FY 2024 ELECTRIC UTILITY FINANCIAL PLAN

FY 2024 TO FY 2028

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SECTION 1: DEFINITIONS AND ABBREVIATIONS

CAISO California Independent System Operator
CARB California Air Resources Board
CIP Capital Improvement Program
CPAU City of Palo Alto Utilities Department
CPUC California Public Utilities Commission
CVP Central Valley Project
GWh a gigawatt-hour, equal to 1,000 MWh or 1,000,000 kWh. Commonly used for discussing total monthly or annual electric load for the entire city, or the monthly or annual output of an electric generator.
kWh a kilowatt-hour, the standard unit of measurement for electricity sales to customers.
kW a kilowatt, a unit of measurement used in reference a customer's peak demand (the highest 15 minute average consumption level in a month), which is used for billing large and mid-size commercial customers.
kV a kilovolt, one thousand volts, a unit of measurement of the voltage at which a section of the distribution system operates. The transmission system operates at 115-500 kV, and this is lowered to 60 kV in the sub-transmission section of the Electric Utility's distribution section, then 12 kV or 4 kV in the rest of the distribution system, and finally 120, 240, or 480 volts at the electric outlet.
MWh a megawatt-hour, equal to 1,000 kWh. Commonly used for measuring wholesale electricity purchases.
MW a megawatt, equal to 1,000 kW. Commonly used when discussing maximum electricity demand for all customers in aggregate.
PG&E Pacific Gas and Electric
REC Renewable Energy Certificate
RPS Renewable Portfolio Standard
Sub-transmission System: The section of the Electric Utility's distribution system that operates at 60 kV and which interfaces with PG&E's transmission system.
Transmission System: Sections of the electric grid that operate at high voltages, generally 115 kV or more. The voltage at the intersection of the Electric Utility's distribution system and PG&E's transmission system is 115 kV. The Electric Utility does not own or operate any transmission lines.
UCC Utility Control Center
SCADA Supervisory Control and Data Acquisition system, the system of sensors, communications, and monitoring stations that enables system operators to monitor and operate the system remotely.
WAPA, or **Western:** Western Area Power Administration, the agency that markets power from CVP hydroelectric generators and other hydropower owned by the Bureau of Reclamation.

SECTION 2: EXECUTIVE SUMMARY AND RECOMMENDATIONS

This document presents a Financial Plan for the City of Palo Alto (City) Electric Utility for the next five-year forecast, FY 2024 - 2028. This Financial Plan describes how revenues will cover the costs of operating the utility safely over that time while adequately investing for the future. It also addresses the financial risks facing the utility over the short term and long term and includes measures to mitigate and manage those risks.

SECTION 2A: OVERVIEW OF FINANCIAL POSITION

From July 2019 through April 2022 the City did not increase rates, to mitigate the economic impact of the COVID-19 pandemic on residents and businesses. In that time supply and distribution expenses increased $50 million (30%). The expense increases combined with pandemic-related electricity sales revenue declines created a $43 million shortfall in FY 2022. Some of this was related to the impacts of extreme drought and rising electricity market prices, and in response, the City activated the hydroelectric rate adjuster (E-HRA) in April 2022. In 2023 the City began increasing base rates to begin recovering costs, starting with a 5% rate increase on July 1, 2022. The intent was to use loans from the Electric Special Projects Reserve and what Operations Reserves remained to phase in rate increases gradually. But in late 2022 electricity market prices increased at unprecedented levels, leading to the need to increase the hydroelectric rate adjuster on January 1, 2023 to match the cost of replacing hydroelectric power with market power. Costs are projected to exceed revenues again in FY 2023, leading to further depletion of reserves.

This forecast assumes some decrease in power prices after this year, but prices are expected to continue to remain elevated over FY 2022 and earlier levels based on forward market price curves developed by OTC Global Holdings, an independent commodity broker. Some recovery of hydroelectric generation is forecasted in FY 2024 based on the Western Area Power Administration's current forecast, but not to normal levels given the dry ground and low reservoir levels, which are expected to absorb a significant share of precipitation even if it is above average. Normal levels of hydroelectric generation are not forecasted until FY 2026, assuming normal rainfall in the winter of 2022/2023 and 2023/2024. The forecast assumes it takes multiple years to recover because reservoirs can take multiple seasons to fill and return to normal operations based on historical experience. To reduce hydroelectric-related volatility in the future, staff is now making its rate projections assuming that long-term "normal" production from the City's hydroelectric resources is about 80% of historical average levels.

Since presenting the rate proposal and financial plan to the UAC on March 1, 2023, new information has arisen that materially improves the electric utility's financial position. Staff expects to receive a $24 million payment in the coming weeks from successful litigation against the Bureau of Reclamation for overcharges related to power purchased from the Central Valley Project. The litigation was filed in 2014 by the Northern California Power Agency (NCPA) and its members (*NCPA, City of Redding and City of Roseville v. United States;* Case No. 14-817C)[1]. Based on the information, staff revised the rate proposal provided to the UAC and proposes a net average rate reduction of 5%. The net rate reduction results from the combination of deactivating the hydroelectric rate adjuster (HRA) and increasing the base rates by 21%. The previous plan presented to UAC reduced the HRA by 50% and increased the base rates by 14%, resulting in a negligible average rate change. However, the $24M damages repayment can be used to replenish reserves with some funds available for rate stabilization, providing adequate reserves to manage hydroelectric risk and enabling future rate increases to be phased over a slightly longer period. Significantly for this year's rate proposal, the replenished reserves enable the HRA to be removed entirely.

Over the forecast period other costs are increasing as well. Cost increases include:

- Significant increases in transmission costs
- Significant increases in capital investment to replace aging infrastructure
- Increased operations costs
- Debt service costs for grid modernization improvements and investments in fiber infrastructure to support AMI.

Long-term costs are expected to continue to increase, so the 5% drop in customer bills forecast for July 1, 2023 is projected to be offset with a 5% increase in FY 2025 and another increase of 5% in FY 2026 as shown in table 3, even if hydroelectric and power market conditions improve.

There are some significant uncertainties in this forecast. Load is assumed to stay fairly flat in this forecast, with long-term declines in electric load offset by some load growth due to electrification and potential new data centers. If load growth exceeds expectations, it could improve this forecast and reduce the size of future rate increases. On the other hand, if costs for electrification-related grid modernization and electrification programs exceed forecasts, which is quite possible given the high uncertainties involved in current cost projections, it could offset the benefits of increased load.

The Electric Utility's costs are projected to decline by about 2% per year from FY2023 levels, before then increasing again in FY2026, for an average of 1% increase from FY 2024 - 2028, as shown in Table 1. As noted above most of the costs are related to electric supply purchases, which continue to increase mainly due to rising transmission costs over the span of the financial plan, but also higher commodity costs in the near term due to low hydro conditions and higher

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[1] NCPA is a Joint Powers Authority with sixteen public electric utility members, including the City of Palo Alto.

market prices. Overall supply costs are projected to increase at an estimated 0.5% per year on average from FY2023 levels, which are estimated to be the highest on record. Operations and maintenance costs are about 30% of total costs and are projected to increase by about 1.5% per year on average due to both inflation as well as salary and benefits increases. Capital improvement costs are projected to fall slightly in the short term as the Smart Grid technology project and rebuilding of the Foothill distribution system spending declines from its peaks in FY2022 and FY2023, then stabilize just over $20 million a year thereafter. Ongoing projects will include rebuilds of existing underground districts as well as substation improvements and voltage conversion projects.

As shown in Table 1, debt service payments for grid modernization and fiber begin in FY2025 and increase to $9.6m in FY2028. These new bonds and investments are expected to commence in FY2024 as shown in Table 1.1 below.

Table 1: Electric Utility Expenses for FY 2022 to FY 2028

Expenses ($000)	FY 2022 (act)	FY 2023 (est)	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028
Power Supply Purchases	112,525	117,900	118,019	115,638	118,069	118,851	121,028
Operations	61,948	69,337	68,329	65,303	66,547	67,638	64,877
Capital Projects	34,525	28,991	25,508	24,610	22,644	22,716	22,730
Debt Service from Grid Modernization and Fiber Projects				2,032	3,632	6,432	9,632
TOTAL	208,998	216,228	211,856	207,583	210,892	215,637	218,268

Table 2.1: Electric Utility Investments FY 2024 to FY 2028

Expenses ($000)	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028
Grid Modernization Projects	25,000	25,000	50,000	50,000	50,000
Electric Utility Fiber Backbone	13,000	0	0	0	0
TOTAL	38,000	25,000	50,000	50,000	50,000

Table 2 below shows the proposed rate projections alongside the current rates with the hydroelectric rate adjuster. While base rates increase by 21%, the removal of the hydroelectric rate adjuster means that the total effective rate for FY2024 is 5% lower than the current total effective rate.

Table 3: Projected Electric Rates, FY 2024 to FY 2028

	Current	Proposed	Projected			
Projection	**Mid-Year FY 2023**	**FY 2024**	**FY 2025**	**FY 2026**	**FY 2027**	**FY 2028**
System Average Base Rates ($/kWh)	$0.171	$0.208	$0.217	$0.227	$0.237	$0.249
Proposed % Base Rate Increase		21%	5%	5%	5%	5%
Hydroelectric Rate Adjuster ($/kWh)	$0.048	Inactive	Inactive	Inactive	Inactive	Inactive
Proposed % HRA Decrease		-100%	0%	0%	0%	0%
Total System Average Rate ($/kWh) (with Hydroelectric Rate Adjuster)	$0.219	$0.208	$0.217	$0.227	$0.237	$0.249
% Change in Total System Average Rate		-5%	5%	5%	5%	5%

The rate changes above are made possible by the $24 million refund from the successful litigation against the Bureau of Reclamation for overcharges related to power purchases from the Central Valley Project. Staff is proposing to use $10 million of the funds to repay a loan from the Electric Special Projects Reserve.

- In FY 2018 Council approved (Staff Report 8186[2]), a $10 million transfer from the Electric Special Projects (ESP) Reserve to the Operations Reserve to mitigate higher supply costs due to the drought, the costs of new renewable energy projects coming online and increasing transmission charges. $5 million was repaid in FY 2020
- In FY 2022 Council approved (Staff Report 13361, June 13, 2022), a $5 million transfer from the ESP Reserve to the Operations Reserve to avoid rate increases exceeding 5%.

Staff proposes using $8 million of the $24 million refund payment from the Central Valley Project litigation to fund the balance of the Hydroelectric Stabilization Reserve, bringing the balance above the minimum requirement and eliminating the need for the hydroelectric rate adjuster.

Table 4 shows the projected reserve transfers over the forecast period.

[2] https://www.cityofpaloalto.org/files/assets/public/agendas-minutes-reports/reports/city-manager-reports-cmrs/year-archive/2017/8186.pdf

Table 4: Reserves Starting and Ending Balances, Revenues, Expenses, Transfers To/(From) Reserves, Operations and Capital (CIP) Reserve Guideline Levels for FY 2023 to FY 2028 ($000)

			FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028
	Starting Reserve Balances							
1		Supply Operations	27,197	14,378	14,003	19,933	27,680	33,136
2		Distribution Operation	2,945	5,077	7,208	10,124	10,673	12,304
3		CIP	880	880	880	880	5,880	10,880
4		Electric Special Projects	24,649	17,649	24,649	24,649	26,649	28,649
5		Hydro Stabilization	400	400	8,400	8,400	8,400	8,400
6		Low Carbon Fuel Standard	7,236	6,214	5,142	4,574	4,121	3,668
7		Cap and Trade Program	1,189	5,612	8,577	11,307	11,307	11,307
	Revenues							
8		Supply	134,629	141,976	132,031	136,751	134,384	135,204
9		Distribution	60,314	79,398	86,837	94,660	100,856	107,187
	Transfers							
a		-From Supply Operations to Distribution	(12,000)					
b		-From Supply Operations to Cap and Trade Program	(4,423)	(2,965)	(2,730)			
c		-Into Supply Operations from ESP	-					
a+b+c = 10		Supply Operations Total	(16,423)	(12,965)	(2,730)	(2,000)	(2,000)	(2,000)
11		Distribution Operations	12,000	-	-	(5,000)	(5,000)	(5,000)
12		CIP	-	-	-	5,000	5,000	5,000
13		Electric Special Projects	-	10,000	-	2,000	2,000	2,000
14		Hydro Stabilization	-	8,000	-	-	-	-
15		Low Carbon Fuel Standard	-	-	-	-	-	-
16		Cap and Trade Program	4,423	2,965	2,730	-	-	-
	Capital Program Contribution							
17		Distribution Operations						
18		CIP Reserve						
	Expenses							
19		Supply Funded Expenses	(131,025)	(129,386)	(123,371)	(127,004)	(126,927)	(131,698)
20		Distribution Non-CIP Expenses	(48,191)	(54,759)	(58,311)	(63,467)	(67,510)	(78,601)
21		Planned CIP	(21,991)	(22,508)	(25,610)	(25,644)	(26,716)	(25,730)
22		ESP Funded	(7,000)	(3,000)	-	-	-	(10,000)
23		Hydro Funded	-	-	-	-	-	-
24		LCFS Funded	(1,022)	(1,072)	(568)	(453)	(453)	-
	Ending Reserve Balance							
1+8+10+19		Supply Operations	14,378	14,003	19,933	27,680	33,136	34,643
2+9+11+17+20+21		Distribution Operation	5,077	7,208	10,124	10,673	12,304	10,160
3+12+18		CIP	880	880	880	5,880	10,880	15,880
4+13+22		Electric Special Projects	17,649	24,649	24,649	26,649	28,649	20,649
5+14+23		Hydro Stabilization	400	8,400	8,400	8,400	8,400	8,400
6+15+24		Low Carbon Fuel Standard	6,214	5,142	4,574	4,121	3,668	3,668
7+16		Cap and Trade Program	5,612	8,577	11,307	11,307	11,307	11,307
	Operations Reserve Guidelines (Supply)							
25		Minimum	21,749	21,765	20,739	21,164	21,326	21,706
26		Maximum	43,499	43,530	41,478	42,328	42,652	43,412
	Operations Reserve Guidelines (Distribution)							
27		Minimum	9,057	8,913	9,458	9,975	10,658	10,788
28		Maximum	15,785	15,419	16,437	17,396	18,687	18,867
	CIP Reserve Guidelines							
29		Minimum	4,938	5,174	5,685	4,215	4,392	5,873
30		Maximum	24,688	25,869	28,425	31,223	34,288	34,288

SECTION 2B: SUMMARY OF PROPOSED ACTIONS

Staff recommends the City Council adopt a Resolution:

1. Approving the Fiscal Year (FY) 2024 Electric Financial Plan;
2. Approving the following transfers at the end of FY 2023:
    a. Up to $12 million from the Supply Operations Reserve to the Distribution Operations Reserve; and
    b. Up to $4.5 million from the Supply Operations Reserve to the Cap and Trade Program Reserve; and
3. Approving the following transfers in FY 2024:
    a. Up to $10 million from the Supply Operations Reserve to the Electric Special Projects (ESP) reserve; and
    b. Up to $8 million from the Supply Operations Reserve to the Hydroelectric Stabilization Reserve; and
    c. Up to $3 million from the Supply Operations Reserve to the Cap and Trade Program Reserve; and
4. Approving the following rate actions for FY 2024:
    a. Deactivation of the hydroelectric rate adjuster from customer bills effective July 1, 2023;
    b. An increase to 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) of 21% effective July 1, 2023;
    c. An increase to the Export Electricity Compensation (E-EEC-1) rate to reflect 2022 avoided cost, effective July 1, 2023;
    d. An increase to the Net Surplus Electricity Compensation (E-NSE-1) rate to reflect current projections of FY 2023 avoided cost, effective July 1, 2023; and
    e. 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, 2023.

SECTION 3: DETAIL OF FY 2024 RATE AND RESERVES PROPOSALS

SECTION 3A: RATE DESIGN

The Electric Utility's rates are evaluated and implemented in compliance with cost of service requirements set forth in the California Constitution and applicable statutory law. This Financial Plan is based on staff's assessment of the financial position of the Electric Utility and updated using the methodology from the "City of Palo Alto Electric Cost of Service and Rate Study"[3]

[3] Staff Report 6857 http://www.cityofpaloalto.org/civicax/filebank/documents/52274

drafted by EES Consulting, Inc. in 2015/16. The COSA is also based on design guidelines adopted by Council on September 15, 2015 (Staff Report 6061).

SECTION 3B: CURRENT AND PROPOSED RATES

The City adopted the current rates effective July 1, 2022, when CPAU increased electric rates by 5%. Staff held back further rate increases during the COVID-19 pandemic and instead drew down reserves. While using reserves mitigated larger increases during the pandemic, costs have continued to rise and higher rates are needed to recover costs. In order to move towards full cost recovery, staff recommends a rate increase to all customer classes of 21%. Staff is also engaging the services of consultants to review and revise the Electric Utility's Cost of Service study and rates. This study will examine how costs are allocated among the residential and commercial classes and realign them if needed, and will develop cost-based rates for several emerging groups, such as: all-electric customers, DC-fast charging facilities, and micro-grid customers. The current rates and proposed FY 2024 rates are reflected in Table 4 below:

Table 5: Current and Proposed Electric Rates

	Current Rates	Proposed Rates (7/1/2023)	Change	
			$	%
Electric Hydro Rate Adjuster				
E-HRA ($/kWh)	0.04800	0.00000	-0.04800	-100%
E-1 (Residential)				
Tier 1 Energy ($/kWh)	0.14445	0.17522	0.03077	21%
Tier 2 Energy ($/kWh)	0.20335	0.24666	0.04331	21%
Minimum Bill ($/day)	0.34470	0.41812	0.07342	21%
E-2 & E-2-G (Small Non-Residential)				
Summer Energy ($/kWh)	0.21896	0.26560	0.04664	21%
Winter Energy ($/kWh)	0.15355	0.18626	0.03271	21%
Minimum Bill ($/day)	0.87770	1.06465	0.18695	21%
E-4 & E-4-G (Medium Non-Residential)				
Summer Energy ($/kWh)	0.13490	0.16363	0.02873	21%
Winter Energy ($/kWh)	0.10443	0.12667	0.02224	21%
Summer Demand ($/kW)	30.36000	36.82668	6.46668	21%
Winter Demand ($/kW)	19.92000	24.16296	4.24296	21%
Minimum Bill ($/day)	18.13790	22.00127	3.86337	21%
E-7 & E-7-G (Large Non-Residential)				
Summer Energy ($/kWh)	0.12004	0.14561	0.02557	21%
Winter Energy ($/kWh)	0.08125	0.09856	0.01731	21%
Summer Demand ($/kW)	32.22000	39.08286	6.86286	21%
Winter Demand ($/kW)	17.90000	21.71270	3.81270	21%
Minimum Bill ($/day)	51.56960	62.55392	10.98432	21%

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-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) 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 increasing the E-NSE-1 rate to $0.1535/kWh based on updated avoided cost calculations for 2022 reflecting the greatly increased 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 Export Electricity Compensation (EEC-1) 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 10.45 cents/kWh, which is significantly lower than the avoided cost on the proposed NEM compensation rate (16.85 cents/kWh). This increase in the overall avoided cost is driven by greatly increased electricity market prices.

Table 5: NEM Buyback Rates – Current vs. Proposed

Rate	Current $/kWh	Proposed $/kWh
Export Electricity (E-EEC)	$0.1045	$0.1685
Net Surplus Electricity (E-NSE)	$0.1026	$0.1535

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 the vast majority 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 $6.5/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.

SECTION 3C: BILL IMPACT OF PROPOSED RATE CHANGES

Table 6 shows the impact of the proposed July 1, 2023 rate changes on the residential and non-residential bills for various consumption levels. For more on comparisons of rates with surrounding agencies, see Section 4F: Competitiveness below.

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

Rate Schedule	Usage (kWh/mo)	Peak Demand (kW-mo)	Bill under Current Rates ($/mo)	Bill Under Rates Proposed 7/1/23 ($/mo)	Change	
					$/mo	%
E-1 (Residential)	300	N/A	$58	$53	($5)	-9%
	(Summer Median) 365	N/A	$72	$66	($6)	-8%
	(Winter Median) 453	N/A	$94	$88	($6)	-7%
	650	N/A	$144	$137	($7)	-5%
	1200	N/A	$282	$272	($10)	-3%
E-2 (Small Non-Residential)	1,000	N/A	$234	$226	($8)	-4%
E-4 (Medium Non-Residential)	160,000	274	$33,715	$31,580	($2,135)	-6%
	500,000	856	$105,352	$98,680	($6,672)	-6%
E-7 (Large Non-Residential	2,000,000	3,424	$383,095	$348,247	($34,849)	-9%

SECTION 3D: PROPOSED RESERVE TRANSFERS

In FY 2018, Council approved a $10 million loan from the ESP Reserve. Prior financial plans assumed full repayment by FY 2025, but with the $24 million refund payment from the successful litigatoin against the Bureau of Reclamation, staff is proposing to repay the loan early. Staff proposes using $8 million of the $24 million payment to increase the balance of the hydro stabilization reserve from the current level of $400,000 above the minimum guideline level, but still below the target level of $19 million.

Given the drought over the prior 3 years and FY 2023 hydroelectric projections currently remaining fairly low, there is an estimated supply cost increase of $8-$10 million in FY 2023 compared to FY 2022. Because of this, Council approved an increase to the hydroelectric rate adjuster effective January 1, 2023 to bring in additional revenue to cover increased supply costs. Staff proposes to eliminate the HRA mechanism in FY 2024 given the $8 million that can be transferred into the hydro stabilization reserve.

The remaining $6 million would be added to the Supply and Distribution Operations Reserve and used to phase in the rate increases needed to stabilize those reserves slightly more gradually over the forecast period.

There are repayments of $2 million per year from FY 2026 through FY 2030 to the ESP Reserve for loans to the electric, gas, and fiber utilities for AMI investments.

The City maintains a Cap and Trade Program Reserve within the Electric fund to hold revenues from the sale of carbon allowances freely allocated by the California Air Resources Board to the City's electric utility. Cap and Trade Program revenues are provided to the electric utility to support a wide variety of carbon reducing activities, including local decarbonization. Until the establishment of the REC Exchange program, adopted by Council in August 2020 (Staff Report #11556),[4] all of this revenue was spent on purchasing renewable energy. In accordance with Council's August 2020 direction, the City has began exchanging certain types of renewable energy to take advantage of market conditions to reduce supply costs, fund electric utility programs and capital investment, and raise funds for local decarbonization. For FY 2021 and FY 2022 Council directed that 1/3 of the revenue be used for local decarbonization and 2/3 for rate reduction. On December 12, 2022[5] Council approved continuation of the program with 100% of revenue going to local decarbonization. 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 the FY 2022 Renewable Energy Credit (REC) Exchange program revenues, currently estimated to be between $2.7 million and $4.5 million going forward, for future local decarbonization projects.

Figure 8 (for Supply Fund Reserves) and Figure 9 (for Distribution Fund Reserves) in *Section 5E:* FY 2022 – FY 2026 *Projections* show the impact of these transfers on reserves levels. Table 7 shows the projected balance of each of the Electric Utility reserves for the period covered by this Financial Plan. See also: *Appendix A: Electric Utility Financial Forecast Detail*

[4] https://www.cityofpaloalto.org/civicax/filebank/documents/78046

[5] https://cityofpaloalto.primegov.com/Portal/Meeting?meetingTemplateId=8713
Agenda Item 3, *Utilities Advisory Commission Recommend the City Council Affirm the Continuation of the REC Exchange Program*, Staff Report #14375

Table 7: End of Fiscal Year Electric Utility Reserve Balances for FY 2022 to FY 2028

Ending Reserve Balance ($000)	**FY 2022 (Act)**	**FY 2023**	**FY 2024**	**FY 2025**	**FY 2026**	**FY 2027**	**FY 2028**
Re-appropriations	120	120	120	120	120	120	120
Commitments	6,679	6,679	6,679	6,679	6,679	6,679	6,679
Low Carbon Fuel Standard (LCFS)	7,236	6,214	5,142	4,574	4,121	3,668	3,668
Cap and Trade	1,189	5,612	8,577	11,307	11,307	11,307	11,307
Underground Loan	727	727	727	727	727	727	727
Public Benefits	3,891	4,608	5,380	6,175	6,910	7,585	8,200
Special Projects	24,649	17,649	24,649	24,649	26,649	28,649	30,649
Hydro Stabilization	400	400	8,400	8,400	8,400	8,400	8,400
Capital	880	880	880	880	5,880	10,880	15,880
Rate Stabilization	-	-	-	-	-	-	-
Distribution and Supply Operations	30,142	19,455	21,211	30,057	38,354	45,440	44,802
Unassigned	845	-	-	-	-	-	-
TOTAL	76,757	62,344	81,765	93,569	109,147	123,455	130,432

SECTION 4: UTILITY OVERVIEW

This section provides an overview of the utility and its operations. It is intended as general background information to help readers better understand the forecasts in *Section 5: Utility Financial Projections* and *Section 6: Details* and Assumptions.

SECTION 4A: ELECTRIC UTILITY HISTORY

On January 16, 1900, Palo Alto began operating its own electric system. One of the earliest sources of Palo Alto's electricity was a steam engine, which was later replaced by a diesel engine in 1914 due to rising fuel oil costs. As the population and the demand for electricity continued to grow, CPAU connected to PG&E's system in the early 1920s. Power from PG&E proved more economical than the diesel engines, and by the late 1920s CPAU was using its own diesel engines only during peak demand periods. At that time CPAU owned 45 miles of distribution lines and the City used 9.7 GWh annually, less than 1% of today's annual consumption. The diesel engines remained in operation until 1948, when they were retired.

From 1950 to 1970 electric consumption in Palo Alto grew dramatically, just as it did throughout the rest of the country. In 1970 total annual sales were 602 GWh, twenty times the sales in 1950 (30 GWh). Some of that growth was related to a development boom in Palo Alto, which doubled the number of customers. Some was related to the proliferation of electric appliances, as evidenced by the fact that residential customers were using three times more electricity in 1970 than they had been in 1950. But the most notable factor was the growth of industry in Palo Alto during that time. By 1970, commercial customers were using 20 times more electricity per customer than they had been in 1950. These decades also saw several other notable events, including:

- 1964: CPAU entered into a favorably priced 40-year contract with the Federal Bureau of Reclamation to purchase power from the Central Valley Project (CVP), a contract which later was managed by the Western Area Power Administration (WAPA) an office of the Department of Energy created in the 1970s to market power from various hydroelectric projects operated by the Federal Government, including the CVP.
- 1965: The City began a long-term program to underground its overhead utility lines (Ordinance 2231).
- 1968: Palo Alto joined several other small municipal utilities to form the Northern California Power Agency (NCPA), a joint action agency intended to make the group less vulnerable to actions by private utilities and to enable investment in energy supply projects.

Palo Alto's first new power plant investment in over 50 years came in the mid-80s. Palo Alto joined other NCPA members to invest in the construction and operation of the Calaveras Hydroelectric Project on the Stanislaus River in the Sierra-Nevada Mountains. The project commenced operation in 1990. The 1980s also saw an increased focus on infrastructure maintenance. In 1987 the UCC was built to house the terminals for a new SCADA system, which enabled utility staff to monitor the distribution system in real time, improving response time to outages. CPAU also commenced a preventative maintenance and planned replacement program for its underground system in the early 1990s.

In the early 1990s the CPUC issued a ruling to deregulate the electric industry in California, and in 1996 the State legislature passed Assembly Bill 1890, which, among other things, created the California Independent System Operator (CAISO) to operate the transmission system and the Power Exchange to facilitate wholesale energy transactions. This restructuring was anticipated to bring lower costs to consumers, and while CPAU was not required to participate in the industry restructuring, in 1997 the Council approved a Direct Access Program for the Electric Utility[6] that enabled CPAU to sell electricity outside its service territory and allowed customers within CPAU's service territory to choose other providers. The utility unbundled its electric rates, creating separate supply and distribution components, which would enable customers to receive only distribution service while purchasing the electricity itself from another provider. The energy crisis in 2000 to 2001 led to the suspension of direct access by the CPUC in September 2001 as wholesale energy prices skyrocketed. The Electric Utility was less impacted than other utilities by the 2000 to 2001 energy crisis thanks to the Calaveras project and its contract with WAPA for CVP hydropower.

In 2001 CPAU began planning for the impacts associated with the new terms of its contract with WAPA, set to take effect in 2005. The previous contract had provided 90% of Palo Alto's power supply at favorable rates, and PG&E, as a party to the contract, had provided supplemental power

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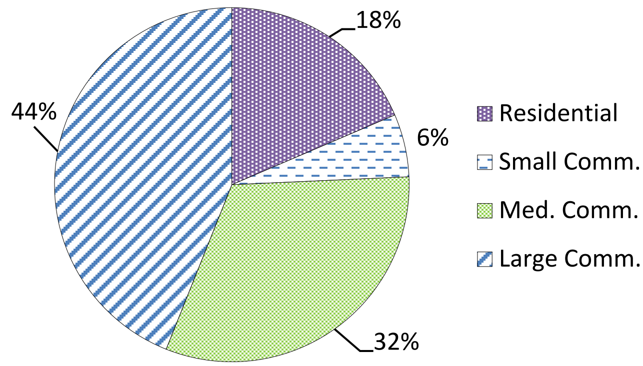
[6] *Implementation of Direct Access for Electric Utility Customers*, CMR:460:97, December 1, 1997

to balance the monthly and annual variability of CVP generation. The new contract would provide only a third of Palo Alto's requirement, and the monthly and annual variability in CVP generation would be passed directly to Palo Alto. As a result, electric supply costs would increase and CPAU needed to more actively manage its supply portfolio. CPAU began purchasing power from marketers and also investigated building a power plant in Palo Alto or partnering in the development of a gas-fired power plant elsewhere. Climate change was also becoming more of a concern to the community, and gradually CPAU shifted its focus to the procurement of renewable energy. In 2002 the Council adopted a goal of achieving 20% of its energy supply from renewables by 2015. Subsequently the City signed its first contract for renewable power, a contract for energy from a wind generator commencing deliveries in 2005. In 2011 the renewable energy goal was increased to at least 33% by 2015, and in 2013 the City adopted a plan to make its electric supply 100% carbon neutral, which it achieves through the combination of its carbon-free hydroelectric supplies, purchases of long-term renewable energy supplies, and short-term RECs to meet the balance of its needs.

SECTION 4B: CUSTOMER BASE

Figure 1: Customer Consumption By Class (FY 2022)



The City of Palo Alto's Electric Utility provides electric service to the residents, businesses, and other electric customers in Palo Alto. There are roughly 29,700 customers connected to the electric system, 25,600 (86%) of which are residential and 4,100 (14%) of which are non-residential. Residential customers consumed 154 gigawatt-hours (GWh) in FY 2022, approximately 20% of the electricity sold, while non-residential customers consumed 80% or 659 GWh. Residential customers use electricity primarily for lighting, refrigeration, electronics, and air conditioning.[7] Non-residential customers use the majority of their electricity for cooling, ventilation, lighting, office equipment (offices), cooking (restaurants), and refrigeration (grocery stores).[8]

As shown in Figure 1, large customer loads represent the biggest proportion of sales for the Electric Utility. The proportion of sales to large vs. small customers is greater than for the City's other utilities. For example, the largest customers (the 70 customers on the E-7 rate schedule) account for around 44% of CPAU's sales. The next largest customer group (the 890 non-residential customers on the E-4 rate schedule) represents another 30% of sales. In total, that means that about 3% of customers account for nearly three quarters of the electric load.

SECTION 4C: DISTRIBUTION SYSTEM

The Electric Utility receives electricity at a single connection point with PG&E's transmission system. From there the electricity is delivered to customers through nearly 472 miles of distribution lines, of which 211 miles (45%) are overhead lines and 261 miles (55%) are underground. The Electric Utility also maintains nine substations, roughly 2,000 overhead line transformers, around 1,100 underground and substation transformers, and the associated electric services (which connect the distribution lines to the customers' homes and businesses). These lines, substations, transformers, and services, along with their associated poles, meters, and other associated electric equipment, represent the vast majority of the infrastructure used to deliver electricity in Palo Alto.

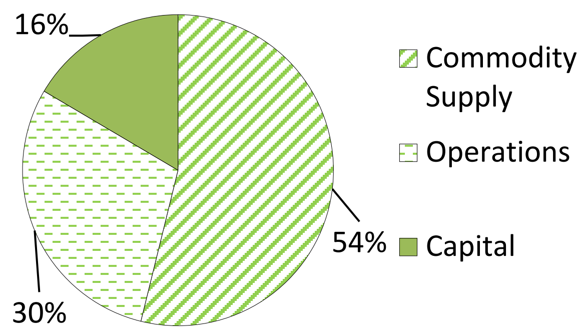
[7] Source: Residential Appliance Saturation Survey, California Energy Commission, 2010

[8] Source: Statewide Commercial End Use Study, California Energy Commission report, 2006.

SECTION 4D: COST STRUCTURE AND REVENUE SOURCES

As shown in Figure 2, electric commodity purchases accounted for roughly 54% of the Electric Utility's costs in FY 2022. Operational costs represented roughly 30%, and capital investment was responsible for the remaining 16%. CPAU's non-hydro long-term commodity supply is heavily dependent on long-term contracts which have little variability in price. On average, costs for these long-term contracts are not predicted to increase as quickly as operations and CIP costs, and will steadily become a smaller proportion of the Electric Utility's costs. Staff projects commodity supply costs to be approximately 55% of total costs in FY 2028.

Figure 2: Cost Structure (FY 2022)



While average year purchase costs for the electric utility are predictable due to its long-term contracts, variability in hydroelectric generation can result in increased or decreased costs. This is by far the largest source of variability the utility faces. Figure 3 shows the difference in the annual load resource balance under high, projected, and low hydroelectric generation scenarios for FY 2022. Additional costs associated with a very low generation scenario can range from $8-20 million per year, depending on market prices. For the current hydroelectric risk assessment see *Section 5F: Risk Assessment and Reserves Adequacy*.

Figure 3: Hydroelectric Variability as a % of Load (FY 2022)

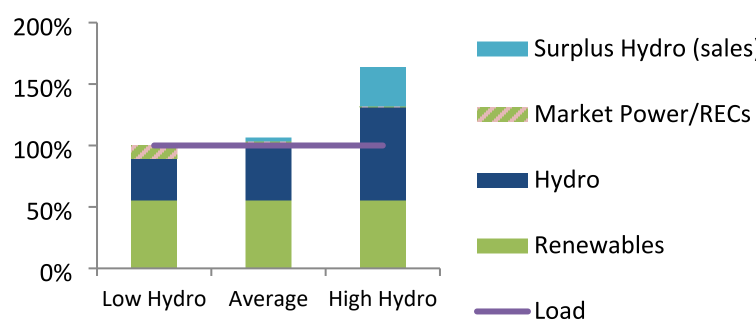
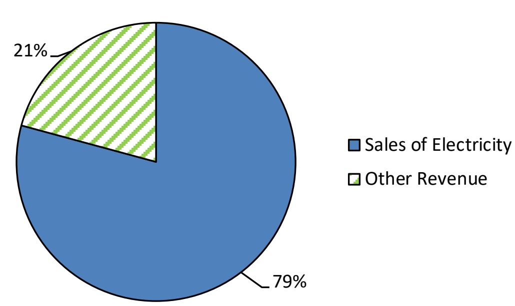


Figure 4: Revenue Structure (FY 2022)



As shown in Figure 4 the Electric Utility receives 79% of its revenue from sales of electricity and the remainder from connection fees, interest on reserves, cost recovery transfers from other funds for shared services provided by the electric utility, accounting entries that reflect things such as CPAU's participation in a pre-funding program associated with its contract with WAPA, revenues from sales of surplus hydroelectric energy during wet years, as well as LCFS and Cap and Trade revenues. *Appendix A: Electric Utility Financial Forecast Detail* shows more detail on the utility's cost and revenue structures.

As discussed in *Section 4B: Customer Base*, nearly three quarters of the utility's electricity sales are to the 960 largest customers, which provide a similar share of the utility's revenue stream. About 25% of the utility's revenue comes from peak demand charges on large non-residential customers. Due to moderate weather and the prevalence of natural gas heating, however, loads (and therefore revenues) are very stable for this utility, without the large seasonal air conditioning or winter heating loads seen at some other utilities.

SECTION 4E: RESERVES STRUCTURE

CPAU maintains several reserves for its Electric Utility to manage various types of contingencies and for ease of reporting. It also maintains two funds, the Supply Fund and the Distribution Fund, to manage costs associated with electricity supply and electricity distribution, respectively. The City established this separation of supply and distribution costs as the City prepared to allow its customers a choice of electricity providers (referred to as "Direct Access") in the late 1990s and early 2000s. Though the 2000/2001 energy crisis halted these plans, CPAU continues to maintain separate funds to facilitate separation of supply and distribution costs in the rates. This could be important if California ever decides to broadly reintroduce Direct Access, and is useful for rate design as the nature of utility service evolves in response to higher penetrations of distributed generation. Thus, individual reserves may reside within a particular fund (for instance, Electric Special Projects is under Electric Supply) or be included within both funds (there are both Supply and Distribution Reserves for Commitments).

The summary below describes the various reserves, but see *Appendix B: Electric Utility Reserves Management Practices* for more detailed definitions and guidelines for reserve management:

- **Reserves for Commitments:** Reserves equal to the utility's outstanding contract liabilities for the current fiscal year. Most City funds, including the General Fund, have a Commitments Reserve.
- **Reserves for Reappropriations:** Reserves for funds dedicated to projects re-appropriated by the City Council, nearly all of which are capital projects. Most City funds, including the General Fund, have a Re-appropriations Reserve. This is currently an important reserve for all utility funds, but changes in budgeting practices will change that in future years, as described in Section 3C (Reserves Management Practices).
- **Electric Special Projects (ESP) Reserve:** This reserve was formerly called the Calaveras Reserve, which was accumulated during deregulation of California's electric system to fund the stranded costs associated primarily with the Calaveras hydroelectric resource and the California-Oregon Transmission Project. When that reserve was no longer needed for that purpose, the reserve was renamed and the purpose was changed to fund projects with significant impact that provide demonstrable value to electric ratepayers.

- **Hydroelectric Stabilization Reserve:** This contingency reserve is used for managing additional costs due to below average hydroelectric generation, or to hold surpluses resulting from above average hydroelectric generation.
- **Underground Loan Reserve:** This reserve is an accounting tool used to offset receivables associated with loans made through the underground loan program. It is adjusted according to principal payments made on those loans.
- **Cap and Trade Program Reserve:** This reserve tracks unspent or unallocated revenues from the sale of carbon allowances freely allocated by the California Air Resources Board to the electric utility, under the State's Cap and Trade Program. Funds in this Reserve are managed in accordance with the City's Policy on the Use of Freely Allocated Allowances under the State's Cap and Trade Program.
- **Low Carbon Fuel Standard (LCFS) Reserve:** This reserve tracks revenues earned via the sale of Low Carbon Fuel Credits allocated by the California Air Resources Board to the City, in accordance with California's Low Carbon Fuel Standard program.
- **Public Benefits Reserve:** CPAU's electric rates include a separate charge called the "Public Benefits Charge" which generates revenue to be used for energy efficiency, demand-side renewable energy, research and development, and low-income energy efficiency services. Any funds not expended in the current year are added to the Public Benefits Reserve for use in future years.
- **Capital Improvement Program (CIP) Reserve:** The CIP reserve can be used to accumulate funds for future expenditure on CIP projects, as well as to manage cash flow for ongoing capital projects. This reserve can also act as a contingency reserve for unforeseen capital expenses. This type of reserve is used in other utility funds (Water, Gas, and Wastewater Collection) as well.
- **Supply and Distribution Rate Stabilization Reserves:** These reserves are intended to be empty unless one or more large rate increases are anticipated in the forecast period. In that case, funds can be accumulated to spread the impact of those future rate increases across multiple years. This type of reserve is used in other utility funds (Gas, Wastewater Collection, and Water) as well.
- **Supply and Distribution Operations Reserves:** These are the primary contingency reserves for the Electric Utility and are used to manage yearly variances from budget for operational costs and electric supply costs (aside from variances related to hydroelectric generation). This type of reserve is used in other utility funds (Gas, Wastewater Collection, and Water) as well.
- **Unassigned Reserves (Supply/Distribution):** As in the other utility funds, these reserves are for any financial resources not assigned to the other reserves and are normally empty.

SECTION 4F: COMPETITIVENESS

For the median consumption level, the annual CPAU residential electric bill for calendar year 2022 was $792, which was $683 (46%) lower than the annual bill for a PG&E customer with the same consumption ($1,475) and approximately $142 (22%) higher than the annual bill for a City of Santa Clara customer ($649). The bill calculations for PG&E customers are based on PG&E Climate Zone X, which includes most surrounding comparison communities.

Table 8 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, 2023.

Over the next several years low usage customers in PG&E territory are expected to continue to see higher percentage rate increases than high usage customers as PG&E compresses its tiers from the highly exaggerated levels that have been in place since the energy crisis. This is likely to make the bill for the median Palo Alto consumer look even more favorable compared to most PG&E customers. Even with the compressed tiers, bills for high usage Palo Alto consumers are likely to remain substantially lower than the bills for high usage PG&E customers.

Table 8: Residential Monthly Electric Bill Comparison (Effective 1/1/2023, $/mo.)

Season	Usage (kwh)	Palo Alto	PG&E	Santa Clara
Winter	300	57.74	94.11	39.31
	453 (Median)	94.42	143.32	60.09
	650	143.94	221.07	86.85
	1200	282.18	438.13	161.54
Summer	300	57.74	97.76	39.31
	(Median) 365	72.31	123.41	48.14
	650	143.94	235.88	86.85
	1200	282.18	452.94	161.54

SECTION 5: UTILITY FINANCIAL PROJECTIONS

SECTION 5A: LOAD FORECAST

Figure 5 shows a 38-year history of Palo Alto electricity consumption. Average electricity consumption grew from 1986 to 1998, then returned to 1986 levels by 2002. Since then electricity consumption has declined slowly as a result of a continuing focus on energy efficiency, as well as the adoption of more stringent appliance efficiency standards and energy standards in building codes. Electrification will likely reverse some of this trend, although the pace of that impact is uncertain at this time. In recent years, some larger commercial customers have relocated operations or shifted to more light-commercial type usage. It is unknown how long this trend may continue, or what the longer-term impacts of COVID and work-from home policies might mean for commercial utilization in Palo Alto.

Figure 5: Historical Electricity Consumption

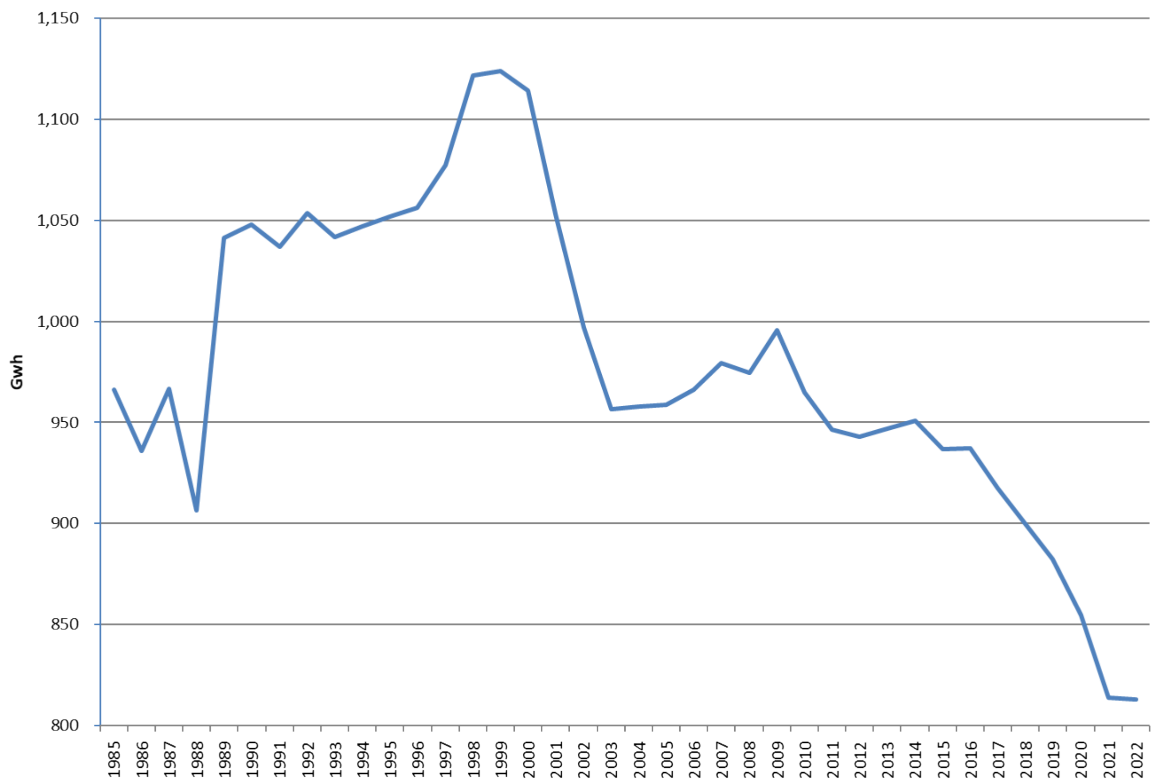
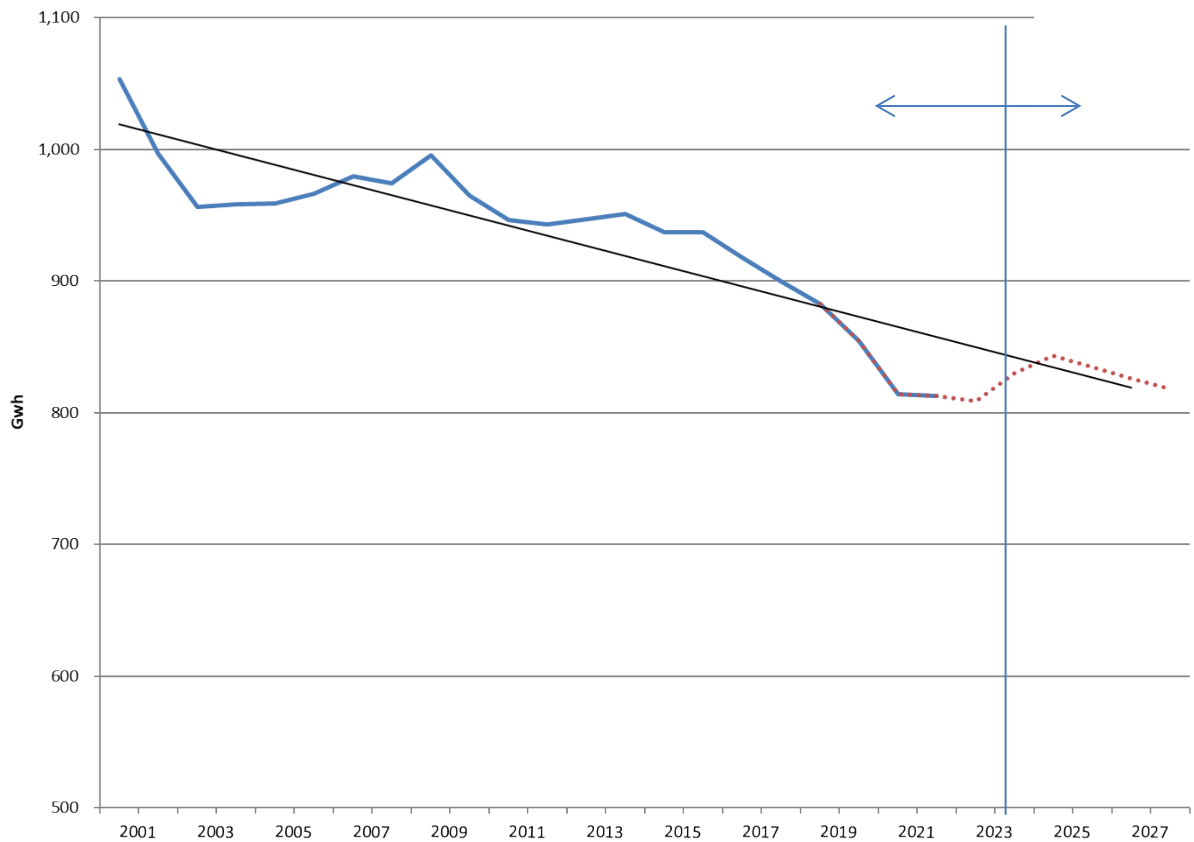


Figure 6 shows the forecast of electricity consumption through FY 2028. The solid black straight line is the long-term average trend of usage.

The small-dash red line represents the projected retail sales used in the financial forecast. Sales are assumed to recover to a level slightly above the long-term trend line due to conservative expected load growth from data centers. These projections will be revised if continuing sales change.

Figure 6: Forecasted Electricity Consumption



SECTION 5B: FY 2018 TO FY 2022 COST AND REVENUE TRENDS

As shown in *Appendix A: Electric Utility Financial Forecast Detail*, annual expenses for the Electric Utility increased markedly in FY 2018 but came back down in FYs 2019 and 2020 before increasing again in FY 2021 and FY 2022. On the capital side, the large Upgrade Downtown CIP project began in FY 2018. Electric supply costs increased as new renewable projects came online, and transmission costs rose and have continued to rise as improvements are made to the California grid.

Section 6A: Electricity Purchases discusses the factors influencing Electric Utility expenses. During the last drought in FYs 2014 and 2015 commodity costs were higher due to lower than average output from hydroelectric resources, and similar circumstances are occurring in FY 2021, FY 2022 and are projected to continue through FY 2024. Transmission costs have increased as projected in prior financial plans. Better than average hydro conditions in FY 2019 led to lower than expected generation expenses as well as better than expected surplus energy revenues, but extreme drought followed.

Commodity costs have increased, on average, by about 4.8% per year over this timeframe. Operations costs have increased by about 2.9% annually on average. Revenues have increased on average by about 0.5% per year over this period and have been negatively impacted due to declining sales and COVID.

Figure 7 shows the electric utility revenues, expenses, and proposed rate changes for the previous five years, the current year, and the projections for the next five years. **The percentages listed do not include the hydroelectric rate adjuster.** The total rate, including the adjuster, is shown in Figure 8.

Embedded in the revenue line in Figure 7 is the assumption that the hydroelectric rate adjuster will be cut in half in FY 2024 and the proposed rates changes are just the changes to base rates.

Figure 7: Electric Utility Revenues, Expenses, and Rate Changes:
Actual Costs through FY 2022 and Projections through FY 2028

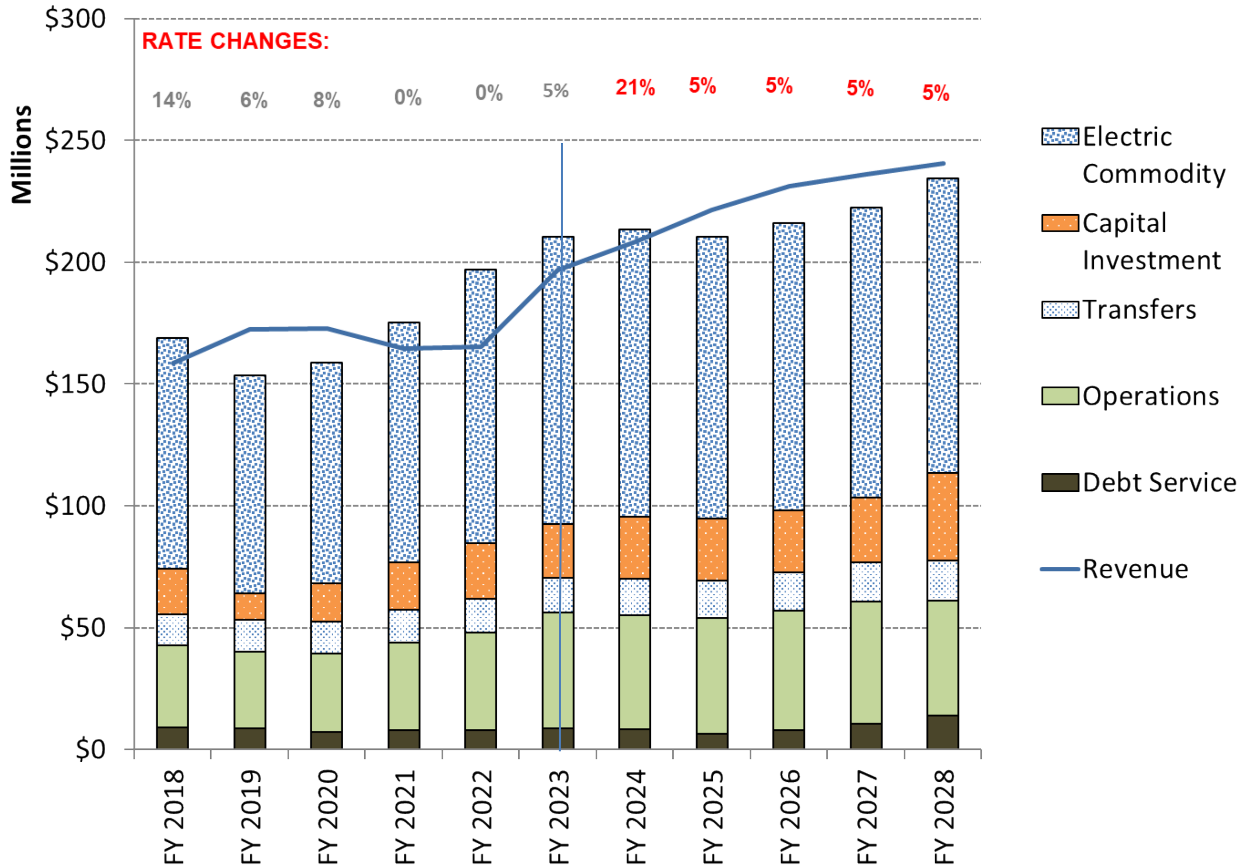
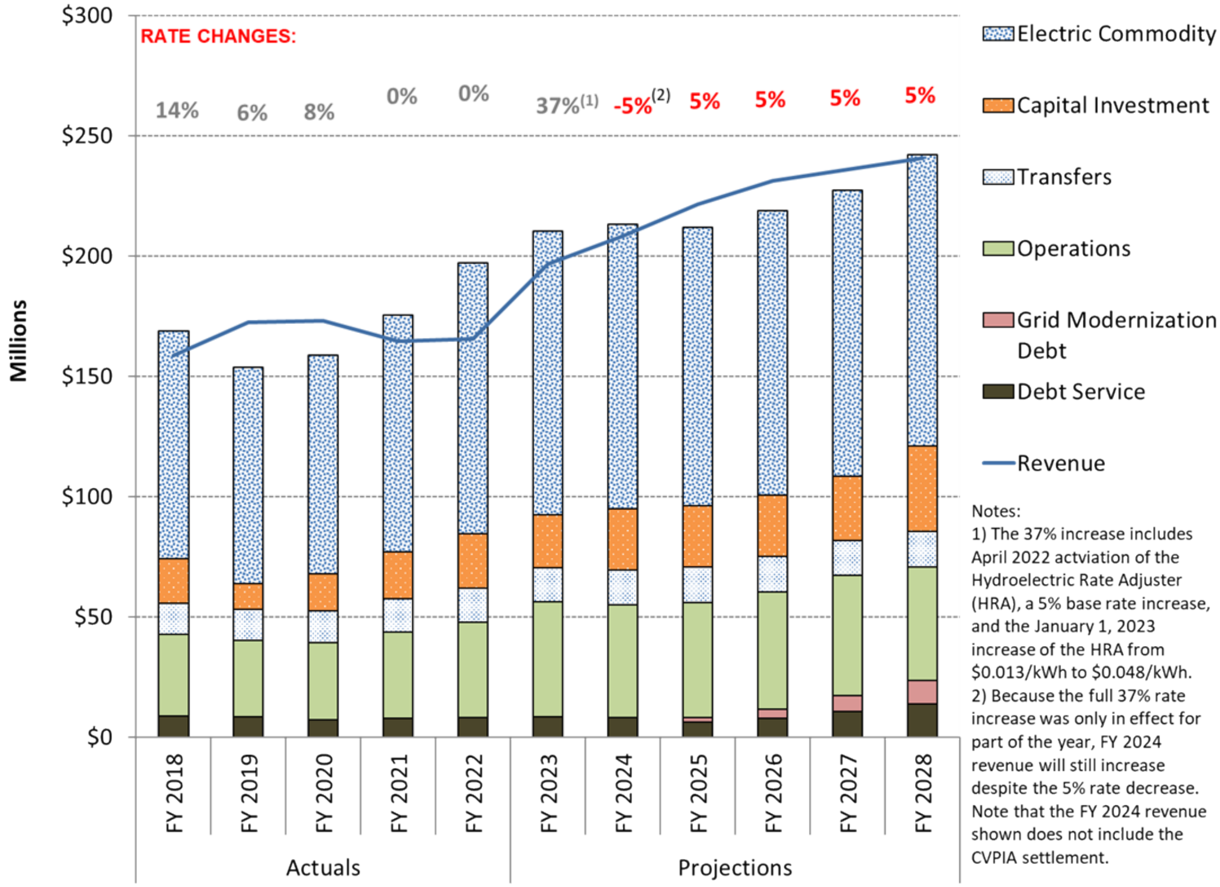


Figure 8, similar to Figure 7, shows the historical and projected revenues and expenses, but instead of showing the proposed base rate changes, it shows the change to the overall system rate, including both the base rate and the hydroelectric rate adjuster. This shows how significantly rates increased in FY 2022 and FY 2023 due to poor hydroelectric conditions and steeply increasing electricity market prices. In FY 2024, the system average rate decreases 5% from the current system average rate established on January 1, 2023. These forecasts could change depending on changes in hydroelectric generation and electricity market prices.

Figure 8: Electric Utility Revenues, Expenses, and Rate Changes:
Actual Costs through FY 2022 and Projections through FY 2028



SECTION 5C: FY 2022 RESULTS

FY 2022 revenues were $4 million lower than projections, as retail sales and surplus energy sales combined were $2 million less than projected. Revenues from the HRA were also $2 million less than projected as the rate went into effect later than anticipated. Net supply purchase costs came in $12 million higher than projected, but these costs were partially offset by approximately $6 million savings from surplus energy sales as well as lower administration and demand side management (DSM) costs. Capital projects costs exceed projections by $4 million.

Table 9 FY 2022, Actual Results vs. FY 2022 Financial Plan Forecast ($000)

	Net Cost/(Benefit)	Type of change
Lower revenues from retail sales, surplus energy sales, and Hydroelectric Rate Adjuster	$4,000	Revenue decrease
High Capital Projects cost	$4,000	Cost increase
Higher net purchase cost	$12,446	Cost increase
Lower Admin, DSM, and Surplus Energy Costs	(5,962)	Cost decrease
Net Cost / (Benefit) of Variances	**$14,482**	

SECTION 5D: FY 2023 PROJECTIONS

Net purchase costs are currently projected to increase by about $19.6 million, due to significantly higher market prices and poor hydro conditions. Some of this increased cost is being recovered by the increase to the hydroelectric rate adjuster on January 1, 2023. About $8 million more in revenue is expected for FY 2023 than the FY 2022 as a result. Surplus energy costs and administration costs are roughly $3 million lower than projected, partially offsetting higher supply costs. However, the increased revenues and lower costs are not sufficient to offset the higher purchase costs completely, leading to a $8.5 million decrease in the Operations Reserve in FY 2023.

Table 10 FY 2022, Change in Projected Results, 2023 Forecast vs. 2022 Forecast ($000)

	Net Cost/(Benefit)	Type of change
Sales revenues higher than forecasted	($8,000)	Revenue increase
Purchased electricity costs higher than forecasted	$19,609	Cost increase
Reduced Surplus Energy Cost and Admin	($3,064)	Cost decrease
Net Cost / (Benefit) of Variances to Ops Reserve	**$8,545**	

SECTION 5E: FY 2024 – FY 2028 PROJECTIONS

As shown in Figure 7 above, the Electric Utility's costs rose significantly in FY 2023 due to extremely high power market prices combined with deep, extended drought that decreased the amount of power coming from the City's hydroelectric resources. Some recovery of hydroelectric generation and reduction in prices is forecasted in FY 2024, but not to normal levels given the dry ground and low reservoir levels, which are expected to absorb a significant share of precipitation even if it is above average. Normal levels of hydroelectric generation are not forecasted until FY 2026, assuming normal rainfall in the winter of 2022/2023 and 2023/2024. To reduce hydroelectric-related volatility in the future, staff is now making its rate projections assuming that long-term "normal" production from the City's hydroelectric resources is about 80% of historical average levels.

Staff projects other costs for the Electric Utility to increase through FY 2028 and as a result projects rate increases in FY 2025 through FY 2028 to keep revenues in line with expenses over the next five years. Beyond hydro conditions, electricity purchase costs are increasing substantially as transmission costs rise to make improvements to the California grid. Operations costs are expected to increase at or near the average inflation rate (2-3%/year) through the forecast period. Projected capital expenses are higher due to the rebuilding of existing underground districts, substation and line voltage upgrades. The City is also evaluating the cost and scope of other system resiliency projects, such as pole replacements, which may increase costs as well as rates in the future.

Reserves trends based on these revenue projections are shown in Figure 9 (for Supply Fund Reserves) and Figure 10 (for Distribution Fund Reserves), below. The Supply and Distribution Operations Reserves are not projected to recover until FY 2026. However, the benefits of repaying the loan from the Electric Special Projects Reserve early and transferring $8 million to the Hydro Stabilization Reserve allow staff to comfortably recommend keeping the supply and distribution operation reserves below guidelines in FY 2024 and FY 2025. This forecast includes transfers from the Electric Special Projects Reserve to the Operations Reserve for Advanced Metering Infrastructure expenses, as approved by Council in 2018, but not for other potential projects that might be approved by Council for Electric Special Projects Reserve funding, such as a second transmission line.

Figure 9: Electric Utility Reserves (Supply Fund):
Actual Reserve Levels through FY 2022 and Projections through FY 2028

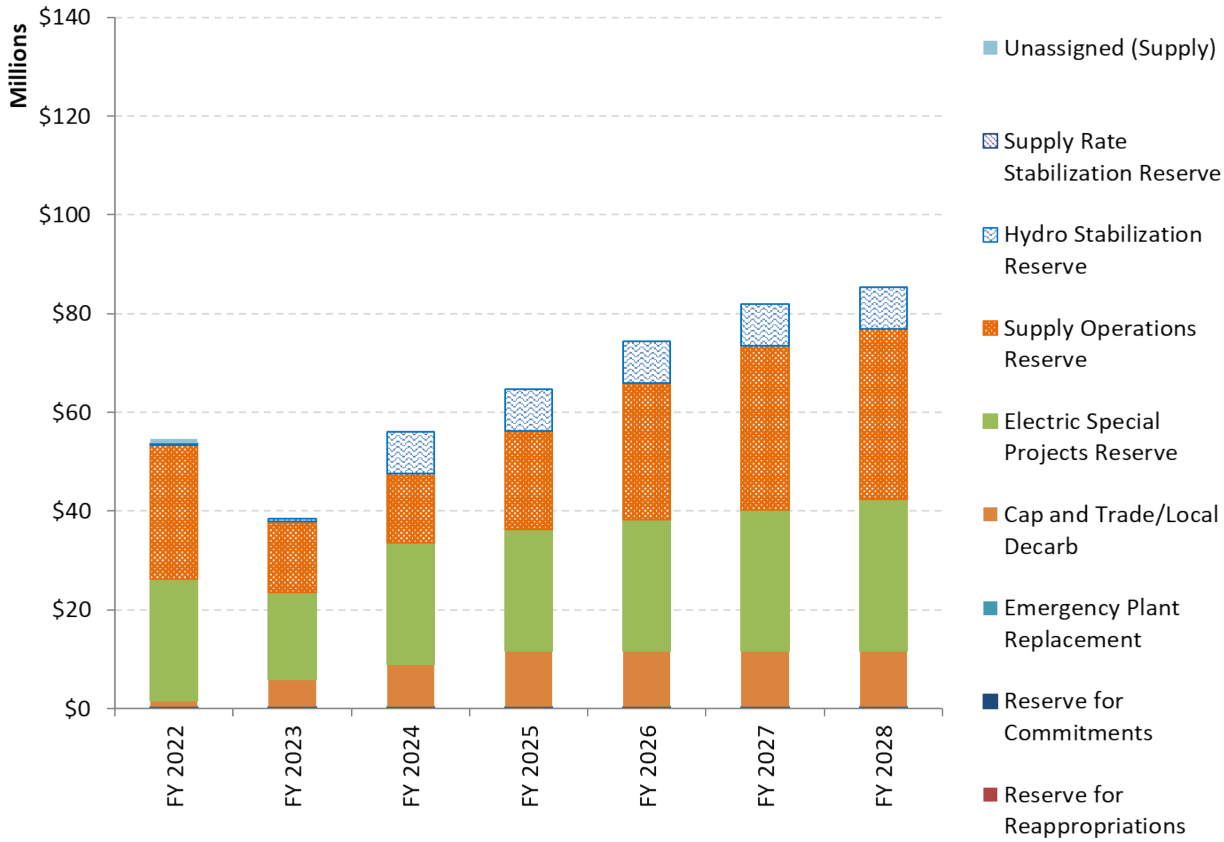
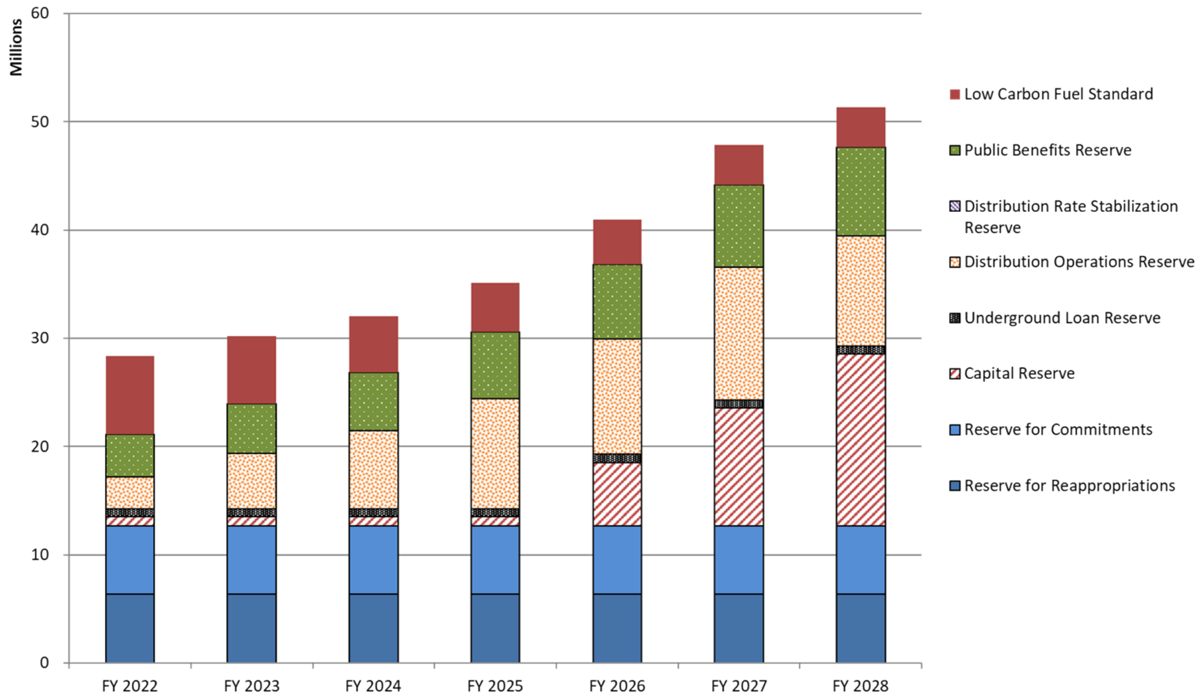


Figure 10: Electric Utility Reserves (Distribution Fund):
Actual Reserve Levels through FY 2022 and Projections through FY 2028



SECTION 5F: RISK ASSESSMENT AND RESERVES ADEQUACY

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 ESP Reserve, and a Capital Reserve, which can be utilized with Council approval.

This Financial Plan does not maintain reserves above the reserve minimum for both the Supply and Distribution Operations Reserves in FY 2024 and FY 2025, but does between FY 2026 and FY 2028. Reserve levels also exceed the short-term risk assessment level for the Distribution Fund.

There are a variety of risks associated with the Supply Fund related to resource generation variability, market price volatility, transmission cost increases, regulatory changes to market rules. Because of the high range of uncertainty in energy price predictions more than three years in 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 of these adverse scenarios occurring simultaneously and to the degree described in Table 12 is very low.

Table 12: Electric Supply Fund Risk Assessment

Categories of Electric Supply Cost Uncertainties	Estimates of Adverse Outcomes (M$)	Estimates of Adverse Outcomes (M$)
	FY 2024	**FY 2025**
1. Load Net Revenue	4.9	5.0
2. Hydro Production: Western & Calaveras	8.1	9.1
3. Renewable Production: Landfill & Wind & Solar	1.8	1.8
4. REC Purchases	0.52	0.56
5. REC Sales	-0.52	-0.56
6. Market Price	0.7	0.2
7. Resource Adequacy	1	1
8. Transmission/CAISO	3.9	4.3
9. Plant Outage	1	1
10. Western Cost	1.1	1.6
11. Legislative & Regulatory	0	0
12. Supplier Default+	0.2	0.2
Electric Supply Fund Risks	**22.73**	**24.22**

Of the risks faced by the Electric Utility's Supply Fund, the risk of a dry year with very low hydroelectric output is normally the largest, accounting for more than one-third ($8.1 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 2024, $3.9 million is related to potential transmission cost increases (above staff's current forecast). $4.9 million is related to the potential that total load (and the associated retail sales revenue) may be lower than projected, $1.8 million is associated with uncertainty around renewables production, and $1.0 million is associated with possible decreases in Resource Adequacy capacity sales revenues (and/or increases in Resource Adequacy capacity purchase costs).

As shown in Figure 11, staff projects the Supply Operations Reserve to drop below the minimum guideline levels in FY 2023 but return to minimum levels and slowly increase towards the end of the forecast period. Figure 12 shows that the combined Hydro Stabilization and Supply Operations Reserves are projected to be above what is needed for the risk assessment level in FY 2023, but that FY 2024 are approximately at the Risk Assessment level.

Figure 11: Electric Supply Operations Reserve Adequacy

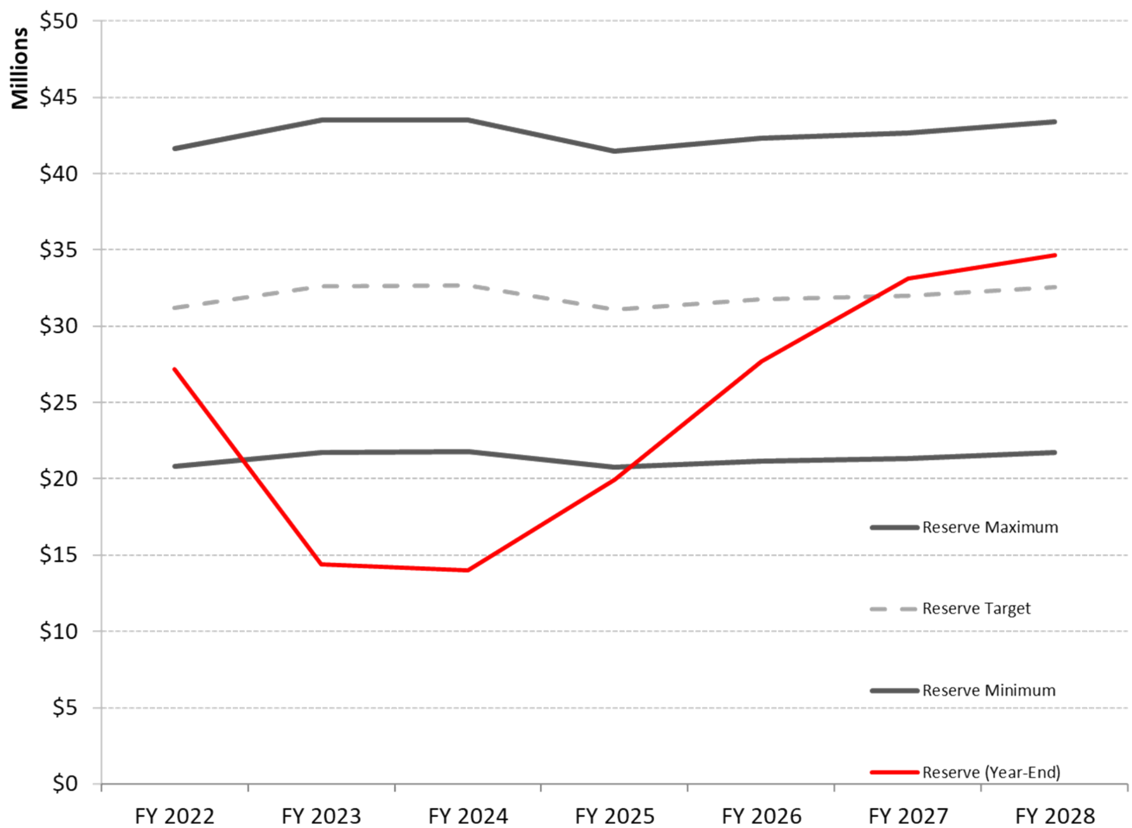


Figure 12: Adequacy of Supply Operations and Hydro Stabilization Reserves, Combined

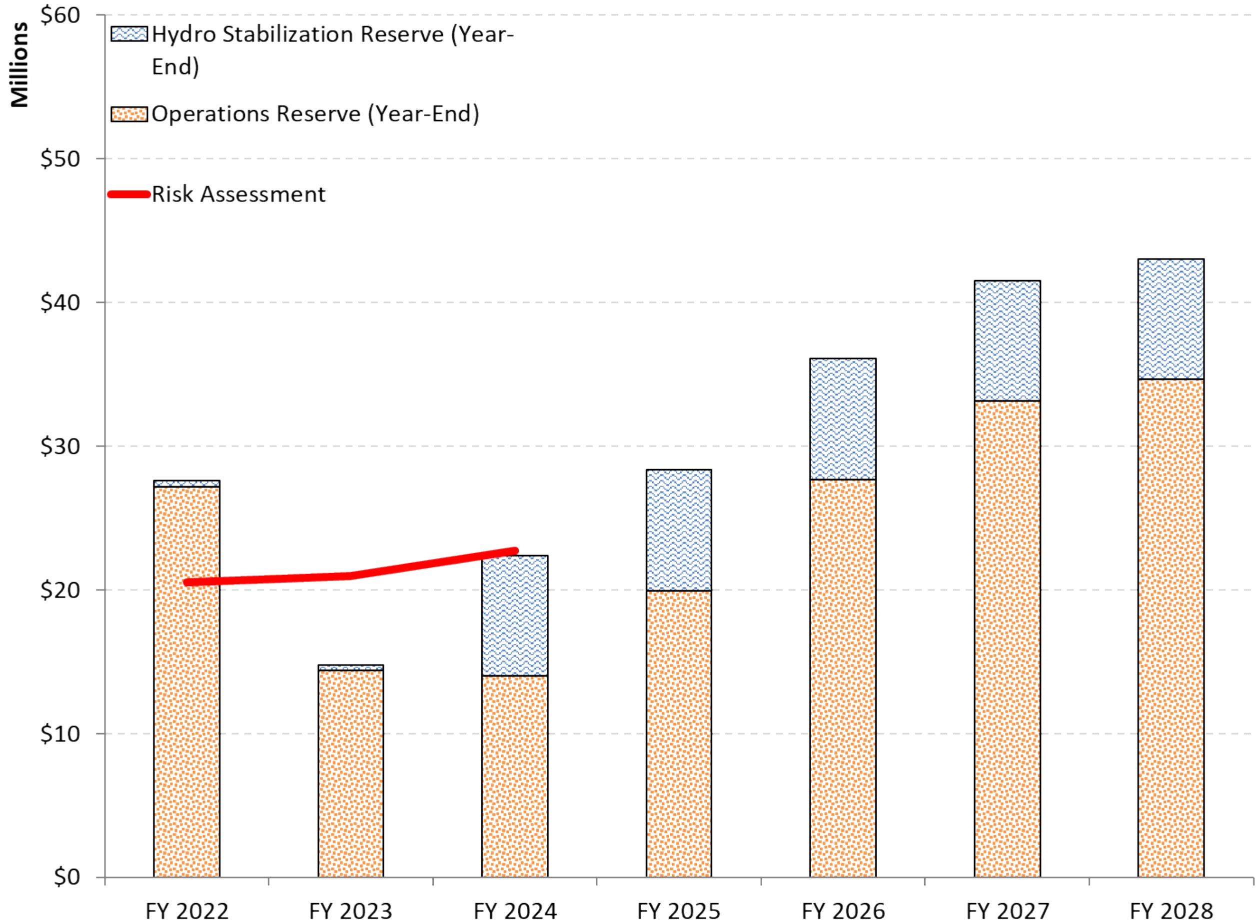


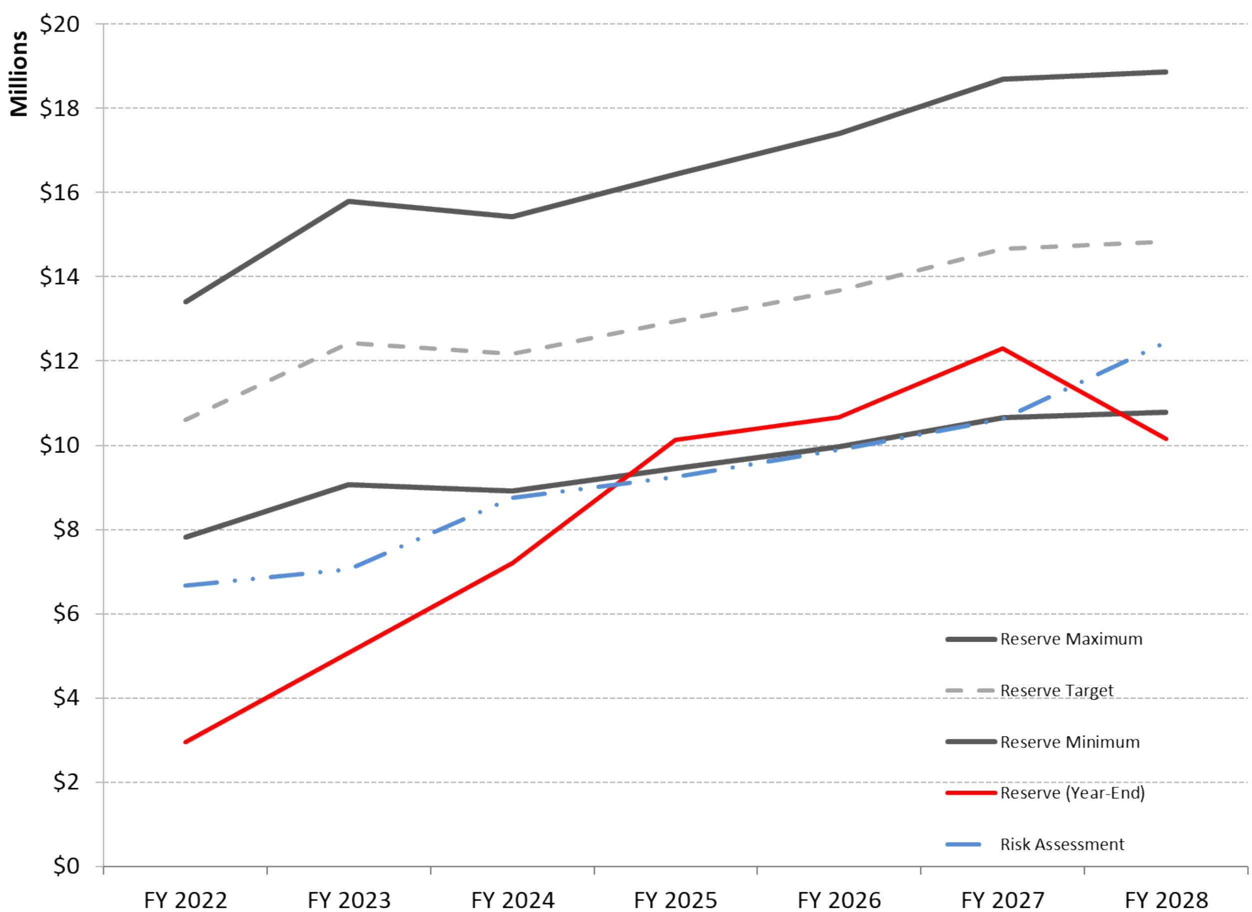
Table 13 summarizes the risk assessment calculation for the Distribution Operations Reserve through FY 2027. As shown in Figure 13, the Distribution Operations Reserve is also projected to drop near to the minimum reserve guidelines in FY 2024, but is projected to recover to near target levels over the 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 13: Electric Distribution Fund Risk Assessment ($000)

	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028
Total non-commodity revenue	$76,791	$82,662	$88,987	$99,524	$109,529
Max. revenue variance, previous ten years	8%	8%	8%	8%	8%
Risk of revenue loss	$6,061	$6,524	$7,023	$7,855	$8,645
CIP Budget	$25,508	$24,610	$22,644	$22,716	$22,730
CIP Contingency @10%	$2,551	$2,461	$2,264	$2,272	$2,273
Total Risk Assessment value	$8,612	$8,985	$9,288	$10,126	$10,918

Figure 13: Electric Distribution Operations Reserve Adequacy



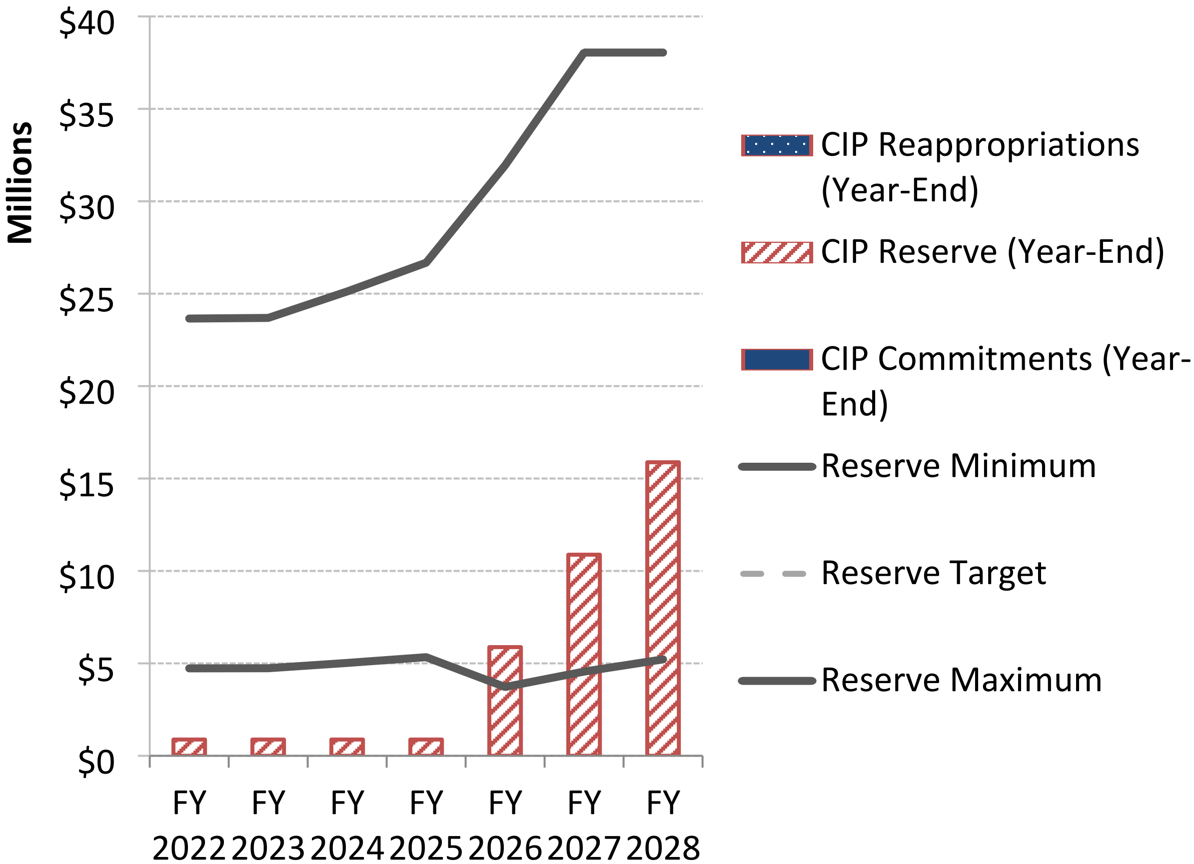
The Electric Utility also has a CIP Reserve that acts as a reserve for short term capital contingencies or as a place to set aside funds for large, one-time projects that the Utilities would otherwise need to debt-fund. In the future, staff would also like to use this reserve to manage cash flow for capital projects on an ongoing basis.

Figure 14 below reflects the maximum and minimum CIP Reserve guideline levels, starting in FY 2022. 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.

Because of constrained operating conditions resulting from COVID, increasing power supply costs and a desire not to raise rates more than needed, the 2024 Financial Plan doesn't anticipate funding the CIP Reserve from the Distribution Operations Reserve. In future years, the CIP Reserve will reflect actual fluctuations in CIP expenditures (money spent on actual projects in a given year). CIP expenditures are currently reflected in the Operations Reserve. Staff is anticipating, once the CIP Reserve has an adequate ending balance, to annually fund the CIP reserve with an amount based on average anticipated CIP spending for that year (currently estimated at $20 to $25 million in FY 2024 through FY 2026 and increasing to $30 to $35 million once grid modernization expenses ramp up in FY 2027 and FY 2028. Moving forward, the reserve will allow any cost savings or over-runs be reflected in the CIP Reserve instead of the Operations Reserve, as described above. This will allow for better transparency and accounting of CIP related funds, will address uneven annual funding associated with ongoing CIP projects, and offer a funding source for one-time or immediately needed projects. Having the reserve guidelines in place will ensure the reserve has sufficient funding for budgeted CIP as fluctuating annual amounts of capital investment occur going forward.

Figure 14 shows the projected CIP Reserve balances and guideline levels for FY 2022 through FY 2028, as well as the prior reserve and guidelines in FY 2022. Because of constrained financial conditions, the CIP reserve is projected to be below the minimum guideline for two years, until reserve funding can take place. Per the Reserves Management Practices (Appendix B), Section 10, any rate plan that does not return CIP reserves to minimum levels within one year requires Council approval. Council approved the FY 2023 Electric Utility Financial Plan, which included keeping the CIP Reserve below minimum until FY 2027, and this FY 2024 Financial Plan modifies that plan to keep CIP Reserves below minimum until FY 2026.

Figure 14: Electric CIP Reserve Adequacy



SECTION 5G: LONG-TERM OUTLOOK

This forecast covers the period from FY 2024 through FY 2028, but various long-term developments may create new costs for the utility over the next 10 to 35 years. While it is challenging to accurately forecast the impact these events will have on the utility's costs, it is worth noting them as future milestones and keeping them in mind for long-term planning purposes.

For the supply portfolio, the 2020s will see a number of notable events. The contract with the Western Area Power Administration (Western) for power from the Central Valley Project (CVP) will expire in 2024. Determining the future relationship with Western after 2024 will be important in the years leading up to the contract expiration, especially because this resource represents nearly 40% of the electric portfolio and is the utility's largest source of carbon-free electricity. The utility's three earliest and lowest cost renewable contracts will also begin expiring around that time, with the first contract expired in 2021 and the last in 2028. These three contracts, plus one more expiring in 2030, currently provide 17% to 18% of the energy for the utility's supply portfolio at prices under $65 per megawatt-hour (MWh). It is difficult to know what renewable energy prices will be when those contracts expire. Although recent prices have been in that range (or even lower), and costs may decrease in the future, current renewable projects also benefit from a wide range of tax and other incentives that may or may not be available in the 2020s and beyond. However, staff procured a replacement for the contract expiring in 2021 at a lower price than any of the City's current renewable contracts. In addition, staff is in the process of procurement for a renewable geothermal project expected to start in 2025.

The costs of the Calaveras hydroelectric project will also change in the 2020s, with debt service costs dropping by half or approximately $4 million in 2025 as some of the debt is paid off, and all debt retired by the end of 2032. Some additional debt may be issued to fund the costs of relicensing the project, but this is not anticipated to be as high as the current debt service. The project will only be 40 years old at that time, and hydroelectric projects can last for 70-100 years before major rebuilding is needed. Calaveras debt service represents roughly 70% of the annual costs of that project (and nearly 7% of the utility's total costs), so when the debt is retired, the project could be a low-cost asset for the utility, providing carbon-free energy equal to around 13% of the Electric Utility's supply needs in an average year.

Another factor that may affect the utility's supply costs in the long run is carbon allowance revenue. Currently the Electric Utility receives $3 to $5 million per year in revenue from allocated carbon allowances under the State's cap-and-trade program. It uses that revenue to pay for energy efficiency programs and to purchase renewable energy to support the utility's Carbon Neutral Plan. Staff expects that revenue source to continue in some fashion through 2030, although the number of allowances allocated to Palo Alto have been reduced. Discussions at the state level are ongoing to determine any further restrictions CARB may wish to enact on both the number of future allowances received as well as usage of allocation sales revenues. If the Electric Utility no longer received these allowances or was limited in how it could spend revenues, it would have to fund these programs from sales revenues.

Transmission costs are also continuing to rise. If the State continues to increase mandates or incentives for renewable energy development, integrating these new projects into the transmission grid will be an ever-increasing challenge, some costs of which will be borne by Palo Alto. The planned expansion of the CAISO to a larger regional grid control area may result in additional transmission costs that could further increase CPAU's transmission costs. In addition to the costs of new transmission lines that will need to be built, flexible resources will be required to balance rapid changes in wind or solar output throughout the day. Palo Alto will likely bear some of the costs of these new lines and resources. CPAU is also currently investigating installing a second transmission interconnection for Palo Alto, which could be funded by the Electric Special Projects Reserve.

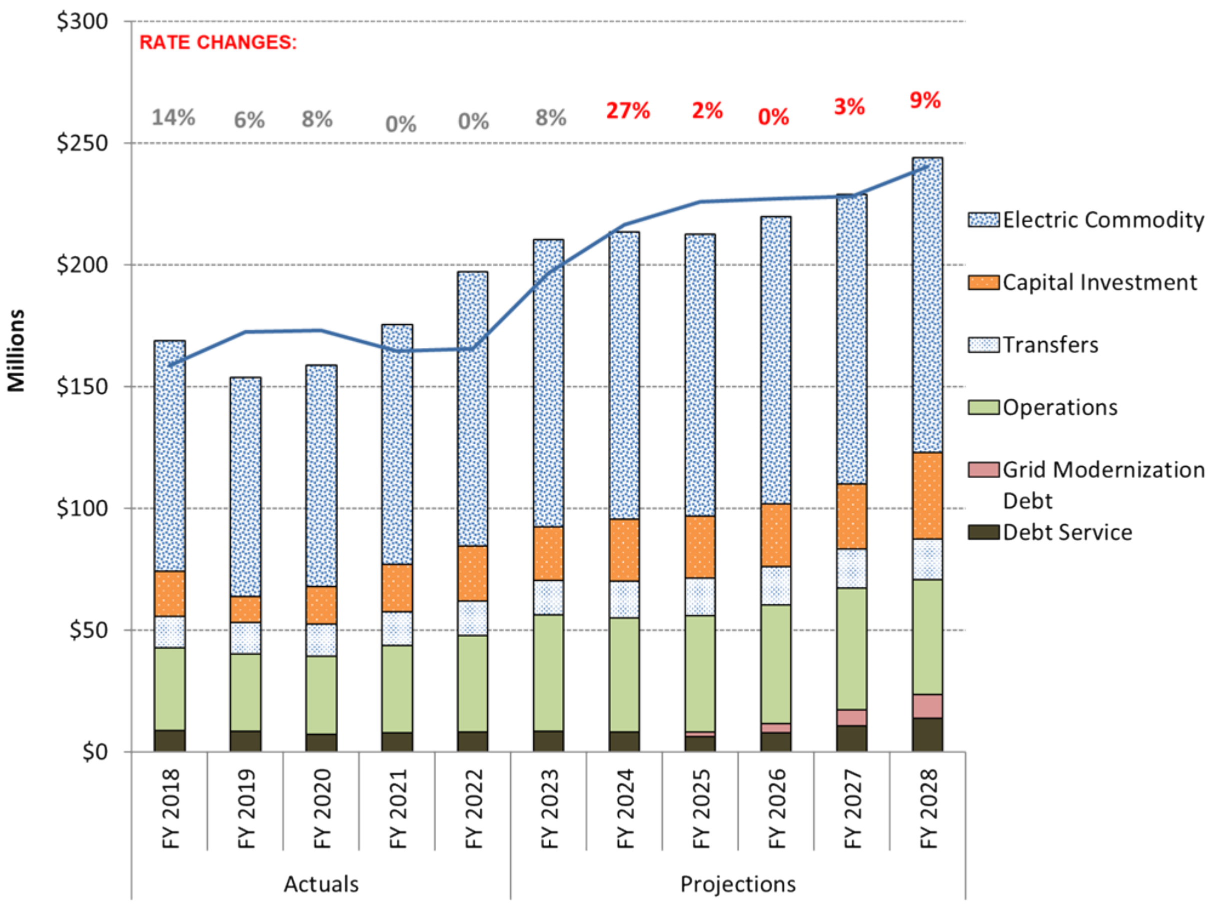
Over the next several years the Electric Utility will continue to execute its usual monitoring, repair, and replacement routine for the distribution system, but will also begin the rollout of various smart grid technologies. The utility is actively promoting electric vehicle ownership and gas-to-electric fuel switching in Palo Alto. In the coming years these factors are expected to create notable increases in electric consumption and have a variety of impacts on the distribution system. Other technologies such as battery storage and rooftop solar installations are also becoming even more common. The utility has already started to take some of these factors into account in its long-term planning processes but will need to continue to incorporate them into its planning methodologies.

Over the long term, electricity may replace natural gas and petroleum almost entirely as part of the City's efforts to combat climate change. Many, if not most, vehicles would use electricity, though hydrogen is another potential fuel source under development and other technologies might be developed. Staff is undertaking initial analysis of these types of scenarios in the context of the Sustainability and Climate Action Plan (S/CAP) development process. These types of scenarios require careful planning for the associated load growth to make sure the distribution system does not end up overloaded, or conversely, to avoid over-investment, and the evaluation of changes to utility distribution system management to accommodate integration of the various technologies involved in electrification. Utility analyses in progress that take into account potential load growth include a grid modernization study, the Electric Integrated Resource Plan, and a potential upcoming S/CAP funding needs and sources study that may help assess the impact of these trends on rates. Staff will integrate results from these studies in Financial Plans as they become available.

SECTION 5H: ALTERNATIVE RATE PROJECTIONS

As an alternative to the proposed rate increases shown above in figures 7 and 8 of -5% (21% increase to base rates) in FY 2024, 5% in FY 2025-FY 2028, staff could instead set rates to increase the supply and operations reserves to minimum guidelines in FY 2024 as opposed to FY 2026. This alternative still assumes that the HRA is removed starting in FY 2024 and that revenues must be derived from general rates. This leads to a 1% system average rate reduction (or a 27% increase to base rates) in FY 2024, followed by increases of 2%, 0%, 3%, and 9% in the following years. Supply and Distribution Operations Reserves would reach the minimum guideline levels in FY24 and target levels thereafter.

Figure 15: Alternative Rate Proposal



SECTION 6: DETAILS AND ASSUMPTIONS

SECTION 6A: ELECTRICITY PURCHASES

As shown in Figure 16 the utility is projected to get roughly 40% of its energy from hydroelectric projects in a normal year, but only 30% is expected or projected during FY 2023 and FY 2024 due to the drought. Contracts with renewable sources make up approximately 50% of the portfolio in FY 2024 before increasing to 60% by FY 2025. Staff expects contracts with renewable sources to continue at approximately 50% of the portfolio for the forecast period. The remainder comes from unspecified market sources. Under the City's Carbon Neutral Plan, CPAU purchases RECs corresponding to the amount of market energy it purchases.

Figure 16: Electricity Supply by Source

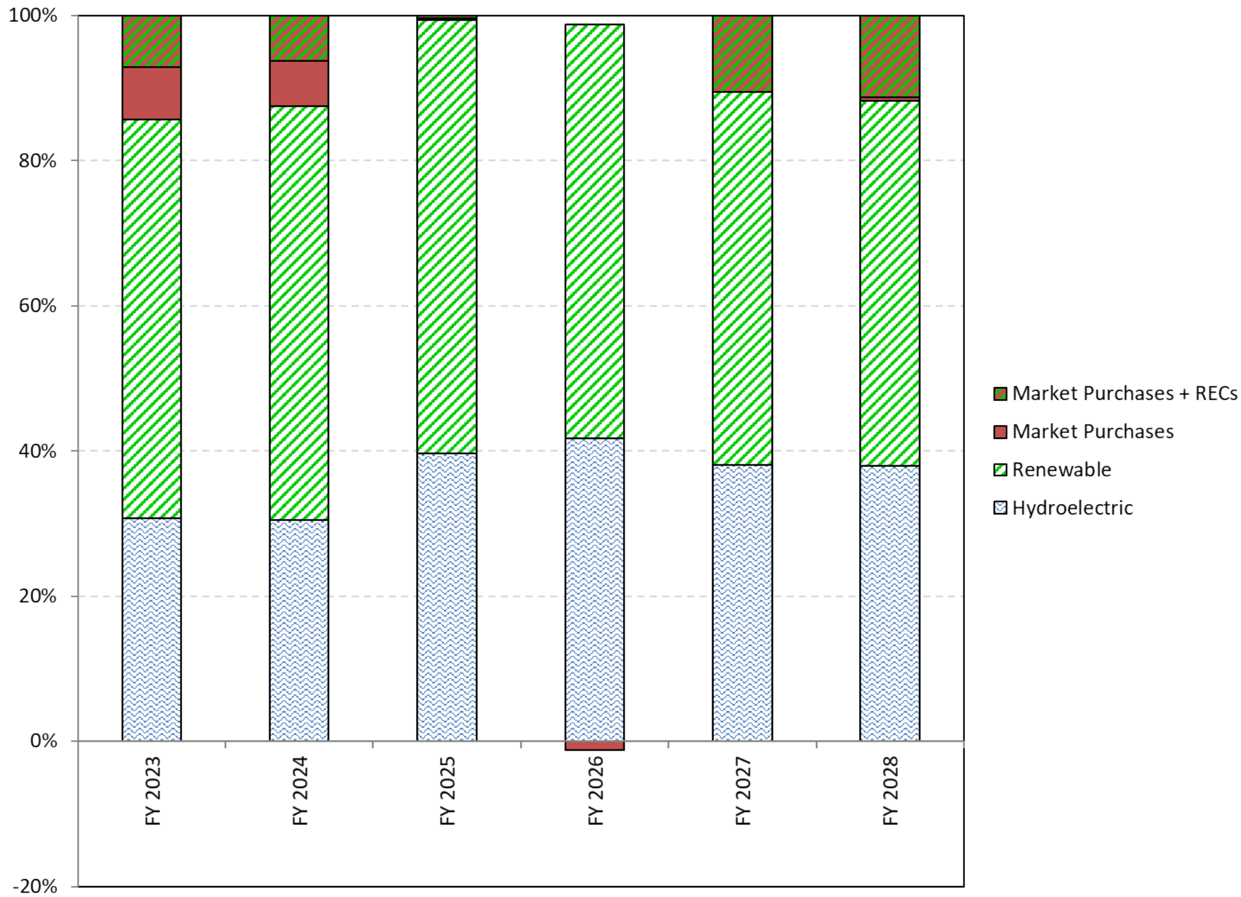


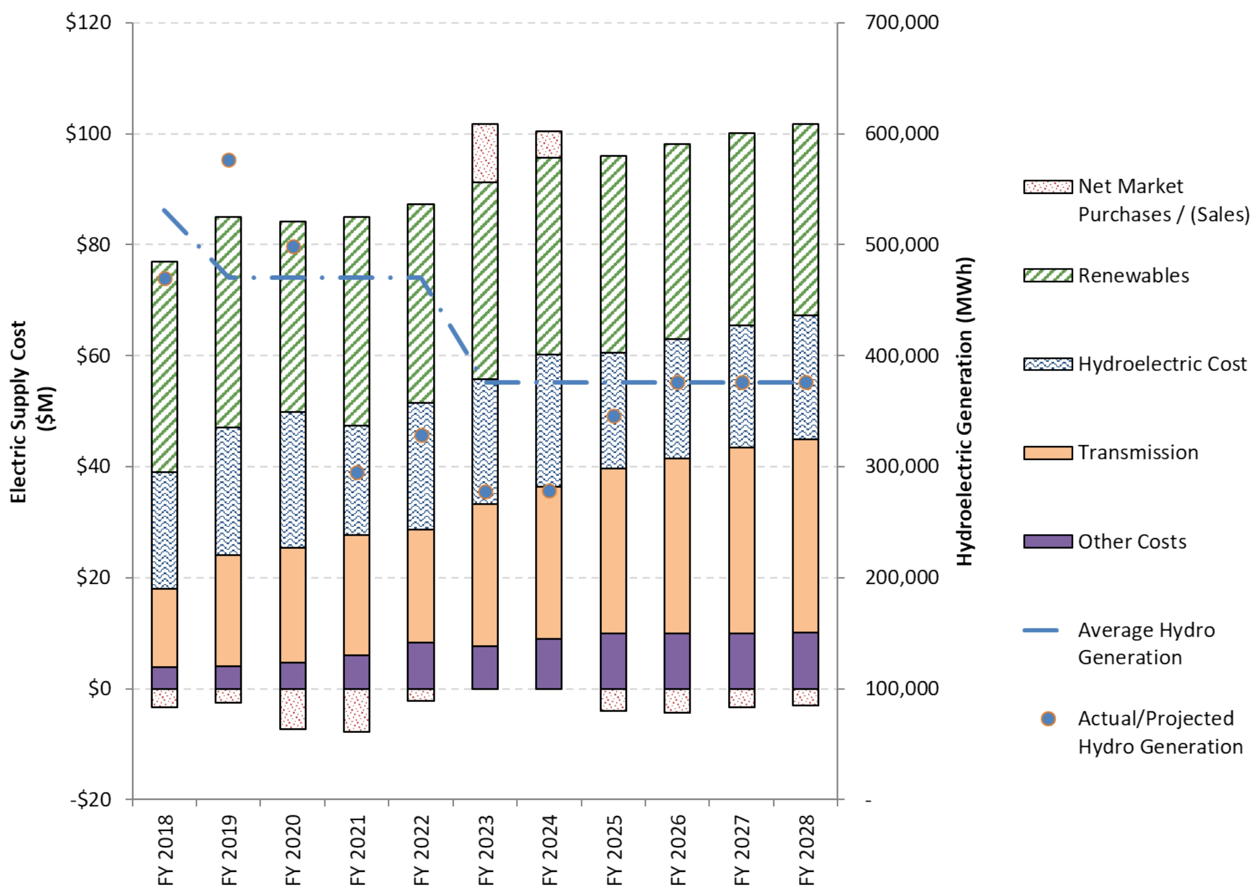
Figure 16 shows the historical and projected costs for the electric supply portfolio,[9] as well as average and actual hydroelectric generation.[10] FY 2021, FY 2022, FY 2023, and FY2024 had lower hydroelectric generation than or are projected to be lower. In addition, staff has reduced average hydro generation output expectations to more closely align with the past 10 year 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 tailwinds from federal subsidies. Transmission charges are projected to increase as new transmission lines are built throughout California to

[9] Costs are shown net of wholesale revenues and cannot be directly compared with the electric supply purchase figures shown in Appendix A: Electric Utility Financial Forecast Detail.

[10] Average hydroelectric generation based on the current E-HRA rate schedule.

accommodate new renewable projects. In total, net electric supply costs are projected to increase from about average of $80 million from FY 2018 through FY 2022 to about $100 million between FY 2023 through FY 2028.

Figure 17: Electric Supply Portfolio Costs, Historical and Projected



SECTION 6B: OPERATIONS

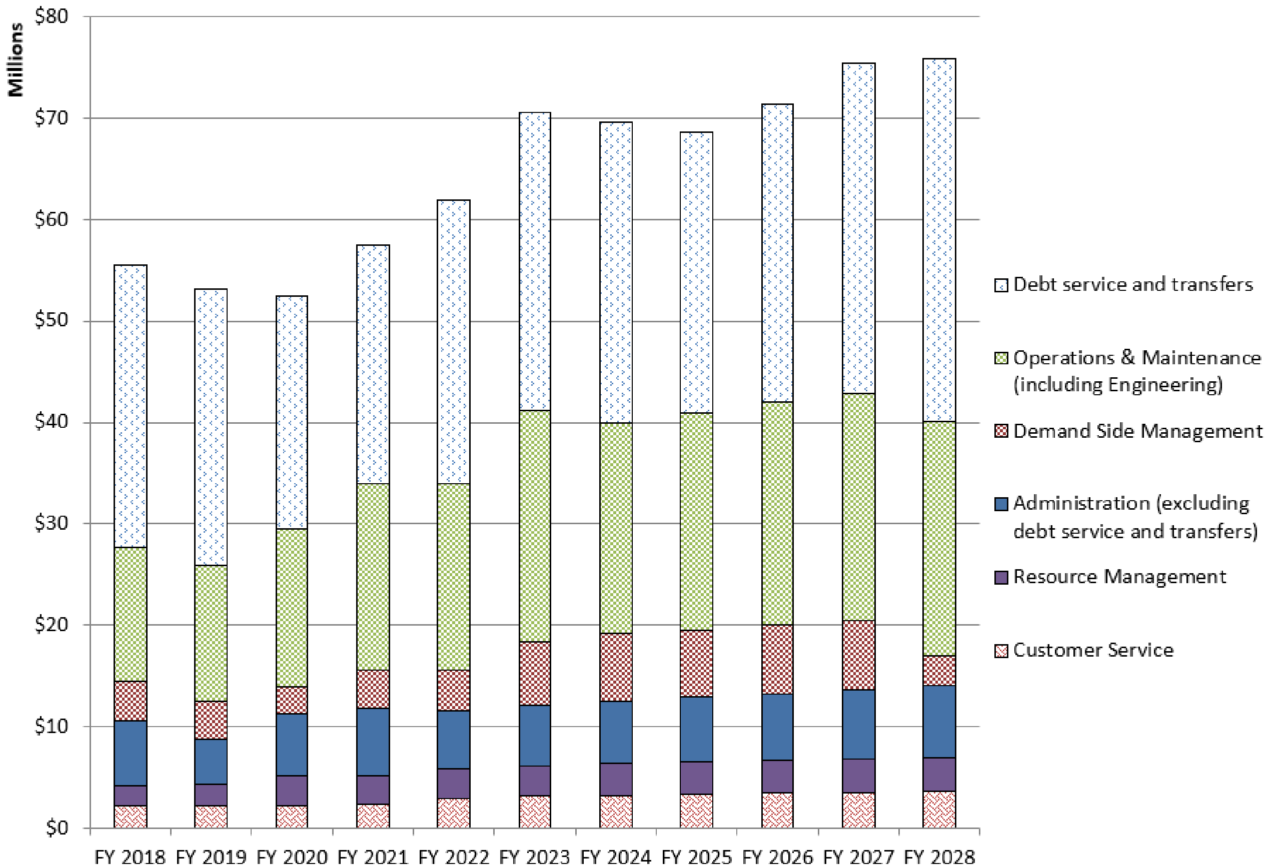
CPAU's Electric Utility operations include the following activities:

- 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. Additional detail on Electric Utility debt service is provided in Section 6D (Debt Service)
- Customer Service
- Engineering work for maintenance activities (as opposed to capital activities)
- Operations and Maintenance of the distribution system; and
- Resource Management

Appendix C: Description of Electric utility Operational Activities includes detailed descriptions of the work associated with each of these activities.

From FY 2018 to FY 2022, overall operations costs have risen annually by about 3% on average. Operations and maintenance costs are increasing mainly due to higher inflation, especially in salaries and benefits, as well as the use of contract line crew to help while the Utility is understaffed. These costs may be reduced depending on how much work is needed and may be phased out as longer-term employees are gained. Debt service is also forecasted to increase due to grid modernization and fiber investments.

Figure 18: Historical and Projected Electric Utility Operational Costs



SECTION 6C: CAPITAL IMPROVEMENT PROGRAM (CIP)

Staff projects CIP spending for FY 2024 through FY 2028 to be consistent with last year's forecast, though there is a slight shift in the funding by project category. There will be a reduction in funding for undergrounding conversion from overhead to underground as current projects are completed and others are delayed. There will be an increase in funding for underground rebuilding and 4/12kV conversion as improvements are made to the system in portions of the Crescent Park/Duveneck/St. Francis/Community Center/Leland Manor/Garland neighborhoods to facilitate rebuild of the Hopkins Substation. An increase in funding is also needed for replacement of distribution system and substation facilities that are at the end of their useful life. Other significant projects are deteriorated wood pole replacements, substation physical security upgrades, smart grid implementation, and ongoing capital investment in the electric distribution system to maintain/improve reliability. This forecast assumes that the utility finances smart grid projects (along with funding from the water and gas funds), the Foothill fire mitigation rebuilds, and the 115kV electric interconnection from the ESP Reserve. Bond financing may also be considered for some of these capital projects.

Excluding the one-time projects listed above, the CIP plan for FY 2024 to FY 2028 is primarily funded by utility rates, but other sources of funds include connection fees (for Customer Connections), phone and cable companies (primarily for undergrounding), and other funds (for smart grid, foothill rebuilds, electric interconnection). The details of the CIP budget will be available in the Proposed FY 2024 Utilities Capital Budget. Table 14 shows the FY 2022 projected budget and the five year CIP spending plan, although these figures are preliminary pending budget discussions starting in May. The 'committed' column represents funds committed to contracts for which work has not yet been completed or invoices paid.

Table 14: Electric Utility CIP Spending ($000)

Project Category	Current Budget *	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028
One Time Projects	6,987	6,647	7,350	1,000	1,000	-
Reliability	6,802	3,915	4,765	4,765	3,400	529
Undergrounding	190	-	-	100	3,000	-
4/12 kV Conversion	3,500	1,500	1,500	-	-	-
Underground Rebuild	2,395	-	400	1,850	1,600	-
Ongoing	9,211	5,339	5,415	5,375	5,586	6,093
Customer Connections	5,490	2,700	2,700	2,700	2,700	2,700
Grid Modernization and Fiber**	12,984	28,000	25,000	50,000	50,000	50,000
Electrification	-	-	-	4,300	7,800	19,700
Total	47,560	48,101	47,130	70,090	75,086	79,022

* Includes unspent funds from previous years carried forward or reappropriated into the current fiscal year
**Will be funded by sequential bonds, debt service for bonds included in Appendix A

Expenses outlined in table 14 include grid modernization and fiber investments, which are not shown in table 4.

SECTION 6D: DEBT SERVICE

The Electric Utility made its last payment on the 2007 Electric Utility Clean Renewable Energy Tax Credit Bonds, Series A in FY 2021. This $1.5 million bond issuance was to fund a portion of the construction costs of solar demonstration projects at the Municipal Services Center, Baylands Interpretive Center, and Cubberley Community Center.

The Electric Utility also pledges reserves and net revenue as security for the bond issuances listed in Table 15, 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 currently foresee this occurring. In FY 2022, the Electric Utility's net revenues dropped to -12% of debt service. However, the other utilities listed in Table 15 below were able to make their debt service payments in FY 2022 and Electric Utility's net revenues were not needed. Staff projects that the Electric Utility's net revenues in each future year will exceed 125% of debt service (see Appendix B, line 70).

Table 15: 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**
1999 Utility Revenue Bonds, Series A	Storm Drain Wastewater Collection Wastewater Treatment	$1,207	No	Yes
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*				

Embedded in this year's financial plan is the assumption that grid modernization and fiber investments will begin in FY 2024. While the financing details are still being assessed and may differ a bit from these assumptions, the current financial plan assumes the city will issue sequential $50 million bonds every 18 months beginning in FY 2024 until $300 million or 6 bonds have been issued. In addition, the fiber investment costs are estimated to be $13 million and included in the first bond, for a total of $63 million in FY 2024 and $313 million cumulatively. As shown in Appendix A, the financial plan assumes debt service costs beginning in FY 2025 of $2 million and increasing to $9.6 million in FY 2028. Depending on the scope of work, schedule and bond issuance costs, the timing, number of bonds, and amount of the bonds maybe be adjusted.

Table 16 illustrates the estimated bond proceeds and debt service costs over the next ten years.

Table 16: Projected Bond Proceeds and Debt Service Costs

Expenses ($000)	**FY 2024**	**FY 2025**	**FY 2026**	**FY 2027**	**FY 2028**	**FY 2029**	**FY 2030**	**FY 2031**	**FY 2032**	**FY 2033**
Bond Proceeds	63,000	50,000	0	50,000	50,000	0	50,000	50,000	0	0
Debt Service Costs	0	-2,032	-3,632	-6,432	-9,632	-12,832	-16,032	-19,232	-20,032	-20,032

SECTION 6E: EQUITY TRANSFER

The City calculates the equity transfer from its Electric Utility based on a methodology adopted by Council in 2009, which has remained unchanged since then.[11] Each year it is calculated according to the 2009 Council-adopted methodology and does not require additional Council action.

[11] 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 equity transfer methodology.

SECTION 6F: WHOLESALE REVENUES AND OTHER REVENUES

The Electric Utility receives most of its revenues from sales of electricity, but about 20 to 25% comes from other sources. Of these other sources, about 50% to 75% represents wholesale revenues of surplus energy sales. These revenues may offset electric supply purchase costs, smooth rate increases, or fund reserves or other costs. Of the remaining revenues, the largest revenue sources are interest on reserves, connection fees for new or replacement electric services, and carbon allowance revenues associated with the State's cap-and-trade program

Revenues from connection fees have increased since FY 2009 but vary from year to year. Connection fee revenues are collected to offset costs incurred in setting up new connections and are pass-through in nature. Staff forecasts $1.8 million in in FY 2024.

Staff projects carbon allowance and interest income revenues to stay relatively stable through the forecast period. However, both of these revenue sources are subject to some uncertainty. This forecast assumes the program State's cap-and-trade program will remain in place but with declining returns through 2030. It is possible this funding source may be removed entirely in the future, as the current CARB plan in the gas fund is for free allowances to stop entirely by 2030.

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

SECTION 6G: SALES REVENUES

The load forecast in *Section 5A: Load Forecast* and the projected rate changes shown in Figure 7 provide the basis for sales revenue projections. As discussed in Section 5A, sales revenues for this utility have been decreasing due to load reduction but are helped by the mild climate in Palo Alto. Palo Alto is a built-out City, so the opportunities for increased load growth are limited to the existing footprint of commercial structures and incremental growth in population. As utilization of existing spaces changes, and energy efficiency measures continue, Palo Alto could see greater load loss. Increased loads from electric vehicles and the electrification of households may increase loads somewhat.

SECTION 7: COMMUNICATIONS PLAN

The fiscal year (FY) 2024 electric utility communications strategy covers these primary areas: market price increases, cost containment measures, efficiency services and utility bill savings, capital improvement, operations and maintenance for infrastructure safety and reliability, renewables, carbon neutral portfolio, and beneficial electrification. City of Palo Alto Utilities (CPAU) communication methods include use of the utilities website, utility bill inserts, messaging on utility bills, email newsletters, print and digital ads in local publications, social media, and community message boards.

In advance of the rate-setting process, staff working on rates and communications are focusing on informing customers of higher than anticipated electric rates this year due to lower revenues from rates and interest income, impacts to hydroelectric supplies as a result of drought conditions, higher purchase costs, and contract line crew costs. The goal is to help customers navigate a challenging economic situation through efficiency services, rate assistance and bill payment relief programs.

CPAU customers also benefit from local control and policy setting, and community values-driven programs and services, including the decision to go carbon neutral in 2013. Palo Alto's renewable energy purchase agreements contribute to our utility's long-term energy security and commitment to sustainability. Power purchase agreements have allowed CPAU to procure long-term renewable electric supplies at low costs. CPAU will highlight these environmental attributes and value in our communications.

Programs such as the Home Efficiency Genie and commercial energy efficiency audits help residents and businesses better understand energy usage, activities and/or upgrades they can implement to improve efficiency and keep utility costs low. For several years, CPAU has offered a Genie in-home assessment, including a virtual option during the pandemic, and webinars about home energy and water efficiency to help customers keep utility costs low. Now the Genie program provides a home electrification readiness assessment so customers who may want to switch out gas for electric appliances or install an electric vehicle (EV) charger, can understand what may be necessary for electric panel upgrades.

Recently CPAU also launched new programs to help businesses improve energy efficiency and investigate the potential to switch from natural gas/fossil-fuel energy supplies to electricity. The Business Energy Advisor provides a "concierge" service for businesses to evaluate areas of their facility for efficiency improvements such as in the areas of building envelope, lighting, and heating. The Business Energy Advisor acts as the flagship program for businesses to then learn about available rebates for appliance or facility upgrades and opportunities for building electrification. CPAU also offers programs to help businesses, multi-family properties, non-profits and schools install EV charging infrastructure to assist employees and tenants with goals to switch from fossil fueled transportation to clean, electric driving.

APPENDICES

APPENDIX A: ELECTRIC UTILITY FINANCIAL FORECAST DETAIL

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1	FISCAL YEAR	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028
2												
3	**ELECTRIC LOAD**			160	159							
4	Purchases (MWh)	925,329	905,071	879,913	827,106	836,828	849,043	869,163	869,404	860,135	851,407	843,088
5	Sales (MWh)	899,997	884,322	854,761	813,881	812,841	809,059	830,051	843,322	834,331	825,865	817,795
6												
7	**BILL AND RATE CHANGES**											
8	System Average Rate ($/kWh)	$ 0.1413	$ 0.1487	$ 0.1624	$ 0.1590	$ 0.1606	$ 0.2010	$ 0.2078	$ 0.2172	$ 0.2270	$ 0.2374	$ 0.2491
9	Change in System Average Rate	13%	5%	9%	-2%	1%	25%	3%	5%	5%	5%	5%
10	Change in Average Residential Bill	11%	6%	8%	-1%	-1%	5%	21%	4%	5%	4%	5%
11												
12	**STARTING RESERVES**											
13	Reappropriations (Non-CIP)	-	-	-	-	56,811	120,000	120,000	120,000	120,000	120,000	120,000
14	Commitments (Non-CIP)	2,970,955	3,725,000	3,910,695	3,518,525	3,512,355	6,679,000	6,679,000	6,679,000	6,679,000	6,679,000	6,679,000
15	Low Carbon Fuel Standard (LCFS) Reserve	-	-	-	6,340,000	6,943,525	7,235,894	6,213,691	5,141,701	4,574,052	4,121,071	3,668,090
16	Cap and Trade Program					1,189,000	1,189,000	5,612,019	8,576,896	11,307,292	11,307,292	11,307,292
17	Underground Loan Reserve	730,147	730,147	726,659	726,659	726,659	726,659	726,659	726,659	726,659	726,659	726,659
18	Public Benefits Reserves	681,330	681,330	809,700	1,904,547	3,027,599	3,890,774	4,608,011	5,380,396	6,175,499	6,910,325	7,584,849
19	Electric Special Projects Reserve	51,837,855	41,837,855	41,664,855	46,664,855	46,664,855	24,649,000	17,649,000	24,649,000	24,649,000	26,649,000	28,649,000
20	Hydro Stabilization Reserve	11,400,000	11,400,000	11,400,000	15,400,000	15,400,000	400,000	400,000	8,400,000	8,400,000	8,400,000	8,400,000
21	Capital Reserves	879,964	879,964	879,964	5,879,964	879,964	879,964	879,964	879,964	879,964	5,879,964	10,879,964
22	Rate Stabilization Reserves	9,010,840	9,010,840	-	-	-	-	-	-	-	-	-
23	Operations Reserves (Supply & Dist)	29,912,981	18,600,000	45,244,167	38,538,459	29,902,850	30,142,000	19,455,158	21,211,224	30,057,451	38,353,661	45,440,073
24	Unassigned	-	244,354	-	0	(0)	844,513	-	-	-	-	-
25	TOTAL STARTING RESERVES	107,424,072	87,109,490	104,636,040	118,973,010	108,303,618	76,756,805	62,343,503	81,764,839	93,568,917	109,146,972	123,454,927
26												
27	**REVENUES**											
28	Net Sales	127,172,308	131,471,245	137,026,504	129,389,001	130,557,545	162,595,679	172,499,236	183,169,260	189,432,176	196,079,973	203,727,979
29	Wholesale Revenues	18,106,327	21,060,071	20,686,925	25,959,207	25,529,188	24,751,851	25,801,694	27,834,224	28,388,544	26,324,976	26,540,307
30	Other Revenues and Transfers In	13,373,312	19,914,635	15,260,937	9,324,996	9,348,837	9,235,543	34,092,443	10,654,877	13,334,635	13,638,723	10,469,612
31	TOTAL REVENUES	158,651,947	172,445,951	172,974,366	164,673,204	165,435,570	196,583,072	232,393,373	221,658,360	231,155,355	236,043,672	240,737,898
32												
33	**EXPENSES**											
34	Electric Supply Purchases	94,629,654	89,625,027	90,645,768	98,460,911	112,524,986	117,899,840	118,019,453	115,637,790	118,068,830	118,850,995	121,028,178
35	Operating Expenses											
36	Administration		110.0%									
37	*Allocated Charges*	*6,374,241*	*4,568,027*	*6,146,498*	*6,674,515*	*5,732,098*	*6,018,937*	*6,217,658*	*6,404,293*	*6,596,079*	*6,793,665*	*6,997,186*
38	*Rent*	*5,284,977*	*5,454,097*	*5,666,805*	*5,949,976*	*6,069,000*	*6,182,562*	*6,329,377*	*6,479,932*	*6,635,163*	*6,794,135*	*6,956,847*
39	*Debt Service*	*8,867,395*	*8,464,883*	*7,170,631*	*7,841,922*	*8,068,219*	*8,502,737*	*8,275,943*	*6,253,175*	*7,855,970*	*10,694,458*	*13,851,850*
40	*Transfers and Other Adjustments*	*13,632,059*	*13,342,321*	*10,133,943*	*9,610,379*	*13,811,097*	*14,572,449*	*15,482,046*	*15,629,938*	*16,040,156*	*16,449,711*	*16,838,612*
41	Subtotal, Administration	34,158,672	31,829,328	29,117,878	30,076,792	33,680,414	35,276,685	36,305,024	34,767,338	37,127,368	40,731,968	44,644,494
42	Resource Management	1,873,954	2,082,405	2,870,524	2,781,010	2,824,303	2,991,189	3,100,525	3,205,176	3,263,228	3,328,493	3,407,229
43	Demand Side Management	3,889,846	3,655,547	2,733,047	3,819,646	4,086,083	6,179,462	6,693,931	6,543,793	6,809,407	6,831,864	3,040,455
44	Operations and Mtc	11,528,747	11,606,585	13,450,568	15,988,315	16,576,083	20,981,726	18,712,141	19,309,318	19,771,526	20,263,837	20,773,883
45	Engineering (Operating)	1,790,942	1,838,799	2,051,303	2,408,524	1,806,550	1,898,848	1,962,319	2,022,073	2,079,850	2,139,750	2,201,511
46	Customer Service	2,291,246	2,180,400	2,228,469	2,320,338	2,974,968	3,145,349	3,258,085	3,365,609	3,434,569	3,510,129	3,588,840
47	Allowance for Unspent Budget	-	-	-	-	-	(568,039)	(587,742)	(606,422)	(621,182)	(636,877)	(654,081)
48	Subtotal, Operating Expenses	55,533,407	53,193,063	52,451,788	57,394,624	61,948,401	69,905,219	69,444,285	68,606,884	71,864,768	76,169,165	77,002,331
49	Capital Program Contribution	18,803,467	10,770,456	15,539,840	21,487,061	34,524,744	28,991,316	25,508,299	25,609,608	25,643,701	26,715,557	35,730,230
50	TOTAL EXPENSES	168,966,528	153,588,546	158,637,396	177,342,596	208,998,131	216,796,374	212,972,036	209,854,282	215,577,300	221,735,717	233,760,738
51												
52	**ENDING RESERVES**											
53	Reappropriations (Non-CIP)	9,063,000	-	-	56,811	120,000	120,000	120,000	120,000	120,000	120,000	120,000
54	Commitments (Non-CIP)	8,637,000	3,910,695	3,518,525	3,512,355	6,679,000	6,679,000	6,679,000	6,679,000	6,679,000	6,679,000	6,679,000
55	Low Carbon Fuel Standard (LCFS) Reserve	-	-	6,340,000	6,943,525	7,235,894	6,213,691	5,141,701	4,574,052	4,121,071	3,668,090	3,668,090
56	Cap and Trade Program				1,189,000	1,189,000	5,612,019	8,576,896	11,307,292	11,307,292	11,307,292	11,307,292
57	Underground Loan Reserve	730,147	726,659	726,659	726,659	726,659	726,659	726,659	726,659	726,659	726,659	726,659
58	Public Benefits Reserves	681,330	809,700	1,904,547	3,027,599	3,890,774	4,608,011	5,380,396	6,175,499	6,910,325	7,584,849	8,199,937
59	Electric Special Projects Reserve	41,837,855	41,664,855	46,664,855	46,664,855	24,649,000	17,649,000	24,649,000	24,649,000	26,649,000	28,649,000	30,649,000
60	Hydro Stabilization Reserve	11,400,000	11,400,000	15,400,000	15,400,000	400,000	400,000	8,400,000	8,400,000	8,400,000	8,400,000	8,400,000
57	Capital Reserve	879,964	879,964	5,879,964	879,964	879,964	879,964	879,964	879,964	5,879,964	10,879,964	15,879,964
58	Rate Stabilization Reserve	9,010,840	-	-	-	-	-	-	-	-	-	-
59	Operations Reserve (Supply & Dist)	18,600,000	45,244,167	38,538,459	29,902,850	30,142,000	19,455,158	21,211,224	30,057,451	38,353,661	45,440,073	44,802,144
60	Unassigned	244,354	-	0	(0)	844,513	-	-	-	-	-	-
61	TOTAL ENDING RESERVES	101,084,490	104,636,040	118,973,010	108,303,618	76,756,805	62,343,503	81,764,839	93,568,917	109,146,972	123,454,927	130,432,086
62												
63	**OPERATIONS RESERVE**											
64	Min (60 days of non-capital expenses)	25,849,452	24,700,922	25,579,071	26,397,217	28,629,395	30,806,909	30,678,262	30,197,099	31,138,925	31,984,104	32,493,679
65	Target (90 days of non-capital expenses)	37,071,179	35,342,766	36,507,588	38,417,367	41,834,515	45,045,206	44,813,743	44,055,844	45,431,537	46,661,127	47,386,164
66	Max (120 days of non-capital expenses)	48,292,905	45,984,610	47,436,104	50,437,517	55,039,635	59,283,502	58,949,225	57,914,590	59,724,148	61,338,150	62,278,648
67	Risk Assessment Value	5,622,455	4,992,321	6,001,771	6,381,125	6,668,204	7,063,828	8,756,964	9,247,811	9,902,791	10,615,661	12,442,421
68												
69	**DEBT SERVICE COVERAGE RATIO**											
70	Net Revenues (125% of Debt Service)	196%	450%	517%	212%	-12%	203%	643%	698%	625%	484%	408%
71	Available Reserves (5x Debt Service)*	9.4	11.9	16.1	13.4	8.7	6.5	9.1	13.9	13.0	10.9	8.9

1	FISCAL YEAR	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028
2												
3	**REVENUES**											
4	Net Sales	80%	76%	79%	79%	78%	71%	74%	83%	82%	83%	85%
5	Other Revenues and Transfers In	20%	24%	21%	21%	21%	17%	26%	17%	18%	17%	15%
6	TOTAL REVENUES	100%	100%	100%	100%	99%	88%	100%	100%	100%	100%	100%
7												
8	**EXPENSES**											
9	Commodity Purchases	50%	53%	53%	53%	56%	56%	55%	52%	51%	51%	49%
10	Operating Expenses											
11	Administration											
12	*Allocated Charges*	*4%*	*3%*	*4%*	*4%*	*3%*	*3%*	*3%*	*3%*	*3%*	*3%*	*3%*
13	*Rent*	*3%*	*4%*	*4%*	*3%*	*3%*	*3%*	*3%*	*3%*	*3%*	*3%*	*3%*
14	*Debt Service*	*5%*	*6%*	*5%*	*4%*	*4%*	*4%*	*4%*	*3%*	*4%*	*5%*	*6%*
15	*Transfers and Other Adjustments*	*8%*	*9%*	*6%*	*5%*	*7%*	*7%*	*7%*	*7%*	*7%*	*7%*	*7%*
16	Subtotal, Administration	20%	21%	18%	17%	17%	17%	17%	17%	17%	18%	19%
17	Resource Management	1%	1%	2%	2%	1%	1%	1%	2%	2%	2%	1%
18	Operations and Mtc	7%	8%	8%	9%	8%	10%	9%	9%	9%	9%	9%
19	Engineering (Operating)	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
20	Customer Service	1%	1%	1%	1%	2%	1%	2%	2%	2%	2%	2%
21	Allowance for Unspent Budget	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
22	Subtotal, Operating Expenses	31%	32%	31%	31%	29%	30%	29%	30%	30%	31%	32%
23	Capital Program Contribution	11%	7%	10%	11%	11%	10%	12%	12%	12%	12%	15%
24	TOTAL EXPENSES	91%	92%	95%	94%	97%	97%	96%	94%	94%	94%	96%
25												
26	**RISK ASSESSMENT DETAIL (SUPPLY FUND)**											
27	FISCAL YEAR	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028
28	1. Load Net Revenue											
29	2. Hydro Production: Western & Calaveras											
30	3. Renewable Production: Landfill & Wind & Solar											
31	4. Carbon Neutral Cost											
32	5. Market Price											
33	6. Local Capacity											
34	7. Transmission/CAISO											
35	8. Plant Outage											
36	9. Western Cost											
37	10. Regulatory & Legal											
38	11. Supplier Default											
39	TOTAL											
40	Supply Operations + Hydro Stabilization Reserves, % of Risk Assessment											
41												
42	**RISK ASSESSMENT DETAIL (DISTRIBUTION FUND)**											
43	FISCAL YEAR	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028
44	Distribution Revenue Variance	3,742,109	3,915,276	4,447,787	4,432,418	4,417,304	4,864,696	6,206,135	6,686,850	7,338,421	7,944,105	8,869,398
45	10% CIP Program Contingency	1,880,347	1,077,046	1,553,984	1,948,706	2,250,900	2,199,132	2,550,830	2,560,961	2,564,370	2,671,556	3,573,023
46	Total Risk Asssessment Value	5,622,455	4,992,321	6,001,771	6,381,125	6,668,204	7,063,828	8,756,964	9,247,811	9,902,791	10,615,661	12,442,421
47	Projected Operations Reserve	18,600,000	45,244,167	38,538,459	29,902,850	30,142,000	19,455,158	21,211,224	30,057,451	38,353,661	45,440,073	44,802,144
48	Operations Reserve, % of Risk Value	331%	906%	642%	469%	452%	275%	242%	325%	387%	428%	360%
49												
44	**SUPPLY OPERATIONS RESERVE**											
45	Min (60 days of non-capital expenses)	17,841,143	16,831,022	16,957,154	18,345,636	20,817,535	21,749,445	21,765,198	20,738,810	21,164,097	21,325,772	21,705,956
46	Target (90 days of non-capital expenses)	26,761,715	25,246,533	25,435,732	27,518,453	31,226,303	32,624,168	32,647,797	31,108,216	31,746,145	31,988,658	32,558,934
47	Max (120 days of non-capital expenses)	35,682,287	33,662,044	33,914,309	36,691,271	41,635,071	43,498,891	43,530,397	41,477,621	42,328,193	42,651,545	43,411,912
48												
49	**DISTRIBUTION OPERATIONS RESERVE**											
50	Min (60 days of non-capital expenses)	8,008,309	7,869,900	8,621,917	8,051,581	7,811,860	9,057,464	8,913,063	9,458,289	9,974,828	10,658,331	10,787,723
51	Target (90 days of non-capital expenses)	10,309,464	10,096,233	11,071,856	10,898,913	10,608,212	12,421,038	12,165,946	12,947,629	13,685,392	14,672,468	14,827,230
52	Max (120 days of non-capital expenses)	12,610,618	12,322,566	13,521,795	13,746,245	13,404,564	15,784,612	15,418,828	16,436,969	17,395,955	18,686,605	18,866,737
53	Risk Assessment Value	5,622,455	4,992,321	6,001,771	6,381,125	6,668,204	7,063,828	8,756,964	9,247,811	9,902,791	10,615,661	12,442,421
54												
55	**DEBT SERVICE COVERAGE RATIO**											
56	Net Revenues (125% of Debt Service)	196%	450%	517%	212%	-12%	203%	643%	698%	625%	484%	408%
57	Available Reserves (5x Debt Service)*	9.4	11.9	16.1	13.4	8.7	6.5	9.1	13.9	13.0	10.9	8.9

APPENDIX B: ELECTRIC UTILITY RESERVES MANAGEMENT PRACTICES

The following reserves management practices are used when developing the Electric Utility Financial Plan:

Section 1. Definitions

a) "Financial Planning Period" – The Financial Planning Period is the range of future fiscal years covered by the Financial Plan. For example, if the Financial Plan delivered in conjunction with the FY 2015 budget includes projections for FY 2015 to FY 2019, FY 2015 to FY 2019 would be the Financial Planning Period.
b) "Fund Balance" – As used in these Reserves Management Practices, Fund Balance refers to the Utility's Unrestricted Net Assets.
c) "Net Assets" - The Government Accounting Standards Board defines a Utility's Net Assets as the difference between its assets and liabilities.
d) "Unrestricted Net Assets" - The portion of the Utility's Net Assets not invested in capital assets (net of related debt) or restricted for debt service or other restricted purposes.

Section 2. Supply Fund Reserves

The Electric Supply Fund Balance is reserved for the following purposes:

a) For existing contracts, as described in Section 4 (Reserve for Commitments)
b) For operating budgets reappropriated from previous years, as described in Section 5 (Reserve for Reappropriations)
c) For special projects for the benefit of the Electric Utility ratepayers, as described in Section 6 (Electric Special Projects Reserve)
d) For year to year balancing of costs associated with the Electric Utility's hydroelectric resources, as described in Section 7 (Hydroelectric Stabilization Reserve)
e) For rate stabilization, as described in Section 1.d) (Rate Stabilization Reserves)
f) For operating contingencies, as described in Section 12 (Operations Reserves)
g) Any funds not included in the other reserves will be considered Unassigned Reserves and shall be returned to ratepayers or assigned a specific purpose as described in Section 13 (Unassigned Reserves).

Section 3. Distribution Fund Reserves

The Electric Distribution Fund Balance is reserved for the following purposes:

a) For existing contracts, as described in Section 4 (Reserves for Commitments)
b) For operating and capital budgets reappropriated from previous years, as described in Section 5 (Reserves for Reappropriations)
c) As an offset to underground loan receivables, as described in Section 8 (Underground Loan Reserve)
d) To hold Public Benefit Program funds collected but not yet spent, as described in Section 9 (Public Benefits Reserve)
e) For cash flow management and contingencies related to the Electric Utility's Capital Improvement Program (CIP), as described in Section 10 (CIP Reserve)
f) For rate stabilization, as described in Section 11.d) (Rate Stabilization Reserves)
g) For operating contingencies, as described in Section 12 (Operations Reserves)
h) Any funds not included in the other reserves will be considered Unassigned Reserves and shall be returned to ratepayers or assigned a specific purpose as described in Section 14 (Unassigned Reserves).

Section 4. Reserves for Commitments

At the end of each fiscal year the Electric Supply Fund and Electric Distribution Fund Reserves for Commitments will be set to an amount equal to the total remaining spending authority for all contracts in force for the Electric Supply Fund and Electric Distribution Fund, respectively, at that time.

Section 5. Reserves for Reappropriations

At the end of each fiscal year the Electric Supply Fund and Electric Distribution Fund Reserves for Reappropriations will be set to an amount equal to the amount of all remaining capital and non-capital budgets that will be reappropriated to the following fiscal year for each Fund in accordance with Palo Alto Municipal Code Section 2.28.090.

Section 6. Electric Special Projects Reserve

The Electric Special Projects Reserve (ESP Reserve) will be managed in accordance with the policies set forth in Resolution 9206 (Resolution of the Council of the City of Palo Alto Approving Renaming the Calaveras Reserve to the Electric Special Project Reserve and Adoption of Electric Special Project Reserve Guidelines). These policies are included from Resolution 9206 as amended to refer to the reserves structure set forth in these Reserves Management Practices:

a) The purpose of the ESP Reserve is to fund projects that benefit electric ratepayers;
b) The ESP Reserve funds must be used for projects of significant impact;
c) Projects proposed for funding must demonstrate a need and value to electric ratepayers. The projects must have verifiable value and must not be speculative, or high-risk in nature;
d) Projects proposed for funding must be substantial in size, requiring funding of at least $1 million;
e) Set a goal to commit funds by the end of FY 2025;
f) Any uncommitted funds remaining at the end of FY 2030 will be transferred to the Electric Supply Operations Reserve and the ESP Reserve will be closed;

Section 7. Hydroelectric Stabilization Reserve

The Hydroelectric Stabilization Reserve is used to manage the supply cost impacts associated with variations in generation from hydroelectric resources. Staff will manage the Hydroelectric Stabilization Reserve as follows:

a) Projected Hydro Output: Near the end of each fiscal year, staff will determine the actual and expected hydro output for that fiscal year, compare that to the long-term average annual output level (495,957 MWh as of March 2018), and multiply the difference by the average of the monthly round-the-clock forward market prices for each month of the current fiscal year.
b) Changes in Reserves. Staff is authorized to transfer the amount described in Sec. 7(a) from the Operations Reserve to the Hydroelectric Stabilization Reserve for hydro output deviations above long-term average levels, or transfer this amount from the Hydroelectric Stabilization Reserve to the Operations Reserve for hydro output deviations below long-term average levels.

c) Implementation of HRA. The level of the Hydroelectric Stabilization Reserve *after* the transfers described above shall be the basis for staff's determination, with Council approval, of whether to implement the Hydro Rate Adjuster (Electric Rate E-HRA) for the following fiscal year.

d) Reserve Guidelines. Staff will manage the Hydroelectric Stabilization Reserve according to the following guideline levels:

Minimum Level	$3 million
Target Level	$19 million
Maximum Level	$35 million

Section 8. Underground Loan Reserve

At the end of each fiscal year, the Underground Loan Reserve will be adjusted by the principal payments made against outstanding underground loans.

Section 9. Public Benefits Reserve

The Public Benefits Reserve will be increased by the amount of unspent Public Benefits Revenues remaining at the end of each fiscal year. Expenditure of these funds requires action by the City Council.

Section 10. CIP Reserve

The CIP Reserve is used to manage cash flow for capital projects and acts as a reserve for capital contingencies. Staff will manage the CIP Reserve according to the following practices:

a) The following guideline levels are set forth for the CIP Reserve. These guideline levels are calculated for each fiscal year of the Financial Planning Period and approved by Council resolution.

Minimum Level	20% of the maximum CIP Reserve guideline level
Maximum Level	Average annual (12 month)[12] CIP budget, for 48 months of budgeted CIP expenses[13]

b) Changes in Reserves: Staff is authorized to transfer funds between the CIP Reserve and the Reserve for Commitments when funds are added to or removed from the Reserve for Commitments as a result of a change in contractual commitments related to CIP projects. Any other additions to or withdrawals from the CIP reserve require Council action.

c) Minimum Level:

i) If, at the end of any fiscal year, the minimum guideline is not met, staff shall present a plan to the City Council to replenish the reserve. The plan shall be delivered by the end of the following fiscal year, and shall, at a minimum, result in the reserve reaching its minimum level by the end of the next fiscal year. For example, if the CIP Reserve is below its minimum level at the end of FY 2017, staff must present a plan by June 30, 2018 to return the reserve to its minimum level by June 30, 2019. In addition, staff

[12] Each month is calculated based upon 1/12 of the annual budget.

[13] For example, in the Financial Plan for FY 2021, the 48 month period to use to derive the annual average is FY 2021 through FY 2024. In the FY 2022 Financial Plan, the 48 month period to use to derive the annual average would be FY 2022 through FY 2025 etc.

may present, and the Council may adopt, an alternative plan that takes longer than one year to replenish the reserve, or that does so in a shorter period of time.

d) Maximum Level: If there are funds in this reserve in excess of the maximum level staff must propose in the next Financial Plan to transfer these funds to another reserve or return them to ratepayers in the funds to ratepayers, or designate a specific use of funds for CIP investments that will be made by the end of the next Financial Planning period. Staff may also seek City Council to approve holding funds in this reserve in excess of the maximum level if they are held for a specific future purpose related to the CIP.

Section 11. Rate Stabilization Reserves

Funds may be added to the Electric Supply or Distribution Fund's Rate Stabilization Reserves by action of the City Council and held to manage the trajectory of future year rate increases. Withdrawal of funds from either Rate Stabilization Reserve requires action by the City Council. If there are funds in either Rate Stabilization Reserve at the end of any fiscal year, any subsequent Electric Utility Financial Plan must result in the withdrawal of all funds from this Reserve by the end of the Financial Planning Period. The Council may approve exceptions to this requirement, when proposed by staff to provide greater rate stabilization to customers.

Section 12. Operations Reserves

The Electric Supply Fund and Electric Distribution Fund Operations Reserves are used to manage normal variations in the costs of providing electric service and as a reserve for contingencies. Any portion of the Electric Utility's Fund Balance not included in the reserves described in Section 4 to 11 above will be included in the appropriate Operations Reserve unless the reserve has reached its maximum level as set forth in Section 12 (e) below. Staff will manage the Operations Reserves according to the following practices:

a) The following guideline levels are set forth for the Electric Supply Fund Operations Reserve. These guideline levels are calculated for each fiscal year of the Financial Planning Period based on the levels of Operations and Maintenance (O&M) and commodity expense forecasted for that year in the Financial Plan.

Minimum Level	60 days of Supply Fund O&M and commodity expense
Target Level	90 days of Supply Fund O&M and commodity expense
Maximum Level	120 days of Supply Fund O&M and commodity expense

b) The following guideline levels are set forth for the Electric Distribution Fund Operations Reserve. These guideline levels are calculated for each fiscal year of the Financial Planning Period based on the levels of O&M expense forecasted for that year in the Financial Plan.

Minimum Level	60 days of Distribution Fund O&M expense
Target Level	90 days of Distribution Fund O&M expense
Maximum Level	120 days of Distribution Fund O&M expense

c) Minimum Level: If, at the end of any fiscal year, the funds remaining in the Supply Fund or Distribution Fund's Operations Reserve are lower than the minimum level set forth above, staff shall present a plan to the City Council to replenish the reserve. The plan shall be delivered within six months of the end of the fiscal year, and shall, at a minimum, result in the reserve reaching its minimum level by the end of the following fiscal year. For example, if the Operations Reserve is below its minimum level at the end of FY 2014, staff must present a plan by December 31, 2014 to return the reserve to its minimum level by June 30, 2015. In addition, staff may present an alternative plan that takes longer than one year to replenish the reserve.

d) Target Level: If, at the end of any fiscal year, either Operations Reserve is higher or lower than the target level, any Financial Plan created for the Electric Utility shall be designed to return both Operations Reserves to their target levels by the end of the forecast period.
e) Maximum Level: If, at any time, either Operations Reserve reaches its maximum level, no funds may be added to this Reserve. Any further increase in that fund's Fund Balance shall be automatically included in the Unassigned Reserve described in Section 13, below.

Section 13. Unassigned Reserves

If the Operations Reserve in either the Electric Supply Fund or the Electric Distribution Fund reaches its maximum level, any further additions to that fund's Fund Balance will be held in the Unassigned Reserve. If there are any funds in either Unassigned Reserve at the end of any fiscal year, the next Financial Plan presented to the City Council must include a plan to assign them to a specific purpose or return them to the Electric Utility ratepayers by the end of the first fiscal year of the next Financial Planning Period. For example, if there were funds in the Unassigned Reserves at the end of FY 2016, and the next Financial Planning Period is FY 2017 through FY 2021, the Financial Plan shall include a plan to return or assign the funds in the Unassigned Reserve by the end of FY 2017. Staff may present an alternative plan that retains these funds or returns them over a longer period of time.

Section 14. Intra-Utility Transfers between Supply and Distribution Funds

Transfers between Electric Distribution Fund Reserves and Electric Supply Fund Reserves are permitted if consistent with the purposes of the two reserves involved in the transfer. Such transfers require action by the City Council.

Section 15. Low Carbon Fuel Standard (LCFS) Reserve

This reserve tracks revenues earned via the sale of Low Carbon Fuel Credits allocated by the California Air Resources Board to the City, as well as expenses incurred, in accordance with California's Low Caron Fuel Standard program. At the end of each fiscal year, the LCFS Reserve will be adjusted by the net of revenues and expenses associated with California's LCFS program.

Section 16. Cap and Trade Program Reserve

This reserve tracks unspent or unallocated revenues from the sale of carbon allowances freely allocated by the California Air Resources Board to the electric utility, under the State's Cap and Trade Program. Funds in this Reserve are managed in accordance with the City's Policy on the Use of Freely Allocated Allowances under the State's Cap and Trade Program (the Policy), adopted by Council Resolution 9487 in January 2015.

APPENDIX C: DESCRIPTION OF ELECTRIC UTILITY OPERATIONAL ACTIVITIES

This appendix describes the activities associated with the various cost categories referred to in this Financial Plan.

Customer Service: This category includes the Electric Utility's share of the call center, meter reading, collections, and billing support functions. Billing support encompasses staff time associated with bill investigations and quality control on certain aspects of the billing process. It does not include maintenance of the billing system itself, which is included in Administration. This category also includes CPAU's key account representatives, who work with large commercial customers who have more complex requirements for their electric services.

Resource Management: This category includes supply portfolio management, energy procurement, rate setting, and tracking of legislation and regulation related to the electric industry.

Operations and Maintenance: This category includes the costs of a variety of distribution system maintenance activities, including:

- monitoring the substations and performing routine maintenance;
- performing preventative maintenance on the system;
- monitoring the system's status from the UCC using SCADA;
- maintaining the SCADA system;
- investigating outages and other customer complaints and performing emergency repairs;
- clearing vegetation near overhead power lines; and
- testing and replacing meters to ensure accurate sales metering.

Administration: Accounting, purchasing, legal, and other administrative functions provided by the City's General Fund staff, as well as shared communications services, Utilities Department administrative overhead and billing system maintenance costs.

Demand Side Management: Includes the cost of administering energy efficiency programs and the direct cost of rebates paid. Includes solar rebates.

Engineering (Operating): The Electric Utility's engineers focus primarily on the CIP, but a small portion of their time is spent assisting with distribution system maintenance.

APPENDIX D: SAMPLES OF RECENT ELECTRIC UTILITY OUTREACH COMMUNICATIONS