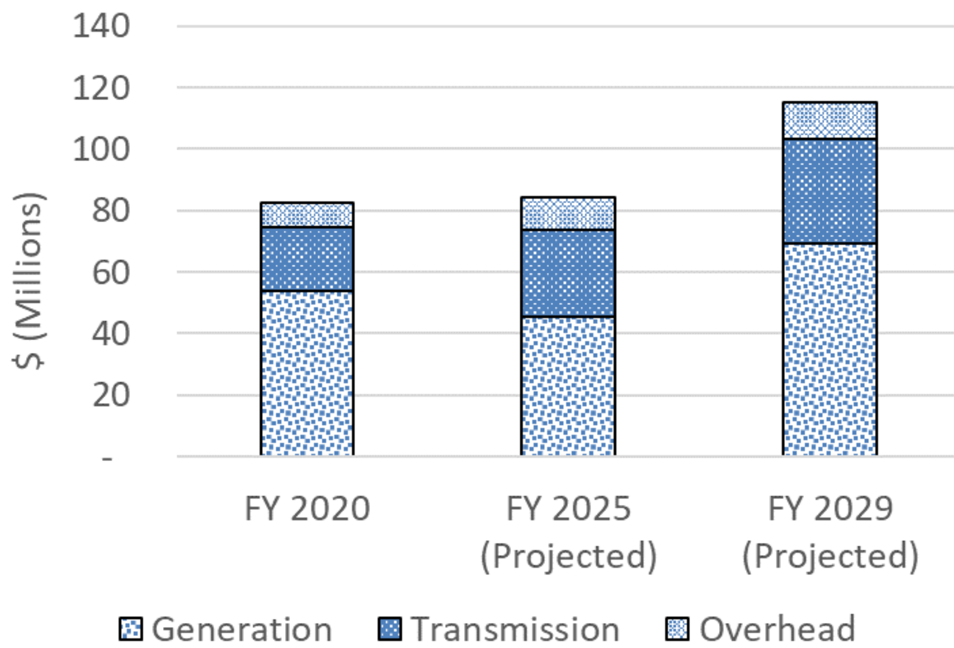


Figure 3 shows commodity costs did not increase significantly from FY 2020 to FY 2025 but as noted above, this is because FY 2025 generation expenses are projected to be lower than usual due to surplus resource adequacy and REC sales revenues that are not expected to continue through the forecast period. Excluding these one-time revenues generation costs have increased 2% to 3% per year since FY 2020 and are expected to increase at a similar rate through FY 2025. Transmission costs increased by 6% annually in the same timeframe and are projected to increase by about 5% annually in future years. These increases are due to rehabilitation and replacement of the statewide electric transmission system as well as expansion of that system to accommodate new generation, mostly renewable.

Cost containment maintains a core value, specifically containment of transmission costs through partner agencies, including the Transmission Agency of Northern California (TANC) and Northern California Power Agency (NCPA), and through direct partnerships with other local utilities (the Bay Area Municipal Transmission group, BAMx). These groups intervene in transmission proceedings at the Federal Energy Regulatory Commission (FERC) and the California Independent System Operator (CAISO) and have achieved some reductions in long-term transmission costs. Cost savings in electric supply and overhead wherever feasible are also sought.

Figure 3: Electric Supply Costs, FY 2019 Actual vs. FY 2024 and FY 2028 Projections



Staff recognizes the importance of managing operating costs and maximizing efficiency to minimize rate increases. As reflected in the Utilities Strategic Plan, staff regularly explores additional ways to effectively use available resources, particularly across divisions.

Electric Bill Comparison with Surrounding Cities

For the median consumption level, the annual CPAU residential electric bill for calendar year 2023 was $964, which was $667 (41%) lower than the annual bill for a PG&E customer with the same consumption ($1,632) and approximately $136 (34%) higher than the annual bill for a City of Santa Clara customer ($718). However, both PG&E and Santa Clara increased rates significantly on January 1, 2024. As shown in Table 8, below, the Palo Alto winter and summer median residential bills are only 18% and 11% higher than Santa Clara, which is about the same as the historical difference between the two, so the high difference for CY 2023 only reflects the fact that the City acted earlier than Santa Clara in recognizing increasing long-term commodity costs. This was something the City had to implement due to low reserves resulting in part from avoiding rate increases through the COVID-19 pandemic to help residents manage the pandemic's economic impact. The PG&E bills based on the January 1, 2024 rates are 50% to 60% higher than Palo Alto, reflecting an increasing cost advantage for Palo Altans over utility customers in PG&E territory. The bill calculations for PG&E customers are based on PG&E Climate Zone X, which includes most surrounding comparison communities.

Table 4 presents sample median residential bills for Palo Alto, PG&E, and the City of Santa Clara (Silicon Valley Power) for several usage levels. Rates used to calculate the monthly bills shown below were in effect as of January 1, 2024.

Table 4: Residential Monthly Electric Bill Comparison (Effective 1/1/2024, $/mo.)

Season	Usage (kwh)	Palo Alto	PG&E	Santa Clara
Winter	300	52.56	126.03	49.02
	453 (Median)	88.16	191.88	74.93
	650	136.75	295.44	108.29
	1200	274.41	584.55	201.42
Summer	300	52.56	130.78	49.02
	(Median) 365	66.45	153.33	60.03
	650	136.75	314.76	108.29
	1200	282.18	603.87	161.54

Staff is updating its methodology for commercial customer rate comparisons and aims to provide an update in the FY 2026 Financial Plan. Commercial rate comparisons are significantly more complicated than residential bill comparisons due to more complex rate designs and greater customer load diversity, and staff is working to develop an accurate and simple reflection of commercial bill comparisons.

Proposed Rate Changes

Services of a consultant were engaged to review and revise the Electric Utility's Cost of Service study and rates. This study, the March 1, 2024 City of Palo Alto Electric Cost of Service and Rate Study by EES Consulting (GDS Associates), examined how the City's costs are allocated among the residential and commercial classes and recommended some realignments. In general costs increased more for residential than non-residential customer classes due to changes in consumption patterns compared to those reflected in the current rates. In addition, increased usage in the residential class led to some recommended changes to the current tiered rate design, increasing the Tier 1 allowance and narrowing the difference between the tiers. Lastly, the minimum bill included in the current rate schedules is recommended to be replaced with a modest fixed charge.

The community's electric use has been changing over time due to the economic disruptions of the pandemic, gradual relocation of industrial users from Palo Alto, adoption of electric vehicles, solar, and building electrification, and may shift more in the future as the pace of vehicle and building electrification picks up and if new commercial loads come online. Rate design changes will be needed to take advantage of new technologies, particularly advanced metering infrastructure. Due to these changes an update to the COSA model is expected more frequently in the coming years and adjust rate designs and cost allocations among classes as needed.

The current rates and proposed FY 2025 rates are reflected in Table 5 below:

Table 5: Current and Proposed Electric Rates

	Current Rates	Proposed Rates (7/1/2024)	Change	
			$	%
E-1 (Residential)				
Tier 1 Energy ($/kWh)	0.17522	0.19461	0.01939	11%
Tier 2 Energy ($/kWh)	0.24666	0.21868	-0.02798	-11%
Customer Charge ($/day)		0.15250	0.15250	
E-2 & E-2-G (Small Non-Residential)				
Summer Energy ($/kWh)	0.26560	0.25210	-0.01350	-5%
Winter Energy ($/kWh)	0.18626	0.16414	-0.02212	-12%
Customer Charge ($/day)		0.18410	0.18410	
E-4 & E-4-G (Medium Non-Residential)				
Summer Energy ($/kWh)	0.16363	0.15387	-0.00976	-6%
Winter Energy ($/kWh)	0.12667	0.11018	-0.01649	-13%
Summer Demand ($/kW)	36.82668	45.29000	8.46332	23%
Winter Demand ($/kW)	24.16296	23.73000	-0.43296	-2%
Customer Charge ($/day)		3.73900	3.73900	
E-7 & E-7-G (Large Non-Residential)				
Summer Energy ($/kWh)	0.14561	0.13570	-0.00991	-7%
Winter Energy ($/kWh)	0.09856	0.08797	-0.01059	-11%
Summer Demand ($/kW)	39.08286	40.36000	1.27714	3%
Winter Demand ($/kW)	21.71270	27.79000	6.07730	28%
Customer Charge ($/day)		17.12210	17.12210	

Table 6 shows the impact of the proposed July 1, 2024 rate changes on the residential and non-residential bills for various consumption levels. The rate changes vary by customer class due to the completion of a cost-of-service analysis as noted above. The rate change for the median residential customer is 9%. Because of the addition of a customer charge and the changes in the design of the tiers for the E1 customer class usage in this class varies widely depending on consumption, generally increasing for customers who use less electricity and decreasing for those who use more. This trend is expected to continue when the utility moves to time of use rates, which provides prices that vary by time of day rather than by how much electricity a customer uses in a month. It is worth noting, however, that increases among low users, while large in percentage terms, are not more than $10.63 per month on average, most low users will see lower increases).

Table 6: Impact of Proposed Electric Rate Changes on Customer Bills

Rate Schedule	Usage (kWh/mo)	Peak Demand (kW-mo)	Bill under Current Rates ($/mo)	Bill Under Rates Proposed 7/1/24 ($/mo)	Change	
					$/mo	%
E-1 (Residential)	300	N/A	$52.57	$63.02	$10.46	20%
	(Summer Median) 365	N/A	$66.46	$75.67	$9.22	14%
	(Winter Median) 453	N/A	$88.16	$92.87	$4.71	5%
	650	N/A	$136.75	$135.95	($0.81)	-1%
	1200	N/A	$272.42	$256.22	($16.20)	-6%
E-2 (Small Non-Residential)	1,000	N/A	$225.93	$213.72	($12.21)	-5%
E-4 (Medium Non-Residential)	160,000	274	$31,580	$30,693	($887)	-3%
	500,000	856	$98,680	$95,667	($3,014)	-3%
E-7 (Large Non-Residential	2,000,000	3,424	$348,247	$340,864	($7,383)	-2%

In addition to the rate changes and bill impacts shown above, there are a few additional changes to the E-4 and E-7 rate schedules meant to simplify and clarify those schedules. These changes do not have significant financial impacts:

- Remove language about three phase service from the E-4 applicability section
- Remove the power factor adjustment from the E-4 and E-7 rate schedules.
- Update the primary voltage discount and standby charges to match the COSA.

<u>Net Energy Metering Buyback Rates</u>

The City operates two Net Energy Metering (NEM) programs. Solar customers served by the CPAU's original NEM program, NEM 1, are compensated at retail rates for net 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 (E-EEC-1) 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. Both surplus compensation rates are based on the City's renewable energy costs, but the calculation methodologies differ slightly to reflect the different characteristics of the NEM programs they are used for and the different regulations applicable to those programs. More detail on these rates is included in Section 3B (Current and Proposed Rates) of the FY 2025 Electric Utility Financial Plan.

The E-NSE-1 rate is recommended at $0.1427/kWh based on updated cost calculations reflecting the current electricity market prices. The Export Electricity Compensation (E-EEC-1) compensation rate is recommended at $0.1420/kWh based on projected market prices.

Table 8: NEM Compensation Rates – Current vs. Proposed

Rate	Current $/kWh	Proposed $/kWh
Net Surplus Electricity (E-NSE)	$0.1535	$0.1427
Export Electricity (E-EEC)	$0.1685	$0.1420

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 purchases and retires Green-e certified 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. In the past year the wholesale cost of Green-e certified RECs in the Western US market has remained relatively flat at around $7.00/REC. As such, the PAG rate premium should remain at $7.5 per 1,000 kWh block (.75 cents/kWh), which includes both the price of the RECs and the administrative overhead.

TIMELINE

The City Council is scheduled to review the FY 2025 Electric Financial Plan[2] and will consider adopting the Financial Plan and rate amendments as part of the FY 2025 budget review and adoption process.

FISCAL/RESOURCE IMPACT

FY 2025 revenues are projected to remain very close to FY 2024 levels if Council adopts this report's recommendations. The City is a non-residential utility customer and can expect a decrease in estimated City utility expenses of about $160,000, approximately $85,000 of that

[2]FY 2025 Electric Financial Plan https://www.cityofpaloalto.org/files/assets/public/v/2/agendas-minutes-reports/reports/city-manager-reports-cmrs/attachments/03-01-2023-id-2301-0844-fy24-electric-utility-financial-plan.pdf

being in the General Fund. Street light expenses (which are paid from the General Fund) are projected to decrease by about $180,000. Resource impacts to City departments and funds of the recommended rate adjustments are programmed in the FY 2025 Proposed Operating Budget. If the final rates adopted by Council in June differ from those proposed in this report, further adjustments may be brought forward as part of the annual budget process.

COMMISSION REVIEW

The UAC reviewed the staff proposal on March 6, 2024 and voted to unanimously recommend that Council adopt the staff recommendation after various in-depth questions by Commissioners on the structure of the residential and commercial rates, the future of time of use, changes in customer demand, solar impacts and rates, the debt service planned for grid modernization, and details of the cost of service study methodology.

STAKEHOLDER ENGAGEMENT

Stakeholder engagement for the rate adoption process includes review by the UAC, Finance Committee, and City Council, as well as outreach to residents via the website and social media.

ENVIRONMENTAL REVIEW

The Finance Committee's review and recommendation to the Finance Committee on the FY 2024 Electric Financial Plans 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: Resolution FY 2025 Electric Rates
Attachment A Exhibit 1.1: COSA Report
Attachment A Exhibit 1.2: COSA Technical Appendix
Attachment A Exhibit 2: Electric Utility Financial Plan FY25
Attachment A Exhibit 3: Electric Rate Schedules
Attachment B: Proposed Amended Electric Utility Reserves Management Practices

APPROVED BY:
Dean Batchelor, Director of Utilities