City of Palo Alto (ID # 11887)

Finance Committee Staff Report

Report Type: Action Items **Meeting Date: 4/6/2021**

Summary Title: FY 2022 Electric Financial Plan and Rates

Title: Staff and the Utilities Advisory Commission Request the Finance Committee Recommend the City Council Adopt a Resolution Approving the Fiscal Year 2022 Electric Financial Plan and Reserve Transfers, and Amending Utility Rate Schedules E-EEC-1 (Export Electricity Compensation), E-NSE-1 (Net Surplus Electricity Compensation), E-2-G (Residential Master-metered and Small Non-residential Green Power Electric Service), E-4-G (Medium Non-residential Green Power Electric Service, and E-7-G (Large Non-residential Electric Service)

From: City Manager

Lead Department: Utilities

Recommendation

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

1. Approving the Fiscal Year (FY) 2022 Electric Financial Plan (Linked Document, Attachment B);
2. Approving a transfer of up to $5 million from the Capital Improvement Project (CIP) Reserve to the Distribution Operations Reserve at the end of FY 2021;
3. Approving a transfer of up to $1 million from the Supply Operations Reserve to the Electric Special Projects (ESP) reserve at the end of FY 2021;
4. Approving an allocation of up to $1.19 million from the Cap and Trade Program Reserve at the end of FY 2021 to be spent on local decarbonization programs;
5. Updating the Export Electricity Compensation (E-EEC-1) rate to reflect current projections of avoided cost, effective July 1, 2021; (Linked Document, Attachment C)
6. Updating the Net Surplus Electricity Compensation (E-NSE-1) rate to reflect current projections of avoided cost, effective July 1, 2021; (Linked Document, Attachment C) and
7. Updating the Palo Alto Green program pass-through premium charge 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 to reflect current costs,

effective July 1, 2021. (Linked Document, Attachment C)

Executive Summary

The FY 2022 Electric Utility Financial Plan includes projections of the utility's costs and revenues through FY 2026. Staff projects costs for the Electric Utility to increase steadily through the forecast period. Revenue increases between 0% to 5% are projected to be necessary to keep revenues in line with expenses over the next five years. Rising transmission costs are the primary contributor to the increases. A lack of precipitation, if it continues through the winter, may necessitate utilizing funds from the Hydroelectric Rate Stabilization Reserve starting in FY 2021.

Operations costs are expected to increase at or near the inflation rate (2% to 3% per year) through the forecast period. Projected capital expenses are higher due to the rebuilding of existing underground districts, substation, the Foothills rebuild, 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.

Electric loads have been gradually decreasing and are expected to continue to decrease in the long-term, mainly due to declining consumption in the commercial sector, putting gradual upward pressure on rates. This decline has been exacerbated by the COVID pandemic. Consumption is currently 5% to 10% below long-term consumption trends. Current models suggest that pandemic economic recovery will take place through 2021 and 2022, with electric consumption stabilizing on the long run average by 2023.

Based on the relative health of the various Electric reserve funds, staff is recommending no rate increase for FY 2022, however this will likely result in reserves falling close to the minimum guideline levels over the next two to three years.

Background

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

The Finance Committee reviewed the preliminary financial forecasts at its February 16, 2021 meeting (Staff Report #11864[1]). The UAC reviewed Staff's FY 2022 Electric Financial Plan, proposed transfers and rate changes at its March 3, 2021 meeting.

[1] https://www.cityofpaloalto.org/civicax/filebank/documents/80154

Discussion
Staff's annual assessment of the financial position of the City's electric utility is completed in compliance with cost of service requirements set forth in the California Constitution and applicable statutory law. The assessment includes making long-term projections of market conditions, of costs associated with the physical condition of infrastructure, and of other factors that could affect utility costs. Rates are then proposed that will be adequate to recover projected costs.

Proposed Actions for FY 2021 and FY 2022:

The FY 2022 Electric Utility Financial Plan includes the following proposed actions:

1. Approving the Fiscal Year (FY) 2022 Electric Financial Plan (Linked Document, Attachment B);
2. Approving a transfer of up to $5 million from the Capital Improvement Project (CIP) Reserve to the Distribution Operations Reserve at the end of FY 2021;
3. Approving a transfer of up to $1 million from the Supply Operations Reserve to the ESP reserve at the end of FY 2021;
4. Approving an allocation of up to $1.19 million from the Cap and Trade Program Reserve at the end of FY 2021, to be spent on local decarbonization programs;
5. Updating the Export Electricity Compensation (E-EEC-1) rate to reflect current projections of avoided cost, effective July 1, 2021; (Linked Document, Attachment C)
6. Updating the Net Surplus Electricity Compensation (E-NSE-1) rate to reflect current projections of avoided cost, effective July 1, 2021; (Linked Document, Attachment C) and
7. Updating the Palo Alto Green program pass-through premium charge 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 to reflect current costs, effective July 1, 2021. (Linked Document, Attachment C)

The transfer from the CIP Reserve will help fund CIP projects, keep the Distribution Operations reserve above minimum guideline levels and balance year to year changes in capital investment.

The transfer to the Electric Special Projects reserve will work towards repaying the remaining $5 million of a $10 million short-term loan taken from the ESP reserve in FY 2018, during the last drought. Repaying the full $5 million in FY 2021, which was part of last year's financial plan, is not recommended as the Supply Operations Reserve would likely go below the minimum guideline level in FY 2023 as a result. Instead, staff anticipates repaying the remaining balance in $1 million installments between FY 2021 and FY 2025.

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 restricted to support specifically carbon reducing activities, including local decarbonization.

In accordance with Council's August 2020 direction, (Staff Report #11556)[2] the City has also exchanged 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. The revenues received from these REC exchanges are kept in the Electric Supply Reserve. With this Financial Plan, and as described in Staff Report #11556, staff is allocating Cap and Trade funds equivalent to 1/3 of the FY 2021 REC Exchange program revenues, or $1.19 million, for future local decarbonization projects.

Table 1 below shows the effects of the proposed transfers on reserve funds, as well as changes to the CIP min/max guidelines. The attached Electric Financial Plan (Linked Document, Attachment B) discusses these reserve changes in greater detail:

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

Table 1: Reserves Starting and Ending Balances, Revenues, Expenses, Transfers To/(From) Reserves, Operations and Capital Reserve Guideline Levels for FY 2021 to FY 2026 ($000)

			FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026
	Starting Reserve Balances							
1		Supply Operations	29,429	25,213	20,120	19,588	23,351	28,131
2		Distribution Operations	9,064	10,808	10,729	10,282	11,415	13,836
3		CIP	5,880	880	880	880	880	9,880
4		Electric Special Projects	46,665	47,665	36,649	30,649	31,649	32,649
5		Hydro Stabilization	15,400	15,400	15,400	15,400	15,400	15,400
6		Low Carbon Fuel Standard	6,340	4,080	3,186	2,164	1,092	524
7		Cap and Trade Program	-	1,189	2,190	5,749	9,316	12,866
	Revenues							
8		Supply	112,482	114,293	118,332	124,988	124,256	124,120
9		Distribution	55,588	59,194	68,325	74,410	77,929	77,179
	Transfers							
10		Supply Operations	(2,189)	(2,000)	(4,560)	(4,567)	(4,550)	(3,700)
11		Distribution Operations	5,000	-	-	-	(9,000)	(3,000)
12		CIP	(5,000)	-	-	-	9,000	3,000
13		Electric Special Projects	1,000	1,000	1,000	1,000	1,000	-
14		Hydro Stabilization	-	-	-	-	-	-
15		Low Carbon Fuel Standard	-	-	-	-	-	-
16		Cap and Trade Program	1,189	1,000	3,560	3,567	3,550	3,700
	Capital Program Contribution							
17		Distribution Operations	-	-	-	-	-	-
18		CIP Reserve						
	Expenses							
19		Supply Expenses	(114,509)	(117,385)	(114,305)	(116,658)	(114,925)	(116,756)
20		Distribution Non-CIP Expense	(36,826)	(40,645)	(48,033)	(41,578)	(52,581)	(53,466)
21		Planned CIP	(22,018)	(18,628)	(20,739)	(31,700)	(13,926)	(21,284)
22		ESP funded	-	(12,016)	(7,000)	-	-	-
23		Hydro funded	-	-	-	-	-	-
24		LCFS funded	(2,260)	(893)	(1,022)	(1,072)	(568)	(453)
	Ending Reserve Balance							
1+8+10+19		Supply Operations	25,213	20,120	19,588	23,351	28,131	31,795
2+9+11+17+20+21		Distribution Operations	10,808	10,729	10,282	11,415	13,836	13,265
3+12+18		CIP	880	880	880	880	9,880	12,880
4+13+22		Electric Special Projects	47,665	36,649	30,649	31,649	32,649	32,649
5+14+23		Hydro Stabilization	15,400	15,400	15,400	15,400	15,400	15,400
6+15+24		Low Carbon Fuel Standard	4,080	3,186	2,164	1,092	524	71
7+16		Cap and Trade Program	1,189	2,190	5,749	9,316	12,866	16,566
	Operations Reserve Guidelines (Supply)							
25		Minimum	17,508	17,981	18,461	19,177	18,892	19,193
26		Maximum	35,017	35,962	36,922	38,353	37,784	38,385
	Operations Reserve Guidelines (Distribution)							
27		Minimum	9,462	9,513	9,803	10,084	10,257	10,472
28		Maximum	15,128	15,152	15,654	16,138	16,402	16,750
	CIP Reserve Guidelines							
29		Minimum	5,005	4,700	4,232	3,803	3,635	3,499
30		Maximum	25,025	23,502	21,162	19,017	18,173	19,406

Due to the continuing COVID-19 pandemic and economic hardships created by it, the Utilities Department has chosen to propose a 0% rate increase option for FY 2022 and no more than 5% rate increases afterwards. Under this scenario, utility reserves are projected to drop to near their minimum guideline levels. Possible program and service cuts may be needed to make up the difference if the utility's financial position ends up being worse than forecasted, but under the assumptions used in this financial plan, existing reserves are anticipated to make up for revenue shortfalls due to the pandemic's impacts.

Table 2 below shows the new proposed rate trajectory and compares current rate projections to those projected in last year's Financial Plan.

Table 1: Projected Electric Rates, FY 2021 to FY 2025

Projection	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026
Current	0%	5%	5%	2%	1%
Last Year	0%	5%	5%	3%	0%

<u>FY 2022 Financial Plan's Projected Rate Adjustments for the Next Five Fiscal Years</u>
Table 3 shows the projected rate adjustments over the next five years and their impact on the annual median residential electric bill (453 kwh per month in winter, 365 kwh per month in summer).

Table 3: Projected Rate Adjustments, FY 2022 to FY 2026

	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026
Electric Utility	0%	5%	5%	2%	1%
Estimated Bill Impact ($/mo)*	-	$3.04	$3.19	$1.34	$0.68

* Estimated impact on median residential electric bill, which is currently $60.70 for CY 2020

The rate increases are related to several factors: increasing transmission costs, the need for substantial additional capital investment in the electric distribution system, potential low hydro supply, and increasing operations costs due to larger contracting needs to complete electric distribution system maintenance work. Revenues have also declined as customer usage has decreased, requiring larger rate increases to cover fixed expenses and offset the shortfalls.

Historically, total electric utility costs (excluding short-term drought impacts) were roughly $120 million per year, allowing the electric utility to go without a rate increase from July 1, 2009 to July 1, 2016. Over the period from FY 2016 to FY 2018, though, annual costs (net of energy supply related revenue, like surplus energy sales) increased to roughly $140 million per year (costs were unusually low in FY 2019 due to some one-time savings from surplus energy sales). Costs are currently projected to increase to roughly $160 million by FY 2026 (net of surplus energy sales).

Figure 1 shows the overall utility's costs (net of surplus sales revenues) in FY 2016, FY 2022, and FY 2026. Costs for the electric supply portfolio have decreased slightly between FY 2016 and FY 2022, but much of this is due to surplus electric supply revenues that are not expected to continue indefinitely as well as the fact that customer sales have declined by 1.5% to 2% annually during this time. Assuming normal hydro conditions going forward, as well as a continuing trend of load loss, costs are projected to increase by about 1% annually for the foreseeable future.

Costs for managing the distribution system (e.g.), maintenance, capital investment, customer service, billing, etc.) have increased as well, growing by about 3% per year on average in the past, and projected to grow by nearly 2-4% per year going forward. FY 2022 capital costs are higher due to the introduction of a large Smart Grid Technologies project, but these costs have been approved by Council to come from the Electric Special Projects Reserve and will not impact rates. Comparisons are difficult as FY 2016 capital costs were very low relative to normal years. Overall, costs are projected to increase by 2% per year over the forecast horizon, but declining loads will necessitate rate increases greater than this to maintain financial health.

Figure 1: Electric Utility Costs, FY 2016 Actual vs. FY 2022 and FY 2026 Projections

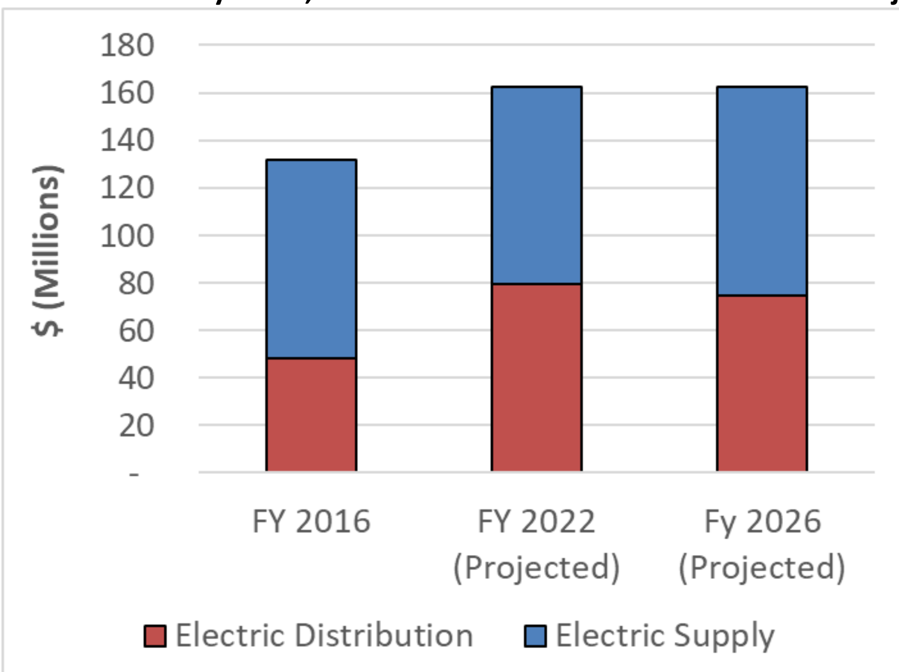
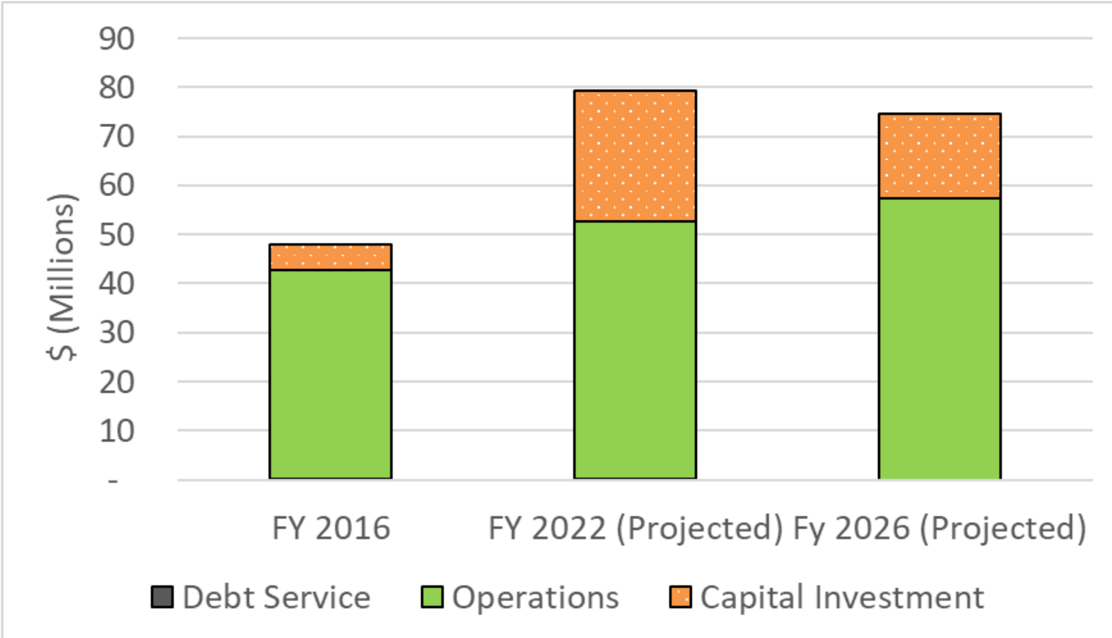


Figure 2 shows electric distribution costs specifically. Capital costs have increased by about 4% per year on average over the last five years but are skewed in this graph due to a large ($17 million) Smart Grid Technology project budgeted for FY 2022 as well as very low spending during FY 2016. Going forward, increased costs are related to greater capital investment in the distribution system (e.g.), underground district rebuilds, as well as substation upgrades). In the last few years, the City has experienced a higher number of outages in underground districts due to aging equipment and infrastructure. Distribution system operational spending is projected to increase by about 3% annually. Some of this is due to projected increases in costs of labor and materials. While there are higher than anticipated staff vacancies, external contracts will be used to enable staff to complete necessary electric system maintenance.

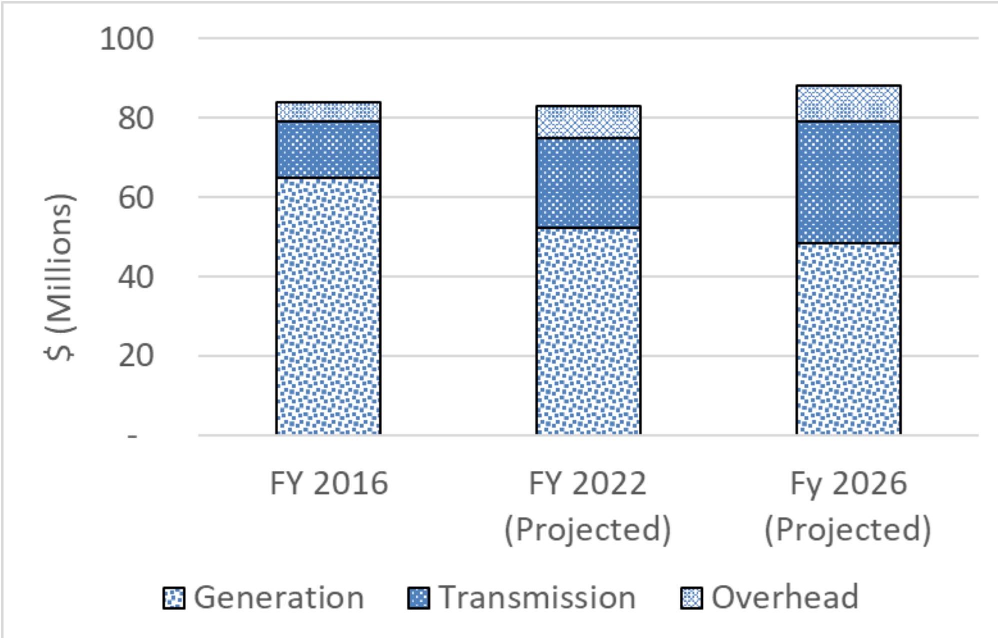
Figure 2: Electric Distribution Costs, FY 2016 vs. FY 2022 and FY 2026 Projections



While net electric supply portfolio costs stayed relatively stable from FY 2016 to FY 2022, this was mainly due to surplus energy revenues and decreasing loads driving down generation cost. Transmission cost increases and, to a lesser extent, operational overhead costs have increased by 8% annually in the same timeframe, as shown in Figure 3. In the future, staff forecasts that increased costs will continue largely come from transmission costs. These increases are due to rehabilitation and replacement of the existing statewide electric transmission system as well as expansion of that system to accommodate new generation, mostly renewable.

Staff works to contain transmission costs through partner agencies, including the Transmission Agency of Northern California (TANC) and Northern California Power Agency (NCPA), and through direct partnerships with other local utilities (the Bay Area Municipal Transmission group, BAMx). These groups intervene in transmission proceedings at the Federal Energy Regulatory Commission (FERC) and the California Independent System Operator (CAISO), and have achieved some reductions in long-term transmission costs. Staff is beginning to look at strategies to achieve cost savings in electric supply and will discuss these strategies in greater detail in future meetings.

Figure 3: Electric Supply Costs, FY 2016 Actual vs. FY 2022 and FY 2026 Projections



Staff also recognizes the importance of managing operating costs and maximizing efficiency in order to minimize rate increases. As discussed above, staff is working on cost containment measures related to transmission and renewable energy costs. Utility consumers also see some long-term cost savings from City-wide efforts to manage personnel costs. As reflected in the Utilities Strategic Plan, staff is exploring additional ways to effectively use available resources, particularly across Divisions.

Electric Bill Comparison with Surrounding Cities

For the median consumption level, the annual residential electric bill for calendar year 2020 was $728 under current CPAU rates, about 37% lower than the annual bill for a PG&E customer with the same consumption and approximately 19% higher than the annual bill for a City of Santa Clara customer. The bill calculations for PG&E customers are based on PG&E Climate Zone X, which includes most surrounding comparison communities.

Table 4 presents sample median residential bills for Palo Alto, PG&E, and the City of Santa Clara (Silicon Valley Power) for several usage levels. Rates used to calculate the monthly bills shown below were in effect as of January 1, 2021.

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 4: Residential Monthly Electric Bill Comparison (Effective 1/1/2021, $/mo.)

Season	Usage (kwh)	Palo Alto	PG&E	Santa Clara
Winter	300	41.27	74.96	36.96
	453 (Median)	69.22	113.19	56.50
	650	107.37	174.55	81.66
	1200	213.89	347.48	151.91
Summer	300	41.27	77.09	36.96
	(Median) 365	52.18	97.53	45.27
	650	107.37	187.14	81.66
	1200	213.89	360.08	151.91

Table 5 shows the average monthly electric bill for commercial customers for various usage levels.

Table 5: Commercial Monthly Electric Bill Comparison (1/1/2021, $/mo.)

Usage (kwh/mo)	Palo Alto	PG&E	Santa Clara
1,000	177	272	185
160,000	24,795	30,804	20,239
500,000	77,477	80,675	63,096
2,000,000	273,431	308,918	252,172

Net Energy Metering Buyback 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 (E-EEC-1) rate for exported electricity.

Customers on the NEM 1 program who have chosen to have the value of any annual net generation they produced over the past 12 months credited back to their account do so under the Net Metering Net Surplus Electricity Compensation (E-NSE-1) rate, which is calculated using the utility’s avoided costs from the prior year. The Net Surplus Electricity Compensation rate represents the value of the City’s avoided costs or value of customer-generated electricity in Palo Alto during the prior calendar year, 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.

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 (E-EEC-1) buyback rate. This buyback 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 10.78 cents/kWh, which is slightly higher than the avoided cost on the current NEM buyback rate (10.09 cents/kWh). This increase in the overall avoided cost is driven by a small increase in the value of the energy and in the City's avoided transmission charges.

Table 6: NEM Compensation Rates – Current vs. Proposed

Rate	Current $/kWh	Proposed $/kWh
Export Electricity (E-EEC-1)	$0.1009	$0.1078
Net Surplus Electricity (E-NSE-1)	$0.0877	$0.0992

Palo Alto Green (PAG) Program

The PaloAltoGreen (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 there has been a significant increase in the wholesale cost of Green-e certified RECs in the Western US market (from approximately $1.50/REC to $6/REC). As such, the PAG rate premium needs to be raised from $2 per 1,000 kWh block (2 cents/kWh) to $6 per 1,000 kWh block (6 cents/kWh). This change will be 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.

Timeline
The City Council will consider adopting the Financial Plan and rate amendments as part of the FY 2022 budget review and adoption process. If Council approves the proposed rate changes, they will become effective July 1, 2021.

Stakeholder Engagement
The UAC reviewed preliminary financial forecasts at its December 2, 2020 meeting (Staff Report

#11649[3]), and the Finance Committee reviewed the preliminary forecasts at its February 16, 2021 meeting (Staff Report #11864[4]).
The UAC reviewed staff's recommendation on the FY 2022 Electric Financial Plan, proposed transfers and rate increases at its March 3, 2021 meeting. At that meeting, Commissioners inquired whether staffing issues were still a concern with regards to projected CIP work. Staff responded that CPAU had consultants on contract, were looking at possibly outsourcing project design work, and that additional field crews were being hired to fill out in-house crews. The UAC approved staff's recommendation 6-0, Commissioner Scharff absent.

If approved, the Finance Committee's recommendation on the FY 2022 Electric rate changes and transfers will be presented to City Council in June during the budget adoption process.

Resource Impact
The FY 2022 Budget is being developed concurrently with these rates and depending on the final recommendations from the Finance Committee, adjustments to the budget may be required. The attached FY 2022 Electric Financial Plan provides a more comprehensive overview of projected costs and revenue changes for the next five years.

Environmental Review
The Finance Committee's review and recommendation to Council on the FY 2022 Electric Financial Plans and rate adjustments does not meet the California Environmental Quality Act's definition of a project, pursuant to Public Resources Code Section 21065, thus no environmental review is required.
Attachments:
- Attachment A: Resolution
- Attachment B: FY22 Electric Financial Plan
- Attachment C: Electricity Compensation Rates

[3] https://cityofpaloalto.org/civicax/filebank/documents/79340
[4] https://www.cityofpaloalto.org/civicax/filebank/documents/80154

Attachment A

* NOT YET APPROVED *

Resolution No. _________

Resolution of the Council of the City of Palo Alto Approving the Fiscal Year 2022 Electric Utility Financial Plan and Reserve Transfers and Amending Utility Rate Schedules E-EEC-1 (Export Electricity Compensation), E-NSE-1 (Net Surplus Electricity Compensation Rate), E-2-G (Residential Master-Metered and Small Non-Residential Green Power Electric Service), E-4-G (Medium Non-Residential Green Power Electric Service), and E-7-G (Large Non-Residential Green Power Electric Service)

R E C I T A L S

A. Each year the City of Palo Alto ("City") regularly assesses the financial position of its utilities with the goal of ensuring adequate revenue to fund operations. This includes making long-term projections of market conditions, the physical condition of the system, and other factors that could affect utility costs, and setting rates adequate to recover these costs. It does this with the goal of providing safe, reliable, and sustainable utility services at competitive rates. The City adopts Financial Plans to summarize these projections.

B. The City uses reserves to protect against contingencies and to manage other aspects of its operations, and regularly assesses the adequacy of these reserves and the management practices governing their operation. The status of utility reserves and their management practices are included in Reserves Management Practices attached to and made part of the Financial Plans.

C. Pursuant to Chapter 12.20.010 of the Palo Alto Municipal Code, the Council of the City of Palo Alto may by resolution adopt rules and regulations governing utility services, fees and charges.

D. On ____, 2021, the City Council heard and approved the proposed rate increase at a noticed public hearing.

The Council of the City of Palo Alto does hereby RESOLVE as follows:

SECTION 1. The Council hereby approves the FY 2022 Electric Utility Financial Plan.

SECTION 2. The Council hereby approves the following transfers as described in the FY 2022 Electric Utility Financial Plan:

1. Approve a transfer of up to $5 million from the Capital Improvement Project Reserve to the Distribution Operations Reserve;
2. Approve a transfer of up to $1 million from the Supply Operations Reserve to the Electric Special Project reserve;

3. Approve an allocation of up to $1.189 million from the Cap and Trade Program Reserve for local decarbonization programs.

SECTION 3. Pursuant to Section 12.20.010 of the Palo Alto Municipal Code, Utility Rate Schedule E-EEC-1 (Export Electricity Compensation) is hereby amended to read as attached and incorporated. Utility Rate Schedule E-EEC-1, as amended, shall become effective July 1, 2021.

SECTION 4. Pursuant to Section 12.20.010 of the Palo Alto Municipal Code, Utility Rate Schedule E-NSE-1 (Net Surplus Electricity Compensation Rate) is hereby amended to read as attached and incorporated. Utility Rate Schedule E-NSE-1, as amended, shall become effective July 1, 2021.

SECTION 5. Pursuant to Section 12.20.010 of the Palo Alto Municipal Code, Utility Rate Schedule E-2-G (Residential Master-Metered and Small Non-Residential Green Power Electric Service) is hereby amended to read as attached and incorporated. Utility Rate Schedule E-2-G, as amended, shall become effective July 1, 2021.

SECTION 6. Pursuant to Section 12.20.010 of the Palo Alto Municipal Code, Utility Rate Schedule E-4-G (Medium Non-Residential Green Power Electric Service) is hereby amended to read as attached and incorporated. Utility Rate Schedule E-4-G, as amended, shall become effective July 1, 2021.

SECTION 7. Pursuant to Section 12.20.010 of the Palo Alto Municipal Code, Utility Rate Schedule E-7-G (Large Non-Residential Green Power Electric Service) is hereby amended to read as attached and incorporated. Utility Rate Schedule E-7-G, as amended, shall become effective July 1, 2021.

SECTION 8. The Council makes the following findings:

a. The revenue derived from the adoption of this resolution shall be used only for the purpose set forth in Article VII, Section 2, of the Charter of the City of Palo Alto.
b. The fees and charges adopted by this resolution are charges imposed for a specific government service or product provided directly to the payor that are not provided to those not charged, and do not exceed the reasonable costs to the City of providing the service or product.

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* NOT YET APPROVED *

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SECTION 9. The Council finds that approving the Financial Plan does not meet the California Environmental Quality Act's (CEQA) definition of a project under Public Resources Code Section 21065 and CEQA Guidelines Section 15378(b)(5), because it is an administrative governmental activity which will not cause a direct or indirect physical change in the environment, and therefore, no environmental assessment is required. The Council finds that changing electric rates to meet operating expenses, purchase supplies and materials, meet financial reserve needs and obtain funds for capital improvements necessary to maintain service is not subject to the California Environmental Quality Act (CEQA), pursuant to California Public Resources Code Sec. 21080(b)(8) and Title 14 of the California Code of Regulations Sec. 15273(a). After reviewing the staff report and all attachments presented to Council, the Council incorporates these documents herein and finds that sufficient evidence has been presented setting forth with specificity the basis for this claim of CEQA exemption.

INTRODUCED AND PASSED:

AYES:

NOES:

ABSENT:

ABSTENTIONS:

ATTEST:

____________________________	____________________________
City Clerk	Mayor
APPROVED AS TO FORM:	APPROVED:
____________________________	____________________________
Assistant City Attorney	City Manager
	____________________________
	Director of Utilities
	____________________________
	Director of Administrative Services

Attachment B

FY 2022 ELECTRIC UTILITY FINANCIAL PLAN

FY 2022 TO FY 2026

FY 2022 ELECTRIC UTILITY FINANCIAL PLAN

FY 2022 TO FY 2026

TABLE OF CONTENTS

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's Electric Utility for the next FY 2022 - 2026. 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

The Electric Utility's costs are projected to increase by about 2% per year on average from FY 2021 - 2026, as shown in Table 1. The majority of cost is related to electric supply purchases, which are increasing mainly due to increased transmission costs, and after the projected drop in consumption in FY 2021 due to the COVID crisis, are projected to grow at an estimated 2.5% per year on average. Operations and maintenance costs are about one third of total costs and are projected to increase by about 2% per year on average due to both inflationary as well as salary and benefits increases. Capital improvement costs are projected to rise steeply in the short term as the Smart Grid technology project gets underway, then stabilize to between $18 to $20 million a year thereafter. Ongoing projects will include rebuilds of existing underground districts as well as substation improvements and voltage conversion projects.

Table 1: Electric Utility Expenses for FY 2020 to FY 2026

Expenses ($000)	FY 2020 (act)	FY 2021 (est)	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026
Power Supply Purchases	90,646	93,402	96,219	98,071	102,284	104,443	106,133
Operations	52,497	60,020	60,762	63,245	64,965	61,611	62,543
Capital Projects	15,540	22,018	30,643	27,739	31,700	13,926	21,284
TOTAL	158,682	175,440	187,624	189,055	198,949	179,980	189,960

Due to the continuing COVID-19 pandemic and economic hardships created by it, the Utilities Department has chosen to propose a 0% rate increase option for FY 2022 and no more than 5% rate increases afterwards. Under this scenario, utility reserves are projected to drop to near their minimum guideline levels. Possible program and service cuts may be needed to make up the difference, but existing reserves are currently anticipated to make up for revenue shortfalls.

Table 2 below shows the new proposed rate trajectory and compares current rate projections to those projected in last year's Financial Plan.

Table 2: Projected Electric Rates, FY 2021 to FY 2025

Projection	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026
Current	0%	5%	5%	2%	1%
Last Year	0%	5%	5%	3%	0%

The Electric Utility maintains several reserves for the purposes of rate stabilization, such as the Hydro Stabilization reserve, which is used to mitigate against both dry and wet hydro conditions. The Electric Utility also has a CIP Reserve which is used to manage cash flow for capital projects, and fund capital contingencies such as unexpected spikes in CIP spending which do not merit separate bond financing.

Table 3 shows the projected reserve transfers over the forecast period. Per Council approval, $10 million was transferred from the Electric Special Projects (ESP) Reserve in FY 2018 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. Any transfers from the ESP Reserve require Council approval. $5 million was repaid in FY 2020, and staff anticipates repaying the remaining balance in $1 million installments between FY 2021 and FY 2025. During this time, withdrawals from the ESP Reserve for the Smart Grid Technologies project will also occur. In addition, in accordance with Council policy, staff will also fund the Cap and Trade Program Reserve with unspent revenues from the sale of carbon allowances freely allocated to the electric utility, as directed in Staff Report #11556 .[1]

Because of the possible economic impacts which may arise because of the ongoing COVID pandemic, staff is presenting all of these transfers as ‘up to’ amounts. If ending FY 2021 reserves are adversely impacted and/or FY 2022 outlooks for the Electric Utility change, staff may recommend transferring smaller amounts, or forgoing some of all of the transfers, as needed to keep the Operations Reserves within guideline ranges, to the greatest extent possible.

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

Table 3: Reserves Starting and Ending Balances, Revenues, Expenses, Transfers To/(From) Reserves, Operations and Capital Reserve Guideline Levels for FY 2021 to FY 2026 ($000)

			FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026
	Starting Reserve Balances							
1		Supply Operations	29,429	25,213	20,120	19,588	23,351	28,131
2		Distribution Operations	9,064	10,808	10,729	10,282	11,415	13,836
3		CIP	5,880	880	880	880	880	9,880
4		Electric Special Projects	46,665	47,665	36,649	30,649	31,649	32,649
5		Hydro Stabilization	15,400	15,400	15,400	15,400	15,400	15,400
6		Low Carbon Fuel Standard	6,340	4,080	3,186	2,164	1,092	524
7		Cap and Trade Program	-	1,189	2,190	5,749	9,316	12,866
	Revenues							
8		Supply	112,482	114,293	118,332	124,988	124,256	124,120
9		Distribution	55,588	59,194	68,325	74,410	77,929	77,179
	Transfers							
10		Supply Operations	(2,189)	(2,000)	(4,560)	(4,567)	(4,550)	(3,700)
11		Distribution Operations	5,000	-	-	-	(9,000)	(3,000)
12		CIP	(5,000)	-	-	-	9,000	3,000
13		Electric Special Projects	1,000	1,000	1,000	1,000	1,000	-
14		Hydro Stabilization	-	-	-	-	-	-
15		Low Carbon Fuel Standard	-	-	-	-	-	-
16		Cap and Trade Program	1,189	1,000	3,560	3,567	3,550	3,700
	Capital Program Contribution							
17		Distribution Operations	-	-	-	-	-	-
18		CIP Reserve						
	Expenses							
19		Supply Expenses	(114,509)	(117,385)	(114,305)	(116,658)	(114,925)	(116,756)
20		Distribution Non-CIP Expense	(36,826)	(40,645)	(48,033)	(41,578)	(52,581)	(53,466)
21		Planned CIP	(22,018)	(18,628)	(20,739)	(31,700)	(13,926)	(21,284)
22		ESP funded	-	(12,016)	(7,000)	-	-	-
23		Hydro funded	-	-	-	-	-	-
24		LCFS funded	(2,260)	(893)	(1,022)	(1,072)	(568)	(453)
	Ending Reserve Balance							
1+8+10+19		Supply Operations	25,213	20,120	19,588	23,351	28,131	31,795
2+9+11+17+20+21		Distribution Operations	10,808	10,729	10,282	11,415	13,836	13,265
3+12+18		CIP	880	880	880	880	9,880	12,880
4+13+22		Electric Special Projects	47,665	36,649	30,649	31,649	32,649	32,649
5+14+23		Hydro Stabilization	15,400	15,400	15,400	15,400	15,400	15,400
6+15+24		Low Carbon Fuel Standard	4,080	3,186	2,164	1,092	524	71
7+16		Cap and Trade Program	1,189	2,190	5,749	9,316	12,866	16,566
	Operations Reserve Guidelines (Supply)							
25		Minimum	17,508	17,981	18,461	19,177	18,892	19,193
26		Maximum	35,017	35,962	36,922	38,353	37,784	38,385
	Operations Reserve Guidelines (Distribution)							
27		Minimum	9,462	9,513	9,803	10,084	10,257	10,472
28		Maximum	15,128	15,152	15,654	16,138	16,402	16,750
	CIP Reserve Guidelines							
29		Minimum	5,005	4,700	4,232	3,803	3,635	3,499
30		Maximum	25,025	23,502	21,162	19,017	18,173	19,406

SECTION 2B: SUMMARY OF PROPOSED ACTIONS

Staff proposes the following actions for the Electric Utility in FY 2021:

1. Approve a transfer of up to $5 million from the Capital Improvement Project (CIP) Reserve to the Distribution Operations Reserve;
2. Approve a transfer of up to $1 million from the Supply Operations Reserve to the Electric Special Projects (ESP) reserve; and
3. Approve an allocation of up to $1.189 million from the Supply Operations to the Cap and Trade Reserve.

Staff proposes the following actions for the Electric Utility in FY 2022:

1. No increase to retail electric rates effective July 1, 2021;
2. Update the Export Electricity Compensation (EEC-1) rate to reflect current projections of avoided cost, effective July 1, 2021;
3. Update the Net Surplus Electricity Compensation Rate (E-NSE) rate to reflect current projections of avoided cost, effective July 1, 2021; and
4. Update the Palo Alto Green program pass-through premium charge 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 to reflect current costs, effective July 1, 2021.

SECTION 3: DETAIL OF FY 2022 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"[2] 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, 2019, when CPAU increased electric rates by 8%. As the Utilities Department is currently not recommending a rate change for FY 2022, the current rates are the same as proposed rates, and are reflected in Table 4 below:

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

Table 4: Current and Proposed Electric Rates

	Current Rates	Proposed Rates (7/1/2020)	Change	
			$	%
E-1 (Residential)				
Tier 1 Energy ($/kWh)	0.13757	0.13757	No Change	-%
Tier 2 Energy ($/kWh)	0.19367	0.19367	-	-%
Minimum Bill ($/day)	0.3283	0.3283	-	-%
E-2 & E-2-G (Small Non-Residential)				
Summer Energy ($/kWh)	0.20853	0.20853	-	-%
Winter Energy ($/kWh)	0.14624	0.14624	-	-%
Minimum Bill ($/day)	0.8359	0.8359	-	-%
E-4 & E-4-G (Medium Non-Residential)				
Summer Energy ($/kWh)	0.12848	0.12848	-	-%
Winter Energy ($/kWh)	0.09946	0.09946	-	-%
Summer Demand ($/kW)	28.91	28.91	-	-%
Winter Demand ($/kW)	18.97	18.97	-	-%
Minimum Bill ($/day)	17.2742	17.2742	-	-%
E-7 & E-7-G (Large Non-Residential)				
Summer Energy ($/kWh)	0.11432	0.11432	-	-%
Winter Energy ($/kWh)	0.07738	0.07738	-	-%
Summer Demand ($/kW)	30.69	30.69	-	-%
Winter Demand ($/kW)	17.05	17.05	-	-%
Minimum Bill ($/day)	42.3648	42.3648	-	-%

Net Energy Metering Buyback 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, which is calculated using the utility's avoided costs from the prior year. 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.

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) buyback rate. This buyback 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 10.78 cents/kWh, which is slightly higher than the avoided cost on the current NEM buyback rate (10.09 cents/kWh). As the table indicates, this increase in the overall avoided cost is driven by a small increase in the value of the energy and in the City's avoided transmission charges.

Table 5: NEM Buyback Rates – Current vs. Proposed

Rate	Current $/kWh	Proposed $/kWh
Export Electricity (E-EEC)	$0.1009	$0.1078
Net Surplus Electricity (E-NSE)	$0.0877	$0.0992

Palo Alto Green (PAGreen) Program

The PaloAltoGreen (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 there has been a significant increase in the wholesale cost of Green-e certified RECs in the Western US market (from approximately $1.50/REC to $6/REC). As such, the PAG rate premium needs to be raised from $2 per 1,000 kWh block (2 cents/kWh) to $6 per 1,000 kWh block (6 cents/kWh). This change will be 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

As no rate change is proposed for July 1, 2021, there is no table showing the impact of rate changes. For more on comparisons of rates with surrounding agencies, see Section 4F: Competitiveness below.

SECTION 3D: PROPOSED RESERVE TRANSFERS

In FY 2018, Council approved a $10 million loan from the Electric Special Projects (ESP) reserve, and this financial plan includes full repayment by FY 2025. The pace of payback may be moderated based upon the general financial health of the electric fund. $5 million was repaid in FY 2020, and this financial plan assumes repayment of the remaining $5 million in $1 million installments by FY 2025.

In addition, and based upon the actual ending balances of the Supply and Distribution Operations Reserves for FY 2021, staff requests withdrawing up to $5 million from the Capital Improvement (CIP) Reserve to both fund CIP projects and keep the Distribution Operations fund above minimum guideline levels. Staff further intends to add funds in the CIP reserve in future years, to keep its balance within guideline levels and to fund contingencies such as projected higher future CIP needs and costs.

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. 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, as directed in Staff Report #11556 .[3]

In accordance with Council's August 2020 direction, (Staff Report #11556)[4] the City has also exchanged 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. The revenues received from these REC exchanges are kept in the Electric Supply Reserve. With this Financial Plan, and as described in Staff Report #11556, staff is allocating Cap and Trade funds equivalent to 1/3 of the FY 2021 REC Exchange program revenues, or $1.189 million, 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 5 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*

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

Table 5: End of Fiscal Year Electric Utility Reserve Balances for FY 2019 to FY 2025

Ending Reserve Balance ($000)	FY 2020 (Act.)	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026
Re-appropriations	-	-	-	-	-	-	-
Commitments	3,519	3,519	3,519	3,519	3,519	3,519	3,519
Low Carbon Fuel Standard (LCFS)	6,340	4,080	3,186	2,164	1,092	524	71
Cap and Trade	-	1,189	2,190	5,749	9,316	12,866	16,566
Underground Loan	727	727	727	727	727	727	727
Public Benefits	1,905	2,664	3,435	4,275	5,101	5,861	6,575
Special Projects	46,665	47,665	36,649	30,649	31,649	32,649	32,649
Hydro Stabilization	15,400	15,400	15,400	15,400	15,400	15,400	15,400
Capital	5,880	880	880	880	880	9,880	12,880
Rate Stabilization	-	-	-	-	-	-	-
Distribution and Supply Operations	38,494	36,192	30,832	29,629	33,771	39,372	42,368
Unassigned	-	-	-	-	-	-	-
TOTAL	118,928	112,314	96,817	92,991	101,454	120,798	130,754

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[5] 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.

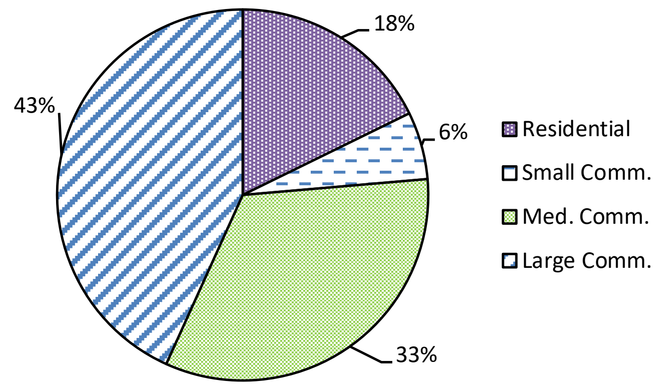
In 2001 CPAU began planning for the impacts associated with the new terms of its contract with WAPA, set to take effect in 2005. The previous contract had provided 90% of Palo Alto's power supply at favorable rates, and PG&E, as a party to the contract, had provided supplemental power

[5] *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 renewable energy purchases (RECs) to meet the balance of its needs.

SECTION 4B: CUSTOMER BASE

Figure 1: Customer Consumption By Class (FY 2020)



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 29,800 customers connected to the electric system, 25,700 (86%) of which are residential and 4,100 (14%) of which are non-residential. Residential customers consumed 152 gigawatt-hours (GWh) in FY 2020, approximately 18% of the electricity sold, while non-residential customers consumed 82% or 703 GWh. Residential customers use electricity primarily for lighting, refrigeration, electronics, and air conditioning.[6] Non-residential customers use the majority of their electricity for cooling, ventilation, lighting, office equipment (offices), cooking (restaurants), and refrigeration (grocery stores).[7]

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 43% of CPAU's sales. The next largest customer group (the 890 non-residential customers on the E-4 rate schedule) represents another 33% 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.

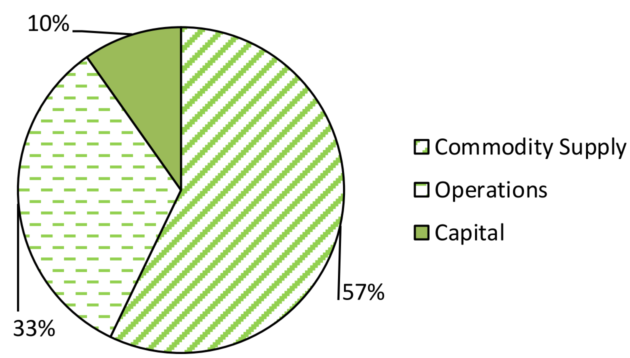
[6] Source: Residential Appliance Saturation Survey, California Energy Commission, 2010

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

SECTION 4D: COST STRUCTURE AND REVENUE SOURCES

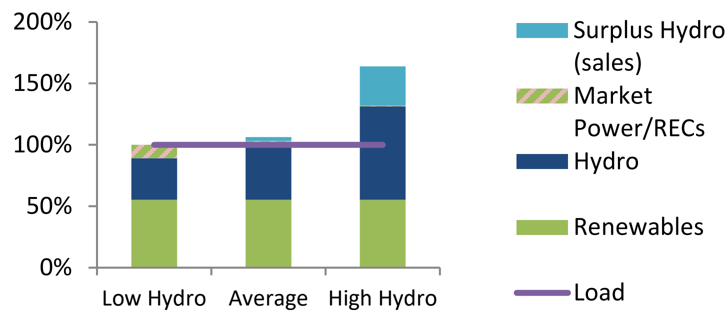
As shown in Figure 2, electric commodity purchases accounted for roughly 57% of the Electric Utility's costs in FY 2020. Operational costs represented roughly 33%, and capital investment was responsible for the remaining 10%. CPAU's non-hydro long-term commodity supply is heavily dependent on long-term 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 56% of total costs in FY 2026.

Figure 2: Cost Structure (FY 2020)



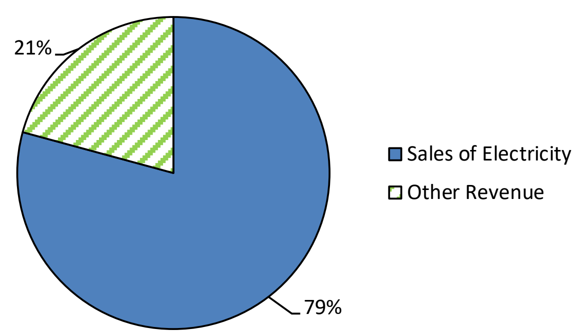
While average year purchase costs for the electric utility are predictable due to its long-term contracts, variability in hydroelectric generation can result in increased or decreased costs. This is by far the largest source of variability the utility faces. Figure 3 shows the difference in costs under high, projected, and low hydroelectric generation scenarios for FY 2020. Additional costs associated with a very low generation scenario can range from $9-11 million per year. For the current hydroelectric risk assessment see *Section 5F: Risk Assessment and Reserves Adequacy*.

Figure 3: Hydroelectric Variability (FY 2020)



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

Figure 4: Revenue Structure (FY 2020)



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 services 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 residential electric bill for calendar year 2020 was $728 under current CPAU rates, about 37% lower than the annual bill for a PG&E customer with the same consumption and approximately 19% higher than the annual bill for a City of Santa Clara customer. The bill calculations for PG&E customers are based on PG&E Climate Zone X, which includes most surrounding comparison communities.

Table 6 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, 2021.

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 6: Residential Monthly Electric Bill Comparison (Effective 1/1/2021, $/mo.)

Season	Usage (kwh)	Palo Alto	PG&E	Santa Clara
Winter	300	41.27	74.96	36.96
	453 (Median)	69.22	113.19	56.50
	650	107.37	174.55	81.66
	1200	213.89	347.48	151.91
Summer	300	41.27	77.09	36.96
	(Median) 365	52.18	97.53	45.27
	650	107.37	187.14	81.66
	1200	213.89	360.08	151.91

Table 7 shows the average monthly electric bill for commercial customers for various usage levels.

Table 7: Commercial Monthly Electric Bill Comparison (1/1/2021, $/mo.)

Usage (kwh/mo)	Palo Alto	PG&E	Santa Clara
1,000	177	272	185
160,000	24,795	30,804	20,239
500,000	77,477	80,675	63,096
2,000,000	273,431	308,918	252,172

SECTION 5: UTILITY FINANCIAL PROJECTIONS

SECTION 5A: LOAD FORECAST

Figure 5 shows a 36-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. In recent years, some larger commercial customers have relocated operations or shifted to more 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

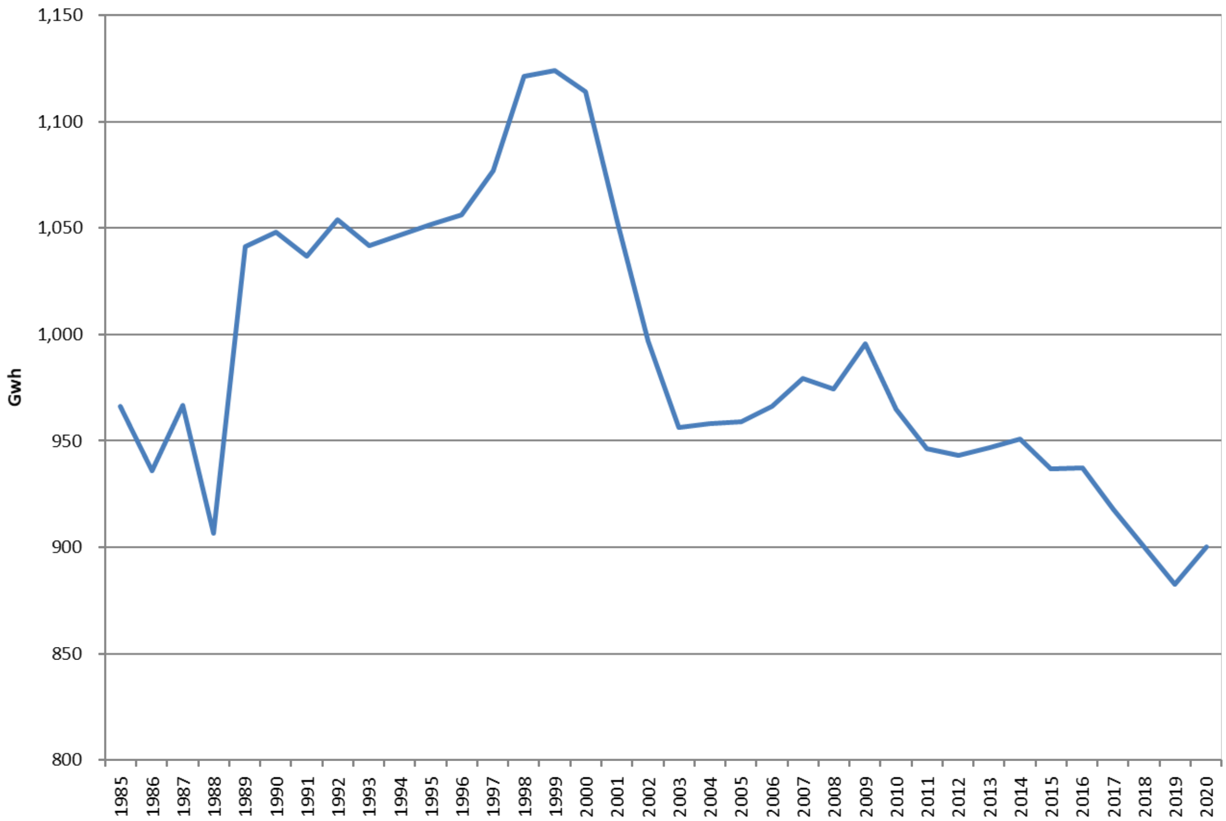
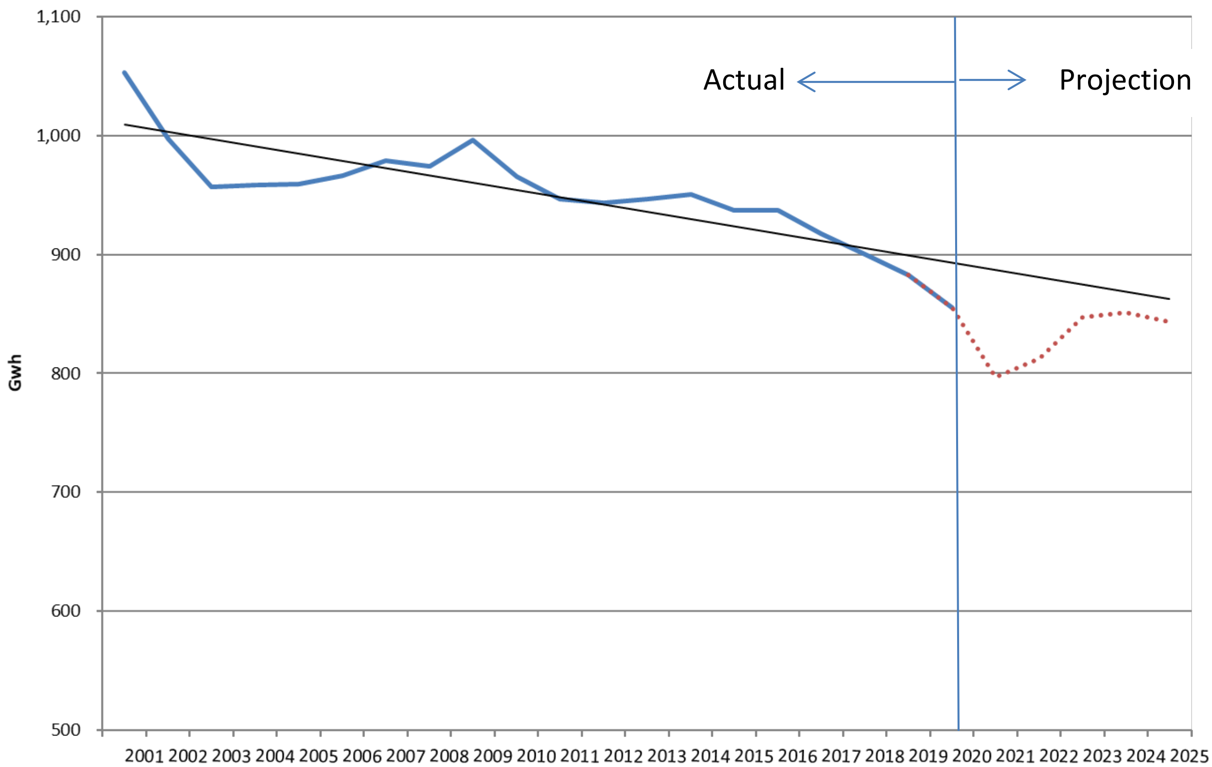


Figure 6 shows the forecast of electricity consumption through FY 2026. The solid black straight line is the long term average trend of usage.

The small-dash red line estimates the estimated drop in consumption due to the ongoing COVID response and is what was used for the current 0% scenario. Staff worked with Northern California Power Agency to incorporate UCLA's Anderson School GDP forecast to estimate the impact of the COVID-19 pandemic. Based upon the forecast and the electricity load impact to date, the UCLA GDP forecast was added to capture the effect of the large and sharp COVID-19 recession through December of 2022. After this, the assumption is that sales will resume to at a level slightly below the long-term trend line. However, these projections will be revised if continuing sales patterns indicate further declines or increases, or changes in customer mix occur.

Figure 6: Forecasted Electricity Consumption



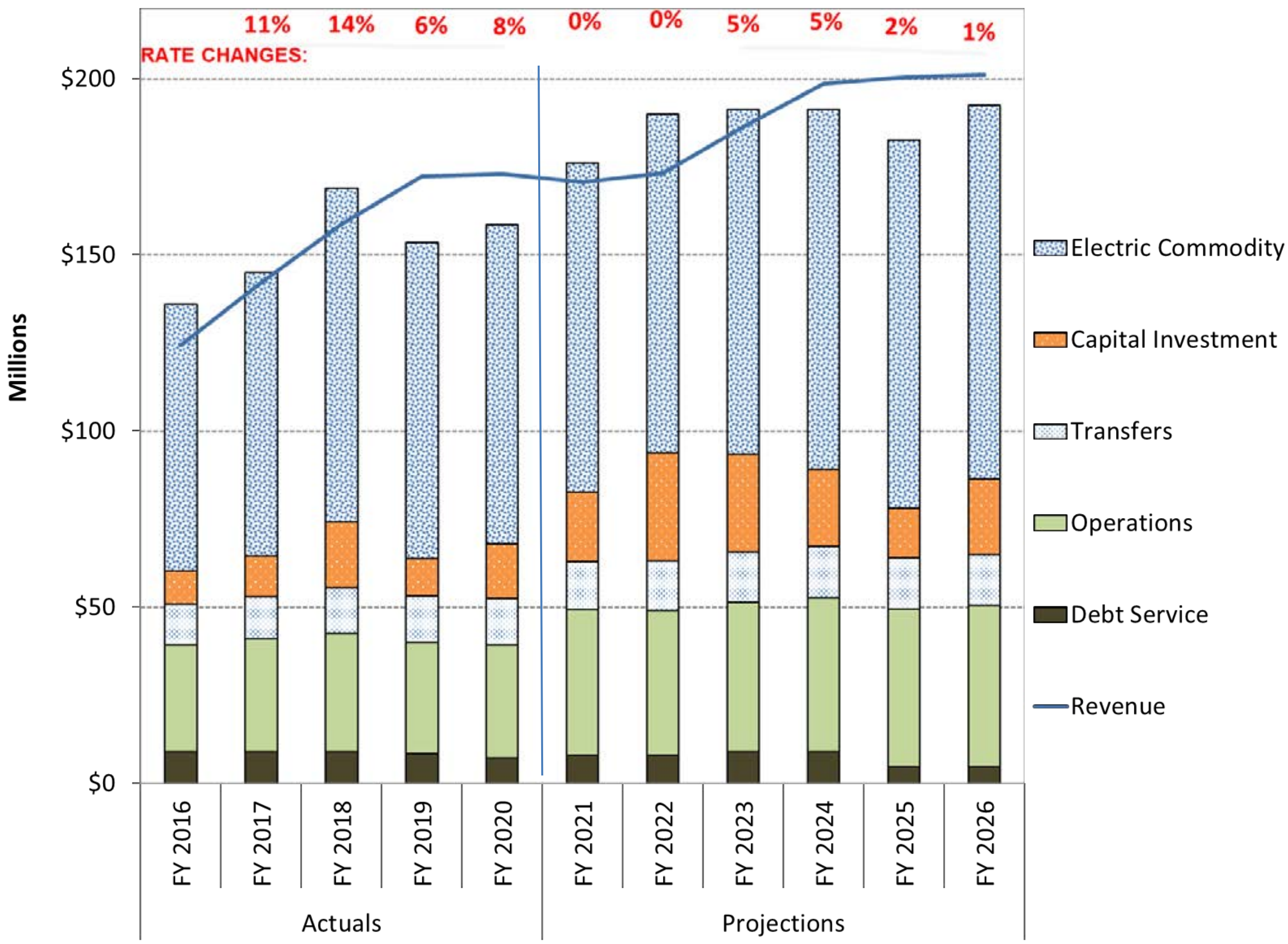
SECTION 5B: FY 2016 TO FY 2020 COST AND REVENUE TRENDS

As shown in Figure 7 and the tables in *Appendix A: Electric Utility Financial Forecast Detail*, the annual expenses for the Electric Utility remained fairly stable between FY 2015 and FY 2017 but increased in FY 2018. On the capital side, the large Upgrade Downtown CIP project got underway in FY 2018, which was a much larger project than usual. 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 overall California grid.

Section 6A: Electricity Purchases discusses the factors influencing Electric Utility expenses. Since FY 2012, total expenses for the utility have included the costs of renewable resources coming online. In FY 2014 through FY 2015 commodity costs were higher due to lower than average output from hydroelectric resources. 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.

Commodity costs have increased, on average, by about 4.6% per year over this timeframe. Operations costs have increased by about 2% annually on average. Revenues have increased on average by about 6% per year over this period, although FY 2018 sales revenues were lower than projected due to declining sales, and FY 2020 sales have been impacted by COVID.

Figure 7: Electric Utility Expenses, Revenues, and Rate Changes:
Actual Costs through FY 2019 and Projections through FY 2025



SECTION 5C: FY 2020 RESULTS

FY 2020 saw lower sales than expected with the onset of the COVID pandemic, but other revenues (such as surplus energy sales) came in higher, offsetting the loss. Net purchase costs came in slightly higher than budget, and while O&M costs came in lower than projected, administrative and overhead costs came in higher. The net effect to the Operating Reserves were that they were $400,000 lower than estimated in the FY 2021 financial Plan.

Table 8 FY 2020, Actual Results vs. Financial Plan Forecast ($000)

	Net Cost/(Benefit)	**Type of change**
Sales revenues lower than forecast	$983	Revenue decrease
Surplus sales, interest, and other income higher than expected	(1,068)	Revenue increase
Higher net purchase cost	435	Cost increase
Higher operating expense	50	Cost increase
Net Cost / (Benefit) of Variances	**$400**	

SECTION 5D: FY 2021 PROJECTIONS

Last year, staff recommended (and Council approved) no rate change for July 1, 2020. Sales are still declining but not as fast as projected earlier, and staff is estimating $4.8 million higher sales for FY 2021. Purchase costs are projected to increase by about $5.4 million, mainly due to poor projected hydro conditions. Other revenues are projected to be about $2.7 million higher, primarily from increasing EMA/Market sales (sales of surplus energy) as well as REC sales revenue. A revised operations cost outlook increased projected expenses by about $3.6 million compared to the FY 2020 Financial Plan, mainly from revised administration costs as FY 2020 actuals were higher. Programs funded by the City's LCFS budget increased as well. With the increased sales outlook, net purchase costs are expected to be $5.4 million higher.

Table 9 FY 2021, Change in Projected Results, 2022 Forecast vs. 2021 Forecast ($000)

	Net Cost/(Benefit)	Type of change
Modified reserve transfers	(5,156)	Operations Reserve increase
Sales revenues higher than forecasted	(4,834)	Revenue increase
Wholesale and other revenues higher than forecast	(2,690)	Revenue increase
Purchased electricity costs higher than forecasted	5,440	Cost increase
Operations costs	3,630	Cost decrease
Net Cost / (Benefit) of Variances to Ops Reserve	**($3,610)**	

SECTION 5E: FY 2022 – FY 2026 PROJECTIONS

As shown in Figure 7 above, staff projects costs for the Electric Utility to increase at a fairly steady rate through the forecast period. Revenue increases between 0% to 5% are projected to keep revenues in line with expenses over the next five years. Rising electricity purchase costs are the primary contributor to the increases. 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 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.

The forecast also assumes the Smart Grid project to bring advanced metering to the Electric, Gas and Water utilities will start with $12 million in FY 2022 and additional $7 million in FY 2023. Funding for this project will come out of the Electric Special Projects reserve, as can be seen in Figure 8 below and in Appendix A: Electric Utility Financial Forecast detail.

Reserves trends based on these revenue projections are shown in Figure 8 (for Supply Fund Reserves) and Figure 9 (for Distribution Fund Reserves), below.

Figure 8: Electric Utility Reserves (Supply Fund):
Actual Reserve Levels through FY 2020 and Projections through FY 2026

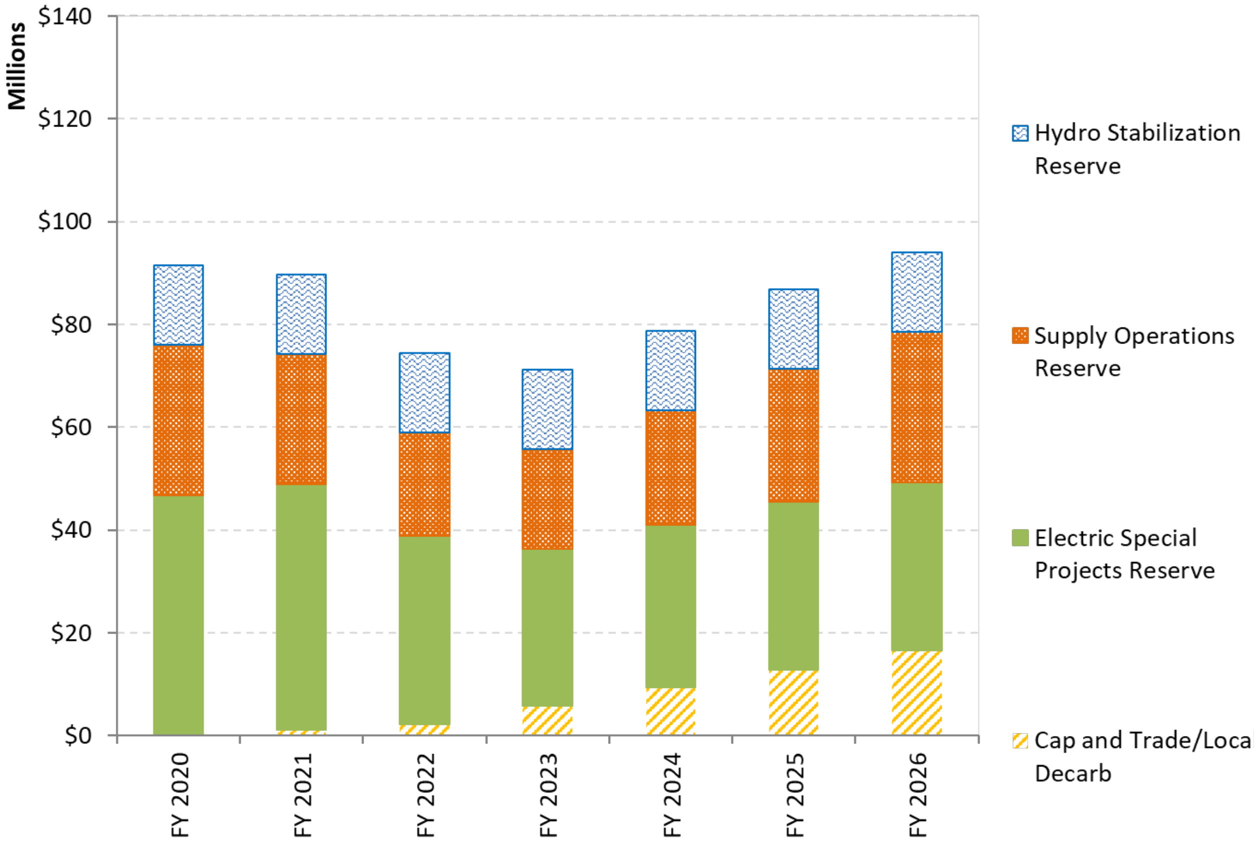
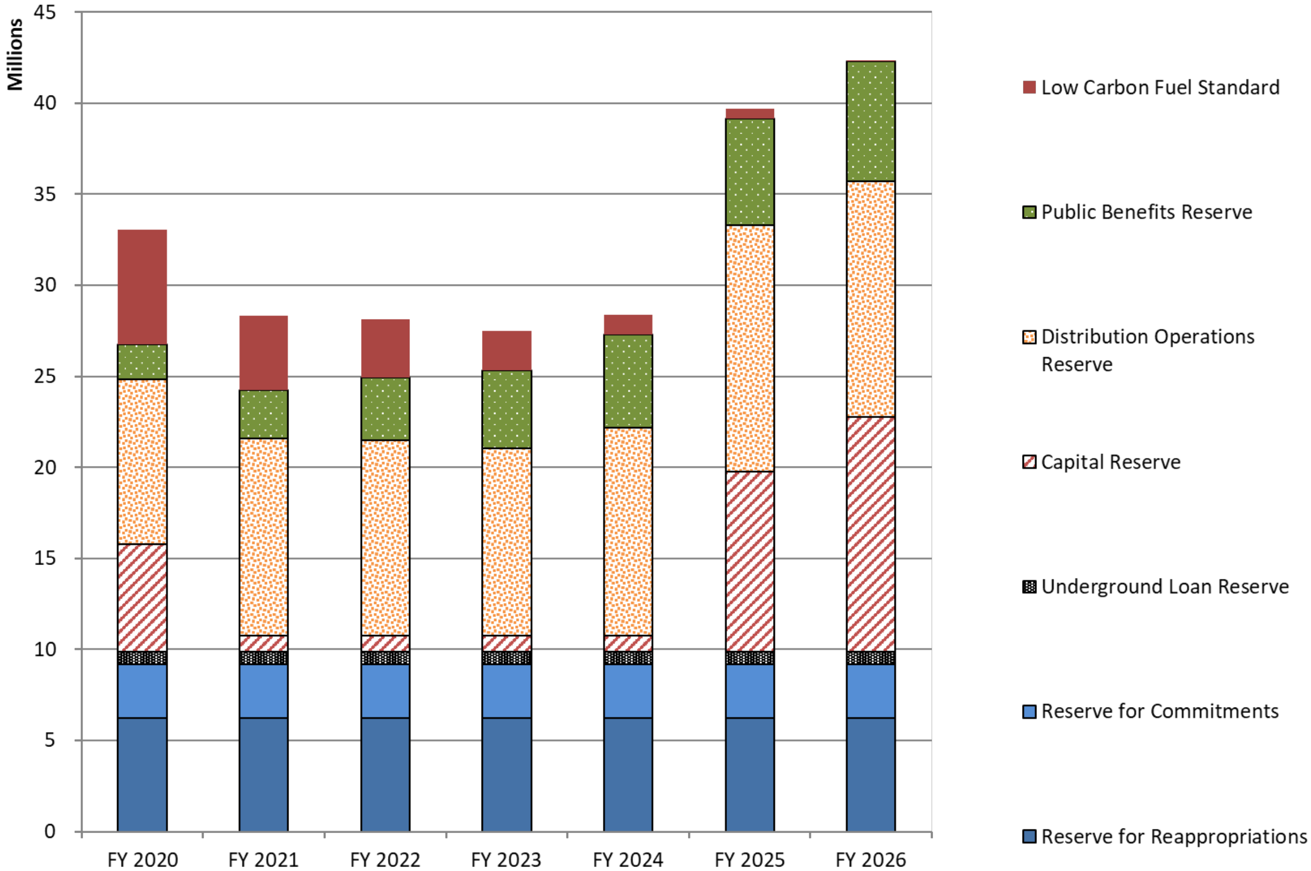


Figure 9: Electric Utility Reserves (Distribution Fund):
Actual Reserve Levels through FY 2020 and Projections through FY 2026



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 the past, the Supply and Distribution funds had Rate Stabilization Reserves (RSR) but both have been drawn to zero, as approved in prior financial plans. In addition, the Electric Utility has a Hydro Stabilization reserve, an Electric Special Projects reserve and a Capital reserve, which can be utilized with prior Council approval.

This Financial Plan maintains reserves above the reserve minimum for the Distribution Operations Reserve throughout the forecast period. Reserve levels also exceed the short-term risk assessment level for the Distribution Fund. The Supply Operations Reserve is also currently within guideline levels.

There are a variety of risks associated with the Supply Fund as are shown in Table 10. 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 10 is very low.

Table 10: Electric Supply Fund Risk Assessment

Categories of Electric Supply Cost Uncertainties	Estimates of Adverse Outcomes (M$)	Estimates of Adverse Outcomes (M$)
	FY 2022	**FY 2023**
1. Load Net Revenue	3.1	3.2
2. Hydro Production: Western & Calaveras	4.8	4.6
3. Renewable Production: Landfill & Wind & Solar	1.8	1.8
4. Carbon Neutral Cost	0.9	0.9
5. REC Sales	1.5	1.8
6. Market Price	0.3*	0.8**
7. Resource Adequacy	1.6	1.4
8. Transmission/CAISO	3.7~	3.9~
9. Plant Outage	1.0	1.0
10. Western Cost	1.6	1.6
11. Legislative & Regulatory	0.0	0.0
12. Supplier Default	0.2†	0.2†
Electric Supply Fund Risks	**$ 20.5 million**	**$ 21.0 million**

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 nearly one-third ($4.8 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 2022, $3.7 million is related to potential transmission cost increases (above staff's current forecast). $3.1 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 $1.6 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 10, staff projects the Supply Operations Reserve to remain slightly above the minimum guideline levels, dropping to its lowest in FY 2023 but recovering to target levels by FY 2026. Figure 11 shows that the combined Hydro Stabilization, Supply Rate Stabilization and

Supply Operations Reserves are projected to be above what is needed for the risk assessment level.

Figure 10: Electric Supply Operations Reserve Adequacy

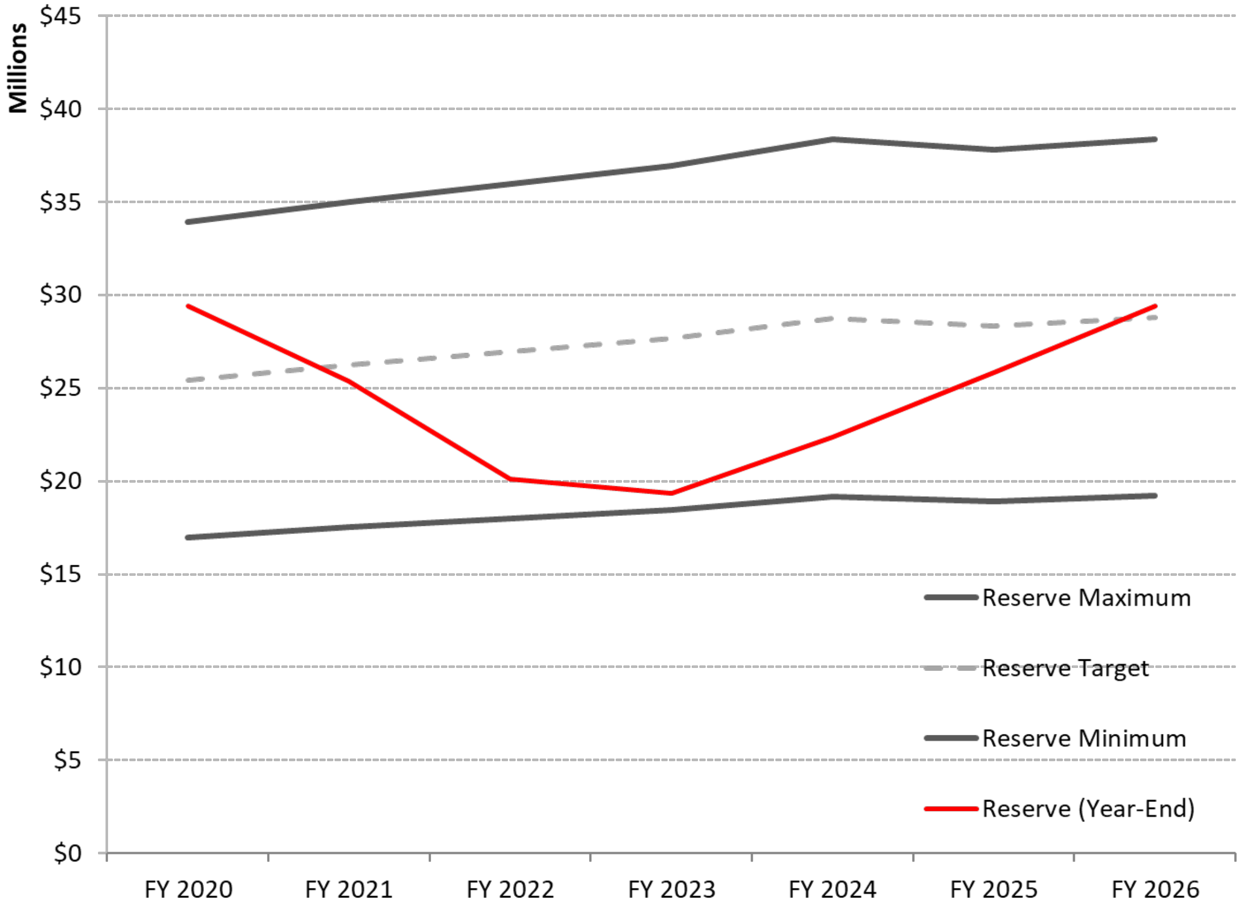


Figure 11: Adequacy of Supply Operations and Hydro Stabilization Reserves, Combined

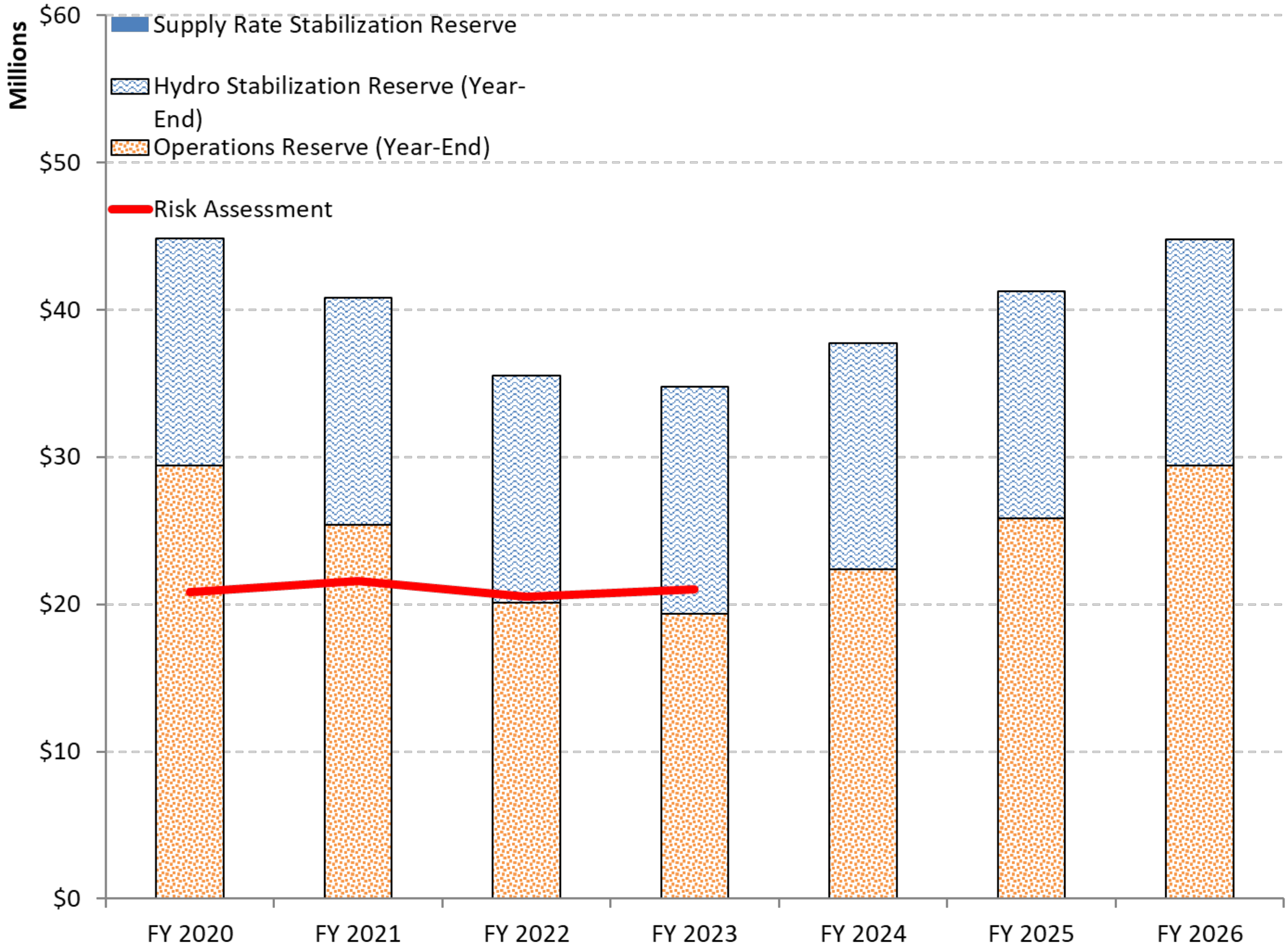


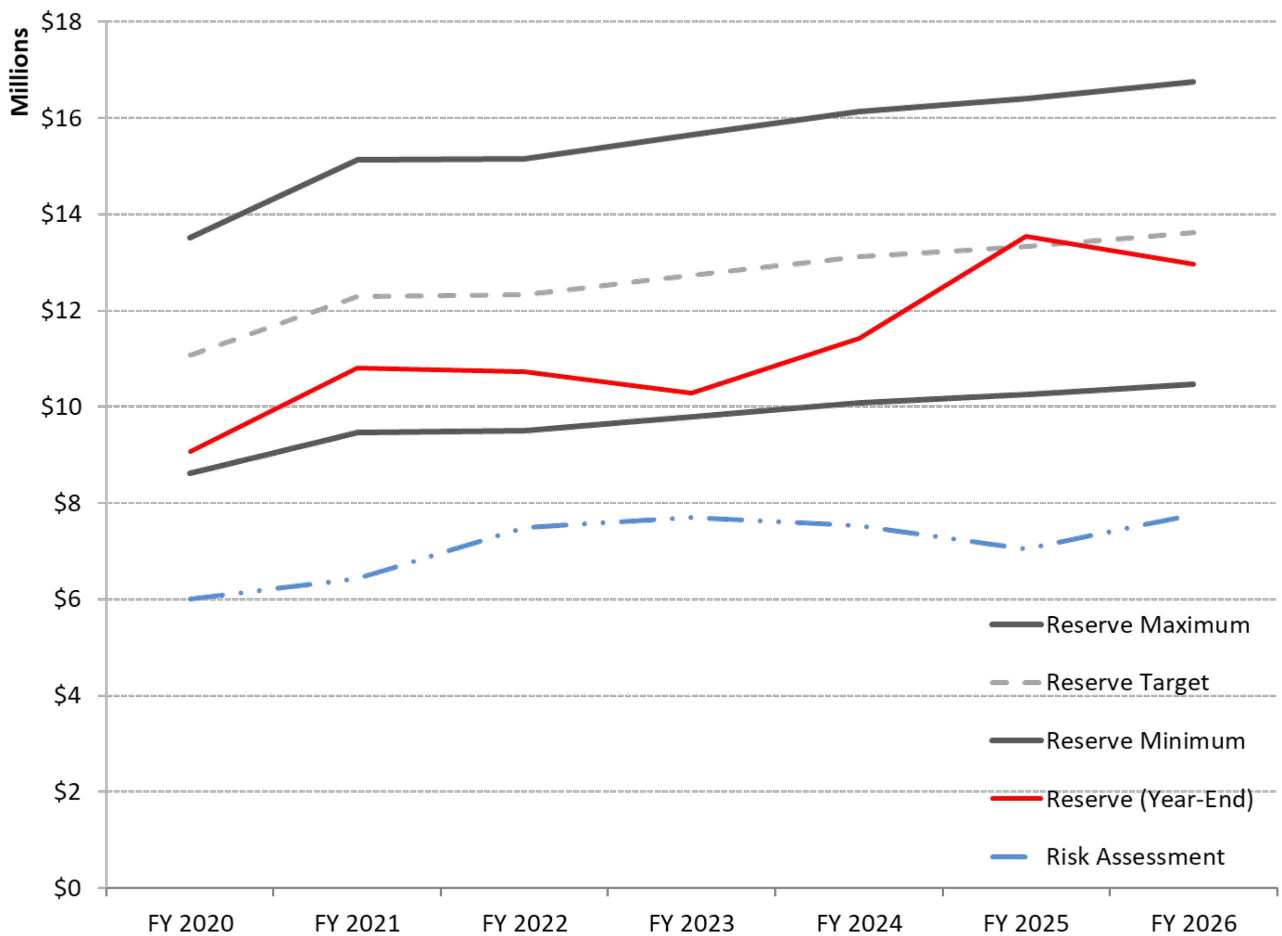
Table 11 summarizes the risk assessment calculation for the Distribution Operations Reserve through FY 2026. As shown in Figure 12, the Distribution Operations Reserve is also projected to drop near to the minimum reserve guidelines in FY 2023, but is projected to recover to near target levels over the 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 11: Electric Distribution Fund Risk Assessment ($000)

	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026
Total non-commodity revenue	$55,969	$62,474	$67,870	$71,707	$71,475
Max. revenue variance, previous ten years	8%	8%	8%	8%	8%
Risk of revenue loss	$4,417	$4,931	$5,357	$5,659	$5,641
CIP Budget	$30,643	$27,739	$21,700	$13,926	$21,284
CIP Contingency @10%	$3,064	$2,774	$2,170	$1,393	$2,128
Total Risk Assessment value	$7,482	$7,705	$7,527	$7,052	$7,770

Figure 12: Electric Distribution Operations Reserve Adequacy



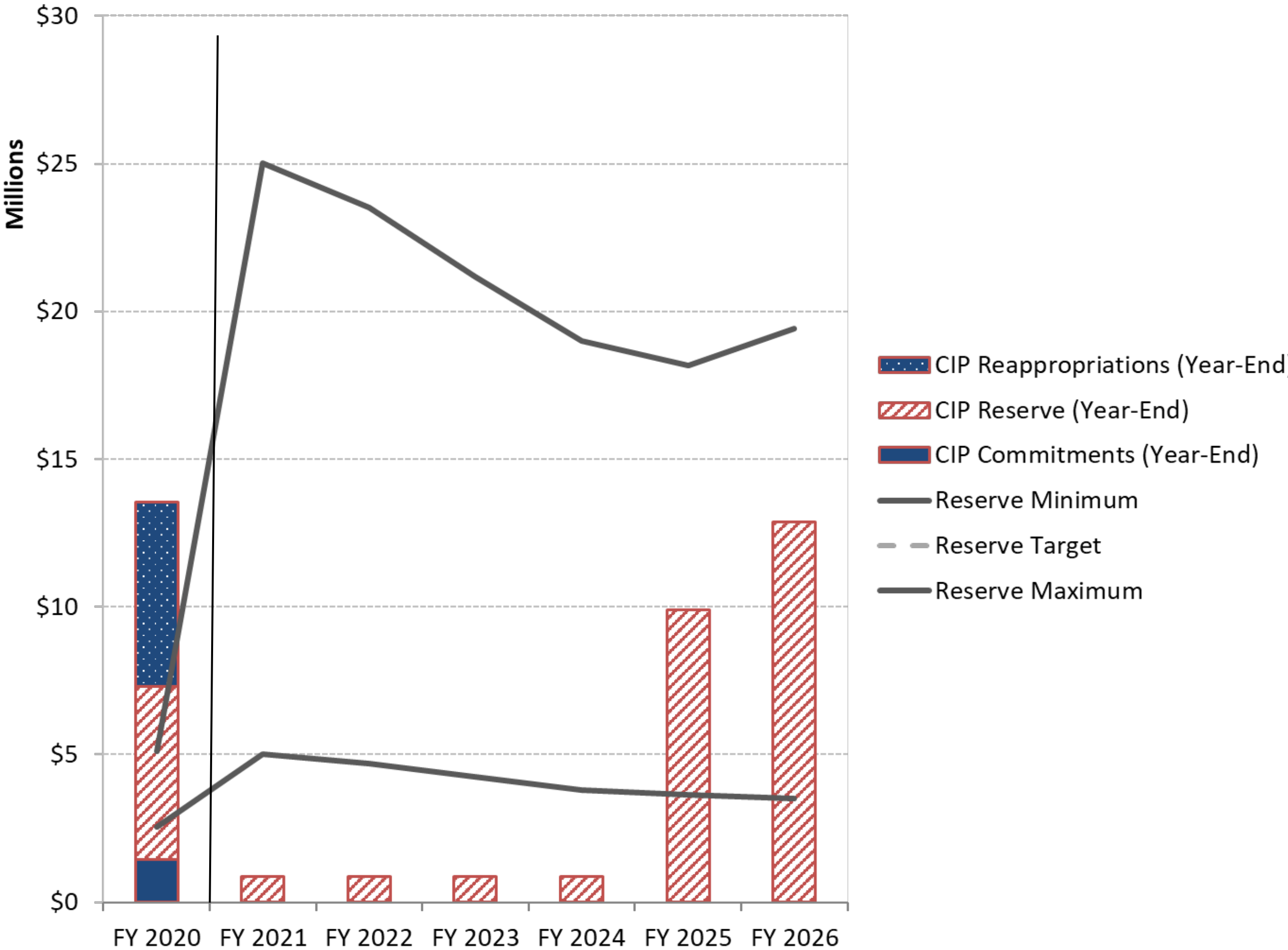
The Electric Utility also has a Capital Improvement Program (CIP) Reserve that acts as a reserve for short term capital contingencies or as a place to set aside funds for large, one-time projects that the Utilities would otherwise need to debt-fund. In the future, staff would also like to use this reserve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

Figure 13 below reflects the maximum and minimum CIP Reserve guideline levels, starting in FY 2021. 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 is 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 the COVID epidemic and a desire not to raise rates too quickly, the 2022 Financial Plan doesn't anticipate funding the CIP Reserve from the Distribution Operations Reserve until FY 2025 ($9 million). 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 $18 to $19 million annually, but subject to change as new projects are added), and have 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 13 shows the projected CIP Reserve balances and guideline levels for FY 2021 through FY 2026, as well as the prior reserve and guidelines in FY 2020. Because of constrained financial conditions, the CIP reserve is projected to be below the minimum guideline for a few years, until reserve funding can take place.

Figure 13: Electric CIP Reserve Adequacy



SECTION 5G: LONG-TERM OUTLOOK

This forecast covers the period from FY 2022 through FY 2026, 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 Western for power from the 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 expiring 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 is in the process of procuring a replacement for the contract expiring in 2021 at a lower price than any of the City's current renewable contracts.

The costs of the Calaveras hydro project will also change in the 2020s, with debt service costs dropping by half 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 through 2020. However, discussions at the state level are ongoing and will determine whether or not these allocations continue till 2030, as well as any further restrictions CARB may wish to enact on 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 continues to monitor the growth of electric vehicle ownership and gas-to-electric fuel switching in Palo Alto. In the next 10 to 20 years, these factors may begin to create notable increases in electric consumption and have a variety of impacts on the distribution system. As housing stock is turned over, however, stricter building codes may help to counteract load growth, as may increasing numbers of rooftop solar installations. 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 are 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.

SECTION 5H: ALTERNATIVE RATE PROJECTIONS

Staff has no alternative projections at this time.

SECTION 6: DETAILS AND ASSUMPTIONS

SECTION 6A: ELECTRICITY PURCHASES

As shown in Figure 14 the utility gets roughly 50% of its energy from hydroelectric projects in a normal year (FY FY2015 was dry). Contracts with renewable sources made up just over 30% of the portfolio in FY 2016, and 50% in FY 2017. 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 14: Electricity Supply by Source

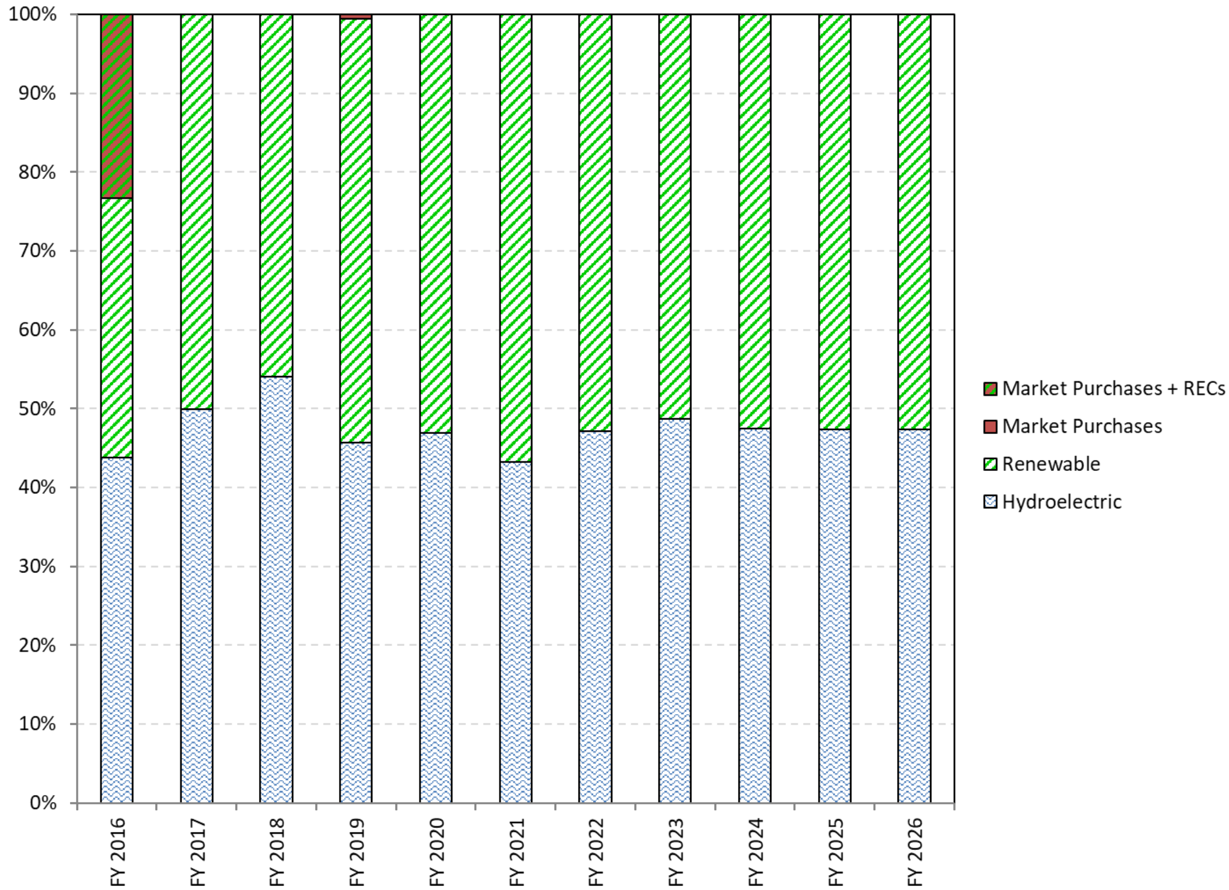
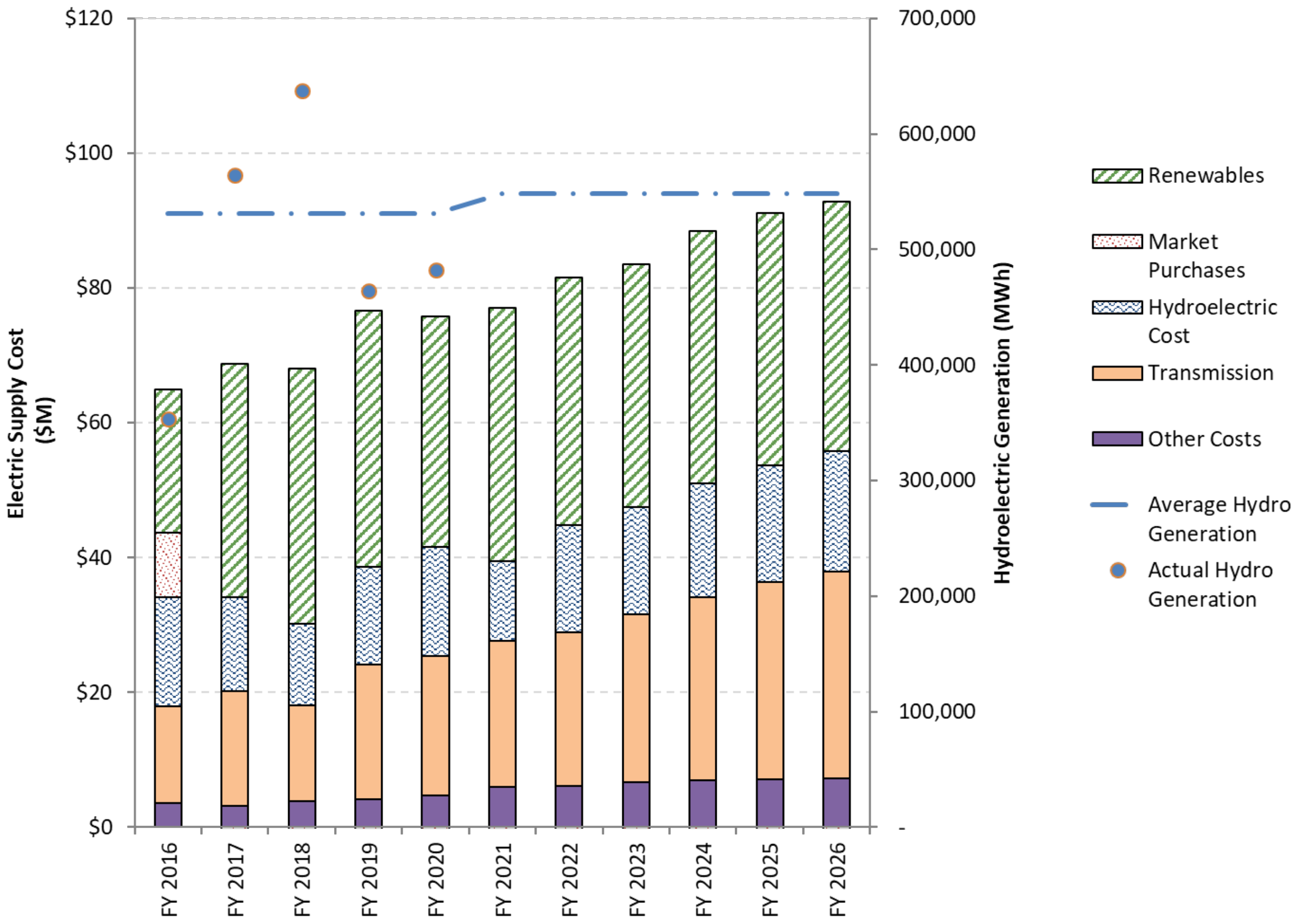


Figure 15 shows the historical and projected costs for the electric supply portfolio,[8] as well as average and actual hydroelectric generation.[9] Electric supply costs increased in FY 2013, FY 2014, and FY 2015 due to the drought, which reduced the amount of generation from hydroelectric resources. Costs decreased slightly in FY 2016 due to better than expected market purchase costs, and FY 2017 and FY 2018 had lower hydroelectric costs. Renewable energy costs assumed a larger portion of cost as various renewable projects came online to fulfill the City's carbon neutral and RPS goals, although some of the older, higher priced contracts will start expiring as early as FY 2022. The current market outlook is that newer renewables projects should come in at lower costs. Transmission charges are also projected to increase as new transmission lines are built throughout California to accommodate new renewable projects. In total, electric supply costs are projected to increase to about $87 million by FY 2026, at which point all currently contracted renewable projects will be online. Supply costs are only projected to change slightly in subsequent years.

[8] 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.
[9] Average hydroelectric generation based on the current E-HRA tariff.

Figure 15: Electric Supply Portfolio Costs, Historical and Projected



SECTION 6B: OPERATIONS

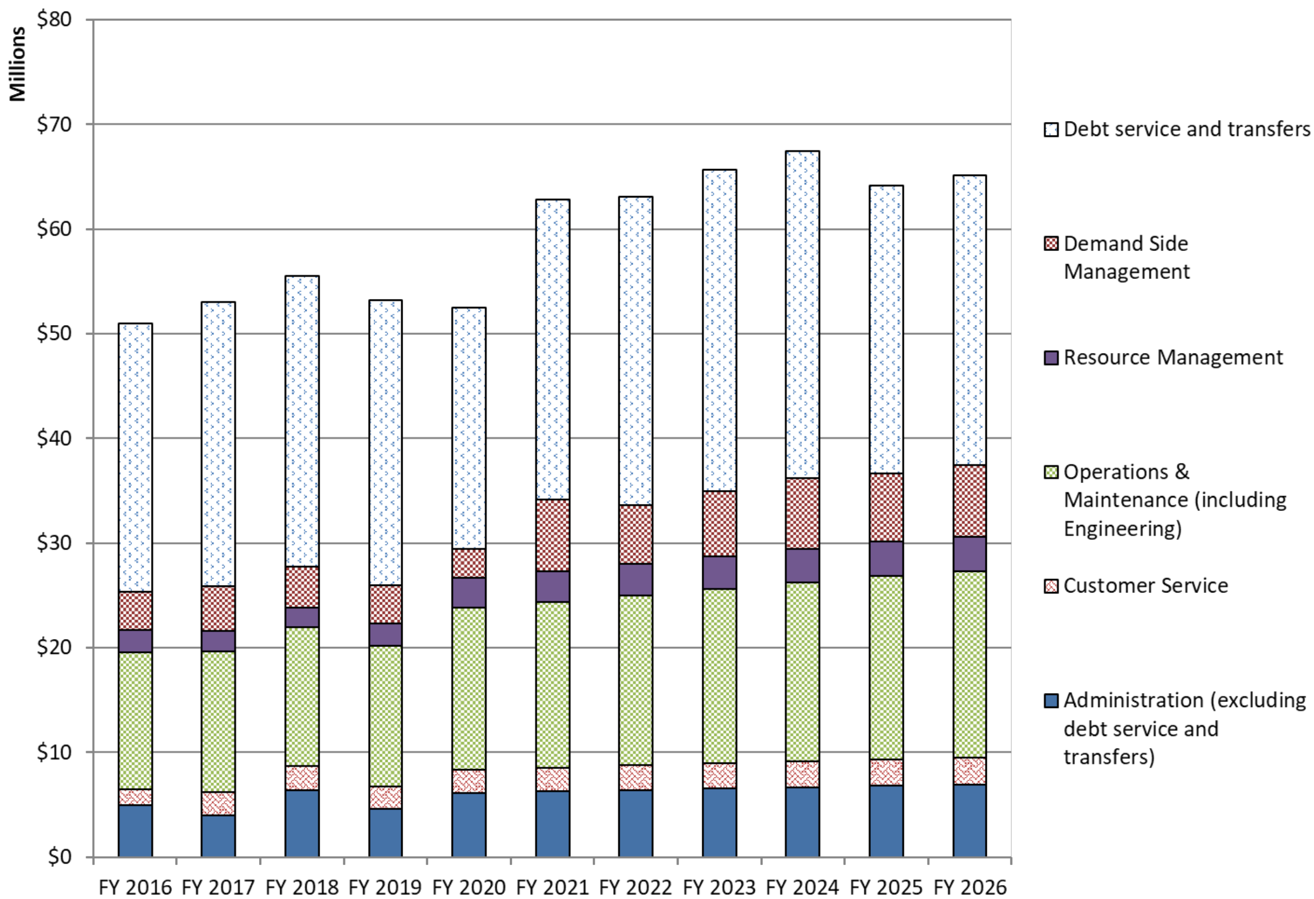
CPAU's Electric Utility operations include the following activities:

- 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 2016 to FY 2020, overall Operations costs have risen annually by about 4% on average. Starting in FY 2021 and continuing for several years, Operations and Maintenance costs are increased mainly due to the introduction of a 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. Demand side management costs are increasing in FY 2021 to reflect new and ongoing costs related to Low Carbon Fuel Standard rebates. Revenues from the same program will offset most of these costs.

Figure 21: Historical and Projected Electric Utility Operational Costs



SECTION 6C: CAPITAL IMPROVEMENT PROGRAM (CIP)

Staff projects CIP spending for FY 2022 through FY 2026 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 as current projects are completed and 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; and increase in funding for replacement of distribution system and substation facilities that are at the end of their useful life. Other significant projects still slated to continue are deteriorated wood pole replacements, substation physical security upgrades, pole relocations to facilitate the Caltrain Railway Electrification project, Smart Grid upgrades, 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 Electric Special Projects Reserve, but it would also be possible to use bond financing. The full deployment of the smart grid project has tentatively been moved out to start in FY 2023.

Excluding the one-time projects listed above, the CIP plan for FY 2022 to FY 2026 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 2022 Utilities Capital Budget. Figure 17 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.

Figure 22: Electric Utility CIP Spending ($000)

Project Category	Current Budget *	Spending, Curr. Yr.	Remain. Budget **	Committed	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025
One Time Projects	4,456	(310)	4,146	265	4,000	2,000	2,000	11,000	-
Reliability	3,531	(1,923)	1,609	1,042	4,020	5,690	4,040	3,000	2,563
Undergrounding	1,548	(35)	1,513	126	-	56	3,750	250	-
4/12 Kv Conversion	1,830	(7)	1,823	-	166	50	120	2,120	1,820
Underground Rebuild	4,955	(24)	4,931	17	2,110	250	400	4,050	461
Ongoing	3,766	(1,051)	2,715	1,169	5,830	4,445	3,805	3,605	3,672
Customer Connections	2,400	(1,515)	885	352	2,550	2,700	2,400	2,400	2,472
Total	**22,486**	**(4,863)**	**17,623**	**2,971**	**18,676**	**15,191**	**16,515**	**26,425**	**10,987**

*** Includes unspent funds from previous years carried forward or re-appropriated into the current fiscal year.**
**** Equal to CIP Reserves (Reserve for Re-appropriations + Reserve for Commitments)**

SECTION 6D: DEBT SERVICE

The Electric Utility's annual debt service is $100,000 per year. The Electric Utility currently makes payment on one bond issuance, the 2007 Electric Utility Clean Renewable Energy Tax Credit Bonds, Series A. 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 capacity of these projects totaled 250 kW. In exchange for funding part of the construction costs, the Electric Utility receives the RECs from these projects. The bonds were Clean Renewable Energy Bonds (CREBs), meaning they are interest free (the investors receive a tax credit from the federal government). This bond issuance is secured by the net revenues of the Electric Utility. Debt service for this bond continues through 2021, and for the financial forecast period is as follows:

Table 15: Electric Utility Debt Service ($000)

	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024
2007 Clean Renewable Energy Bonds	100	100	-	-	-

The 2007 bonds include a covenant stating that the Electric Utility will maintain a debt coverage ratio of 125% of debt service. The current Financial Plan maintains compliance with these covenants throughout the forecast period, as shown in Appendix C.

The Electric Utility also pledges reserves and net revenue as security for the bond issuances listed in Table 16, 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.

Table 16: 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*				

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.[10] Each year it is calculated according to the 2009 Council-adopted methodology and does not require additional Council action.

SECTION 6F: WHOLESALE REVENUES AND OTHER REVENUES

The Electric Utility receives most of its revenues from sales of electricity, but about one quarter comes from other sources. Of these other sources, about 50% to 60% 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. In FY 2020 these sources represented roughly 33% of revenue from sources other than electricity sales. The remaining FY 2020 revenues consisted of a variety of one-time transfers.

Revenues from connection fees have increased since FY 2009 varying from year to year. Connection fee revenues are collected to offset costs incurred in setting up new connections and are pass-through in nature. Revenue from connection fees decreased slightly during the recession, but has increased substantially since then, peaking in FY 2016 declining somewhat in

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

FY 2017 and FY 2018, then hitting a new high in FY 2019. Staff forecasts slightly lower revenue from this source in 2021 with revenue leveling out in subsequent years.

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. This scenario may be pessimistic, but matches what has transpired for free allowances in the gas fund.

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) 2022 Electric Utility communications strategy covers these primary areas: efficiency services and utility bill savings; capital improvement, operations and maintenance for infrastructure safety and reliability; renewables and carbon neutral portfolio; beneficial electrification; and cost containment measures. The 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 FY 2022, CPAU is proposing no increase in electric utility rates. Communications will focus on helping customers with efficiency services, rate assistance and bill payment relief programs to help them navigate a challenging economic situation during the COVID-19 pandemic. They will also highlight CPAU's decision to defer rate increases as a benefit of the organization's management of its financial portfolio, including use of reserves for situations such as what we could not anticipate but observed in 2020. While the cost of transmission fees, capital investment, construction and contract labor costs have increased, CPAU is able to insulate customers against significant rate increases because of its financial portfolio management. Staff anticipates that rate increases around 5% each year beyond FY 2022 will be required in order to keep the reserves within a healthy margin.

CPAU continues to make cost containment an ongoing priority and part of an annual cycle, consistent with the Utilities Strategic Plan. CPAU's electric utility rates remain lower than the neighboring community average, such as for investor-owned utilities like PG&E. The average Palo Alto resident's monthly electric bill is around 34% lower than the PG&E average. Keeping costs low is one of the benefits CPAU offers its customers as a public utility provider.

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. In 2020, we began offering a virtual Genie in-home assessment and webinars about home energy and water efficiency to help customers keep utility costs low while working and studying from home during the pandemic shelter-in-place order. CPAU is exploring additional opportunities to help customers electrify homes, buildings, and personal transportation. Rebates for residential appliances such as heat pump water heaters and electric vehicle charging stations for multi-family and non-profit facilities are incentivizing more and more customers to take action. Staff are piloting programs to explore electrification technologies in other applications as well. These efforts are in line with the City's Sustainability and Climate Action Plan goals to reduce greenhouse gas emissions. CPAU launched an upgraded version of its online utility account services portal in 2020, which provides customers with direct access and more information about utility account and consumption data.

APPENDICES

Appendix A: Electric Utility Financial Forecast Detail
Appendix B: Electric Utility Reserves Management Practices
Appendix C: Description of Electric utility Operational Activities
Appendix D: Samples of Recent Electric Utility Outreach Communications

APPENDIX A: ELECTRIC UTILITY FINANCIAL FORECAST DETAIL

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	FISCAL YEAR	FY 2016	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026
2												
3	**ELECTRIC LOAD**					160	162					
4	Purchases (MWh)	977,292	945,703	925,329	905,071	879,913	818,593	835,246	870,922	875,208	867,019	858,859
5	Sales (MWh)	937,157	917,687	899,997	884,322	854,760	796,450	812,790	846,966	851,449	843,454	835,431
6												
7	**BILL AND RATE CHANGES**											
8	System Average Rate ($/kWh)	$ 0.1156	$ 0.1249	$ 0.1413	$ 0.1487	$ 0.1624	$ 0.1624	$ 0.1624	$ 0.1707	$ 0.1799	$ 0.1843	$ 0.1837
9	Change in System Average Rate	0%	10%	13%	5%	9%	0%	0%	5%	5%	2%	0%
10	Change in Average Residential Bill	3%	11%	11%	6%	8%	-1%	-1%	5%	5%	2%	-1%
11												
12	**STARTING RESERVES**											
13	Reappropriations (Non-CIP)	-	-	-	-	-	-	-	-	-	-	-
14	Commitments (Non-CIP)	3,102,055	3,777,205	2,970,955	3,725,000	3,910,695	3,518,525	3,518,525	3,518,525	3,518,525	3,518,525	3,518,525
15	Low Carbon Fuel Standard (LCFS) Reserve	-	-	-	-	-	6,340,000	4,079,577	3,186,120	2,163,917	1,091,927	524,278
16	Cap and Trade Program							1,189,129	2,189,551	5,749,259	9,315,900	12,866,019
17	Underground Loan Reserve	730,000	729,000	730,147	730,147	726,659	726,659	726,659	726,659	726,659	726,659	726,659
18	Public Benefits Reserves	2,574,000	1,839,000	681,330	681,330	809,700	1,904,547	2,664,195	3,434,974	4,274,785	5,101,307	5,861,122
19	Electric Special Projects Reserve	51,837,855	51,837,855	51,837,855	41,837,855	41,664,855	46,664,855	47,664,855	36,649,107	30,649,107	31,649,107	32,649,107
20	Hydro Stabilization Reserve	17,000,000	11,400,000	11,400,000	11,400,000	11,400,000	15,400,000	15,400,000	15,400,000	15,400,000	15,400,000	15,400,000
21	Capital Reserves	-	-	879,964	879,964	879,964	5,879,964	879,964	879,964	879,964	879,964	9,879,964
22	Rate Stabilization Reserves	14,410,840	9,010,840	9,010,840	9,010,840	-	-	-	-	-	-	-
23	Operations Reserves	22,497,607	21,850,187	29,912,981	18,600,000	45,244,167	38,493,671	36,021,324	30,848,860	29,870,224	34,765,907	41,967,828
24	Unassigned	-	-	-	244,354	-	-	-	-	-	-	-
25	TOTAL STARTING RESERVES	112,152,357	100,444,086	107,424,072	87,109,490	104,636,040	118,928,221	112,144,228	96,833,761	93,232,441	102,449,297	123,393,502
26												
27	**REVENUES**											
28	Net Sales	108,312,917	114,624,726	127,172,308	131,471,245	137,026,501	129,362,400	132,016,388	144,585,888	153,177,157	155,480,812	153,468,878
29	Wholesale Revenues	4,301,366	16,188,920	18,106,327	21,060,071	20,686,925	24,172,722	26,268,047	26,065,562	29,160,236	28,622,338	28,722,008
30	Other Revenues and Transfers In	11,714,494	11,225,911	13,373,312	19,914,635	15,260,935	16,958,432	15,201,708	16,006,051	17,060,870	18,081,320	19,108,217
31	TOTAL REVENUES	124,328,776	142,039,557	158,651,947	172,445,951	172,974,361	170,493,554	173,486,143	186,657,501	199,398,263	202,184,470	201,299,104
32												
33	**EXPENSES**											
34	Electric Supply Purchases	75,705,000	80,467,136	94,629,654	89,625,027	90,645,768	93,402,295	96,218,872	98,071,366	102,283,824	104,443,425	106,132,953
35	Operating Expenses											
36	Administration											
37	*Allocated Charges*	*4,934,195*	*3,990,822*	*6,374,241*	*4,568,027*	*6,146,498*	*6,269,614*	*6,395,499*	*6,524,037*	*6,654,904*	*6,788,290*	*6,937,026*
38	*Rent*	*4,997,101*	*5,121,102*	*5,284,977*	*5,454,097*	*5,666,805*	*6,798,087*	*6,974,837*	*7,156,183*	*7,342,244*	*7,533,142*	*7,729,004*
39	*Debt Service*	*8,885,994*	*8,953,893*	*8,867,395*	*8,464,883*	*7,170,631*	*8,061,159*	*8,068,219*	*8,900,247*	*8,914,853*	*4,898,677*	*4,896,047*
40	*Transfers and Other Adjustments*	*11,798,865*	*13,052,376*	*13,632,059*	*13,342,321*	*10,200,181*	*13,859,349*	*14,460,996*	*14,618,796*	*14,996,752*	*15,004,867*	*15,013,144*
41	Subtotal, Administration	30,616,155	31,118,193	34,158,672	31,829,328	29,184,115	34,988,209	35,899,551	37,199,262	37,908,752	34,224,975	34,575,221
42	Resource Management	2,083,812	1,985,620	1,873,954	2,082,405	2,849,071	2,915,597	2,999,304	3,091,930	3,174,074	3,252,752	3,337,994
43	Demand Side Management	3,643,924	4,271,786	3,889,846	3,655,547	2,733,047	6,813,274	5,597,849	6,226,330	6,735,444	6,579,673	6,835,735
44	Operations and Mtc	11,523,881	11,811,016	11,528,747	11,606,585	13,450,568	13,753,878	14,120,144	14,519,515	14,882,486	15,234,376	15,454,139
45	Engineering (Operating)	1,592,024	1,656,522	1,790,942	1,838,799	2,051,303	2,093,560	2,138,697	2,185,640	2,231,923	2,278,475	2,321,056
46	Customer Service	1,540,884	2,190,993	2,291,246	2,180,400	2,228,469	2,281,952	2,351,324	2,428,904	2,496,527	2,560,731	2,589,553
47	Allowance for Unspent Budget	-	-	-	-	-	(1,413,087)	(1,172,410)	(1,203,369)	(1,232,103)	(1,260,236)	(1,285,146)
48	Subtotal, Operating Expenses	51,000,680	53,034,130	55,533,407	53,193,063	52,496,573	61,433,382	61,934,458	64,448,212	66,197,103	62,870,747	63,828,552
49	Capital Program Contribution	9,331,367	11,558,306	18,803,467	10,770,456	15,539,840	22,017,870	30,643,280	27,739,243	31,700,480	13,926,093	21,284,122
50	TOTAL EXPENSES	136,037,047	145,059,572	168,966,528	153,588,546	158,682,181	176,853,547	188,796,610	190,258,821	200,181,407	181,240,265	191,245,628
51												
52	**ENDING RESERVES**											
53	Reappropriations (Non-CIP)	-	-	9,063,000	-	-	-	-	-	-	-	-
54	Commitments (Non-CIP)	3,777,205	2,970,955	8,637,000	3,910,695	3,518,525	3,518,525	3,518,525	3,518,525	3,518,525	3,518,525	3,518,525
55	Low Carbon Fuel Standard (LCFS) Reserve	-	-	-	-	6,340,000	4,079,577	3,186,120	2,163,917	1,091,927	524,278	71,297
56	Cap and Trade Program						1,189,129	2,189,551	5,749,259	9,315,900	12,866,019	16,565,994
57	Underground Loan Reserve	729,000	730,147	730,147	726,659	726,659	726,659	726,659	726,659	726,659	726,659	726,659
58	Public Benefits Reserves	1,839,000	681,330	681,330	809,700	1,904,547	2,664,195	3,434,974	4,274,785	5,101,307	5,861,122	6,574,538
59	Electric Special Projects Reserve	51,837,855	51,837,855	41,837,855	41,664,855	46,664,855	47,664,855	36,649,107	30,649,107	31,649,107	32,649,107	32,649,107
60	Hydro Stabilization Reserve	11,400,000	11,400,000	11,400,000	11,400,000	15,400,000	15,400,000	15,400,000	15,400,000	15,400,000	15,400,000	15,400,000
57	Capital Reserve	-	879,964	879,964	879,964	5,879,964	879,964	879,964	879,964	879,964	9,879,964	12,879,964
58	Rate Stabilization Reserve	9,010,840	9,010,840	9,010,840	-	-	-	-	-	-	-	-
59	Operations Reserve	21,850,187	29,912,981	18,600,000	45,244,167	38,493,671	36,021,324	30,848,860	29,870,224	34,765,907	41,967,828	45,060,895
60	Unassigned	-	-	244,354	-	-	-	-	-	-	-	-
61	TOTAL ENDING RESERVES	100,444,086	107,424,072	101,084,490	104,636,040	118,928,221	112,144,228	96,833,761	93,232,441	102,449,297	123,393,502	133,446,979
62												

1	FISCAL YEAR	FY 2016	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026
2												
3	**REVENUES**											
4	Net Sales	87%	81%	80%	76%	79%	76%	76%	78%	77%	77%	77%
5	Other Revenues and Transfers In	13%	19%	20%	24%	21%	24%	24%	22%	23%	23%	23%
6	TOTAL REVENUES	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
7												
8	**EXPENSES**											
9	Commodity Purchases	54%	42%	50%	53%	53%	52%	46%	45%	46%	49%	48%
10	Operating Expenses											
11	Administration											
12	*Allocated Charges*	*4%*	*3%*	*4%*	*3%*	*4%*	*4%*	*3%*	*3%*	*3%*	*4%*	*4%*
13	*Rent*	*4%*	*4%*	*3%*	*4%*	*4%*	*4%*	*4%*	*4%*	*4%*	*4%*	*4%*
14	*Debt Service*	*7%*	*6%*	*5%*	*6%*	*5%*	*5%*	*4%*	*5%*	*5%*	*3%*	*3%*
15	*Transfers and Other Adjustments*	*9%*	*9%*	*8%*	*9%*	*6%*	*8%*	*8%*	*8%*	*8%*	*8%*	*8%*
16	Subtotal, Administration	23%	21%	20%	21%	18%	20%	19%	20%	20%	19%	18%
17	Resource Management	2%	1%	1%	1%	2%	2%	2%	2%	2%	2%	2%
18	Operations and Mtc	8%	8%	7%	8%	8%	8%	7%	8%	8%	8%	8%
19	Engineering (Operating)	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
20	Customer Service	1%	2%	1%	1%	1%	1%	1%	1%	1%	1%	1%
21	Allowance for Unspent Budget	0%	0%	0%	0%	0%	-1%	-1%	-1%	-1%	-1%	-1%
22	Subtotal, Operating Expenses	35%	34%	31%	32%	31%	31%	30%	31%	31%	31%	30%
23	Capital Program Contribution	7%	8%	11%	7%	10%	11%	16%	15%	11%	8%	11%
24	TOTAL EXPENSES	96%	83%	91%	92%	95%	94%	92%	90%	89%	88%	89%
25												

26 **RISK ASSESSMENT DETAIL (SUPPLY FUND)**

27	FISCAL YEAR	FY 2016	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026
28	1. Load Net Revenue	652,853	1,208,477									
29	2. Hydro Production: Western & Calaveras	9,050,313	3,397,119									
30	3. Renewable Production: Landfill & Wind (	743,945	539,073									
31	4. Carbon Neutral Cost	303,022	114,983									
32	5. Market Price	775,584	1,138,589									
33	6. Local Capacity	408,388	446,695									
34	7. Transmission/CAISO	3,741,647	2,806,120									
35	8. Plant Outage	1,000,000	1,000,000									
36	9. Western Cost	2,704,738	2,973,619									
37	10. Regulatory & Legal	-	-									
38	11. Supplier Default	-	-									
39	TOTAL	19,380,490	13,624,674									
40	Supply Operations + Hydro Stabilization Reserves, % of Risk Assessment	172%	303%									
41												

42 **RISK ASSESSMENT DETAIL (DISTRIBUTION FUND)**

43	FISCAL YEAR	FY 2016	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026
44	Distribution Revenue Variance	3,260,213	3,182,718	3,742,109	3,915,276	4,447,787	4,432,418	4,417,304	4,930,733	5,356,652	5,659,448	5,641,151
45	10% CIP Program Contingency	933,137	1,155,831	1,880,347	1,077,046	1,553,984	2,001,787	3,064,328	2,773,924	2,170,048	1,392,609	2,128,412
46	Total Risk Asssessment Value	4,193,350	4,338,548	5,622,455	4,992,321	6,001,771	6,434,205	7,481,632	7,704,657	7,526,700	7,052,057	7,769,564
47	Projected Operations Reserve	21,850,187	29,912,981	18,600,000	45,244,167	38,493,671	36,191,535	30,831,986	29,628,922	33,771,081	39,672,192	42,667,847
48	Operations Reserve, % of Risk Value	521%	689%	331%	906%	641%	562%	412%	385%	449%	563%	549%
49												
44	**SUPPLY OPERATIONS RESERVE**											
45	Min (60 days of non-capital expenses)	14,498,215	15,472,236	17,841,143	16,831,022	16,953,628	17,508,370	17,981,164	18,461,032	19,176,632	18,891,837	19,192,697
46	Target (90 days of non-capital expenses)	21,747,322	23,208,354	26,761,715	25,246,533	25,430,442	26,262,555	26,971,747	27,691,548	28,764,949	28,337,756	28,789,046
47	Max (120 days of non-capital expenses)	28,996,429	30,944,472	35,682,287	33,662,044	33,907,256	35,016,739	35,962,329	36,922,065	38,353,265	37,783,675	38,385,394
48												
49	**DISTRIBUTION OPERATIONS RESERVE**											
50	Min (60 days of non-capital expenses)	8,513,675	9,755,012	8,008,309	7,869,900	8,621,917	9,462,487	9,512,586	9,802,609	10,084,238	10,256,803	10,471,541
51	Target (90 days of non-capital expenses)	10,708,963	11,918,803	10,309,464	10,096,233	11,071,856	12,295,398	12,332,333	12,728,321	13,111,059	13,329,457	13,610,674
52	Max (120 days of non-capital expenses)	12,904,252	14,082,593	12,610,618	12,322,566	13,521,795	15,128,308	15,152,079	15,654,034	16,137,881	16,402,112	16,749,808
53	Risk Assessment Value	4,193,350	4,338,548	5,622,455	4,992,321	6,001,771	6,434,205	7,481,632	7,704,657	7,526,700	7,052,057	7,769,564
54												
55	**DEBT SERVICE COVERAGE RATIO**											
56	Net Revenues (125% of Debt Service)	1326%	1391%	1593%	1587%	1896%	1821%	1860%	1726%	1790%	3315%	3371%
57	Available Reserves (5x Debt Service)*	10.9	11.7	9.4	11.9	16.1	13.5	11.6	10.1	11.0	24.0	26.0

58 **For the purposes of debt covenants, the unrestricted reserves of other utilities may be counted toward the available reserves for meeting this measure. A ratio below 5x means that this utility is relying on the reserves of other utilities to mee*

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 and timelines 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 and timelines 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 2017;
f) Any uncommitted funds remaining at the end of FY 2022 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)[11] CIP budget, for 48 months of budgeted CIP expenses[12]

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 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.

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

[12] 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.

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:

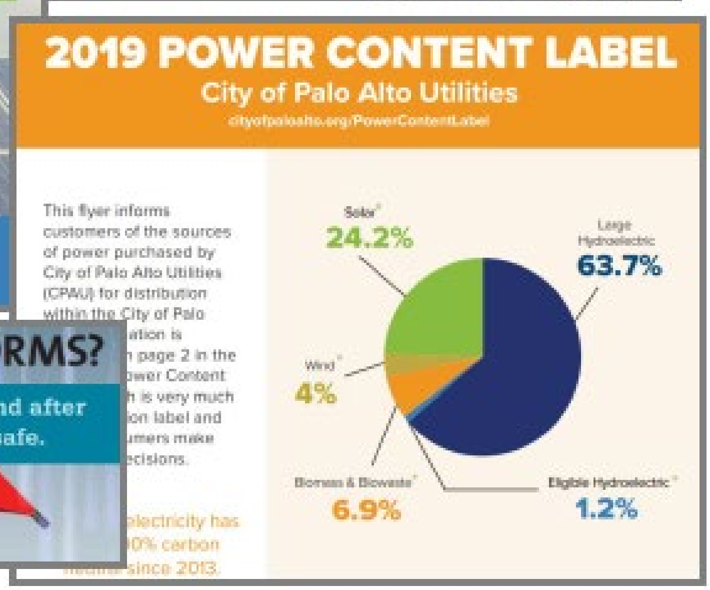
- monitoring the substations and performing routine maintenance;
- performing preventative maintenance on the system;
- monitoring the system's status from the UCC using SCADA;
- maintaining the SCADA system;
- investigating outages and other customer complaints and performing emergency repairs;
- clearing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

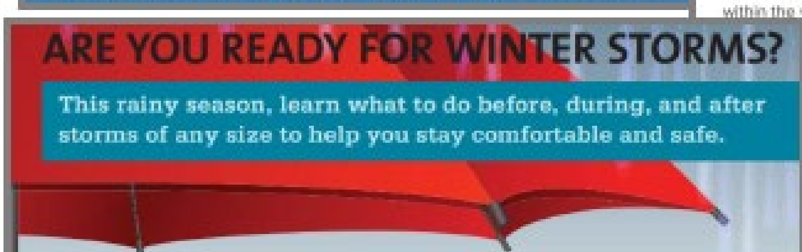
Administration: Accounting, purchasing, legal, and other administrative functions provided by the City's General Fund staff, as well as shared communications services, Utilities Department administrative overhead and billing system maintenance costs.

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





EXPORT ELECTRICITY COMPENSATION

UTILITY RATE SCHEDULE E-EEC-1

A. APPLICABILITY:

This Rate Schedule applies in conjunction with the otherwise applicable Rate Schedules for each Customer class. This Rate Schedule may not apply in conjunction with any time-of-use Rate Schedule. This Rate Schedule applies to Customer-Generators as defined in Rule and Regulation 2 who are either not eligible for Net Energy Metering or who are eligible for Net Energy metering but elect to take Service under this Rate Schedule.

B. TERRITORY:

~~Applies to locations within the service area of the City of Palo Alto.~~This Rate Schedule applies anywhere the City of Palo Alto provides Electric Service.

C. RATE:

The following buyback rate shall apply to all electricity exported to the grid.

	Per kWh
Export electricity compensation rate	$0.1078~~09~~

D. SPECIAL CONDITIONS

1. Metering equipment: Electricity delivered by CPAU to the Customer-Generator or received by CPAU from the Customer-Generator shall be measured using a Meter capable of registering the flow of electricity in two directions (aka "bidirectional meter"). The electrical power measurements will be used for billing the Customer-Generator. CPAU shall furnish, install and own the appropriate Meter.

2. Billing:
   a. CPAU shall measure during the billing period, in kilowatt-hours, the electricity delivered and received after the Customer-Generator serves its own instantaneous load.
   b. CPAU shall bill the Customer-Generator consumption charges for the electricity delivered by CPAU to the Customer-Generator based on the Customer-Generator's applicable Rate Schedule.
   c. In the event the electricity generated exceeds the electricity consumed and therefore is received by CPAU, the Customer will receive a credit for all electricity received by CPAU at the buyback Rate designated in section C above.

{End}

NET METERING NET SURPLUS ELECTRICITY COMPENSATION

UTILITY RATE SCHEDULE E-NSE-1

A. APPLICABILITY:

This Rate Schedule applies to eligible residential and small commercial Net Energy Metering Customers who, at the end of an annual settlement period, as described in Rule 29, are Net Surplus Customer-Generators of electricity who elect to receive monetary compensation as such preference is indicated on the net surplus electricity election form. This Rate Schedule only applies to Customers who participate in Net Energy Metering~~,~~ and does not apply to Customers that take Service under the City's Net Energy Metering Successor Rate, as each of these terms are defined in Rule and Regulation 2.

B. TERRITORY:

This Rate Schedule applies anywhere the City of Palo Alto provides Electric Service.

C. RATES:

	Per kWh
Net Surplus Electricity Compensation rate	$0.0992~~8771~~

D. SPECIAL CONDITIONS

1. Net Surplus Electricity Compensation Rate eligibility shall be determined as specified in Rule 29. Net surplus electricity, as specified in Rule 29, if applicable, will be multiplied by the above compensation rate to determine the Customer's annual net surplus electricity compensation stated in dollars.
2. Additional terms, conditions and definitions govern Net Energy Metering Service and Interconnection, as described in Rule 29.

{End}

RESIDENTIAL MASTER-METERED AND SMALL NON-RESIDENTIAL GREEN POWER ELECTRIC SERVICE

UTILITY RATE SCHEDULE E-2-G

A. APPLICABILITY:

This Rate Schedule applies to the following Customers receiving Electric Service from the City of Palo Alto Utilities under the Palo Alto Green Program:

1. Small non-residential Customers receiving Non-Demand Metered Electric Service; and
2. Customers with Accounts at Master-Metered multi-family facilities.

B. TERRITORY:

This rate schedule applies everywhere the City of Palo Alto provides Electric Service.

C. UNBUNDLED RATES:

1. 100% Renewable Option:

Per kilowatt-hour (kWh)	Commodity	Distribution	Public Benefits	Palo Alto Green Charge	Total
Summer Period	$0.11855	$0.08551	$0.00447	$0.006~~2~~0	$0.21453~~053~~
Winter Period	0.08502	0.05675	0.00447	0.006~~2~~0	$0.15224~~14824~~
Minimum Bill ($/day)					0.8359

2. 1000 kWh Block Purchase Option:

Per kilowatt-hour (kWh)	Commodity	Distribution	Public Benefits	Total
Summer Period	$0.11855	$0.08551	$0.00447	$0.20853
Winter Period	0.08502	0.05675	0.00447	0.14624
Minimum Bill ($/day)				0.8359
Palo Alto Green Charge (per 1000 kWh block)				$6~~2~~.00

D. SPECIAL NOTES:

1. Calculation of Cost Components

The actual bill amount is calculated based on the applicable rates in Section C above and adjusted for any applicable discounts, surcharges and/or taxes. On a Customer's bill statement, the bill amount may be broken down into appropriate components as calculated under Section C.

2. Seasonal Rate Changes

The Summer Period is effective May 1 to October 31 and the Winter Period is effective from November 1 to April 30. When the billing period includes use in both the Summer and Winter Periods, usage will be prorated based upon the number of days in each seasonal period, and the charges based on the applicable rates therein. For further discussion of bill calculation and proration, refer to Rule and Regulation 11.

3. Palo Alto Green Program Description and Participation

Palo Alto Green provides for either the purchase of enough renewable energy credits (RECs) to match 100% of the energy usage at the facility every month, or for the purchase of 1000 kilowatt-hour (kWh) blocks. These REC purchases support the production of renewable energy, increase the financial value of power from renewable sources, and create a transparent and sustainable market that encourages new development of wind and solar power.

Customers choosing to participate shall fill out a Palo Alto Green Power Program application provided by the Customer Service Center. Customers may request at any time, in writing, a change to the number of blocks they wish to purchase under the Palo Alto Green Program.

4. Maximum Demand Meter

Whenever the monthly use of energy has exceeded 8,000 kWh for three consecutive months, a maximum Demand Meter will be installed as promptly as is practicable and thereafter continued in service until the monthly use of energy has fallen below 6,000 kWh for twelve consecutive months, whereupon, at the option of the City, it may be removed.

The maximum Demand in any month will be the maximum average power in kilowatts taken during any 15-minute interval in the month, provided that if the Customer-s load is intermittent or subject to fluctuations, the City may use a 5-minute interval. A thermal-type Demand Meter which does not reset after a definite time interval may be used at the City's option.

The billing Demand to be used in computing charges under this schedule will be the actual maximum Demand in kilowatts for the current month. An exception is that the billing Demand for Customers with Thermal Energy Storage (TES) will be based upon the actual maximum Demand of such Customers between the hours of noon and 6 pm on weekdays.

{End}

MEDIUM NON-RESIDENTIAL GREEN POWER ELECTRIC SERVICE

UTILITY RATE SCHEDULE E-4-G

A. APPLICABILITY:

This Rate Schedule applies to Demand metered Secondary Electric Service for Customers with a maximum Demand below 1,000 kilowatts (kW) who receive power under the Palo Alto Green Program. This Rate Schedule applies to three-phase Electric Service and may include Service to Master-metered multi-family facilities or other facilities requiring Demand metered Service, as determined by the City.

B. TERRITORY:

The Rate Schedule applies everywhere the City of Palo Alto provides Electric Service.

C. UNBUNDLED RATES:

1. 100% Renewable Option:

	Commodity	Distribution	Public Benefits	Palo Alto Green Charge	Total
Summer Period					
Demand Charge (per kW)	$4.41	$24.50			$28.91
Energy Charge (per kWh)	0.10536	0.01865	0.00447	0.006~~2~~0	0.134~~0~~48
Winter Period					
Demand Charge (per kW)	$2.75	$16.22			$18.97
Energy Charge (per kWh)	0.07634	0.01865	0.00447	0.006~~2~~0	0.105~~1~~46
Minimum Bill ($/day)					17.2742

2. 1000 kWh Block Purchase Option:

	Commodity	Distribution	Public Benefits	Total
Summer Period				
Demand Charge (per kW)	$4.41	$24.50		$28.91
Energy Charge (per kWh)	0.10536	0.01865	0.00447	0.12848
Palo Alto Green Charge (per 1000 kWh block)				$~~2~~6.00
Winter Period				
Demand Charge (per kW)	$2.75	$16.22		$18.97
Energy Charge (per kWh)	0.07634	0.01865	0.00447	0.09946
Palo Alto Green Charge (per 1000 kWh block)				$~~2~~6.00
Minimum Bill ($/day)				17.2742

D. SPECIAL NOTES:

1. Calculation of Cost Components

The actual bill amount is calculated based on the applicable rates in Section C above and adjusted for any applicable discounts, surcharges, and/or taxes. On a Customer's bill statement, the bill amount may be broken down into appropriate components as calculated under Section C.

2. Seasonal Rate Changes

The Summer Period is effective May 1 to October 31 and the Winter Period is effective from November 1 to April 30. When the billing period includes use both in the Summer and the Winter Periods, the usage will be prorated based on the number of days in each seasonal period, and the charges based on the applicable rates therein. For further discussion of bill calculation and proration, refer to Rule and Regulation 11.

3. Maximum Demand Meter

Whenever the monthly use of energy has exceeded 8,000 kilowatt-hours for three consecutive months, a Maximum Demand Meter will be installed as promptly as is practicable and thereafter continued in Service until the monthly use of energy has dropped below 6,000 kilowatt-hours for twelve consecutive months, whereupon, at the option of the City, it may be removed.

The Maximum Demand in any month will be the maximum average power in kilowatts taken during any 15-minute interval in the month, provided that if the Customer's load is intermittent or subject to fluctuations, the City may use a 5-minute interval. A thermal-type Demand Meter, which does not reset after a definite time interval, may be used at the City's option.

The Billing Demand to be used in computing charges under this schedule will be the actual Maximum Demand in kilowatts for the current month. An exception is that the Billing Demand for Customers with Thermal Energy Storage (TES) will be based upon the actual Maximum Demand of such Customers between the hours of noon and 6 PM on weekdays.

4. Power Factor

For new or existing Customers whose Demand is expected to exceed or has exceeded 300 kilowatts for three consecutive months, the City has the option of installing applicable Metering to calculate a Power Factor. The City may remove such Metering from the Service of a Customer whose Demand has dropped below 200 kilowatts for four consecutive months.

When such Metering is installed, the monthly Electric bill will include a "Power Factor Adjustment", if applicable. The adjustment will be applied to a Customer's bill prior to the computation of any primary voltage discount. The Power Factor Adjustment is applied by increasing the total energy and Demand charges for any month by 0.25 percent or (1/4) for each one percent (1%) that the monthly Power Factor of the Customer's load was less than 95%.

The monthly Power Factor is the average Power Factor based on the ratio of kilowatt-hours to kilovolt-ampere hours consumed during the month. Where time-of-day Metering is installed, the monthly Power Factor shall be the Power Factor coincident with the Customer's Maximum Demand.

5. Changing Rate Schedules

Customers may request a rate schedule change at any time to any applicable full-service rate schedule as is applicable to their kilowatt-Demand and kilowatt-hour usage profile.

6. Palo Alto Green Program Description and Participation

Palo Alto Green provides for either the purchase of enough renewable energy credits (RECs) to match 100% of the energy usage at the facility every month, or for the purchase of 1000 kilowatt-hour (kWh) blocks. These REC purchases support the production of renewable energy, increase the financial value of power from renewal sources, and creates a transparent and sustainable market that encourages new development of wind and solar.

Customers choosing to participate shall fill out a Palo Alto Green Power Program application provided by the Customer Service Center. Customers may request at any time, in writing, a change to the number of blocks they wish to purchase under the Palo Alto Green Program.

7. Primary Voltage Discount

Where delivery is made at the same voltage as that of the line from which the Service is supplied, a discount of 2.5 percent for available line voltages above 2 kilovolts will be offered, but the City is not required to supply Service at a particular line voltage where it has, or will install, ample facilities for supplying at another voltage equally or better suited to the Customer's electrical requirements, as determined in the City's sole discretion. The City retains the right to change its line voltage at any time after providing reasonable advance notice to any Customer receiving the discount in this section. The Customer then has the option to change the system so as to receive Service at the new line voltage or to accept Service (without voltage discount) through transformers to be supplied by the City subject to a maximum kilovolt-ampere size limitation.

8. Standby Charge

a. Applicability: The standby charge, subject to the exemptions in subsection D(8)(e), applies to Customers that have a non-utility generation source interconnected on the Customer's side of the City's revenue Meter and that occasionally require backup power from the City due to non-operation of the non-utility generation source.

b. Standby Charges:

	Commodity	Distribution	Total
Standby Charge (per kW of Reserved Capacity)			
Summer Period	$0.69	$15.23	$15.92
Winter Period	$0.63	$9.04	$9.67

c. Meters: A separate Meter is required for each non-utility generation source.

d. Calculation of Maximum Demand Credit:

(1) In the event the Customer's Maximum Demand (as defined in Section D.3) occurs when one or more of the non-utility generators on the Customer's side of the City's revenue Meter are not operating, the Maximum Demand will be reduced by the sum of the Maximum Generation of those non-utility generators, but in no event shall the Customer's Maximum Demand be reduced below zero.

(2) If the non-utility generation source does not operate for an entire billing cycle, the standby charge does not apply and the Customer shall not receive the Maximum Demand credit described in this Section.

e. Exemptions:

(1) The standby charge shall not apply to backup generators designed to operate only in the event of an interruption in utility Service and which are not used to offset Customer electricity purchases.

(2) The standby charge shall not apply if the Customer meets the definition of an "Eligible Customer-generator" as defined in California Public Utilities Code Section 2827(b)(4), as amended.

(3) The applicability of these exemptions shall be determined at the discretion of the Utilities Director.

{End}

A. APPLICABILITY:

This Rate Schedule applies to Demand metered Service for large non-residential Customers who choose Service under the Palo Alto Green Program. A Customer may qualify for this Rate Schedule if the Customer's Maximum Demand is at least 1,000KW per month per site, who have sustained this Demand level at least 3 consecutive months during the last twelve months.

B. TERRITORY:

The Rate Schedule applies everywhere the City of Palo Alto provides Electric Service.

C. UNBUNDLED RATES:

1. 100% Renewable Option:

	Commodity	Distribution	Public Benefits	Palo Alto Green Charge	Total
Summer Period					
Demand Charge (per kW)	$5.03	$25.66			$30.69
Energy Charge (per kWh)	0.10932	0.00053	0.00447	0.006~~2~~0	0.~~11632~~12032
Winter Period					
Demand Charge (per kW)	$2.89	$14.16			$17.05
Energy Charge (per kWh)	0.07238	0.00053	0.00447	0.006~~2~~0	0.~~07938~~08338
Minimum Bill ($/day)					49.1139

2. 1000 kWh Block Purchase Option:

	Commodity	Distribution	Public Benefits	Total
Summer Period				
Demand Charge (per kW)	$5.03	$25.66		$30.69
Energy Charge (per kWh)	0.10932	0.00053	0.00447	0.11432
Palo Alto Green Charge (per 1000 kWh block)				$6~~2~~.00
Winter Period				
Demand Charge (per kW)	$2.89	$14.16		$17.05
Energy Charge (per kWh)	0.07238	0.00053	0.00447	0.07738
Palo Alto Green Charge (per 1000 kWh block)				$6~~2~~.00
Minimum Bill ($/day)				49.1139

D. SPECIAL NOTES:

1. Calculation of Charges

The actual bill amount is calculated based on the applicable rates in Section C above and adjusted for any applicable discounts, surcharges and/or taxes. On a Customer's bill statement, the bill amount may be broken down into appropriate components as calculated under Section C.

2. Seasonal Rate Changes

The Summer Period is effective May 1 to October 31 and the Winter Period is effective from November 1 to April 30. When the billing period includes use both in the Summer and the Winter Periods, the usage will be prorated based on the number of days in each seasonal period, and the charges based on the applicable rates therein. For further discussion of bill calculation and proration, refer to Rule and Regulation 11.

3. Maximum Demand Meter

Whenever the monthly use of energy has exceeded 8,000 kilowatt-hours for three consecutive months, a Maximum Demand Meter will be installed as promptly as is practicable and thereafter continued in Service until the monthly use of energy has dropped below 6,000 kilowatt-hours for twelve consecutive months, whereupon, at the option of the City, it may be removed.

The Maximum Demand in any month will be the maximum average power in kilowatts taken during any 15-minute interval in the month, provided that if the Customer's load is intermittent or subject to fluctuations, the City may use a 5-minute interval. A thermal-type Demand Meter which does not reset after a definite time interval may be used at the City's option.

The Billing Demand to be used in computing charges under this schedule will be the actual Maximum Demand in kilowatts for the current month. An exception is that the Billing Demand for Customers with Thermal Energy Storage (TES) will be based upon the actual Maximum Demand of such Customers between the hours of noon and 6 PM on weekdays.

4. Request for Service

Qualifying Customers may request Service under this schedule for more than one Account or one Meter if the Accounts are at one site. A site, for the purposes of this Rate Schedule, consists of one or more Accounts which cover contiguous parcels of land with no intervening public right-of-ways (e.g. streets) and which have a common billing address.

5. Power Factor

For new or existing Customers whose Demand is expected to exceed or has exceeded 300 kilowatts for three consecutive months, the City has the option of installing applicable Metering to calculate a Power Factor. The City may remove such Metering from the Service of a Customer whose Demand has dropped below 200 kilowatts for four consecutive months.

When such Metering is installed, the monthly Electric bill shall include a "Power Factor Adjustment", if applicable. The adjustment shall be applied to a Customer's bill prior to the computation of any primary voltage discount. The power factor adjustment is applied by increasing the total energy and Demand charges for any month by 0.25 percent or (1/4) for each one percent (1%) that the monthly Power Factor of the Customer's load was less than 95%.

The monthly Power Factor is the average Power Factor based on the ratio of kilowatt-hours to kilovolt-ampere hours consumed during the month. Where time-of-day Metering is installed, the monthly Power Factor shall be the Power Factor coincident with the Customer's Maximum Demand.

6. Changing Rate Schedules

Customers may request a rate schedule change at any time to any applicable full service rate schedule as is applicable to their kilowatt-Demand and kilowatt-hour usage profile

7. Palo Alto Green Program Description and Participation

Palo Alto Green provides for either the purchase of enough renewable energy credits (RECs) to match 100% of the energy usage at the facility every month, or for the purchase of 1000 kilowatt-hour (kWh) blocks. These REC purchases support the production of renewable energy, increase the financial value of power from renewal sources, and creates a transparent and sustainable market that encourages new development of wind and solar.

Customers choosing to participate shall fill out a Palo Alto Green Power Program application provided by the Customer Service Center. Customers may request at any time, in writing, a change to the number of blocks they wish to purchase under the Palo Alto Green Program.

8. Primary Voltage Discount

Where delivery is made at the same voltage as that of the line from which the Service is supplied, a discount of 2 1/2 percent for available line voltages above 2 kilovolts will be offered, but the City is not required to supply Service at a qualified line voltage where it has, or will install, ample facilities for supplying at another voltage equally or better suited to the Customer's Electrical requirements, as determined in the City's sole discretion. The City retains the right to change its line voltage at any time after providing reasonable advance notice to any Customer receiving the discount in this section. The Customer then has the option to change the system so as to receive Service at the new line voltage or to accept Service (without voltage discount) through transformers to be supplied by the City subject to a maximum kilovolt-ampere size limitation.

9. Standby Charge

a. Applicability: The standby charge, subject to the exemptions in subsection D(9)(e), applies to Customers that have a non-utility generation source interconnected on the Customer's side of the City's revenue Meter and that occasionally require backup power from the City due to non-operation of the non-utility generation source.

b. Standby Charges:

	Commodity	Distribution	Total
Standby Charge (per kW of Reserved Capacity)			
Summer Period	$0.84	$12.55	$13.39
Winter Period	$0.72	$6.04	$6.76

c. Meters: A separate Meter is required for each non-utility generation source.

d. Calculation of Maximum Demand Credit:

(1) In the event the Customer's Maximum Demand (as defined in Section D.3) occurs when one or more of the non-utility generators on the Customer's side of the City's revenue Meter are not operating, the Maximum Demand will be reduced by the sum of the Maximum Generation of those non-utility generators, but in no event shall the Customer's Maximum Demand be reduced below zero.

(2) If the non-utility generation source does not operate for an entire billing cycle, the standby charge does not apply and the Customer shall not receive the Maximum Demand credit described in this Section.

e. Exemptions:

(1) The standby charge shall not apply to backup generators designed to operate only in the event of an interruption in utility Service and which are not used to offset Customer electricity purchases.

(2) The standby charge shall not apply if the Customer meets the definition of an "Eligible Customer-generator" as defined in California Public Utilities Code Section 2827(b)(4), as amended.

(3) The applicability of these exemptions shall be determined at the discretion of the Utilities Director.

{End}