CITY OF PALO ALTO

UTILITIES ADVISORY COMMISSION
Regular Meeting
Wednesday, March 06, 2024
Council Chambers & Hybrid
6:00 PM

Utilities Advisory Commission meetings will be held as "hybrid" meetings with the option to attend by teleconference/video conference or in person. To maximize public safety while still maintaining transparency and public access, members of the public can choose to participate from home or attend in person. Information on how the public may observe and participate in the meeting is located at the end of the agenda. Masks are strongly encouraged if attending in person. The meeting will be broadcast on Cable TV Channel 26, live on YouTube https://www.youtube.com/c/cityofpaloalto, and streamed to Midpen Media Center https://midpenmedia.org.

VIRTUAL PARTICIPATION **CLICK HERE TO JOIN** (https://cityofpaloalto.zoom.us/j/96691297246)
Meeting ID: 966 9129 7246 Phone: 1(669)900-6833

PUBLIC COMMENTS
Public comments will be accepted both in person and via Zoom for up to three minutes or an amount of time determined by the Chair. All requests to speak will be taken until 5 minutes after the staff's presentation. Written public comments can be submitted in advance to UACPublicMeetings@CityofPaloAlto.org and will be provided to the Council and available for inspection on the City's website. Please clearly indicate which agenda item you are referencing in your subject line.

PowerPoints, videos, or other media to be presented during public comment are accepted only by email to UACPublicMeetings@CityofPaloAlto.org at least 24 hours prior to the meeting. Once received, the Clerk will have them shared at public comment for the specified item. To uphold strong cybersecurity management practices, USB's or other physical electronic storage devices are not accepted.

Signs and symbolic materials less than 2 feet by 3 feet are permitted provided that: (1) sticks, posts, poles or similar/other type of handle objects are strictly prohibited; (2) the items do not create a facility, fire, or safety hazard; and (3) persons with such items remain seated when displaying them and must not raise the items above shoulder level, obstruct the view or passage of other attendees, or otherwise disturb the business of the meeting.

TIME ESTIMATES
Listed times are estimates only and are subject to change at any time, including while the meeting is in progress. The Commission reserves the right to use more or less time on any item, to change the order of items and/or to continue items to another meeting. Particular items may be heard before or after the time estimated on the agenda. This may occur in order to best manage the time at a meeting to adapt to the participation of the public, or for any other reason intended to facilitate the meeting.

CALL TO ORDER 6:00 PM - 6:05 PM

AGENDA CHANGES, ADDITIONS AND DELETIONS 6:05 PM - 6:10 PM
The Chair or Board majority may modify the agenda order to improve meeting management.

PUBLIC COMMENT 6:10 PM - 6:25 PM
Members of the public may speak to any item NOT on the agenda.

APPROVAL OF MINUTES 6:25 PM - 6:30 PM

1. Approval of the Minutes of the Utilities Advisory Commission Meeting Held February 7th, 2024

UTILITIES DIRECTOR REPORT 6:30 PM - 6:45 PM

NEW BUSINESS (a 10 minute break will be imposed during this section)

2. Staff Recommends that the Utilities Advisory Commission Recommend that the City Council Approve Amended Palo Alto CLEAN Program Rules and Requirements, Handbook, and Power Purchase Agreement; CEQA Status: Not a Project under CEQA Guidelines Sections 15378(a) and (b) ***(ACTION** 6:45 PM – 7:15 PM)* Staff: Jim Stack, PhD

3. Staff Recommend the Utilities Advisory Commission Recommend that the City Council Adopt a Resolution: 1) Approving the FY 2025 Wastewater Collection Utility Financial Plan 2) Amending Rate Schedules S-1 (Residential Wastewater Collection and Disposal), S-2 (Commercial Wastewater Collection and Disposal), S-6 (Restaurant Wastewater Collection and Disposal) and S-7 (Commercial Wastewater Collection and Disposal – Industrial Discharger), and 3) Approving up to a $3 million enterprise transfer loan from the Fiber Optics Fund to the Wastewater Collection Utility's Operations Reserve in FY 2024. (***ACTION** 7:15 PM – 8:00 PM)* Staff: Lisa Bilir

4. Staff Recommends the Utilities Advisory Commission Recommend that the City Council Adopt a Resolution: 1) Approving the Fiscal Year (FY) 2025 Electric Financial Plan and Accepting the 2024 City of Palo Alto Electric Cost of Service and Rate Study, and 2) Amending E-1 (Residential Electric Service), E-2 (Residential Master-Metered and Small Non-Residential Electric Service), E-2-G (Residential Master-Metered and Small Non-Residential Green Power Electric Service), E-4 (Medium Non-Residential Electric Service), E-4-G (Medium Non-Residential Green Power Electric Service), E-4 TOU (Medium Non-Residential Time of Use Electric Service), E-7 (Large Non-Residential Electric Service), E-7-G (Large Non-Residential Green Power Electric Service), E-7 TOU (Large Non-Residential Time of Use Electric Service), E-NSE (Net Metering Net Surplus Electricity Compensation), and E-EEC (Export Electricity Compensation) ***(ACTION** 8:00 PM – 9:30*

PM) Staff: Jonathan Abendschein

5. Staff Recommend the Utilities Advisory Commission Recommend that the City Council Adopt a Resolution Approving the Fiscal Year 2025 Gas Utility Financial Plan, Including the General Fund Transfer, and Increasing Gas Rates by Amending Rate Schedules G-1 (Residential Gas Service), G-2 (Residential Master-Metered and Commercial Gas Service), G-3 (Large Commercial Gas Service), and G-10 (Compressed Natural Gas Service) *(**ACTION** 9:30 PM – 10:30 PM)* Staff: Lisa Bilir

6. Staff Recommends the Utilities Advisory Commission Recommend that City Council Adopt a Resolution Approving the Fiscal Year 2025 Water Utility Financial Plan, and Increase Water Rates by Amending Rate Schedules W-1 (General Residential Water Service), W-2 (Water Service From Fire Hydrants), W-3 (Fire Service Connections), W-4 (Residential Master-Metered and General Non-Residential Water Service), and W-7 (Non-Residential Irrigation Water Service) *(**ACTION** 10:30 PM – 11:15 PM)* Staff: Lisa Bilir

COMMISSIONER COMMENTS AND REPORTS FROM MEETINGS/EVENTS

FUTURE TOPICS FOR UPCOMMING MEETING: April 3, 2024

ADJOURNMENT

SUPPLEMENTAL INFORMATION

The materials below are provided for informational purposes, not for action or discussion during UAC Meetings (Govt. Code Section 54954.2(a)(3)).

INFORMATIONAL REPORTS

12-Month Rolling Calendar

Public Letter(s) to the UAC

PUBLIC COMMENT INSTRUCTIONS

Members of the Public may provide public comments to teleconference meetings via email, teleconference, or by phone.

1. **Written public comments** may be submitted by email to UACPublicMeetings@cityofpaloalto.org.
2. **Spoken public comments using a computer** will be accepted through the teleconference meeting. To address the Council, click on the link below to access a Zoom-based meeting. Please read the following instructions carefully.
   - You may download the Zoom client or connect to the meeting in- browser. If using your browser, make sure you are using a current, up-to-date browser: Chrome 30 , Firefox 27 , Microsoft Edge 12 , Safari 7 . Certain functionality may be disabled in older browsers including Internet Explorer.
   - You may be asked to enter an email address and name. We request that you identify yourself by name as this will be visible online and will be used to notify you that it is your turn to speak.
   - When you wish to speak on an Agenda Item, click on "raise hand." The Clerk will activate and unmute speakers in turn. Speakers will be notified shortly before they are called to speak.
   - When called, please limit your remarks to the time limit allotted. A timer will be shown on the computer to help keep track of your comments.
3. **Spoken public comments using a smart phone** will be accepted through the teleconference meeting. To address the Council, download the Zoom application onto your phone from the Apple App Store or Google Play Store and enter the Meeting ID below. Please follow the instructions B-E above.
4. **Spoken public comments using a phone** use the telephone number listed below. When you wish to speak on an agenda item hit *9 on your phone so we know that you wish to speak. You will be asked to provide your first and last name before addressing the Council. You will be advised how long you have to speak. When called please limit your remarks to the agenda item and time limit allotted.

CLICK HERE TO JOIN **Meeting ID: 966 9129 7246** **Phone:1-669-900-6833**

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CITY OF PALO ALTO

Utilities Advisory Commission
Staff Report

From: Dean Batchelor, Director Utilities
Lead Department: Utilities

Meeting Date: March 6, 2024
Staff Report: 2402-2660

TITLE
Approval of the Minutes of the Utilities Advisory Commission Meeting Held February 7th, 2024

RECOMMENDATION
Staff recommends that the UAC consider the following motion:

Commissioner ______ moved to approve the draft minutes of the February 7, 2024 meeting as submitted/amended.

Commissioner ______ seconded the motion.

ATTACHMENTS
Attachment A: 02-07-2024 Draft UAC Minutes

AUTHOR/TITLE:
Jenelle Kamian, Program Assistant I

UTILITIES ADVISORY COMMISSION MEETING
MINUTES OF FEBRUARY 7, 2024 REGULAR MEETING

CALL TO ORDER

Chair Segal called the meeting of the Utilities Advisory Commission (UAC) to order at 6:02 p.m.

Present: Chair Segal, Vice Chair Scharff, Commissioners Croft, Forssell, Mauter (attended remotely at 6:04 p.m.), Metz (attended remotely), and Phillips (arrived at 6:45 p.m.)

Absent:

AGENDA CHANGES, ADDITIONS AND DELETIONS

None

PUBLIC COMMENT

David Coale thanked Utilities for handling the outages very well during the last couple of storms. Barron Park was out twice for a short period and fixed sooner than the time predicted on the website. He appreciated the website containing a lot of information about the outages.

APPROVAL OF MINUTES

ITEM 1: ACTION: Approval of the Minutes of the Utilities Advisory Commission Meeting Held on January 3, 2024

Chair Segal invited comments on the January 3, 2024 UAC draft meeting minutes.

Packet Page 12, Page 7 of the document, Paragraph 1, Lines 5-6, Chair Segal requested to correct statement on water sales reductions as a “cost driver” to “reduction in revenue.”

On Packet Page 13, Paragraph 2, there was a discussion on wastewater rate increases and Mr. Batchelor stated that staff evaluated a 13% increase compared to the 9% proposal and staff could send it to the UAC after the meeting. Commissioner Forssell asked if staff sent the information. Utilities Director Dean Batchelor confirmed staff did not send it to the UAC but would do so. Commissioner Croft recalled a presentation to the Budget Subcommittee Meeting last week regarding the increase. Mr. Batchelor stated he presented a 15% increase.

ACTION: Commissioner Croft moved to approve the draft minutes of the January 3, 2024 meeting as amended.

Chair Segal seconded the motion.

The motion carried 4-0 with Chair Segal, Vice Chair Scharff, Commissioners Croft and Metz.

Commissioners Forssell and Mauter abstained.

Commissioner Phillips absent.

UTILITIES DIRECTOR REPORT

Utilities Director Dean Batchelor delivered the Director's Report

Recent Storm and Power Outage Update: Power outages occurred last weekend and today. The Bay Area experienced atmospheric river storm conditions last weekend. Approximately 161 customers in the Foothills lost power from Sunday evening until Monday at 2:50 p.m. caused by a large tree that came down over Page Mill where CPAU had a joint pole with PG&E. CPAU contacted PG&E but there was no response on Sunday evening. CPAU spoke with PG&E on Monday morning but PG&E could not provide an ETA. The City trimmed the tree and CPAU's lines were put back in place. On Sunday, all outages were tree related with no pole damage. The Outage Management System (OMS) sent 11,880 text messages notifying customers of an outage or providing updates. CPAU received 665 calls and 339 texts reporting an outage. Customers can update their contact information for power outage notifications in MyCPAU or call Utilities Customer Service at (650)-329-2161. Today's outage affected 4000 customers and two substations were offline. CPAU found large tree branches tangled within the 60 kV line (the backbone tying our substations together) and a line going into a substation. Tree trimmers cut and cleared the branches with no damage to the line. The OMS map falsely showed 13 or 14 customers out since Friday afternoon. CPAU was working on this issue with Milsoft, our OMS provider, because those 13 or 14 customers were tied to a transformer that was tied with one or two AMI meters that had bad sensors.

Water Supply Update: Recent storms had a positive impact on Regional Water System storage projections. While precipitation is less than long-term average, storage in the Hetch Hetchy system is above average due to last year's above-average precipitation. The City's water supplier, San Francisco Public Utilities Commission, will provide an update later this month on water supply conditions and rate projections and will release final numbers in April or May.

Hydroelectric Update: As of January 30, Northern California precipitation totals were about 23% below average for this time of year and about 49% below average in Central California. Reservoir levels were slightly higher than average due to last year's precipitation. The City's hydro resources were projected to produce around 108% of the long-term average level of output in FY 2024 and 100% in FY 2025.

Natural Gas Prices: Market prices for December 2023 and January 2024 were 64 cents and 43 cents per therm, respectively. Even with the cost of insurance at 5½ cent per therm, CPAU customers' natural gas costs have been very low this year. Prior to next winter, staff will present to Council a longer-term strategy for mitigating against potential gas price spikes. Staff will notify the UAC when they hear from the Feds or State about the outcome of the investigation into last year's high gas prices.

Upcoming Events: Go to cityofpaloalto.org/workshops for details and registration for upcoming events.

- Thursday, February 8 from 5 to 6 p.m.: Save Money on an EV Now
- Sunday, February 25 from 11 to noon: Lunar New Year Community Event
- Sunday, March 10 from 10 a.m. to 1 p.m.: Is an Electric Car Right for You?

The first item on the City Council's meeting agenda for Monday, February 12 is a study session about resiliency and the strategic plan presented to the UAC last month. Commissioners can attend in person or by Zoom and provide comments if desired.

Chair Segal queried if tree inspections were included in the pole inspections for fiber and grid modernization. Mr. Batchelor replied that trees were trimmed if they were too close to the lines. Public Works called Urban Forest if a tree needed to be removed or was starting to decay.

Strategic Business Manager Dave Yuan addressed Chair Segal's question regarding faulty sensors in AMI meters. Of the 13 customers showing a false outage, four customers had wiring on their side of the system causing errors. Of the 4500 installed electric meters, two were faulty.

NEW BUSINESS

ITEM 2: DISCUSSION: Discussion of the Supervisory Control and Data Acquisition Cyber Security Update

Director of Information Technology Darren Numoto stated their goal was to put systems in place to monitor, detect and react quickly to prevent major issues. Over the last couple years, they focused on shoring up internal infrastructures, processes and procedures. IT received information on common threats from CISA, a federally funded agency. Staff was in discussions with CISA to come on site to evaluate our cybersecurity posture for IT and Supervisory Control and Data Acquisition (SCADA) systems to identify gaps in our policies, procedures and technology.

About 60 percent of email worldwide was spam. Staff received data security awareness training annually. Senior IT staff with elevated privileges will receive specialized training. Many applications were in the cloud, which posed a security challenge because the City does not own or control the infrastructure. Business impact and vendor information security were assessed during the procurement process to ensure companies were prepared to prevent, react and notify us in a timely manner of any security issues. Last year, the City implemented an IT risk assessment program to evaluate solutions, applications and networks.

SCADA was behind the City's infrastructure, one layer removed from direct access to the internet. SCADA information was air-gapped from the network by protocols such as multifactor authentication, VPN services and DMZ infrastructure. Utilities did not have regular meetings with the Cybersecurity Red Team during the pandemic but meetings will resume this year on a quarterly basis. In the event of a SCADA system fault or cyberattack, the SCADA network would operate on manual mode with staff on site to control power. Planned perimeter security enhancements include surveillance outside substations and SCADA device upgrades.

Staff worked with vendors to ensure AMI met our standards of data center security. Security measures include DMZ, VPN, firewalls, OS hardening and patching, multifactor authentication for remote access and role-based access meaning only authorized staff has access to infrastructure.

Some Cities in the Bay Area had ransomware attacks with access gained to their system via a user with elevated access. Multifactor authentication and monitoring could prevent some attacks. We have controls and solutions to understand anomalies and we implement best practices. If an authentication request comes from a different location than the user, the request is alerted and blocked. Technologies on City laptops and mobile devices provide protection even when not on the City's network or VPN.

The City's onsite servers are in an airgap network and do not have internet access. We cannot put some services in the cloud, such as legacy systems. Microsoft's cloud hosts our Microsoft infrastructure. AWS hosts our ERP system. There is a monthly service charge for cloud usage.

Mr. Numoto addressed Commissioner Metz's question regarding meters, sensors and controllers preloaded with software. Those fall under Critical Assets in the hierarchy structure. There is an inventory of assets and their versions. Staff receives alerts about firmware and software vulnerabilities and updates. Utility System Technician Raymond Chin, Sr. remarked that vendors send emails when there are firmware updates. SCADA devices in the field do not connect to the internet and are air-gapped, which makes it difficult to compromise.

Commissioner Forssell queried if the City hired an outside firm for penetration testing. Mr. Numoto replied yes, we contracted with CISA to come onsite for four days of investigation in our network and provided a lot of great information. There were no major findings. We needed to patch some systems or plug some holes. It was an external and internal penetration scan but CISA did not scan our SCADA networks because they were air-gapped. CISA will perform a more in-depth overview of our SCADA networks toward the end of the year. City staff was tested biannually with phishing emails and provided more training if they clicked on them.

Chair Segal opined that training was too infrequent. She recommended informing the entire staff if an employee failed a phishing test as a training mechanism to increase awareness, although not identifying the employee. Mr. Numoto stated the City on-boarded a new platform for security training and phishing and there were plans to increase the frequency of tests, possibly on an ongoing basis throughout the year. Microsoft blocks malicious sites and links by default. IT receives immediate notifications if a user clicks on something malicious. All outbound connections are monitored. CISA and other vendors detect traffic destined to known threat actors.

Backups occur multiple times a day. This year, IT will shore up our Disaster Recovery (DR) plans. Recovery time for critical systems is within 48-72 hours, SCADA within 48 hours.

In response to Chair Segal's query regarding physical security and the planned perimeter security enhancements, Mr. Chin replied they are in the beginning of construction. Some substations are installing lights and security cameras. Mr. Numoto remarked there would be a fence around the Colorado Substation. Mr. Batchelor added that Colorado would have 15-foot blast-proof, bulletproof walls but there was no time estimate for construction.

ACTION: None

ITEM 3: DISCUSSION: <u>Discussion of the Residential Electric and Water Utility Customer Satisfaction Survey Results</u>

Utilities Communications Manager Catherine Elvert delivered a slide presentation. The California Municipal Utilities Association (CMUA) contracts with GreatBlue Research, Inc. (GreatBlue) to conduct surveys of municipal and investor-owned utility customers. GreatBlue conducted a statewide survey of residential electric and water utility customers in fall 2023. CPAU opted to also have GreatBlue conduct an “oversample” survey of Palo Alto residents to gain greater insight into issues important to Palo Alto residents and also compare results to statewide and national survey responses. The random sample groups were different for the electric and water surveys. Statewide, approximately 1,200 customers were surveyed for each electric and water utility. For the oversample, 400 CPAU customers were surveyed in September and October 2023. Surveys were digital and had a 95% confidence level with a 4.8% +/- margin of error. There were 57 questions for water, 64 questions for electric.

Commissioner Phillips wanted to see historical data for comparison. Ms. Elvert replied that CPAU has conducted customer surveys for decades, so there is historical data to compare results to. CMUA recently contracted with a new vendor in the past two years to perform customer surveys. The new vendor attempted but was unable to gain all historical data from the previous survey vendor, but we have some questions and answers to compare, and will be able to close these gaps moving forward.

For the electric customer satisfaction surveys, CPAU received very high marks with ratings significantly higher than Northern California and statewide for average positive organizational characteristic rating, trust, meeting customer expectations and customer service ratings. CPAU’s Net Positive Score of 82.1% was higher than the national average of customers who considered themselves loyal and satisfied. Nearly 80% reported CPAU met their expectations all or most of the time. About 25% believe CPAU was prepared to handle an emergency, which was less than Northern California and statewide.

Channels of communication in order of preference were automated text messages, emails and automated phone calls. Customers prefer to communicate with CPAU via phone call, in-person visit and email. Customers prefer to receive information from CPAU through text, email and website. Respondents in the older age demographic preferred communication through traditional paper methods, such as bill inserts. Younger demographics preferred digital communication. Chair Segal pointed out that surveys were done digitally, which could bias the responses.

At least 25% of customers in each age group reported they own an electric vehicle (EV), about 22 percentage points higher than the statewide average response. Customers aged 55-64 had the highest rate of EV ownership. At least 40% of customers in each age group were likely to purchase an EV. Respondents not interested in purchasing an EV listed barriers of long charge time, limited distance range per charge, higher initial cost to purchase, low availability of charging stations and low availability of EV options. Chair Segal wondered if those concerns differed by age group. Ms. Elvert will review the data and follow up with a response to Chair Segal.

About two-thirds of customers indicated they strongly or somewhat support CPAU investing in electrification with over one-third in all age groups strongly in support of these investments. Nearly one-half reported they were aware of CPAU’s program for residents to switch from gas water heaters to electric heat pump water heaters. Age had a positive correlation with awareness with customers significantly more aware as age increased. Over one-half were considering the purchase of an electrification product, more considering a heat pump water heater, followed by heat pump HVAC system, followed by induction stoves.

A chart was shown comparing organizational characteristic ratings for CPAU, Northern California, statewide and nationwide. CPAU’s ratings were higher than Northern California, statewide and nationwide for 10 out of 11 characteristics.

Vice Chair Scharff noted the intriguing difference between CPAU receiving a high rating for providing reliable electric service, but a low rating for maintaining modern and reliable infrastructure. Ms. Elvert said the consultant's interpretation is that perhaps CPAU needs to communicate more about what we are doing to keep our infrastructure up to date. Mr. Batchelor believed the low rating was due to recent power outages.

Vice Chair Scharff asked if Alameda, Santa Clara and Roseville's surveys were available to compare with CPAU. Ms. Elvert replied that not all NCPA members participated in the survey. We can compare CPAU's results to the NCPA member average but we might be able to obtain data by a specific member utility.

Commissioner Phillips pointed out that if respondents were rating CPAU low because of outages, the rating would be low for "providing consistent and reliable electric service to customers" but it was rated the highest. Mr. Batchelor said that CPAU frequently restores power much more quickly compared to other utilities like PG&E, citing the recent storm and power outages throughout the Bay Area as a perfect example. Some PG&E customers are still without power following the storm on Sunday, yet all customers in Palo Alto had power restored within a couple hours. Commissioner Phillips suggested adding a question at the end of the survey asking if respondents had experienced an outage in the last two months and if so, were they satisfied with CPAU's response.

Chair Segal opined the low rating on maintaining modern and reliable infrastructure was due to Palo Alto's high Tesla penetration, high interest in electrification and many remodels causing customers to pay to upgrade their panel to have enough power in their home.

Commissioner Croft thought people might envision a modern system as underground instead of seeing wires above ground. Many customers have a big line going through their backyard, which does not look modern. Commissioner Forssell noted the local press recently ran stories about grid modernization and people thought CPAU was on an undergrounding schedule but we are not.

Ms. Elvert continued her electric survey presentation. Two-thirds of CPAU's respondents (slightly higher than the statewide average) indicated their electric rates were very reasonable or somewhat reasonable. Respondents who had a recent customer service interaction provided higher ratings for three out of four characteristics regarding the CPAU representative they spoke with compared to customers in Northern California and statewide. CPAU respondents reported a significantly higher average positive rating for the customer service representative they spoke with being polite and courteous, higher than Northern California and statewide. An average of 71% of CPAU's respondents provided positive ratings. The top reasons customers contacted CPAU were to report an outage, discuss a high bill or ask a question on a bill.

The consultant recommended tailoring our messaging to different age demographics. Younger customers believe electrification saves them money on their electric bills and has an environmental benefit. An electrification program might get better uptake if promoted during times of higher average energy consumption and we demonstrate a correlation between energy and cost savings. The consultant also recommended that CPAU consider implementing an off-peak EV charging rate in conjunction with

Customers were more interested in installing a Level 2 charger if it resulted in less electrical infrastructure upgrades at their home, thus being less costly. Over four-fifths were likely to charge their EV during off-peak hours. The consultant recommended that CPAU consider implementing an off-peak

EV charging rate in conjunction with Level 2 home charger installation. Commissioner Forssell asked how off-peak hours were defined in this survey. Ms. Elvert stated she would get back to Commissioner Forssell with the specific time period included with the question. There was discussion about peak versus off-peak hours and what CPAU might include in a potential time-of-use (TOU) rate. Strategic Business Manager Dave Yuan clarified that CPAU's peak hours are between 4pm to 9pm, and that CPAU is exploring offering TOU rates for residential and commercial customers as part of the Advanced Metering Infrastructure (AMI) project.

Ms. Elvert presented the results from the water customer survey. CPAU ratings from water utility customers were higher than electric survey results. The Net Positive Score for water was 87.4%. Over one-quarter of customers reported being an advocate or loyal customer of CPAU. The highest ratings were for maintaining an adequate supply of water, which was higher than Northern California and statewide. About 81% reported satisfaction with their most recent customer service experience. 85% indicated CPAU met their expectations all or most of the time. Nearly one-half of customers indicated they try hard to use less water but could probably do a little more. Nearly two-fifths indicated they were doing everything they possibly can to use less water. Renters more often than homeowners indicated they try not to waste water but often do not focus too much on the amount of water they use. The top reasons for customers contacting CPAU were for a billing question, high bill or consumption, general maintenance, water leak or broken pipe. Customers preferred contacting CPAU via traditional methods but preferred to receive information from CPAU digitally.

CPAU's average positive organizational characteristic rating was about 79%, significantly higher than Northern California and statewide. The top three characteristics included monitoring water quality, maintaining an adequate supply of water, and providing good service and value for the cost of water. Over four-fifths reported the Utility met their expectations all or most of the time. Customers who had a recent customer service interaction indicated the representative was courteous and treated them with respect. Over one-half of customers indicated CPAU's customer service was among the best or above average compared to other service providers such as banks, telephone, cable company or other utilities.

Over two-fifths were familiar with the WaterSmart home report, landscape rebate program and landscape workshops but fewer customers were familiar with the Project PLEDGE utility bill assistance program. More homeowners than renters were familiar with the Home Efficiency Genie. About 89% of customers acknowledged that CPAU provided them with data or a report on how much water their household used in the prior bill period. Over two-thirds indicated they would find "materials on specific ways to reduce their household's water use at no cost to you" useful.

Recommendations based on survey results included elevating and optimizing our online presence as well as ensuring our website is user friendly, mobile responsive, and provides seamless access to critical information, important updates, educational content and avenues for customer feedback and inquiries. It is important to target our outreach to all customer groups including renters who expressed desire to participate in a program or use water more efficiently but may not know how to do so.

Chair Segal pointed out that about 20% of Palo Alto residents were over 65 years old and was worried those customers were not reflected in this survey because it was digital.

Commissioner Croft noted on both surveys that two-thirds thought the Utility was open and honest. She wondered what the other one-third of respondents thought and what they didn't believe they were getting enough information on, such as utility rates or infrastructure. Ms. Elvert stated that CPAU works hard to provide as much information as possible on these important subjects to customers across a variety of communication channels and is always looking for ways to improve upon our outreach. Ms. Elvert speculated that CPAU can do more to talk about our utility rates, operations, and maintaining and upgrading our infrastructure. Commissioner Croft suggested having FAQs on our website.

Regarding Slide 7, Vice Mayor Lauing wondered how many first-time buyers were in the 47% planning to purchase an EV. Ms. Elvert replied she would get back to Vice Mayor Lauing with the answer but recalled the consultant stated that people who own an EV might not be as inclined to purchase another EV in the near future.

Vice Mayor Lauing said Council should see these survey results and asked if staff could attach an information packet to a Council report or present a more condensed version in a short study session.

ACTION: None

The UAC took a break at 7:50 p.m. and returned at 8:01 p.m.

ITEM 4: DISCUSSION: Discussion of Electric Grid Modernization Plan

Utilities Director Dean Batchelor explained why our outages were typically large. The system configuration did not have many switches. When a fault occurs, it shuts down the substation. There are usually 4000-5000 customers on a substation. Depending on the time of day, CPAU patrols the fault location, turns on some switches and usually turns the substation back up quickly. We need to upgrade the system so outages only affect customers located at the fault instead of the entire substation. As we rebuild this portion of the system, capacity will increase for electrification loads. Now, the system can only handle adding small loads such as heat pump water heaters. As we develop fiber and put in the fiber backbone, we can buy new transformers and switches where you can run a piece fiber to control that equipment to clear faults more quickly.

Chair Segal asked if customers in underground areas were responsible from the street to their box. Mr. Batchelor explained that if the transformer was not loaded and you wanted to add an EV charger or heat pump water heater, CPAU was responsible for the wires from the transformer into the secondary box. Customers were responsible for conduit for wires from the secondary box to the side of their home.

Mr. Batchelor addressed Vice Chair Scharff's question about the difference in service fees for 200 and 400 amps. When you put in 400-amp service, the wire size changes and you may overload the transformer size. An estimator provides an evaluation and you need engineering drawings to determine what is needed to feed the 400-amp service. For 200-amp service, you can use a smaller wire in the conduit or to the transformer. From June/July to the end of the year, 66 customers wanted 400-amp service, usually because they wanted to electrify and the 200-amp panel in their home was unable to handle it. CPAU charged on average $3200-$3700 for the estimate, drawings and wire increase. The estimate does not include the cost to install the panel because CPAU does not have on-site electricians. In addition, the customer has to pay tens of thousands of dollars if a transformer upgrade is necessary.

CPAU's strategic projects: Upgrade infrastructure to larger transformers and larger cable in the secondary side where the customer is connected. Integrate new technology. Complete residential AMI installation by the end of this year. Have better fault indicators in underground areas to identify direction of a fault. Have remote switching and fuse savers. Customer technologies such as solar battery backup and heat pump water heaters.

The fiber to the premise (FTTP) goal is to upgrade and expand the existing fiber backbone. Depending on pilot results, staff will request authorization from Council to offer fiber to all homes and businesses.

System upgrades: We are upgrading the 4 kV lines installed in 1967 to 12 kV. Upgrade 4 of 30 substation transformers. Upgrade 1741 of 3000 distribution system transformers from a minimum of 25 kV to 50 kV. Upgrade 56 miles of secondary and 17 miles of primary distribution lines. Phase 1 system upgrades affects about 6800 customers. Pilot area for fiber and electric grid modernization includes 1224 customers. Of 409 poles, 87 need replacement because they cannot take the weight of 50 kV transformers. There will be eight customers on each 50 kV transformer. Approximately 1400 single-phase pole-top transformers need to be replaced with a 50 kV or larger transformer.

For the underground secondary system, staff could not find any companies building submergible transformers. We need to remove all underground transformers and make them pad-mounted 75 kV or larger transformers. There will be 12 customers per pad-mounted transformer. Bases for pad-mounted transformer were too big to fit in the median strips or in between the curb and gutter. The City had easements rights in customers' front yards. Strategic Business Manager Dave Yuan remarked there were 261 pad-mount transformers and 231 underground. We will move all 231 underground transformers above ground. In addition, we have to add 83 transformers above ground to meet capacity loads.

Commissioner Croft asked if the curb could be extended into the street because she thought residents would rather have a reduction in parking than have a transformer on their yard. Mr. Batchelor replied that staff could evaluate that option as well as putting it on a side yard, put something over the top to camouflage it or bushes around it.

ENTRUST is an electrical contractor helping CPAU with design. Magellan is the fiber contractor. Soudi performed the initial study to determine what we needed. MP Nexlevel, Hot Line and VIP are contractors working on the lines and fiber. The City retained MP Next Level and VIP for electric work to put in substructure on the secondary side. VIP does underground and overhead work.

Staff had to determine the funding source for an estimated $200-$300 million. In addition to bond issuance, CIP funds will offset costs.

Proposed timeline: Fall 2024, pilot area complete for fiber and grid modernization. Summer 2025, Phase 1 complete. Depending on the uptick and take rates for fiber in the pilot area, staff will obtain approval from Council if there is enough interest before moving forward with fiber, although poles would be made ready for fiber in Phase 1. All phases will be complete by winter of 2030, although we may need the help of additional contractors.

Mr. Yuan addressed Chair Segal's question regarding bonds. Revenue bonds do not require a vote but do need Council approval. Staff will ask Council for $50 million increments for each phase. Bond funding has to be spent within three years. The plan is to issue bonds over the next seven years.

Public Comment: Hamilton Hitchings asked how much of the $220-$306 million was for fiber and if there would be separate bonds for electrical and fiber. Utility has a monopoly on electricity and a guaranteed revenue stream, so you can calculate the payback based on the number of electric customers whereas for fiber it depends on take rate because customers can choose CPAU, AT&T or Comcast. Mr. Hitchings suggested continuing overhead but undergrounding the main trunk to improve system reliability. Undergrounding along and across major arteries (El Camino, University, San Antonio, Embarcadero, Page Mill and Middlefield) was important to avoid blocking traffic if there was a major earthquake or big storm. Mr. Hitchings is in the process of electrifying his home and thought about a 400 kV panel but he used the City-provided calculator and decided on 200 kV. He recently saved about $6000 with the Heat Pump Water Heater Program and highly recommended the program to other customers.

Regarding Packet Page 69, Slide 13, Commissioner Metz asked about the plan to integrate AMI and other customer technology such as EVs and storage as well as how those technologies affect the distribution grid design for residential and commercial. Mr. Batchelor replied that AMI allows customers to look at their usage in 15-minute intervals and Utilities can ping AMI meters to pinpoint the location of an outage, thereby reducing the time of restoration and patrolling. A couple of substations are not fully loaded. Mr. Batchelor spoke to Engineering and Operations to see if it was possible to change the feeder configurations. We have eight substations but we can go down to six. To allow us better reliability, the remaining two substations can be filled with batteries for storage and tied into the grid. Depending on the amount of battery storage in a substation footprint, it can be used for outages or other times as needed. New technologies for heat pump water heaters, furnaces, induction stoves and one charger will be close to a 6 kV load.

Mr. Batchelor responded to Mr. Hitchings' question. The $200-$300 million estimate did not include dollars allocated for the fiber fund. Staff had authorization to use the fiber reserve. The pilot area does not spend all the reserve monies. Staff did not want to spend 100% of the fiber reserve. If costs exceed reserves, we need to issue a bond. Mr. Yuan remarked that the total cost for the backbone and the FTTP network is $140 million. Commissioner Phillips commented there was approximately $35 million in the fund. Mr. Batchelor stated we needed to bond approximately $100 million.

In reply to Commissioner Phillips inquiring if staff expected to learn anything from the fiber pilot that may affect the cost or if the pilot was primarily focused on the fiber take rate, Mr. Batchelor stated they were also looking at grid modernization and what could be done with fiber in the pilot area.

Mr. Batchelor addressed Commissioner Forssell's request for more information on V2X listed among the technologies on Packet Page 62. Our system is a one-way feed. Our capabilities do not allow vehicle to grid. Rebuilding the system will allow vehicle to home but there needs to be a switch to stop you from feeding back into the grid because it is a safety issue if you are in an outage when you put power into the grid when everybody thinks it is in the off position. Similarly, off switches for solar were needed so it does not feed back into the system.

Commissioner Forssell asked if the grid modernization project could support thousands of new housing units expected in Palo Alto over the next several years, assuming they are all-electric and net-zero energy. Mr. Batchelor replied that they would consider the transformer size needed in areas of future development during the design phase and use bigger wire for the secondary side, the feed line. There is plenty of power in the main line and we can buy more power if needed.

Chair Segal inquired if the City should change its approach of waiting to order equipment to avoid supply chain delays. Mr. Batchelor explained that in the past it was City rules to buy through a third party. Not buying direct pushed us further back in line to buy equipment. Staff proved we could get better pricing by buying directly. Our timeframe has shortened because we will buy bulk from the manufacturer directly as Tesla did with their transformers. We will buy bulk wire. We are trying to standardize the size of transformers by putting 50s in the substations, 50s in the overhead sections and 75s in the underground sections; currently, a couple of substations have 15s and another has 25. Standardizing transformer size and connectors helps with reordering, tools, splicing and making connections.

Commissioner Forssell noted the map on Packet Page 64 differed from the map in the presentation. Mr. Yuan responded that the map in the packet was correct and the most up-to-date version whereas the map in the presentation was an older version. The design work was completed for the pilot, so the red section was not moving but the blue sections could move. Underground work was not included in the first phase because construction would slow down the project.

ACTION: None

COMMISSIONER COMMENTS and REPORTS from MEETINGS/EVENTS

Commissioner Croft reported the Budget Subcommittee met to review the fiber business plan and wastewater rates. Commissioner Croft thought there was support for higher wastewater rates and rebuilding the reserve.

On January 25, Commissioner Metz participated in the Heat Pump Water Heater Program status update. There were over 160 installs with about 270 pending, which is about 12% to 20% of all water heaters per year. Program challenges included lead generation and getting customers to advance. There was a strong multimedia promotional effort. Outreach to participants revealed very positive feedback with the majority of customers happy with their installation. Cost and urgency were two reasons people cited for not going forward. Staff is developing an emergency replacement program that will launch by June.

FUTURE TOPICS FOR UPCOMING MEETINGS

Commissioner Forssell noted the CLEAN program was of interest to the UAC but it was going to Council before the UAC had an opportunity to talk about it. Mr. Yuan explained it was a one-year process from the time you apply for the CLEAN program until you complete your solar panels but for the Housing Authority it took a lot longer. Staff was adding a rule for future housing that met minimum housing rules could have up to three years to join the CLEAN program. CPAU hoped the new rule would encourage new housing development to join the CLEAN program because some capacity remained in the first tier, although there will be lower capacity after the first tier. Commissioner Forssell asked how much capacity was left at the attractive rate. Mr. Yuan did not know. He stated it was a question for Jonathan and staff would get back to Commissioner Forssell with the response.

Commissioner Metz saw in the Commission packet a resident comment regarding lead in water piping, indicating CPAU was required to have an inventory of water piping materials by October. Commissioner Metz queried if the UAC needed a meeting to discuss this topic. Mr. Batchelor confirmed we do have an October mandate. In the August/September timeframe, staff planned to present a status update to the UAC and the plan to replace lead services if any lead was found.

NEXT SCHEDULED MEETING: March 6, 2024

ADJOURNMENT

Commissioner Forssell moved to adjourn.

Commissioner Scharff seconded the motion.

The motion carried 7-0 with Chair Segal, Vice Chair Scharff, Commissioners Croft, Forssell, Mauter, Metz, and Phillips.

Meeting adjourned at 9:15 p.m.

Respectfully Submitted
Jenelle Kamian
City of Palo Alto Utilities

CITY OF PALO ALTO

Utilities Advisory Commission
Staff Report

From: Dean Batchelor, Director Utilities
Lead Department: Utilities

Meeting Date: March 6, 2024
Staff Report: 2403-2707

TITLE

Staff Recommends that the Utilities Advisory Commission Recommend that the City Council Approve Amended Palo Alto CLEAN Program Rules and Requirements, Handbook, and Power Purchase Agreement; CEQA Status: Not a Project under CEQA Guidelines Sections 15378(a) and (b)

RECOMMENDATION

Staff recommends that the Utilities Advisory Commission recommend that the City Council:

1. Approve the attached amended Clean Local Energy Accessible Now (CLEAN) Program Eligibility Rules and Regulations (Attachment A) as follows:
   a. Continue the CLEAN Program rate structure for local solar energy resources at 16.5 cents per kilowatt-hour (¢/kWh) until the program reaches 3 MW of solar energy resource capacity, after which the contract rate for solar energy resources reduces to the City's estimated avoided cost of energy generated by these resources, which is updated to:
      i. 9.5 ¢/kWh for a 15-Year Contract Term,
      ii. 9.8 ¢/kWh for a 20-Year Contract Term, and
      iii. 10.2 ¢/kWh for a 25-Year Contract Term; and
   b. Continue the CLEAN Program rate structure for local non-solar eligible renewable resources without any participation cap at a contract price equal to the City's estimated avoided cost of energy generated by these resources, which is updated to:
      i. 9.4 ¢/kWh for a 15-Year Contract Term,
      ii. 9.8 ¢/kWh for a 20-Year Contract Term, and
      iii. 10.1 ¢/kWh for a 25-Year Contract Term.

2. Approve the attached amended CLEAN Program Handbook (Attachment B) to extend the allowable time to complete a project to three years from the date of execution of the Power Purchase Agreement (PPA) for affordable housing developments.

3. Approve the attached amended Palo Alto CLEAN Program Eligible Renewable Energy Resource PPA (Attachment C) to implement the recommended changes to the CLEAN

Program.

EXECUTIVE SUMMARY

The Palo Alto CLEAN program, established in March 2012, aimed to encourage local generation of solar energy by allowing property owners to install solar systems and sell energy to the City under a fixed-rate, long-term contract. Initially priced at 14 ¢/kWh for a 20-year term, the program failed to attract interest. In December 2012, the Council increased the contract price to 16.5 ¢/kWh, which has been maintained since. Despite no applications in the first four years, since 2016 the program has enrolled six currently operating solar projects totaling 2.84 MW of capacity.

Currently, a customer planning an affordable housing development wishes to submit a CLEAN solar project application but requires an extension of the completion deadline from one to three years to align with permitting and construction timelines for housing projects in Palo Alto. This modification, while maintaining the same initial rate and program capacity, would have minimal financial impact on the City. Staff supports the request and has proposed changes to the program rules and contract designed to accommodate the customer's needs as well as the needs of future residential construction developments that satisfy the basic affordable housing requirements. Council action will also update the avoided costs for CLEAN projects and make conforming changes in the City's CLEAN Power Purchase Agreement.

BACKGROUND

In March 2012 the Council adopted the Palo Alto CLEAN program (also commonly referred to as a feed-in tariff, or FIT, program). The program was designed to address the City's objective of enhancing supply reliability through the pursuit of local generation opportunities. Palo Alto CLEAN enabled property owners to build a new solar system on their property and sell the energy to CPAU under a long-term, fixed-rate, standardized contract rather than simply using the energy on-site.

Though solar developers expressed interest in Palo Alto CLEAN in 2012, the initial contract price (14 ¢/kWh for a 20-year term) proved insufficient to attract any program applications. Council increased the Palo Alto CLEAN price to 16.5 ¢/kWh in December 2012, and has maintained it at that level ever since (last reaffirming it in May 2017). In May 2015, Council added a 25-year contract term option, and expanded the program to include non-solar eligible renewable energy resources, setting their contract prices at the avoided cost level. In May 2017, Council added a 15-year contract term option and updated the avoided cost rates. After receiving zero applications in its first four years, since 2016, the CLEAN program has executed contracts for six solar projects that account for about 2.84 MW of capacity.

ANALYSIS

Staff has recently discussed the program structure with a customer who is working on a residential development that consists of 100% affordable housing units and who intends to submit an application for a CLEAN solar project that would consume a significant portion of the remaining 160 kW of solar program capacity available at the 16.5 ¢/kWh rate. In order for this solar project to go forward, the customer requested that the CLEAN program rules be modified to extend the project completion deadline to align with the City's permitting and construction timeline for housing developments, from the current one-year timeline up to three years.

Making this modification for the CLEAN program – while maintaining the same contract rate and program capacity available at this rate – would have virtually no financial impact on the City. As such, staff supports the customer's request, and the proposed program changes are designed to accommodate that request. Council action will also update the avoided costs for CLEAN projects for the first time since 2017. This change would result in no financial impact to the City.

FISCAL/RESOURCE IMPACT

The following table summarizes staff's estimates of the current cost of buying energy from solar resources outside of Palo Alto (including transmission and capacity) over a 15-year, 20-year, or 25-year term, as well as the annual excess costs of purchasing the output from an additional 160 kW of local solar projects at a contract price of 16.5 ¢/kWh over those terms. (For non-solar renewable energy projects, and for solar capacity that exceeds the 3 MW program cap on the 16.5 ¢/kWh contract rate the excess cost is zero, because the contract rate is set based on the City's avoided cost for the energy.)

Contract Term	Contract Rate	Avoided Cost	Annual Excess Cost
15 years	16.5 ¢/kWh	9.5 ¢/kWh	$24,500
20 years		9.8 ¢/kWh	$23,500
25 years		10.2 ¢/kWh	$22,000

STAKEHOLDER ENGAGEMENT

In considering the proposal to extend the completion deadline for certain projects in the CLEAN Program, staff has had multiple conversations with the customer who requested this modification about the impact it would have on their affordable housing development as well as the future residents of this development. Utilities staff also consulted with Planning and Development Services staff with regard to the City's affordable housing standards and the typical timeline for completion of new residential housing developments.

ENVIRONMENTAL REVIEW

Adoption of the attached resolution and the associated amendment of the CLEAN Program Eligibility Rules and Requirements and Power Purchase Agreement is not subject to California Environmental Quality Act (CEQA) review these are administrative government activities that will not result in any direct or indirect physical change to the environment as a result (CEQA Guidelines section 15378(b)(5)). Eligible customer projects are subject to CEQA analysis on a project-level basis through the City's development permitting process.

ATTACHMENTS

Attachment A: Palo Alto CLEAN Program Rules & Requirements (redline)
Attachment B: Palo Alto CLEAN Program Handbook (redline)
Attachment C: Palo Alto CLEAN Program Power Purchase Agreement (redline)

AUTHOR/TITLE:
Dean Batchelor, Director of Utilities
Staff: James Stack, Ph.D., Senior Resource Planner

A. PARTICIPATION ELIGIBILITY:

The Palo Alto Clean Local Energy Accessible Now Program (the "CLEAN Program") is open to participation by any Eligible Renewable Energy Resource, as defined in Section D.4, that satisfies these Program Eligibility Rules and Requirements.

B. TERRITORIALITY REQUIREMENT:

In order to be eligible to participate in the CLEAN Program, an Eligible Renewable Energy Resource must be located in and generating electricity from within the utility service area of the City of Palo Alto.

C. PRICES AND TERM FOR ELIGIBLE RENEWABLE RESOURCES:

The following purchase prices shall apply to the electricity produced by an Eligible Renewable Energy Resource participating in the Program, except as provided in Section D.5.

Solar Energy Resources:

Total Solar Capacity Reserved	Contract Term	Contract Price
0-3 MW	15, 20 or 25 years	$0.165 / kWh
More than 3 MW	15 years	$0.~~088~~095 / kWh
More than 3 MW	20 years	$0.~~089~~098 / kWh
More than 3 MW	25 years	$0.~~091~~102 / kWh

For Solar Energy Resources that straddle ~~multiple pricing tiers~~more than one capacity tier, the purchase price shall ~~receive~~be a weighted~~-~~ average ~~purchase price~~of the above values based on the amount of their capacity that is contained in each tier.

Non-Solar Eligible Renewable Energy Resources:

Contract Term	Contract Price
15 years	$0.~~083~~094 / kWh
20 years	$0.~~084~~098 / kWh
25 years	$0.~~085~~101 / kWh

D. ADDITIONAL RULES AND REQUIREMENTS:

1. The owner of the Eligible Renewable Energy Resource shall enter into an Eligible Renewable Energy Resource Power Purchase Agreement ("PPA") with the City of Palo Alto prior to delivering energy to the City.

2. An application for participation in the CLEAN Program to sell output to the City (the

"Application") may be submitted at any time. Applications will be considered in the order received.

3. Eligible Renewable Energy Resource means an electric generating facility that: (a) is defined and qualifies as an "eligible renewable energy resource" under California Public Utilities Code Section 399.12(e) and California Public Resources Code Section 25471, respectively, as amended; and (b) meets the territoriality requirement set forth in Section B.

4. The California Energy Commission's ("CEC") certification of the Eligible Renewable Energy Resource shall be required within six (6) months of the commercial operation date of the generating facility; the facility's owner shall provide written notice of the CEC's certification to the City within ten (10) business days of receipt of said certification. If the City agrees, in its sole discretion, to take delivery of the generating facility's electricity prior to the CEC's certification, then, as the facility's electricity cannot be considered in fulfillment of the City's RPS requirements, the price that the City will pay for the generating facility's electricity (the "Pre-Certification Price") will be set to $0.072 per kWh (for a 15-year contract term), $0.076 per kWh (for a 20-year contract term~~)~~), or $0.08 per kWh (for a 25-year contract term), based on the City's estimated levelized cost of ~~brown~~generic power over a 15-year, 20-year, or 25-year period, respectively. Upon the CEC's certification of the generating facility and the provision of notice of such certification to the City in accordance with this section, the City will pay the Price set forth in Section C of these CLEAN Program Rules and Requirements and the PPA (collectively referred to as the "Contract Price") for the generating facility's electricity delivered on and after the date of the CEC's certification. The City will, in its sole discretion, "true-up", as appropriate, the difference between the Contract Price and the Pre-Certification Price for any electricity received and paid for by the City, effective as of the date of certification of the Eligible Renewable Energy Resource.

5. If an Eligible Renewable Energy Resource is authorized to participate in the CLEAN Program, then that Resource shall not be entitled to receive any rebate or other incentive from the City's Photovoltaic (PV) Partners Program or any other similar incentive program funded by the City's ratepayers. To the extent any rebate or incentive is paid to the owner of the Resource, that rebate or incentive shall be disgorged and refunded to the City upon 30 days' notice, if the Eligible Renewable Energy Resource continues to participate in the CLEAN Program. If a rebate or an incentive has been paid to the Eligible Renewable Energy Resource, then that Resource shall be ineligible to participate in the CLEAN Program.

6. All electricity generated by the Eligible Renewable Energy Resource shall be delivered only to the City. No portion of the electricity may be used to offset any load of the generating facility (other than incidental loads associated with operating the generating facility).

7. A metering and administration fee will be charged to each Eligible Renewable Energy Resource that participates in the CLEAN Program. See Utilities Rate Schedule E-15 (Electric Service Connection Fees).

PALO ALTO CLEAN

CLEAN LOCAL ENERGY ACCESSIBLE NOW

PROGRAM HANDBOOK

City of Palo Alto Utilities
~~May 9, 2017~~
March 2024

Questions about Palo Alto CLEAN?

Contact:

Palo Alto CLEAN Program Manager

Ph: 650-329-2241

Email: PACLEAN@cityofpaloalto.org

City of Palo Alto Utilities
250 Hamilton Ave, 3rd Floor
Palo Alto, CA 94301

Table of Contents

Program Overview

Palo Alto CLEAN (Clean Local Energy Accessible Now) is a program to purchase electricity generated by eligible renewable energy resources located in City of Palo Alto Utilities (CPAU) service territory, which coincides with the Palo Alto city boundaries. The power is separately metered and delivered wholesale to CPAU, and it is then used to fulfill CPAU’s renewable goals. Programs like this are also known as "feed-in tariff" programs in reference to the fact that the power is "fed into" the electric grid. None of the power is used to offset the host customer’s load, in contrast to a net metering program.

The program was adopted in March 2012, and was revised in January 2013, February 2014, May 2015, March 2016, February 2017, ~~and~~ May 2017, and March 2024. CPAU is currently offering to purchase the output from renewable energy generation facilities according to the rates in the following table.

Resource Description	Contract Term	Contract Rate
Solar resources, up to 3 MW total	15, 20, or 25 years	16.5 ¢/kWh
Solar resources, greater than 3 MW total	15 years	~~8.8~~9.5 ¢/kWh
	20 years	9.8~~.9~~ ¢/kWh
	25 years	~~9.1~~10.2 ¢/kWh
Non-solar resources	15 years	~~8.3~~9.4 ¢/kWh
	20 years	9.8~~.4~~ ¢/kWh
	25 years	~~8.5~~10.1 ¢/kWh

As shown in the table, there is no total program cap on the capacity participating in the program; there is only a cap on the solar capacity that can receive the 16.5 ¢/kWh contract rate.

CPAU staff will review and re-evaluate the program status, terms, and contract rates with the Palo Alto City Council ~~and Utilities Advisory Commission on an approximately annual~~on a regular basis.

Summary of Program Rules

- CPAU will sign power purchase agreements (PPAs) for the output of eligible renewable energy generation facilities.

- There is no total program capacity limit.

- Each PPA will entitle CPAU to the entire output of the generating facility, including all energy, renewable energy credits (RECs), and capacity attributes, if any.

- The energy from the generating facility must be delivered to CPAU. No part of the energy may be used to serve the customer load on the host site or any other customer load.

- Generating facilities must be located in the CPAU service territory (which corresponds to the Palo Alto city limits).

- Generating facilities required by the California Independent System Operator (CAISO) to participate in ISO markets (typically those facilities larger than 1 MW) are subject to additional scheduling and forecasting requirements.

- There are no limitations on how many generating facilities any single developer or customer may develop.

- Developers are responsible for obtaining CEC Certification. RECs from the project will be created and tracked in the Western Renewable Energy Generation Information System (WREGIS). CPAU will register each generator under the CPAU WREGIS account and will be responsible for uploading meter data.

- Project developers may not seek other CPAU ratepayer~~ – ~~-funded rebates for the generating facility. Any facility that has already received a rebate is not eligible for the program.

Timeline of a Palo Alto CLEAN Project

The chart below shows how you can expect your Palo Alto CLEAN project to progress:

Site Identification	Identify a site for your project.
Site Control	Obtain site control for the entire term of the PPA.
Preliminary Design	Develop a preliminary design for the project.
Application Submittal	Submit an application. Applications are accepted in the order received. Pay reservation deposit within ten days.
Permit Submittal	Prepare your project for Building Permit and Interconnection Submittal. Your permit application will be accepted at the City's Development Center and routed to our Electric Engineering Division for interconnection review.
Permit Review	The Development Center and Electric Engineering Division will return initial comments. At this time, if the interconnection will require no significant review or costs, the Electric Engineering Division will send an interconnection agreement for your signature. If additional interconnection review is required, an Advance Engineering Fee may be required.
Interconnection Agreement	Upon receipt of the Interconnection Agreement you will be required to submit a deposit for any interconnection costs. At this time you may terminate your PPA instead of submitting the deposit and proceeding with interconnection. If you exercise this option your full reservation deposit will be returned, but not any permit review fees.
Project Construction	Following Building Permit issuance and signature of the Interconnection Agreement the applicant can proceed with project construction. At some point prior to completing construction CPAU recommends you apply for pre-certification of the project with the California Energy Commission (CEC) to ensure the entire output of the project is certified as eligible to fulfill Renewable Portfolio Standard (RPS) requirements starting on the Commercial Operation Date. Uncertified energy is not eligible for the full contract price. CPAU will commence registration of the project with WREGIS during this time.
Commercial Operation	Upon final building inspection CPAU will send a letter memorializing the commercial operation date. At this

point CPAU will return your total reservation deposit or any smaller portion of the deposit you are eligible to receive. CPAU will begin sending payments for energy produced, but the payments will be made at the pre-certification rate until the CEC certifies the project as eligible to fulfill RPS requirements.

Development of Palo Alto CLEAN Projects

1.0 Site Identification and Control

1.1 Types of Projects Accepted

All projects must be eligible renewable energy resources. There are no limitations on the type of solar technology used to receive the contract price for solar resources. The eligible renewable energy generating facility may be located anywhere in Palo Alto city limits so long as it complies with all City codes and generator interconnection requirements. Ground mounted, rooftop mounted, or carport solar projects are acceptable, but CPAU recommends you investigate the codes and requirements applicable to your site prior to submitting an application.

1.2 Proof of Site Control

Evidence of site control for the entire term of the contract is required in order to submit an application. CPAU requires documentation showing ownership of, a leasehold interest in, or a right to develop property upon which the Generating Facility will be located for the entire term of the contract being requested, or an option to acquire such ownership, leasehold interest, or right to develop.

2.0 Application Process

2.1 Submittal Process

Applications will only be accepted by e-mail, and must be sent to PACLEAN@cityofpaloalto.org**.** Applications will be considered in the order received.

2.2 Where and When to Submit

The application is considered "submitted" on the date and time CPAU has received all required documents in Section 2.3, below, with the exception of the reservation deposit, which must be paid within ten business days following application submittal. See Section 2.4, below, for instructions on how to submit a reservation deposit. If the deposit is not received by the end of the tenth business day, the application will be rejected. Please note that the maximum attachment size accepted by the City's e-mail system is 20 MB. To ensure your application is accepted, we recommend sending attachments no larger than 10 MB. If it is necessary to send multiple e-mails to send all of the application materials, please note that fact in your first e-mail. The time and date of the first e-mail will be considered the time and date your application was submitted so long as all application materials are received within two hours of that e-mail.

CPAU will notify applicants of their application's status by e-mail within five business days, and will mail a copy of the executed PPA within ten business days of receipt of the reservation deposit (see Section 2.4, below).

2.3 Submittal Requirements

All of the following items are required before an application will be considered "submitted," with the exception of the reservation deposit, which must be paid within ten business days of the submittal date of the application:

- Applicant, system owner, and site owner contact information.
- Description of the generating system
- Preliminary single-line diagram
- Preliminary site diagram showing the project site and layout
- Two signed copies of the Palo Alto CLEAN standard Power Purchase Agreement
- Proof of site control (see 1.2, above)
- Two signed copies of the WREGIS Assignment of Registration Rights Agreement (see 4.3, below)
- Federal Internal Revenue Service Form W-9
- Reservation deposit (see 2.4, below)

2.4 Reservation Deposit

The reservation deposit must be paid within ten business days of application submittal. The preferred method for submitting a reservation deposit is a certificate of deposit payable to the City of Palo Alto, but submitting a payment by check or wire transfer is also acceptable.

- **Check:** Checks should be made out to the City of Palo Alto and may be submitted by mail to:

  City of Palo Alto, Attn: PA CLEAN
  Utilities RMD, 3rd Floor
  250 Hamilton Ave
  Palo Alto, CA 94301

  or in person at the Revenue Collections Desk in the lobby of the Civic Center at 250 Hamilton Ave, Palo Alto, CA during normal business hours.

- **Wire Transfer:** To submit by wire transfer, send notification of the payment to both PACLEAN@cityofpaloalto.org and TreasuryNotice2@cityofpaloalto.org. The City's wire transfer information is as follows:

  Bank Name: Wells Fargo Bank, N.A.
  Bank Routing (RTN/ABA) Number: 121 000 248
  Account Number: 412 107 6145
  Beneficiary Account Name: City of Palo Alto
  Type of Account: Checking
  Bank Address, City, State:
  420 Montgomery Street, San Francisco, CA 94104
  Federal Tax ID #: 94 6000 389
  For International Transfer Only:
  International SWIFT BIC WFBIUS6S

The deposit will be returned:

- If, for whatever reason, CPAU is unable to accept the application.
- Upon early termination of the PPA by the applicant prior to Commercial Operation Date, subject to the rules regarding such early termination in Section 7.0 of the PPA.
- Upon the commercial operation date of the project, subject to the rules regarding timely completion of the project in Section 7.0 of the PPA.

2.5 Determining Priority

Applications are accepted in the order received based on the date and time stamp of the e-mailed application received by the City at paclean@cityofpaloalto.org. In the event multiple applications are received simultaneously, all will be assigned an application number and precedence will be established by the use of the random number generator at random.org, or another publicly verifiable random number generator in the event random.org is not available.

For the purpose of determining whether applications were received simultaneously, applications will be considered received based on the date and time stamp on the e-mail. If multiple copies of the same application are received, the time stamp on the first e-mail received will be used. The time stamp on the City's e-mail system shows the hour, minute, and second the e-mail was received.

3.0 Permitting

3.1 Time to Complete Project

Applicants have one year from the execution date of the PPA to achieve Commercial Operation for the proposed project~~.~~, or three years from the PPA execution date if the project site is a new residential construction development that satisfies the basic affordable housing requirement for residential ownership projects under Palo Alto Municipal Code section 16.65.030. If Commercial Operation is achieved after that time, the amount of the Reservation Deposit returned is reduced for each full week the project is delayed (see Section 5.1 and Section 7.0 of the PPA). If Commercial Operation has not been achieved by ten weeks after the applicable deadline to complete the project~~one year plus ten weeks after the execution date of the PPA~~, CPAU retains the option to terminate the PPA.

3.2 Permit Submittal

Applicants apply for a building permit and interconnection agreement at the City's Development Center. The Building Division manages the routing of applications for review by all necessary departments. Consult the City's Building Division with questions about building permit requirements and the project review process. The Division maintains pre-submittal and inspection checklists that detail the City's code requirements. Visit the City's website (http://www.cityofpaloalto.org/gov/depts/ds/default.asp) for the most recent versions of these checklists.

The City's Planning Division typically does not review rooftop solar projects, but if a project will involve landscape changes or carport or ground mounted solar systems, the applicant should consult the Planning Division to understand the code requirements applicable to the proposed project site.

3.3 Interconnection Review

Upon receipt of a project application routed from the City's Building Division, the Electric Engineering Division will review the project to determine whether it qualifies for simplified review or whether supplemental review or an interconnection study is required. If the project qualifies for simplified review the Electric Engineering Division will send the applicant an Interconnection Agreement for signature.

If the project does not qualify, the applicant must pay an Advance Engineering Fee for additional evaluation work. Once the additional review is complete the Electric

Engineering Division will send the applicant an Interconnection Agreement with an estimate of any additional interconnection costs. Upon receiving the interconnection agreement the applicant may either 1) execute and return the interconnection agreement along with payment for any additional estimated interconnection costs, or 2) notify CPAU in writing that the applicant is terminating the agreement. If this notification is received within 30 calendar days of the day CPAU notifies the applicant of the interconnection costs, the reservation deposit will be returned in full per Section 7.0 of the PPA. No portion of the building permit fees or Advance Engineering Fees will be returned.

See Utility Rule and Regulation 27 (Generator Interconnection) for more detail on the interconnection process.

4.0 Construction

4.1 Building Inspection

Consult the City's Building Division with questions about the building inspection process. The Division maintains inspection checklists that detail the City's code requirements. If there are any interconnection facilities to be constructed CPAU will build those facilities during the construction process. Once construction is completed and actual costs are known, CPAU will issue a final invoice for the interconnection facilities. CPAU may require the applicant to make an additional payment to the extent actual costs differ from the estimated costs.

4.2 CEC Pre-Certification

CPAU recommends that the applicant apply for pre-certification of the project from the California Energy Commission (CEC) at some point prior to Commercial Operation. Once the generating facility is completed the applicant must apply for CEC certification (see Section 5.2, below), and pre-certification ensures that certification will begin on the Commercial Operation Date, meaning that all energy output will be certified as eligible to fulfill Renewable Portfolio Standard (RPS) requirements. Per Section 2.4 of the PPA, CPAU will pay for any energy not certified by the CEC at the "Pre-Certification Price" rather than the contract price. See form CEC-RPS-1 published by the CEC for instructions on how to apply.

4.3 WREGIS Registration

During the construction process CPAU will begin registration of the project in WREGIS (the Western Renewable Energy Generation Information System). The system owner is required to assign to CPAU the right to register the project in WREGIS when submitting an application to the Palo Alto CLEAN program. This will enable CPAU to receive Renewable Energy Credits (RECs) from the system directly in its WREGIS account rather than having to execute a transfer of RECs each month. CPAU will be responsible for uploading the meter data to WREGIS each month to enable creation of the RECs.

5.0 Commercial Operation

5.1 Meter Set and Commercial Operation Date

The Commercial Operation Date for the generator is the date of the final building inspection by the City's Building Division. Prior to that CPAU's Electric Meter Shop will set a revenue meter that will be used for billing. Following the final inspection CPAU will send the applicant a letter memorializing the Commercial Operation Date, and the applicant must return a signed copy to CPAU. This letter is required before CPAU can complete WREGIS registration (see Section 4.3 above). WREGIS registration is a prerequisite for CEC Certification (see Section 5.2 below). At this time CPAU will return the entire reservation deposit or any portion of that deposit that the applicant is entitled to under Section 7.0 of the PPA.

5.2 CEC Certification

Within six months following the Commercial Operation Date the applicant is required to have the system certified by the California Energy Commission as eligible to fulfill Renewable Portfolio Standard (RPS) requirements. CPAU will pay for the output of the system at the pre-certification price until this certification is granted (see Section 2.4 of the PPA).

Typically CEC Certification is retroactive to the Commercial Operation Date if 1) the applicant has obtained CEC Pre-Certification for the project (see Section 4.2 above) or 2) the applicant has submitted an application for CEC Certification prior to the commercial operation date. If CPAU receives energy prior to certification and pays for it at the Pre-Certification Price, and that energy is later certified by the CEC as eligible to fulfill RPS requirements, CPAU will issue a true-up equal to the difference between the Pre-Certification Price and the Contract Price upon CEC certification.

See also Sections 2.4 and 3.1 of the PPA, as well as form CEC-RPS-1 published by the CEC.

5.3 Metering and Payment

Payment for the project output will be made monthly by check based on a City-provided revenue meter. The applicant will be responsible for the cost associated with the meter's telemetry system.

Additional Resources

Palo Alto CLEAN program website
https://www.cityofpaloalto.org/Departments/Utilities/Business/Ways-to-Save/CLEAN

City of Palo Alto Utilities Electric Engineering and Operations
https://www.cityofpaloalto.org/Departments/Utilities/Utilities-Services-Safety/Engineering-and-Operations

City of Palo Alto Utilities Rule and Regulation 27 (Generator Interconnection)
https://www.cityofpaloalto.org/civicax/filebank/blobdload.aspx?BlobID=28741

City of Palo Alto Utilities Electric Standard Drawings
https://www.cityofpaloalto.org/Departments/Utilities/Utilities-Services-Safety/Engineering-and-Operations/Electric-Service-Requirements

City of Palo Alto Development Services
http://www.cityofpaloalto.org/gov/depts/ds/default.asp

California Energy Commission Renewables Portfolio Standard Handbook and Generator Certification Application Forms
https://www.energy.ca.gov/programs-and-topics/programs/renewables-portfolio-standard/renewables-portfolio-standard-0

Western Renewable Energy Generation Information System (WREGIS)
https://www.wecc.org/WREGIS/Pages/Default.aspx

POWER PURCHASE AGREEMENT
ELIGIBLE RENEWABLE ENERGY RESOURCE
(Palo Alto Clean Local Energy Accessible Now Program)

This Power Purchase Agreement - Eligible Renewable Energy Resource, dated, for convenience, _________________(the "Effective Date"), is entered into by and between the CITY OF PALO ALTO, a California chartered municipal corporation, and____, a________________corporation (individually, a "Party" and, collectively, the "Parties").

RECITALS

1. The Buyer has adopted and implemented its CLEAN Program, which allows an owner of a qualifying electric generation system to sell to the Buyer the power output of a small-scale distributed generation Eligible Renewable Energy Resource, subject to the CLEAN Program's rules and requirements.

2. The Seller owns or operates and desires to interconnect its Facility in parallel with Buyer's Distribution System and sell the Energy produced by its Facility, net of Station Service Load, directly to the Buyer in furtherance of the CLEAN Program.

3. The Parties do not intend this Agreement to constitute an agreement by the Buyer to provide retail electrical service to the Seller.

4. The Parties wish to enter into a power purchase agreement for the sale and purchase of the Output of the Facility. The Parties will enter into a separate "Interconnection Agreement" in connection with this Agreement.

NOW THEREFORE, in consideration of the foregoing recitals and the following covenants, terms and conditions, the Parties agree, as follows:

AGREEMENT

1.1 DEFINITIONS

The initially capitalized terms, whenever used in this Agreement, have the meanings set forth below, unless they are otherwise herein defined. The terms "include," "includes," and "including," when used in this Agreement, shall mean, respectively, "include, without limitation," "includes, without limitation" and "including, without limitation."

"Affordable Housing Development" means a new residential construction development that satisfies the basic affordable housing requirement for residential ownership projects under Palo Alto Municipal Code section 16.65.030.

"**Agreement**" means this Power Purchase Agreement – Eligible Renewable Energy Resource between the Buyer and the Seller.

"**Business Day**" means any day except a Saturday, Sunday, or a day that the City observes as a regular holiday under Palo Alto Municipal Code section 2.08.100(a).

"**Buyer**" refers to the City of Palo Alto, California, with a principal place of business at 250 Hamilton Avenue, Palo Alto, California 94301.

"**Buyer's Distribution System**" means the wires, transformers, and related equipment used by the Buyer to deliver electric power to the Buyer's retail customers, typically at sub-transmission level voltages or lower.

"**CAISO**" means the California Independent System Operator Corporation, or successor entity.

"**CAISO Tariff**" means the CAISO FERC Electric Tariff, as amended.

"**Capacity**" means the ability of a generator at any given time to produce Energy at a specified rate, as measured in megawatts ("MW") or kilowatts ("kW"), and any reporting rights associated with it.

"**Capacity Attributes**" means any current or future defined characteristic, certificate, tag, credit, or ancillary service attribute, whether general in nature or specific as to the location or any other attribute of the Facility, intended to value any aspect of the Contract Capacity of the Facility to produce Energy or ancillary services, including contributions towards Resource Adequacy (including those requirements defined in Section 40 of the CAISO Tariff) or reserve requirements (if any), and any other reliability or power attributes.

"**CEC**" means the California Energy Resources Conservation and Development Commission, or successor agency.

"Certificate of RPS Eligibility" means a certificate issued by the CEC as evidence of RPS Certification of the Facility.

"City" means the government of the City of Palo Alto, California.

"**CLEAN Program**" refers to the Palo Alto Clean Local Energy Accessible Now Program, a renewable energy program established by the City by adoption of resolution number________, dated_______, of the Palo Alto City Council, whereby the Buyer will purchase from the Seller the Output of Eligible Renewable Energy Resources that meet specified criteria set forth in the City's applicable ordinances and resolutions.

"**Commercial Operation**" means the period of operation of the Facility, once the Commercial Operation Date has occurred.

"**Commercial Operation Date**" means the date specified in the Commercial Operation Date Confirmation Letter, which the Parties execute and exchange in accordance with this Agreement.

"**Contract Capacity**" means the installed electrical Capacity available upon the Commercial Operation Date of the Facility in an amount, as specified in Exhibit "PPA-A." "Contract Capacity" is measured at the Buyer's revenue meter at the Delivery Point and is net of any Station Service Loads, any applicable Facility step-up transformer losses, and distribution losses on Buyer's Distribution System up to the Delivery Point.

"**Contract Price**" means the price paid by the Buyer to the Seller for the Output generated at the Facility and received by the Buyer, as set forth in Exhibit "PPA-A."

"CPUC" means the California Public Utilities Commission, or successor agency.

"**Delivery Point**" means the point of interconnection to Buyer's Distribution System, where the Buyer accepts title to the Output.

"**Delivery Term**" has the meaning set forth in Section 14.2 hereof.

"**Eligible Renewable Energy Resource**" means an electric generating facility that is defined and qualified as an "eligible renewable energy resource" under California Public Utilities Code Section 399.12(e) and California Public Resources Code Section 25471, respectively, as amended.

"**Energy**" means electrical energy generated from the Facility and delivered to Buyer's Distribution System with the voltage and quality required by the Buyer, and measured in megawatt-hours ("MWh") or kilowatt-hours ("kWh"), as metered at the Delivery Point.

"**Facility**" means the qualifying renewable energy generation equipment and associated power conditioning and interconnection equipment that deliver the Output to the Buyer at the Delivery Point.

"**FERC**" means the Federal Energy Regulatory Commission, or successor agency.

"**Forced Outage**" means an unplanned outage of one or more of the Facility's components that results in a reduction of the ability of the Facility to produce Capacity.

"**Force Majeure**" means an event or circumstance, which prevents a Party from performing its obligations under this Agreement, and which is not in the reasonable control of, or the result of negligence of, the Party claiming Force Majeure, and which by the exercise of due diligence is unable to overcome or cause to be avoided. "Force Majeure" shall include: (a) An act of nature, riot, insurrection, war, explosion, labor dispute, fire, flood, earthquake, storm, lightning, tidal wave, backwater caused by flood, act of the public enemy, terrorism, or epidemic; (b) Interruption of transmission or generation services as a result of a physical emergency condition (and not congestion-related or economic curtailment) not caused by the fault or negligence of the Party claiming Force Majeure and reasonably relied upon and without a reasonable source of substitution to make or receive deliveries hereunder, civil disturbances, strike, labor disturbances, labor or material shortage, national emergency, restraint by court order or other public authority or governmental agency, actions taken to limit the extent of disturbances on the electrical grid; or (c) Other similar causes beyond the control of the Party affected, which causes such Party could not have avoided by the exercise of due diligence and reasonable care. A Party's financial incapacity, the Seller's ability to sell the Output at a more favorable price or under more favorable conditions, or the Buyer's ability to acquire the Output at a more favorable price or under more favorable conditions or other economic reasons shall not constitute an event of Force Majeure. "Force Majeure" does not include a Forced Outage to the extent such event is not caused or exacerbated by an event of Force Majeure, as described above, and does not include the Seller's inability to obtain financing, permits, or other equipment and instruments necessary to plan for, construct, or operate the Facility.

"**Good Utility Practice**" means those practices, methods and acts that would be implemented and followed by prudent operators of electric energy generating facilities in the western United States, similar to the Facility, during the relevant time period, which practices, methods and acts, in the exercise of prudent and responsible professional judgment in the light of the facts known at the time the decision was made, could reasonably have been expected to accomplish the desired result consistent with good business practices, reliability, and safety. The Seller acknowledges that its use of Good Utility Practice does not exempt it from performing any of its obligations arising under this Agreement. "Good Utility Practice" includes, at a minimum, those professionally responsible practices, methods and acts described in the preceding paragraph that comply with manufacturers' warranties, restrictions in this Agreement, the interconnection requirements of Buyer, the requirements of governmental authorities, and WECC and NERC standards. "Good Utility Practice" also includes the taking of reasonable steps to ensure that:

(a) Equipment, materials, resources, and supplies, including spare parts inventories, are available to meet the Facility's needs;
(b) Sufficient operating personnel are available at all times and are adequately experienced and trained and licensed as necessary to operate the Facility properly and efficiently, and are capable of responding to reasonably foreseeable emergency conditions at the Facility and emergencies whether caused by events on or off the Facility's site;
(c) Preventive, routine, and non-routine maintenance and repairs are performed on a basis that ensures reliable, long-term and safe operation of the Facility, and are performed by knowledgeable, trained, and experienced personnel utilizing proper equipment and tools;
(d) Appropriate monitoring and testing are performed to ensure equipment is functioning as designed; and
(e) Equipment is not operated in a reckless manner, in violation of manufacturer's guidelines or in a manner unsafe to workers, the general public, or the connecting utility's electric system or contrary to environmental laws, permits or regulations or without regard to defined limitations such as, flood conditions, safety inspection requirements, operating voltage, current, volt ampere reactive (VAR) loading, frequency, rotational speed, polarity, synchronization, and control system limits; and equipment and components are designed and manufactured to meet or exceed the standard of durability that is generally used for electric energy generating facilities operating in the western United States and will function properly over the full range of ambient temperature and weather conditions reasonably expected to occur at the Facility site and under both normal and emergency conditions.

"**Green Attributes**" refers to the definition set forth in the Standard Terms and Conditions, Appendix A-2, as amended, Decision D.07-02-011, as modified by D.07-05-057, of the CPUC, which incorporates the definition of "Environmental Attributes" set forth in the Standard Terms and Conditions, Appendix A-1, as amended, D. 04-06-014. "Green Attributes" includes any and all credits, benefits, emissions reductions, environmental air quality credits, offsets, and allowances, howsoever entitled, attributable to the generation from the Facility, and its displacement of conventional energy generation, whether existing now or arising in the future. "Green Attributes" includes RECs, as well as (1) any avoided emissions of pollutants to the air, soil or water, such as sulfur oxides ("SOx"), nitrogen oxides ("NOx"), carbon monoxide ("CO") and other pollutants; (2) any avoided emissions of carbon dioxide ("CO2"), methane ("CH4"), nitrous oxide, hydrofluorocarbons, perfluorocarbons, sulfur hexafluoride, and other greenhouse gases ("GHGs") that have been determined by the United Nations Intergovernmental Panel on Climate Change, or otherwise by law, to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere; and (3) the reporting rights to these avoided emissions such as Green Tag Reporting Rights and RECs. "Green Tag Reporting Rights" are the right of a Green Tag Purchaser to report the ownership of accumulated Green Tags in compliance with federal or state law, if applicable, and to a federal or state agency or any other party at the Green Tag Purchaser's discretion, and include those Green Tag Reporting Rights accruing under Section 1605(b) of the Energy Policy Act of 1992 and any present or future federal, state, or local law, regulation or bill, and international or foreign emissions trading program. Green Tags are accumulated on a kWh basis and one Green Tag represents the Green Attributes associated with one (1) MWh of Energy. "Green Attributes" do not include (i) any Energy, Capacity, reliability, or other power attributes of the Facility, (ii) production or investment tax credits associated with the construction or operation of the Facility and other financial incentives in the form of credits, grants, reductions, or allowances associated with the Facility that are applicable to a state or federal income taxation obligation, (iii) fuel-related subsidies or "tipping fees" that may be paid to Seller to accept certain fuels, or local subsidies received by the generator for the destruction of particular pre-existing pollutants or the promotion of local environmental benefits, or (iv) emission reduction credits encumbered, used or created by the Facility for compliance with or sale under local, state, or federal operating and/or air quality permits or programs. If the Facility is a biomass or landfill facility and the Seller receives any tradable Green Attributes based on the Facility's greenhouse gas reduction benefits or other emission offsets attributed to its fuel usage, the Seller shall provide the Buyer with sufficient Green Attributes to ensure that there are zero net emissions associated with the production of electricity from the Facility. "Green Attributes" includes any other environmental credits or benefits recognized in the future and attributable to Energy generated by the Facility during the Term that may not be represented by Green Tag Reporting Rights or RECs, unless otherwise excluded herein. Any Green Attributes provided under this Agreement shall be documented by RECs, or any other representation of the environmental benefits of the Output, the monthly cumulative total of which shall be provided to the Buyer, as specified herein.

"**Interconnection Agreement**" refers to the agreement between the Buyer and the Seller, specific to the interconnection of the Facility to Buyer's Distribution System.

"**NERC**" means the North American Electric Reliability Corporation, or successor organization.

"**NCPA**" means Northern California Power Agency, a California joint action agency, or successor agency.

"**Output**" means all Capacity associated with Contract Capacity and associated Energy made available from the Facility, as well as any Capacity Attributes, Green Attributes, or other attributes existing now or in the future associated with Contract Capacity and/or associated Energy. "Output" does not include production or investment tax credits associated with the construction or operation of the Facility and other financial incentives in the form of credits, grants, reductions, or allowances associated with the Facility that are applicable to a state or federal income taxation obligation.

"**Planned Outage**" means an outage, scheduled in advance, of one or more of the Facility's components that results in a reduction of the ability of the Facility to produce Capacity.

"**Pre-Certification Price**" means the contract price to be paid for all Energy delivered to the Buyer prior to the RPS Certification Date, as specified in Exhibit "PPA-A".

"**Renewable Energy Credit**" or "**REC**" has the meaning set forth in Section 399.12(h)(1) and (2) of the California Public Utilities Code, and includes a certificate of proof that one unit of electricity was generated by an Eligible Renewable Energy Resource. Currently, RECs are used to convey all Green Attributes associated with electricity production by a renewable energy resource. RECs are accumulated on a kWh basis and one REC represents the Green Attributes associated with the generation of 1 MWh (1,000 kWhs) from the Facility. For purposes of this Agreement, the term REC shall be synonymous with the term Green Tag, green ticket, bundled or unbundled renewable energy credit, tradable renewable energy certificates, or any other term used to describe the documentation that evidences the renewable and Green Attributes associated with electricity production by an Eligible Renewable Energy Resource.

"Renewables Portfolio Standard" or **"RPS"** means the standard adopted by the State of California pursuant to Senate Bill 2 1st Extraordinary Session (SBX1 2, Chapter 1, Statutes 2011-12), and California Public Utilities Code Sections 399.11through 399.31, inclusive, as may be amended, setting minimum renewable energy targets for local publicly owned electric utilities.

"**Reservation Deposit**" means the monetary deposit submitted by the Seller (or the Facility sponsor on behalf of the Seller) to secure a reservation of the CLEAN Program's prices. The Reservation Deposit is set forth in Exhibit "PPA-A."

"**Resource Adequacy**" means a requirement by a governmental authority or in accordance with its FERC-approved tariff, or a policy approved by a local regulatory authority, that is binding upon either Party and that requires that Party to procure a certain amount of electric generating capacity.

"**RPS Certification**" means certification by the CEC that the Facility qualifies as an Eligible Renewable Energy Resource for RPS purposes, and that all Energy produced by the Facility qualifies as generation from an Eligible Renewable Energy Resource, as evidenced by a Certificate of RPS Eligibility.

"RPS Certification Date" means the date on which the RPS Certification begins, as specified in the Certificate of RPS Eligibility.

"Seller" means ______________________________ with a principal place of business at ____, ______________________________, __________.

"**Station Service Load**" means the electrical loads associated with the operation and maintenance of the Facility, which may at times be supplied from the Facility's Energy.

"**Term**" has the meaning set forth in Section 14.1 hereof.

"WECC" means the Western Electricity Coordinating Council, the regional entity responsible for coordinating and promoting regional bulk electric system reliability in the Western Canada and the United States, or any successor organization.

2.0 SELLER'S GENERATING FACILITY, PURCHASE PRICE AND PAYMENT

2.1 Facility. This Agreement governs the Buyer's purchase of the Output from the Facility, as described in Exhibit "PPA-A." The Seller shall not modify the Facility to increase or decrease the Contract Capacity after the Commercial Operation Date.

2.2 Products Purchased. During the Delivery Term, the Seller shall sell and deliver, or cause to be delivered, and the Buyer shall purchase and receive, or cause to be received, the Output from the Facility. The Seller shall not have the right to procure the Output from sources other than the Facility for sale or delivery to the Buyer under this Agreement or to substitute the Output.

2.3 Delivery Term. The Delivery Term shall commence on the Commercial Operation Date under this Agreement, and shall continue for an uninterrupted period of [fifteen (15), twenty (20), or twenty-five (25) years]. This period will commence on the first day of the calendar month immediately following the Commercial Operation Date. As evidence of the Commercial Operation Date, the Parties shall execute and exchange the "Commercial Operation Date Confirmation Letter," attached hereto as Exhibit "PPA-B." The Commercial Operation Date shall be the date on which the Parties acknowledge, in writing, that the Facility starts operating and is otherwise in compliance with applicable interconnection and system protection requirements, including the final approvals by the City's building department official.

2.4 Payment for Products Purchased.

2.4.1 Deliveries Prior to RPS Certification Date. Once the Facility has achieved Commercial Operation, if the CEC has not issued a Certificate of RPS Eligibility for the Facility or the Facility has not been registered with the appropriate entity for the tracking of Green Attributes, the Buyer will pay the Seller for the Output by multiplying the Pre-Certification Price by the quantity of Energy.

2.4.2 Deliveries After RPS Certification Date. Once the Facility has achieved Commercial Operation, the CEC has issued a Certificate of RPS Eligibility for the Facility, and the Facility has been registered with the appropriate entity for the tracking of Green Attributes, the Buyer shall pay the Seller for all Output on or after the RPS Certification Date by multiplying the Contract Price by the quantity of Energy.

2.4.3 True-up Upon Issuance of Certificate of RPS Eligibility. Once the Facility has achieved Commercial Operation, the CEC has issued a Certificate of RPS Eligibility for the Facility, and the Facility has been registered with the appropriate entity for the tracking of Green Attributes, the Buyer will pay the Seller an amount equal to the difference between the Contract Price and the Pre-Certification Price for the Output (a) that was delivered on or after the RPS Certification Date and (b) for which the Seller has already received payment at the Pre-Certification Energy Price.

2.4.4 Energy in Excess of Contract Capacity. The Seller shall not receive payment for any Energy or Green Attributes delivered in any hour to the Buyer in excess of the following amount of energy (in kilowatt-hours): 110% of the Contract Capacity (in kilowatts) multiplied by one hour. Any payment in excess of this amount shall be refunded to the Buyer, on demand.

2.5 Billing. The Buyer shall pay the Seller by check or electronic funds transfer, on a monthly basis, within thirty (30) days of the meter reading date.

2.6 Title and Risk of Loss. Title to and risk of loss related to the Output shall be transferred from the Seller to the Buyer at the Delivery Point. The Seller warrants that it will deliver to the Buyer the Output free and clear of all liens, security interests, claims, encumbrances or any interest therein or thereto by any person, arising prior to the Delivery Point.

2.7 No Additional Incentives. The Seller warrants that it has not received any other incentives funded by the Buyer's ratepayers and it further agrees that, during the Term, it shall not seek additional compensation or other benefits from the Buyer pursuant to the following programs of the Buyer: (a) Photovoltaic (PV) Partners Program; (b) Power from Local Ultra-Clean Generation Incentive (PLUG-In) Program; or (c) other similar programs that are or may be funded by the Buyer's ratepayers.

3.0 RPS CERTIFICATION; GREEN ATTRIBUTES

3.1 CEC Certification. The Seller, at its own cost and expense, shall obtain the RPS Certification within six (6) months of the Commercial Operation Date. The Seller shall maintain the RPS Certification at all times during the Delivery Term. The foregoing provision notwithstanding, the Seller shall not be in breach of this Agreement and the Buyer shall not have the right to terminate this Agreement, if the Seller's failure to obtain or maintain the RPS Certification is due to a change in California law, occurring after the Commercial Operation Date, so long as the Seller has used commercially reasonable efforts to obtain and maintain the RPS Certification and the Seller's actions or omissions did not contribute to its inability to obtain and maintain the RPS Certification.

3.2 Obligation to Deliver Green Attributes. The Seller shall sell and deliver to the Buyer, and the Buyer shall buy and receive from the Seller, all right, title, and interest in and to Green Attributes associated with Energy, produced by the Facility and delivered to the Buyer at the Delivery Point, whether now existing or that hereafter come into existence during the Term, except as otherwise excluded herein; provided, the Buyer shall not be obligated to purchase and pay the Seller for any Green Attributes associated with any amount of the Output, that is generated by any fuel which is not renewable and which cannot be counted for the purpose of the production of Green Attributes. The Seller agrees to sell and make all such Green Attributes available to the Buyer to the fullest extent allowed by applicable law, in accordance with the terms and conditions of this Agreement. The Seller warrants that the Green Attributes provided under this Agreement to the Buyer shall be free and clear of all liens, security interests, claims and encumbrances.

3.3 Conveyance of Green Attributes. The Seller shall provide Green Attributes associated with the Facility, which shall be documented and conveyed to the Buyer in accordance with the procedure described in Exhibit "PPA-D."

3.4 Additional Evidence of Green Attributes Conveyance. At the Buyer's request, the Seller shall provide additional reasonable evidence to the Buyer or to third parties of the Buyer's right, title, and interest in the Green Attributes and any other information with respect to Green Attributes, as may be requested by the Buyer.

3.5 Modification of Green Attributes Conveyance Procedure. The Buyer may unilaterally modify Exhibit "PPA-D" in order to reflect changes necessary in the Green Attributes conveyance procedures, so that the Buyer may be able to receive and report the Green Attributes, purchased under this Agreement, as belonging to the Buyer.

3.6 Reporting of Ownership of Green Attributes. The Seller shall not report to any person or entity that the Green Attributes sold and conveyed to the Buyer belong to any person other than the Buyer. The Buyer may report under any applicable program that Green Attributes purchased by the Buyer hereunder belong to it.

3.7 Greenhouse Gas Emissions. The Seller shall comply with any laws and/or regulations regarding the need to offset emissions of GHGs by delivering to the Buyer the Energy from the Facility with a net zero GHG impact.

4.0 CONVEYANCE OF CAPACITY ATTRIBUTES

4.1 Conveyance of Resource Adequacy Capacity. The Seller shall not report to any person or entity that the Resource Adequacy Capacity, as defined in the CAISO Tariff) associated with the Facility, if any, belongs to a person other than the Buyer, which may report that Resource Adequacy Capacity purchased hereunder belongs to it to fulfill the Resource Adequacy requirements, as defined in Section 40 of the CAISO Tariff, as amended, or any successor program. The Seller shall take those actions described in Section 6.0 hereof, as applicable, to secure recognition of Resource Adequacy Capacity by the CAISO.

4.2 Conveyance of Other Capacity Attributes. In addition to the obligations imposed on the

Seller under Section 4.1, the Seller will undertake any and all actions reasonably needed to enable the Buyer to effect the recognition and transfer of any Capacity Attributes in addition Resource Adequacy, to the extent that such Capacity Attributes exist now or will exist in the future; provided, if such actions require any actions beyond the giving of notice by the Seller, then the Buyer shall reimburse all out-of-pocket costs and charges of such actions.

4.3 Reporting of Ownership of Capacity Attributes. The Seller shall not report to any person or entity that the Capacity Attributes sold and conveyed to the Buyer belong to any person other than the Buyer. The Buyer may report under any such program that such Capacity Attributes purchased hereunder belong to it.

5.0 METERING AND OPERATIONS

5.1 Timing of Outages. The Seller may not schedule or take any Planned Outage from 12:00 p.m. through 7:00 p.m. Pacific Time during the months of June through October.

5.2 Outage Reporting.

5.2.1 Buyer Request. The Seller is not required to report any Planned Outage or Forced Outage, unless the Buyer first submits a written request to the Seller to commence Outage reporting. Upon receipt of such a request, the Seller shall report all subsequent Planned Outages and the Forced Outages according to the procedures described in subsections 5.2.2 and 5.2.3, and shall continue such reporting until (a) the termination of this Agreement for any reason, or (b) the Buyer subsequently provides written notice to the Seller that the Seller may cease such reporting in the future.

5.2.2 Planned Outage Notifications. The Seller shall notify the Buyer at least 72 hours in advance of any Planned Outage that would result in a reduction in the effective Output of the Facility during the period over which the Planned Outage is scheduled. Notification shall be provided by e-mail to the e-mail address (or addresses) set forth in Exhibit "PPA-F."

5.2.3 Forced Outage Notifications. Within 24 hours of the occurrence of a Forced Outage of the Facility that impacts the ability of the Facility to produce Energy, the Seller shall notify the Buyer of the Forced Outage, including the Capacity of the Facility that is impacted, and the expected duration of the Forced Outage. Within 24 hours of the return of the Facility to service following the Forced Outage, the Seller shall notify the Buyer of the return-to-service details. Notification shall be made by e-mail to the address (or addresses) set forth in Exhibit "PPA-F."

5.3 Metering. The Buyer shall furnish and install one or more standard watt-hour meters to read Energy generated by the Facility, and it will charge a meter fee to the Seller to cover the costs associated with the meter's purchase and installation. As requested, the Seller shall provide and install a meter socket in accordance with the Buyer's metering standards. The Buyer reserves the right to install additional metering equipment at its sole cost and expense.

6.0 PARTICIPATING GENERATORS

6.1 Applicability. This Section 6.0 shall apply if the Facility meets the definition of a "Participating Generator," as may be defined by the CAISO Tariff. This Section 6.0 shall not apply if the definition applies to the Facility only upon the election by the Seller. For the purposes of this Section 6.0, all special terms not otherwise defined in Section 1.0 are defined in the CAISO Tariff.

6.2 Participating Generator Agreement. The Buyer will notify the CAISO of the Seller's interconnection to Buyer's Distribution System. If the CAISO requires it, the Seller, at its own expense, shall negotiate and enter in to two contracts, a "Participating Generator Agreement" and a "Meter Services Agreement for CAISO Metered Entities," with the CAISO.

6.3 Scheduling Coordination. If the CAISO requires the Seller to enter in to a Participating Generator Agreement, then the Seller shall designate NCPA as the Buyer's scheduling coordinator. The Buyer, acting in its sole discretion, may replace NCPA as the scheduling coordinator for the Facility. If NCPA ceases to be the scheduling coordinator for the Facility and the Buyer has not, upon fourteen (14) days' prior written notice of inquiry from the Seller, appointed a replacement scheduling coordinator, then the Seller shall have the right to appoint a replacement scheduling coordinator on the Buyer's behalf. Thereafter, the Buyer shall enter into all reasonable and appropriate agreements with such replacement scheduling coordinator at its own costs.

6.4 Scheduling Procedure. The Buyer may require the Seller to provide the Buyer with Energy forecasts on a periodic basis, as may be necessary for the Buyer to account for expected Facility generation in its daily power scheduling process. The requirements are set forth in Exhibit "PPA-C."

6.5 Modification of Scheduling and Outage Notification Procedure. The Buyer may unilaterally modify Exhibit "PPA-C" to reflect changes necessary in the scheduling and Outage notification procedures. The Buyer shall give the Seller reasonable notice of any such changes.

6.6 Provision of Other Equipment. If the Seller is required to enter into a Participating Generator Agreement with the CAISO, then the Seller, at its own cost and expense, shall provide and maintain data transmission-grade phone line and telecommunications equipment at the meter location that complies with applicable requirements of the CAISO, the Buyer, and NCPA. Any meter installed by the Seller shall comply at all times with the CAISO's metering requirements. If the Seller fails to provide or maintain any such required equipment or data connection, then the Buyer shall acquire, install and maintain the same at the Seller's sole cost and expense.

6.7 Designation as Resource Adequacy Resource. The Buyer may submit a written request to the Seller to obtain the CAISO's designation of the Facility as a Resource Adequacy Resource. Upon receipt of such request, the Seller shall provide such information and undertake such steps as may be required by the CAISO in order to complete such an assessment. If the Buyer makes such a request, then the Buyer shall be responsible for the following: (1) any costs charged to the Seller by the CAISO as a condition of applying for or receiving designation as a Resource Adequacy Resource, including any deposits required during the study process or the cost of any related studies or deliverability assessments performed by the CAISO; (2) the capital, installation, and maintenance costs of any additional equipment required by the CAISO as a condition of receiving designation as a Resource Adequacy Resource; (3) the costs of any Network Upgrades, as defined in the CAISO Tariff, as may be required by the CAISO, provided, the Buyer shall receive any subsequent repayments from the CAISO or the Participating Transmission Owner related to such upgrades; and (4) any charges or penalties assessed by the CAISO as a consequence of the Facility's designation as a Resource Adequacy Resource.

6.8 CAISO Charges. The Buyer shall be solely responsible for paying all costs and charges associated with the receipt of Energy under this Agreement, at the Delivery Point, and for the transmission and delivery of Energy from the Delivery Point to any other point downstream of the Delivery Point, including transmission costs and charges, competition transition charges, applicable control area service charges, transmission congestion charges, inadvertent energy flows, any other CAISO charges related to the transmission of such Energy by the CAISO and any charge assessed or collected in the future pursuant to any utility tariff or rate schedule, however defined, for transmission or transmission-related service rendered by or for any transmission-owning or operating entity. The Seller will undertake any and all actions reasonably needed to allow the Buyer to comply with any obligations, and minimize any potential liability, under the CAISO tariff. If and to the extent that the Seller fails to comply with the notice provision in Exhibit "PPA-C," concerning Outages, or with its obligations as outlined in the previous sentence, the Seller shall be wholly responsible for all imbalances, deviations, or any other CAISO charges or penalties associated with such Outage or other CAISO Tariff obligation.

6.9 Inclusion in Metered Subsystem. At the option of the Buyer, the Facility may be included within NCPA's metered sub-system in connection with the scheduling of power over the CAISO grid and related functions; provided, however, that such inclusion shall have no adverse effect on the Facility's operations or the Seller (or any such effect shall be fully mitigated by the Buyer). The Seller will undertake any and all actions reasonably needed to allow the Buyer to comply with any obligations and minimize any potential liability, under the CAISO Tariff; provided, that if such actions require any actions beyond the giving of notice to be provided by the Buyer, then the Buyer shall reimburse the Seller for all out-of-pocket costs and charges of such actions.

7.0 COMMERCIAL OPERATION DATE; REFUND OF RESERVATION DEPOSIT

7.1 Commercial Operation Date. The Facility shall achieve Commercial Operation by the Commercial Operation Date deadline (the "Deadline"), which is one (1) year from the Effective Date~~.~~, or, for Affordable Housing Developments, three (3) years from the Effective Date.

7.2 Reservation Deposit. The Buyer acknowledges that, as of the Effective Date or other date established by the Buyer, the Seller has provided the Reservation Deposit to the Buyer.

7.2.1 If the Commercial Operation Date occurs on or prior to the Deadline, the Buyer shall refund to the Seller the Reservation Deposit without interest.

7.2.2 If the Commercial Operation Date commences within seventy (70) days of the Deadline, the Seller, as liquidated damages and not as a penalty, shall relinquish its claim to a ten percent (10%) portion of the amount of the Reservation Deposit for every full week transpiring between the Deadline and the Commercial Operation Date, but the total amount to be relinquished to the Buyer shall not exceed 100% of the Reservation Deposit.

7.2.3 If the Facility has not achieved Commercial Operation within seventy (70) days of the Deadline, then the Buyer may terminate this Agreement without liability of either Party to the other (other than as set forth in Section 7.2.2) by giving written notice of termination to the Seller.

7.2.4 If the Seller gives notice of termination to terminate the Agreement before Commercial Operation occurs, then the Buyer shall refund a percentage of the Reservation Deposit equal to the following: the percentage to be refunded will equal A/B, where A equals the number of days between the date of the Seller's notice of termination, received by the Buyer, and the Deadline, and B equals the number of days between the Effective Date and the Deadline.

7.3 Return of Reservation Deposit. The Buyer shall return to the Seller the Reservation Deposit, without interest, in the event that (a) the Buyer furnishes written notice of the costs of interconnection (defined in the Interconnection Agreement to include the costs related to the Interconnection Facilities and Distribution Upgrades) to the Seller and (b) within thirty (30) days of receipt of the notice regarding costs of interconnection, the Seller provides the Buyer with written notice that the Seller does not intend to sign the Interconnection Agreement and does intend to proceed with the project.

8.0 REPRESENTATION AND WARRANTIES; COVENANTS

8.1 Representations and Warranties. On the Effective Date, each Party represents and warrants to the other Party that:

8.1.1 It is duly organized, validly existing and in good standing under the laws of the jurisdiction of its formation;

8.1.2 The execution, delivery and performance of this Agreement is within its powers, have been duly authorized by all necessary action and do not violate any of the terms and conditions in its governing documents, any contracts to which it is a party or any law, rule, regulation, order or the like applicable to it;

8.1.3 This Agreement and each other document executed and delivered in accordance with this Agreement constitutes its legally valid and binding obligation enforceable against it in accordance with its terms;

8.1.4 It is not bankrupt and there are no proceedings pending or being contemplated by it or, to its knowledge, threatened against it which would result in it being or becoming bankrupt;

8.1.5 There is not pending or, to its knowledge, threatened against it or any of its affiliates, if any, any legal proceedings that could materially adversely affect its ability to perform its obligations under this Agreement; and

8.1.6 It is acting for its own account, has made its own independent decision to enter into this Agreement and as to whether this Agreement is appropriate or proper for it based upon its own judgment, is not relying upon the advice or recommendations of the other Party in so doing, and is capable of assessing the merits of, and understands and accepts, the terms, conditions and risks of this Agreement.

8.2 General Covenants. Each Party covenants that, during the Term:

8.2.1 It shall continue to be duly organized, validly existing and in good standing under the laws of the jurisdiction of its formation;

8.2.2. It shall maintain (or obtain from time to time as required, including through renewal, as applicable) all regulatory authorizations necessary for it to legally perform its obligations under this Agreement; and

8.2.3 It shall perform its obligations under this Agreement in a manner that does not violate any of the terms and conditions in its governing documents, any contracts to which it is a party or any law, rule, regulation, order or the like applicable to it.

8.3 Covenant by Seller. The Seller covenants that, during the Term:

8.3.1 If the Eligible Renewal Energy Resource or the Facility is considered an 'eligible qualifying facility' under applicable law and has a net power production capacity of greater than one (1) megawatt, then the Seller covenants and agrees that, within thirty (30) days of the Effective Date or longer period allowed by law, it will complete and file Form No. 556 or other similar form with FERC as the same may be required by law."

9.0 GENERAL CONDITIONS

9.1 Facility Care and Interconnection. During the Delivery Term, the Seller shall execute and maintain an "Interconnection Agreement" with the Buyer, whereby the Seller shall pay and be responsible for designing, installing, operating, and maintaining the Facility in accordance with all applicable laws and regulations and shall comply with all applicable Buyer, WECC, FERC, and NERC requirements, including applicable interconnection and metering requirements. The Seller shall also comply with any modifications, amendments or additions to the applicable tariff and protocols. The Seller also shall arrange and pay independently for any and all necessary costs under the Interconnection Agreement with the Buyer.

9.2 Standard of Care. The Seller shall: (a) operate and maintain the Facility in a safe manner in accordance with its existing applicable interconnection agreements, manufacturer's guidelines, warranty requirements, Good Utility Practice, industry norms (including standards of the National Electrical Code, Institute of Electrical and Electronic Engineers, American National Standards Institute, and the Underwriters Laboratories, and in accordance with the requirements of all applicable federal, state and local laws and the National Electric Safety Code, as such laws and code norms may be amended from time to time; (b) obtain any governmental authorizations and permits required for the construction and operation thereof. The Seller shall make any necessary and commercially reasonable repairs with the intent of optimizing the availability of electricity to the Buyer. The Seller shall reimburse the Buyer for any and all losses, damages, claims, penalties, or liability that the Buyer incurs as a result of the Seller's failure to obtain or maintain any governmental authorizations and permits required for the construction and operation of the Facility throughout the Term.

9.3 Access Rights. The Buyer, its authorized agents, employees and inspectors shall have the right to inspect the Facility on reasonable advance notice during normal business hours and for any purposes reasonably connected with this Agreement or the exercise of any and all rights secured to the Buyer by law, including, without limitation, its ordinances, resolutions, tariffs, utility rate schedules or utilities rules and regulations. The Buyer shall make reasonable efforts to coordinate its emergency activities with the safety and security departments, if any, of the Facility's operator. The Seller shall keep the Buyer advised of current procedures for communicating with the Facility operator's safety and security departments.

9.4 Protection of Property. Each Party shall be responsible for protecting its own facilities from possible damage resulting from electrical disturbances or faults caused by the operation, faulty operation, or non-operation of the other Party's facilities and such other Party shall not be liable for any such damages so caused.

9.5 Insurance. During the Term, the Seller shall obtain and maintain and otherwise comply with the insurance requirements, as set forth in Exhibit "PPA-E."

9.6 Buyer's Performance Excuse; Seller Curtailment.

9.6.1 Buyer Performance Excuse. The Buyer shall not be obligated to accept or pay for the Output during Force Majeure that affects the Buyer's ability to accept Energy.

9.6.2 Seller Curtailment. The Buyer may require the Seller to interrupt or reduce deliveries of Energy: (a) whenever necessary to construct, install, maintain, repair, replace, remove, or investigate any of its equipment or part of the Buyer's Distribution System or facilities; or (b) if the Buyer determines that curtailment, interruption, or reduction is necessary due to a System Emergency, as defined in the CAISO Tariff, an unplanned outage on Buyer's Distribution System, Force Majeure, or compliance with Good Utility Practice.

9.7 Notices of Outages. Whenever possible, the Buyer shall give the Seller reasonable notice of the possibility that interruption or reduction of deliveries may be required.

9.8 No Additional Loads. The Seller shall not connect any loads not associated with Station Service Loads at the location of the Facility in a manner that would reduce Energy provided from the Facility to the Buyer hereunder. The Seller shall obtain separate retail electric service under the Buyer's rate schedules for the service of such additional loads.

10.0 FORCE MAJEURE

10.1 Effect of Force Majeure. A Party shall be excused from its performance under this Agreement to the extent, but only to the extent, that its performance hereunder is prevented by Force Majeure. A Party claiming Force Majeure shall exercise due diligence to overcome or mitigate the effects of Force Majeure; provided, that nothing in this Agreement shall be deemed to obligate the Party affected by Force Majeure (a) to forestall or settle any strike, lock-out or other labor dispute against its will; or (b) for Force Majeure affecting the Seller only, to purchase electric power to cure Force Ma

10.2 Remedial Action. A Party shall not be liable to the other Party if the Party is prevented from performing its obligations hereunder due to Force Majeure. The Party rendered unable to fulfill an obligation by reason of Force Majeure shall take all action necessary to remove such inability with all due speed and diligence. The nonperforming Party shall be prompt and diligent in attempting to remove the cause of its failure to perform, and nothing herein shall be construed as permitting that Party to continue to fail to perform after that cause has been removed. Notwithstanding the foregoing, the existence of Force Majeure shall not excuse any Party from its obligations to make payment of amounts due hereunder.

10.3 Notice of Force Majeure. In the event of any delay or nonperformance resulting from Force Majeure, the Party directly impacted by Force Majeure shall, as soon as practicable under the circumstances, notify the other Party, in writing, of the nature, cause, date of commencement thereof and the anticipated extent of any delay or interruption in performance.

10.4 Termination Due to Force Majeure. If a Party will be prevented from performing its material obligations under this Agreement for an estimated period of twelve (12) consecutive months or longer due to Force Majeure, then the unaffected Party may terminate this Agreement, without liability of either Party to the other (other than any liability set forth in Section 7.2.2 arising prior to such extended Force Majeure), upon thirty (30) Days' prior written notice at any time during Force Majeure.

11.0 INDEMNITY

11.1 Indemnity by the Seller. The Seller shall indemnify, defend, and hold harmless the Buyer, its elected and appointed officials, directors, officers, employees, agents, and representatives against and from any and all losses, claims, demands, liabilities and expenses, actions or suits, including reasonable costs and attorney's fees, resulting from, or arising out of or in any way connected with claims by third parties associated with (A) (i) Energy delivered at the Delivery Point; (ii) the Seller's operation and/or maintenance of the Facility; or (iii) the Seller's actions or inactions with respect to this Agreement, and (B) any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to or destruction of property belonging to the Buyer or other third party, excepting only such loss, claim, action or suit as may be caused solely by the willful misconduct or gross negligence of the Buyer, its agents, employees, directors or officers.

11.2 Indemnity by the Buyer. The Buyer shall indemnify, defend, and hold harmless the Seller, its directors, officers, employees, agents, and representatives against and from any and all losses, claims, demands, liabilities and expenses, actions or suits, including reasonable costs and attorney's fees resulting from, or arising out of or in any way connected with claims by third parties associated with acts of the Buyer, its officers, employees, agents, and representatives, relating to: (A) Energy delivered by the Seller under this Agreement after the Delivery Point, and (B) any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to or destruction of property belonging to the Seller or other third party, excepting only such loss, claim, action or suit as may be caused solely by the willful misconduct or gross negligence of the Seller, its agents, employees, directors or officers.

12.0 LIMITATION OF DAMAGES

EXCEPT AS OTHERWISE PROVIDED IN THIS AGREEMENT THERE IS NO WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE, AND ANY AND ALL IMPLIED WARRANTIES ARE DISCLAIMED. LIABILITY SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES ONLY, SUCH DIRECT ACTUAL DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED UNLESS EXPRESSLY HEREIN PROVIDED. NEITHER PARTY SHALL BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR

CONTRACT, UNDER ANY INDEMNITY PROVISION OR OTHERWISE. UNLESS EXPRESSLY HEREIN PROVIDED, AND SUBJECT TO THE PROVISIONS OF SECTION 11 (INDEMNITY), IT IS THE INTENT OF THE PARTIES THAT THE LIMITATIONS HEREIN IMPOSED ON REMEDIES AND THE MEASURE OF DAMAGES BE WITHOUT REGARD TO THE CAUSE OR CAUSES RELATED THERETO, INCLUDING THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH NEGLIGENCE BE SOLE, JOINT OR CONCURRENT, OR ACTIVE OR PASSIVE.

13.0 NOTICES

Notices shall, unless otherwise specified herein, be given, in writing, and may be delivered by hand delivery, United States mail, overnight courier service, facsimile or electronic messaging (e-mail) to the addresses set forth in Exhibit "PPA-F.". Whenever this Agreement requires or permits delivery of a "notice" (or requires a Party to "notify"), the Party with such right or obligation shall provide a written communication in the manner specified below. A notice sent by facsimile transmission or electronic mail will be recognized and shall be deemed received on the Business Day on which such notice was transmitted if received before 5 p.m. Pacific Time (and if received after 5 p.m., on the next Business Day) and a notice by overnight mail or courier shall be deemed to have been received two (2) Business Days after it was sent or such earlier time as is confirmed by the receiving Party unless it confirms a prior oral communication, in which case any such notice shall be deemed received on the day sent. A Party may change its addresses by providing notice of same in accordance with this provision. A Party may request a change to Exhibit "PPA-F" as necessary to keep the information current.

14.0 TERM, TERMINATION EVENT AND TERMINATION

14.1 Term. The Term shall commence upon the execution by the duly authorized representatives of each of the Parties, and shall remain in effect until the conclusion of the Delivery Term, unless terminated sooner pursuant to the terms and conditions of this Agreement. All indemnity rights shall survive the termination of this Agreement for twelve (12) months.

14.2 Delivery Term. The Delivery Term of the Agreement is _______ years and is defined as the period of time from the Commercial Operation Date through the expiration or early termination of this Agreement.

14.3 Termination Event.

14.3.1 The Buyer shall have the right, but not the obligation, to terminate this Agreement upon the occurrence of any of the following, each of which is a "Termination Event": (a) The Facility has not achieved Commercial Operation within seventy (70) days following the Deadline; (b) After the Commercial Operation Date, the Seller has not sold or delivered Energy from the Facility to the Buyer for a period of twelve (12) consecutive months; (c) If the Facility does not obtain RPS Certification within six (6) months of the Commercial Operation Date and maintain RPS Certification as required by Section 3.2; or (d) The Seller breaches any other material obligation of this Agreement.

14.3.2 The Seller shall have the right, but not the obligation, to terminate this Agreement upon the occurrence of any of the following, each of which is a "Termination Event": (a) The Buyer fails to make a payment due and payable under this Agreement within thirty (30) days after written notice that such payment is due; or (b) The Buyer breaches any other material obligation of this Agreement. The preceding sentence notwithstanding, the Seller may terminate this Agreement without cause at any time prior to the Commercial Operation Date, subject to the provisions of Section 7 of this Agreement.

14.4 Time to Cure. None of the events described in Section 14.3.1 and 14.3.2 shall constitute a Termination Event if the Buyer or the Seller cures the event, failure, or circumstance within thirty (30) days after receipt of written notification sent by the other Party, seeking termination, or such longer period as may be necessary to cure so long as the Party subject to the Terminating Event is exercising diligent efforts to cure.

14.5 Termination.

14.5.1 Declaration of a Termination Event. If a Termination Event has occurred and is continuing, the Party with the right to terminate shall have the right to: (a) send notice, designating a day, no earlier than thirty (30) days after such notice is deemed to be received (as provided in Section 13), as an early termination date of this Agreement (the "Early Termination Date"), unless the Seller has timely communicated with the Buyer and the Parties have agreed to resolve the circumstances giving rise to the Termination Event; (b) accelerate all amounts owing between the Parties; and (c) terminate this Agreement and end the Delivery Term effective as of the Early Termination Date.

14.5.2 Release of Liability for Termination Event. Upon termination of this Agreement pursuant to this section neither Party shall be under any further obligation or subject to liability hereunder, except with respect to the indemnity provision in Section 11 hereof, which shall remain in effect for a period of 12 months following the Early Termination Date.

14.6 No Limitation on Damages. Nothing in this Agreement shall be deemed or construed to limit a Party's right to recover damages from the other Party, except as otherwise provided in this Agreement.

15.0 RELEASE OF DATA

Except as may be exempt from disclosure under applicable law, the Seller authorizes the Buyer to release to any regulatory authority having jurisdiction over the Facility or a Party, or to any request made pursuant to the California Constitution or the California Public Records Act, information regarding the Facility, including the Seller's name and location, operational characteristics, the Term of this Agreement, the Facility resource type, the scheduled Commercial Operation Date, the actual Commercial Operation Date, the Contract Capacity, payments made to the Seller and Energy production information. The Seller acknowledges that this information may be made publicly available.

16.0 ASSIGNMENT

Neither Party shall assign this Agreement or its rights hereunder without the prior written consent of the other Party, which consent shall not be unreasonably withheld.

16.1 Upon the written request of the Seller, the Buyer will execute a "Lender Consent and Agreement" between the Seller and the Seller's lender(s), if any, in the form acceptable to the Parties; provided, for illustration purposes only, an exemplar is attached hereto as Exhibit "PPA-G."

16.2 Notwithstanding the foregoing, no Consent and Agreement shall be required for:

16.2.1 Any assignment or transfer of this Agreement by the Seller to an affiliate of the Seller, provided that such affiliate's creditworthiness is equal to or better than that of Seller, as reasonably determined by the non-assigning or non-transferring Party; or

16.2.2 Any assignment or transfer of this Agreement by the Seller or the Buyer to a person succeeding to all or substantially all of the assets of such Party, provided that such person's creditworthiness is equal to or greater than that of such Party, as reasonably determined by the non-assigning or non-transferring Party.

16.2.3 Notification of any assignment or transfer of this Agreement under Section 16.2.1 or 16.2.2 shall be given to the non-assigning or non-transferring Party in accordance with Exhibit "PPA-F."

17.0 APPLICABLE LAW, VENUE, ATTORNEYS' FEES, AND INTERPRETATION

This Agreement will be governed by and construed in accordance with the laws of the State of California. The Parties will comply with applicable laws pertaining to their obligations arising under this

Agreement. In the event that an action is brought, the Parties agree that trial of such action will be vested exclusively in the state courts of California or in the United States District Court for the Northern District of California in the County of Santa Clara, State of California. The prevailing party in any action brought to enforce the provisions of this Agreement may recover its reasonable costs and attorneys' fees expended in connection with that action. If a court of competent jurisdiction finds or rules that any provision of this Agreement, the Exhibits, or any amendment thereto is void or unenforceable, the unaffected provisions of this Agreement, the Exhibits, or any amendment thereto will remain in full force and effect. The Parties agree that the normal rule of construction to the effect that any ambiguity is to be resolved against the drafting party will not be employed in the interpretation of this Agreement or any Exhibit or any amendment thereof.

18.0 SEVERABILITY

If any provision in this Agreement is determined to be invalid, void or unenforceable by any court having jurisdiction, such determination shall not invalidate, void, or make unenforceable any other provision, agreement or covenant of this Agreement and the Parties shall use their best efforts to modify this Agreement to give effect to the original intention of the Parties.

19.0 COUNTERPARTS; INTERPRETATION OF CONFLICTING PROVISIONS

This Agreement may be executed in one or more counterparts, each of which shall be deemed an original and all of which shall be deemed one and the same Agreement. Delivery of an executed counterpart of this Agreement by facsimile or portable document format (“PDF”) transmission will be deemed as effective as delivery of an originally executed counterpart. Each Party delivering an executed counterpart of this Agreement by facsimile or PDF transmission will also deliver an originally executed counterpart, but the failure of any Party to deliver an originally executed counterpart of this Agreement will not affect the validity or effectiveness of this Agreement. In the event of a conflict between the Agreement and any, some or all of the Exhibits, the document imposing the more specific duty or obligation will prevail.

20.0 GENERAL

No amendment to or modification of this Agreement shall be enforceable unless reduced to writing and executed by both Parties. This Agreement shall not impart any rights enforceable by any third party other than a permitted successor or assignee bound to this Agreement. Waiver by a Party of any default by the other Party shall not be construed as a waiver of any other default. The headings used herein are for convenience and reference purposes only.

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21. EXHIBITS

The following exhibits shall be deemed incorporated in and made a part of this Agreement.

Exhibit "PPA-A" - Facility Description, Prices, and Reservation Deposit
Exhibit "PPA-B" - Commercial Operation Date Confirmation Letter
Exhibit "PPA-C" - Scheduling and Outage Notification Procedure
Exhibit "PPA-D" - Green Attributes Reporting and Conveyance Procedures
Exhibit "PPA-E" - Insurance Requirements
Exhibit "PPA-F" - Notices
Exhibit "PPA-G" - Form of Lender Consent and Agreement

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their authorized representatives as of the Effective Date.

CITY OF PALO ALTO	**SELLER**
APPROVED AS TO FORM	______________________________
______________________________ Senior Deputy City Attorney	
APPROVED	
______________________________ City Manager	
______________________________ Director of Utilities	

EXHIBIT "PPA-A"

Facility Description, Rates, and Reservation Deposit

Program Rates

Contract Term:	[Fifteen (15), twenty (20), or twenty-five (25) years]
Contract rate:	$0.165 per kWh for solar resources, 15- or 20- or 25-year contract term (up to 3 MW solar energy resources program capacity) $0.~~088~~ 095 per kWh for solar resources, 15-year contract term (beyond 3 MW) $0.~~089~~ 098 per kWh for solar resources, 20-year contract term (beyond 3 MW) $0.~~091~~ 102 per kWh for solar resources, 25-year contract term (beyond 3 MW) $0.~~083~~ 094 per kWh for non-solar resources, 15-year contract term $0.~~084~~ 098 per kWh for non-solar resources, 20-year contract term $0.~~085~~ 101 per kWh for non-solar resources, 25-year contract term
Pre-certification rate:	$0.08 per kWh

Reservation Deposit

Reservation Deposit ($20/kW of Contract Capacity): $_________________

Service address: ____

Facility Description:

____
____
____
____

Contract Capacity: ___________ kW (CEC-AC), based on solar array rating (Panel rated output at PV USA test conditions x inverter efficiency) or inverter rating

Facility primary fuel/technology: ____

EXHIBIT "PPA-B"

Commercial Operation Date Confirmation Letter

In accordance with the terms of the Power Purchase Agreement (Palo Alto CLEAN), dated _______________ (the "Agreement") by and between the City of Palo Alto, as the Buyer, and ____, as the Seller, this Confirmation Letter serves to document the Parties' agreement that (i) the conditions precedent to the occurrence of the Commercial Operation Date have been satisfied, and (ii) the Buyer has received Energy, as specified in the Agreement, as of_______________,________. The actual installed Contract Capacity is_____________kW.

This Confirmation Letter shall confirm the Commercial Operation Date, as defined in the Agreement, as of the date referenced in the preceding sentence.

IN WITNESS WHEREOF, each Party has caused this letter to be duly executed by its authorized representative as of the date of last signature provided below:

Buyer	**Seller**
By: _________________________________	**By**: _______________________________
Name:	**Name:** _____________________________
Title: Director of Utilities	**Title:** ______________________________
Date: _______________________________	**Date:** ______________________________

In recognition of the Commercial Operation Date relative to the Effective Date of the Agreement by and between the Buyer and the Seller, the Seller hereby calculates the amount to return, if any, of the Seller's deposit, as follows:

Original Reservation Deposit Amount: $________________

Commercial Operation Date Deadline: ___________________

□ Commercial Operation Date is prior to Deadline

□ Commercial Operation Date occurred _ weeks following the Deadline, meaning that % of the Reservation Deposit is relinquished by Seller per Section 7.2.2 of the Power Purchase Agreement.

Amount (if any) of Reservation Deposit to return to the Seller is: $_____________________

EXHIBIT "PPA-C"

Scheduling and Outage Notification Procedure

C.1 Applicability. This Exhibit" PPA-C" shall apply if the Facility is subject to Section 6.0 of this Agreement.

C.2 Annual Operations Forecast

C.2.1 By the tenth (10th) day September of each calendar year, the Seller will provide NCPA with an annual operations forecast detailing hourly expected generation and all proposed planned Outages for the next calendar year. The annual operations forecast for the calendar year shall be provided by not later than ninety (90) days prior to the scheduled Commercial Operation Date of the Generating Facility.

C.2.2 NCPA may request modifications to the annual operations forecast at any time, and the Seller shall use good faith efforts to accommodate the requested modifications.

C.2.3 The Seller shall not conduct Planned Outages at times other than as set forth in its annual operations forecast, unless approved in advance by NCPA, which approval shall not be withheld or delayed unreasonably.

C.2.4 The Seller shall not schedule or conduct Planned Outages from 12:00 p.m. through 7:00 p.m. Pacific Time during the months of June through October.

C.3. Short Term Operations Forecasts

C.3.1. Quarterly Operations Forecast

C.3.1.1 By the fifth (5th) day of January, April and July of each Contract Year, the Seller shall provide a calendar quarter-operations forecast by hour of expected generation and all proposed Planned Outages for the next full calendar quarter and the twelve (12) months following that calendar quarter. As an example, by January 5, 2014, the Seller would provide a calendar quarter-operations forecast by hour of expected generation for the period, April 1, 2014 through June 30, 2014, and identify all proposed Planned Outages for the period, April 1, 2014 through June 30, 2015.

C.3.1.2 NCPA will approve or require modifications to the proposed calendar quarter-operations forecast within ten (10) days of receipt of the forecast.

C.3.1.3 If required by NCPA, the Seller will provide a modified calendar quarter-operations forecast within seven (7) days after receipt of required modifications from NCPA.

C.3.2 Weekly Update

C.3.2.1 By 14:00 of each Wednesday, the Seller shall provide an electronic update, in a format specified by NCPA, to the calendar quarter-operations forecast for the following seven (7) days (Thursday through the next Wednesday).

C.3.2.2 The weekly update shall include hourly expected generation and all proposed planned Outages for the relevant seven (7) day period.

C.4 Outage Detail for Annual and Short Term Operations Forecasts. Outage information provided by the Seller shall include, at a minimum, the start time and stop time of the Outage, capacity out of service (kW), the equipment that is or will be out of service, and the reason for the Outage.

C.5 General Scheduling Protocols

C.5.1 Daily Modifications to Forecasts. Unless otherwise mutually agreed, the Seller may make changes to the weekly update to the calendar quarter-operations forecast by providing such changes to NCPA prior to 08:00 of the day that is two (2) Business Days before the active scheduling day as determined by the WECC prescheduling calendar. Example: For power that is scheduled for generation or delivery on Friday, March 29, 2014, changes must be submitted to NCPA by 08:00 on Wednesday, March 27, 2014.

C.5.2 Hourly Modifications to Active Schedules. Unless otherwise mutually agreed, the Seller may request changes to active schedules by providing such changes to NCPA with a minimum of four (4) hours' notice prior to the applicable CAISO market deadline (e.g. Hour Ahead Scheduling Process ("HASP") Scheduling deadline, as defined in the CAISO Tariff). Active day Schedule changes are not binding. Changes to active Schedules are limited to two (2) changes per day, excluding forced Outages, unless otherwise agreed to between the Parties. One request for a Schedule change, of one-hour or multiple-hours duration, constitutes one Schedule change. Example: For power that is scheduled for generation or delivery in hour ending 15:00 (for the period from 14:01 to 15:00), changes must be submitted to NCPA by 10:00.

C.5.3. Unforeseen Circumstances. At the Seller's request, NCPA may, but is not required to, modify the Schedules for the Generation Facility Output due to unforeseen circumstances in accordance with the above scheduling timeline constraints described in this Exhibit PPA-C.

C.5.4. Absence of Forecasts. In the absence of forecasts and schedules as required by this Agreement or this Exhibit, NCPA shall utilize the most current information the Seller provides in the development and submission of Schedules.

C.6 Outage Reporting Protocols

C.6.1. Notification. The Seller shall notify NCPA of all planned or forced Outages of the Generating Facility to ensure compliance with the CAISO Outage Coordination and Enforcement Protocols.

C.6.1.1 Outage information provided by the Seller shall include, at a minimum, the start time and stop time of the Outage, Capacity out of service (kW), equipment out of service, and the reason for the Outage.

C. 6.1.2 Seller shall provide the Planned Outages not included in the annual operations forecast, the calendar quarter-operations forecast, or the weekly update, to NCPA at least four (4) Business Days prior to the start of the requested outage.

C. 6.1.3 At any time prior to the start of a Planned Outage, the CAISO may deny the Outage due to a System Emergency (as defined in the CAISO Tariff) or as otherwise permitted under the CAISO Tariff. If NCPA receives notice that the CAISO has denied an Outage in accordance with the CAISO Tariff, NCPA will notify the Seller as soon as possible and the Seller shall modify the planned Outage as required by the CAISO.

C.6.2 Commencement of an Outage. The Seller shall not begin any Planned Outage without the prior approval of NCPA and the CAISO.

C.6.3 Forced Outages

C.6.3.1 The Seller shall report the Forced Outages to NCPA within twenty (20) minutes of such Outages.

C.6.3.2 The Seller's notice of a Forced Outage sent to NCPA shall include the reason for the Outage (if known), expected duration of the Outage, and the Capacity reduction.

C.6.3.3 By the end of the next Business Day following the day on which a Forced Outage has occurred, the Seller shall provide to NCPA a detailed written report, specifying the reason for the Outage, expected duration of such Outage, capacity reduction, and actions taken to mitigate such Outage.

C.6.4 Return to Service. The Seller shall notify NCPA as soon as possible, but in any case before the Generating Facility is returned to service.

C.7 Notices. All Scheduling notices and Schedules shall be submitted to NCPA by phone, fax or email, or other means as may be mutually agreed by the Parties, to the persons designated in Exhibit "PPA-F."

C.8 Changes in Scheduling and Outage Procedure. The Buyer shall revise Exhibit "PPA-C," or, as appropriate, give written notice to the Seller regarding the revision, and issue a new Exhibit "PPA-C," which shall then become part of the Agreement to reflect changes in the scheduling and outage notification procedure.

EXHIBIT "PPA-D"

Green Attributes Reporting and Conveyance Procedures

D.1 Additional Definitions for the Conveyance of Green Attributes

D.1.1 "Certificate Transfers" means the process, as described in the WREGIS Operating Rules, whereby a WREGIS account holder may request that WREGIS Certificates from a specific generating unit shall be directly deposited to another WREGIS account.

D.1.2 "WREGIS Certificates" means a certificate created within the WREGIS system that represents all Renewable and Green Attributes from one MWh of electricity generation from an Eligible Renewable Energy Resource that is registered with WREGIS.

D.1.3 "WREGIS Operating Rules" means the document published by WREGIS that governs the operation of the WREGIS system for registering, tracking, and conveying, among others, RECs produced from Eligible Renewable Energy Resources that shall be registered with WREGIS.

D.1.4 "WREGIS" means Western Renewable Energy Generation Information System.

D.2 RECs. Green Attributes shall be conveyed by the Seller to the Buyer through RECs, which shall be registered tracked and conveyed to the Buyer, using WREGIS.

D.3 WREGIS Registration. Prior to the Commercial Operation Date, the Buyer will register the Facility in the Buyer's WREGIS account on behalf of the Seller. The Buyer shall charge back to the Seller any costs of registering and maintaining the registration of the Facility with WREGIS. The Seller shall provide to the Buyer any documents required by WREGIS and assign the Seller's rights to register the Facility in WREGIS, using agreements provided by WREGIS.

D.4 Buyer's WREGIS Account. The Buyer shall, at its sole expense, establish and maintain the Buyer's WREGIS account sufficient to accommodate the WREGIS Certificates produced by the output of the Facility. The Buyer shall be responsible for all expenses associated with (A) establishing and maintaining the Buyer's WREGIS Account, and (B) subsequently transferring or retiring WREGIS Certificates.

D.5 Qualified Reporting Entity. The Buyer shall be the Qualified Reporting Entity (as such term is defined by WREGIS) for the Facility, and shall be responsible for providing the metered Output data to WREGIS.

D.6 Reporting of Environmental Attributes. In lieu of the Seller's transfer of the WREGIS Certificates using Certificate Transfers from the Seller's WREGIS account to the Buyer's WREGIS account, the Buyer shall report the Facility as being held directly in its WREGIS account, which will preclude the Seller from reporting the Facility in its own WREGIS account.

D.6.1 By avoiding the use of Certificate Transfers, there will be no transaction costs to the Seller or the Buyer for the Certificate Transfers that would otherwise be used.

D.6.2 WREGIS Certificates for the Facility will be created on a calendar month basis in accordance with the certification procedure established by the WREGIS Operating Rules in an amount equal to the Energy generated by the Project and delivered to the Buyer in the same calendar month.

D.6.3 WREGIS Certificates will only be created for whole MWh amounts of energy generated. Any fractional MWh amounts (i.e., kWh) will be carried forward until sufficient generation is accumulated for the creation of a WREGIS Certificate and all such accumulated

MWh of Environmental Attributes will then be available to Buyer.

D.6.4 If a WREGIS Certificate Modification (as such term is defined by WREGIS) will be required to reflect any errors or omissions regarding the Green Attributes from the Facility, then the Buyer will manage the submission of the WREGIS Certificate Modification.

D.6.5 Due to the expected delay in the creation of WREGIS Certificates relative to the timing of invoice payments under Section 2, the Buyer will normally be making an invoice payment for the Output for a given month in accordance with Section 2 before the WREGIS Certificates for such month may be created in the Buyer's WREGIS account. Notwithstanding this delay, the Buyer shall have all right and title to all such WREGIS Certificates upon payment to the Seller in accordance with Section 2.

D.7 Changes in Green Attributes Reporting and Conveyance Procedures. The Buyer shall revise this Exhibit "PPA-D," as appropriate, give written notice to the Seller regarding the revision, and issue a new Exhibit "PPA-D," which shall then become part of this Agreement in the event that:

D.7.1 WREGIS changes the WREGIS Operating Rules (as defined by WREGIS) after the Effective Date or applies the WREGIS Operating Rules in a manner inconsistent with this Exhibit "PPA-D" after the Effective Date; or,

D.7.2 WREGIS is replaced as the primary method that the Buyer uses for conveyance of Green Attributes, or additional methods to convey all Green Attributes, are required.

EXHIBIT "PPA-E"

Insurance Requirements

CONTRACTORS TO THE CITY OF PALO ALTO (CITY), AT THEIR SOLE EXPENSE, WILL FOR THE TERM OF THE CONTRACT OBTAIN AND MAINTAIN INSURANCE IN THE AMOUNTS FOR THE COVERAGE SPECIFIED BELOW, **AFFORDED BY COMPANIES WITH A BEST'S KEY RATING OF A-:VII, OR HIGHER, LICENSED OR AUTHORIZED TO TRANSACT INSURANCE BUSINESS IN THE STATE OF CALIFORNIA.**

AWARD IS CONTINGENT ON COMPLIANCE WITH CITY'S INSURANCE REQUIREMENTS, AS SPECIFIED, BELOW:

REQUIRED	TYPE OF COVERAGE	REQUIREMENT	MINIMUM LIMITS	
			EACH OCCURRENCE	AGGREGATE
YES YES	WORKER'S COMPENSATION AUTOMOBILE LIABILITY	STATUTORY STATUTORY		
YES	COMMERCIAL GENERAL LIABILITY, INCLUDING PERSONAL INJURY, BROAD FORM PROPERTY DAMAGE BLANKET CONTRACTUAL, AND FIRE LEGAL LIABILITY	BODILY INJURY PROPERTY DAMAGE BODILY INJURY & PROPERTY DAMAGE COMBINED.	\$1,000,000 \$1,000,000 \$1,000,000	\$2,000,000 \$2,000,000 \$2,000,000
YES	COMPREHENSIVE AUTOMOBILE LIABILITY, INCLUDING, OWNED, HIRED, NON-OWNED	BODILY INJURY - EACH PERSON - EACH OCCURRENCE PROPERTY DAMAGE BODILY INJURY AND PROPERTY DAMAGE, COMBINED	\$1,000,000 \$1,000,000 \$1,000,000 \$1,000,000 \$1,000,000	\$1,000,000 \$1,000,000 \$1,000,000 \$1,000,000 \$1,000,000
NO	PROFESSIONAL LIABILITY, INCLUDING, ERRORS AND OMISSIONS, MALPRACTICE (WHEN APPLICABLE), AND NEGLIGENT PERFORMANCE	ALL DAMAGES	\$1,000,000	
YES	**THE CITY OF PALO ALTO IS TO BE NAMED AS AN ADDITIONAL INSURED**: PROPOSER, AT ITS SOLE COST AND EXPENSE, SHALL OBTAIN AND MAINTAIN, IN FULL FORCE AND EFFECT THROUGHOUT THE ENTIRE TERM OF ANY RESULTANT AGREEMENT, THE INSURANCE COVERAGE HEREIN DESCRIBED, INSURING NOT ONLY PROPOSER AND ITS SUBCONSULTANS, IF ANY, BUT ALSO, WITH THE EXCEPTION OF WORKERS' COMPENSATION, EMPLOYER'S LIABILITY AND PROFESSIONAL INSURANCE, **NAMING AS ADDITIONAL INSURES CITY, ITS COUNCIL MEMBERS, OFFICERS, AGENTS, AND EMPLOYEES.**			

I. INSURANCE COVERAGE MUST INCLUDE:

A. A PROVISION FOR A WRITTEN THIRTY DAY ADVANCE NOTICE TO CITY OF CHANGE IN COVERAGE OR OF COVERAGE CANCELLATION; AND

B. A CONTRACTUAL LIABILITY ENDORSEMENT PROVIDING INSURANCE COVERAGE FOR CONTRACTOR'S AGREEMENT TO INDEMNIFY CITY – SEE, SAMPLE AGREEMENT FOR SERVICES.

II. SUBMIT CERTIFICATE(S) OF INSURANCE EVIDENCING REQUIRED COVERAGE, **OR** COMPLETE THIS SECTION AND IV THROUGH V, BELOW.

A. NAME AND ADDRESS OF COMPANY AFFORDING COVERAGE (NOT AGENT OR BROKER):

____

B. NAME, ADDRESS, AND PHONE NUMBER OF YOUR INSURANCE AGENT/BROKER:

____

C. POLICY NUMBER(S):

____

D. DEDUCTIBLE AMOUNT(S) (DEDUCTIBLE AMOUNTS IN EXCESS OF $5,000 REQUIRE CITY'S PRIOR APPROVAL):

____

III. AWARD IS CONTINGENT ON COMPLIANCE WITH CITY'S INSURANCE REQUIREMENTS, AND PROPOSER'S SUBMITTAL OF CERTIFICATES OF INSURANCE EVIDENCING COMPLIANCE WITH THE REQUIREMENTS SPECIFIED HEREIN.

IV. ENDORSEMENT PROVISIONS, WITH RESPECT TO THE INSURANCE AFFORDED TO "ADDITIONAL INSURES"

A. <u>PRIMARY COVERAGE</u>

WITH RESPECT TO CLAIMS ARISING OUT OF THE OPERATIONS OF THE NAMED INSURED, INSURANCE AS AFFORDED BY THIS POLICY IS PRIMARY AND IS NOT ADDITIONAL TO OR CONTRIBUTING WITH ANY OTHER INSURANCE CARRIED BY OR FOR THE BENEFIT OF THE ADDITIONAL INSURES.

B. <u>CROSS LIABILITY</u>

THE NAMING OF MORE THAN ONE PERSON, FIRM, OR CORPORATION AS INSURES UNDER THE POLICY SHALL NOT, FOR THAT REASON ALONE, EXTINGUISH ANY RIGHTS OF THE INSURED AGAINST ANOTHER, BUT THIS ENDORSEMENT, AND THE NAMING OF MULTIPLE INSUREDS, SHALL NOT INCREASE THE TOTAL LIABILITY OF THE COMPANY UNDER THIS POLICY.

C. <u>NOTICE OF CANCELLATION</u>

1. IF THE POLICY IS CANCELED BEFORE ITS EXPIRATION DATE FOR ANY REASON OTHER THAN THE NON-PAYMENT OF PREMIUM, THE ISSUING COMPANY SHALL PROVIDE CITY AT LEAST A THIRTY (30) DAY WRITTEN NOTICE BEFORE THE EFFECTIVE DATE OF CANCELLATION.

2. IF THE POLICY IS CANCELED BEFORE ITS EXPIRATION DATE FOR THE NON-PAYMENT OF PREMIUM, THE ISSUING COMPANY SHALL PROVIDE CITY AT LEAST A TEN (10) DAY WRITTEN NOTICE BEFORE THE EFFECTIVE DATE OF CANCELLATION.

V. PROPOSER CERTIFIES THAT PROPOSER'S INSURANCE COVERAGE MEETS THE ABOVE REQUIREMENTS:

THE INFORMATION HEREIN IS CERTIFIED CORRECT BY SIGNATURE(S) BELOW. SIGNATURE(S) MUST BE SAME SIGNATURE(S) AS APPEAR(S) ON SECTION II, ATTACHMENT A, PROPOSER'S INFORMATION FORM.

Firm: ____

Signature: ______________________________________

Name: ______________________________________
(Print or type name)

Signature: ______________________________________

Name: ______________________________________
(Print or type name)

NOTICES SHALL BE MAILED TO:

PURCHASING AND
CONTRACT ADMINISTRATION
CITY OF PALO ALTO
P.O. BOX 10250
PALO ALTO, CA 94303.

EXHIBIT "PPA-F"

Notices

Contract Administration

BUYER:	SELLER:
City of Palo Alto Utilities Resource Management 250 Hamilton Avenue Palo Alto, CA 94301 Ph: 650-329-2689 Email: UtilityCommoditySettlements@CityofPaloAlto.Org	

Billing and Settlements

BUYER:	SELLER:
City of Palo Alto Utilities Resource Management 250 Hamilton Avenue Palo Alto, CA 94301 Ph: 650-329-2689 Email: UtilityCommoditySettlements@CityofPaloAlto.Org	

Forecasting and Outage Reporting under Section 6 of this Agreement

Planned Outages:

BUYER:	SELLER:
Northern California Power Agency Real-Time Dispatch 651 Commerce Drive Roseville, CA 95678 Ph: 916-786-3518	

Forced Outages

BUYER:	SELLER:
Northern California Power Agency Real-Time Dispatch 651 Commerce Drive Roseville, CA 95678 Ph: 916-786-3518	

Forecasting and Scheduling

BUYER:	SELLER:
Northern California Power Agency Operations and Pre-Scheduling 651 Commerce Drive Roseville, CA 95678 Ph: 916-786-0123	

EXHIBIT "PPA-G"

Form of Lender Consent and Agreement

This CONSENT AND AGREEMENT (this "Consent"), dated as of _ _ , 20_ , is entered into by and among the CITY OF PALO ALTO, a California chartered municipal corporation (the "City"), ______________________________, a _________ corporation (the "Lender")," by its agent, ___________________________ (the "Administrative Agent"), and , a _______________corporation (the "Borrower") (collectively, the "Parties"). Unless otherwise defined, all capitalized terms have the meaning given in the Contract (as hereinafter defined).

RECITALS

A. Borrower intends to develop, construct, install, test, own, operate and use an approximately MW electric generating facility located in the city of Palo Alto in the State of California, known as the Project (the "Project").

B. In order to partially finance the development, construction, installation, testing, operation and use of the Project, Borrower has entered into that certain financing agreement dated as of __ (as amended, amended and restated, supplemented or otherwise modified from time to time, the "Financing Agreement"), among Borrower, the financial institutions from time to time parties thereto (collectively, the "Lenders") , and Administrative Agent for the Lenders, pursuant to which, among other things, Lenders have extended commitments to make loans and other financial accommodations to, and for the benefit of, Borrower.

C. The City and Borrower have entered into that certain Power Purchase Agreement, dated as of ______________(attached hereto and incorporated herein by reference, as amended, amended and restated, supplemented or otherwise modified from time to time in accordance with the terms thereof and hereof, the "Power Purchase Agreement").

D. The City and Borrower have entered into that certain Interconnection Agreement, dated as of _____________ (attached hereto and incorporated herein by reference, as amended, amended and restated, supplemented or otherwise modified from time to time in accordance with the terms thereof and hereof, the "Interconnection Agreement").

E. Pursuant to a security agreement executed by Borrower and Administrative Agent for the Lenders (as amended, amended and restated, supplemented or otherwise modified from time to time, the "Security Agreement"), Borrower has agreed, among other things, to assign, as collateral security for its obligations under the Financing Agreement and related documents (collectively, the "Financing Documents"), all of its right, title and interest in, to and under the Power Purchase Agreement and Interconnection Agreement to Administrative Agent for the benefit of itself, the Lenders and each other entity or person providing collateral security under the Financing Documents.

F. It is a requirement under the Financing Agreement that the Parties hereto execute this Consent.

AGREEMENT

NOW THEREFORE, for good and valuable consideration, the receipt and adequacy of which are hereby acknowledged, and intending to be legally bound, the Parties agree, as follows:

1. CONSENT TO ASSIGNMENT. The City acknowledges the assignment referred to in Recital E above, consents to an assignment of the Power Purchase Agreement and Interconnection Agreement pursuant thereto, and agrees with Administrative Agent, as follows:

(a) Administrative Agent shall be entitled (but not obligated) to exercise all rights and to cure any defaults of Borrower under the Power Purchase Agreement or Interconnection Agreement, as the case may be, subject to applicable notice and cure periods provided in the Power Purchase Agreement and Interconnection Agreement. Upon receipt of notice from Administrative Agent, the City agrees to accept such exercise and cure by Administrative Agent if timely made by Administrative Agent under the Power Purchase Agreement or Interconnection Agreement, as the case may be, and this Consent. Upon receipt of Administrative Agent's written instructions and to the extent allowed by law, the City agrees to make directly to such account as Administrative Agent may direct the City, in writing, from time to time, all payments to be made by the City to Borrower under the Power Purchase Agreement or Interconnection Agreement, as the case may be, from and after the City’s receipt of such instructions, and Borrower consents to any such action. The City shall not incur any liability to Borrower under the Power Purchase Agreement, Interconnection Agreement, or this Consent for directing such payments to Administrative Agent in accordance with this subsection (a).

(b) The City will not, without the prior written consent of Administrative Agent (such consent not to be unreasonably withheld), (i) cancel or terminate the Power Purchase Agreement or Interconnection Agreement, or consent to or accept any cancellation, termination or suspension thereof by Borrower, except as provided in the Power Purchase Agreement or Interconnection Agreement and in accordance with subparagraph 1(c) hereof, (ii) sell, assign or otherwise dispose (by operation of law or otherwise) of any part of its interest in the Power Purchase Agreement or Interconnection Agreement, except as provided in the Power Purchase Agreement or Interconnection Agreement, or (iii) amend or modify the Power Purchase Agreement or Interconnection Agreement in any manner materially adverse to the interest of the Lenders in the Power Purchase Agreement and Interconnection Agreement as collateral security under the Security Agreement.

(c) The City agrees to deliver duplicates or copies of all notices of default delivered by the City under or pursuant to the Power Purchase Agreement or Interconnection Agreement to Administrative Agent in accordance with the notice provisions of this Consent. The City shall deliver any such notices concurrently with delivery of the notice to Borrower under the Power Purchase Agreement or Interconnection Agreement. To the extent that a cure period is provided under the Power Purchase Agreement or Interconnection Agreement, Administrative Agent shall have the same period of time to cure the breach or default that Borrower is entitled to under the Power Purchase Agreement or Interconnection Agreement, except that if the City does not deliver the default notice to Administrative Agent concurrently with delivery of the notice to Borrower under the Power Purchase Agreement or Interconnection Agreement, then as to Administrative Agent, the applicable cure period under the Power Purchase Agreement or Interconnection Agreement shall begin on the date on which the notice is given to Administrative Agent. If possession of the Project is necessary to cure such breach or default, and Administrative Agent or its designee(s) or assignee(s) declare Borrower in default and commence foreclosure proceedings, Administrative Agent or its designee(s) or assignee(s) will be allowed a reasonable period to complete such proceedings so long as Administrative Agent or its designee(s) continue to perform any monetary obligations under the Power Purchase Agreement or Interconnection Agreement, as the case may be. The City consents to the transfer of Borrower's interest under the Power Purchase Agreement and Interconnection Agreement to the Lenders or Administrative Agent or their designee(s) or assignee(s) or any of them or a purchaser or grantee at a foreclosure sale by judicial or nonjudicial foreclosure and sale or by a conveyance by Borrower in lieu of foreclosure and agrees that upon such foreclosure, sale or conveyance, the City shall recognize the Lenders or Administrative Agent or their designee(s) or assignee(s) or any of them or other purchaser or grantee as the applicable party under the Power Purchase Agreement and Interconnection Agreement (provided that such Lenders or Administrative Agent or their designee(s) or assignee(s) or purchaser or grantee assume the obligations of Borrower under the Power Purchase Agreement and Interconnection Agreement, including, without limitation, satisfaction and compliance with all credit provisions of the Power Purchase Agreement and Interconnection Agreement, if any, and provided further that such Lenders or Administrative Agent or their designee(s) or assignee(s) or purchaser or grantee has a creditworthiness equal to or better than

Borrower, as reasonably determined by City).

(d) In the event that either the Power Purchase Agreement or Interconnection Agreement, or both is rejected by a trustee or debtor-in-possession in any bankruptcy or insolvency proceeding, and if, within forty-five (45) days after such rejection, Administrative Agent shall so request, the City will execute and deliver to Administrative Agent a new power purchase agreement or interconnection agreement, as the case may be, which power purchase agreement or interconnection agreement shall be on the same terms and conditions as the original Power Purchase Agreement or Interconnection Agreement for the remaining term of the original Power Purchase Agreement or Interconnection Agreement before giving effect to such rejection, and which shall require Administrative Agent to cure any defaults then existing under the original Power Purchase Agreement or Interconnection Agreement. Notwithstanding the foregoing, any new renewable power purchase agreement or interconnection agreement will be subject to all regulatory approvals required by law. The City will use good faith efforts to promptly obtain any necessary regulatory approvals.

(e) In the event Administrative Agent, the Lenders or their designee(s) or assignee(s) elect to perform Borrower's obligations under the Power Purchase Agreement and Interconnection Agreement, succeed to Borrower’s interest under the Power Purchase Agreement and Interconnection Agreement, or enter into a new power purchase agreement or interconnection agreement as provided in subparagraph 1(d) above, the recourse of the City against Administrative Agent, Lenders or their designee(s) and assignee(s) shall be limited to such Parties’ interests in the Project, and the credit support required under the Power Purchase Agreement and Interconnection Agreement, if any.

(f) In the event Administrative Agent, the Lenders or their designee(s) or assignee(s) succeed to Borrower's interest under the Power Purchase Agreement and Interconnection Agreement, Administrative Agent, the Lenders or their designee(s) or assignee(s) shall cure any then-existing payment and performance defaults under the Power Purchase Agreement or Interconnection Agreement, except any performance defaults of Borrower itself, which by their nature are not susceptible of being cured. Administrative Agent, the Lenders and their designee(s) or assignee(s) shall have the right to assign all or a pro rata interest in the Power Purchase Agreement and Interconnection Agreement to a person or entity to whom Borrower’s interest in the Project is transferred, provided such transferee assumes the obligations of Borrower under the Power Purchase Agreement and Interconnection Agreement and has a creditworthiness equal to or better than Borrower, as reasonably determined by the City. Upon such assignment, Administrative Agent and the Lenders and their designee(s) or assignee(s) (including their agents and employees) shall be released from any further liability thereunder accruing from and after the date of such assignment, to the extent of the interest assigned.

2. REPRESENTATIONS AND WARRANTIES. The City hereby represents and warrants that as of the date of this Consent:

(a) It (i) is duly formed and validly existing under the laws of the State of California, and (ii) has all requisite power and authority to enter into and to perform its obligations hereunder and under the Power Purchase Agreement and Interconnection Agreement, and to carry out the terms hereof and thereof and the transactions contemplated hereby and thereby;

(b) the execution, delivery and performance of this Consent, the Power Purchase Agreement and the Interconnection Agreement have been duly authorized by all necessary action on its part and do not require any approvals, material filings with, or consents of any entity or person which have not previously been obtained or made;

(c) each of this Consent, the Power Purchase Agreement, and the Interconnection Agreement is in full force and effect;

(d) each of this Consent, the Power Purchase Agreement, and the Interconnection Agreement has been duly executed and delivered on its behalf and constitutes its legal, valid and binding obligation, enforceable against it in accordance with its terms, except as the enforceability thereof may be limited by (i) bankruptcy, insolvency, reorganization or other similar laws affecting the enforcement of creditors' rights generally and (ii) general equitable principles (whether considered in a proceeding in equity or at law);

(e) there is no litigation, arbitration, investigation or other proceeding pending for which the City has received service of process or, to the City's actual knowledge, threatened against the City relating solely to this Consent, the Power Purchase Agreement, or the Interconnection Agreement and the transactions contemplated hereby and thereby;

(f) the execution, delivery and performance by it of this Consent, the Power Purchase Agreement, and the Interconnection Agreement, and the consummation of the transactions contemplated hereby, will not result in any violation of, breach of or default under any term of any material contract or material agreement to which it is a party or by which it or its property is bound, or of any material requirements of law presently in effect having applicability to it, the violation, breach or default of which could have a material adverse effect on its ability to perform its obligations under this Consent;

(g) neither the City nor, to the City's actual knowledge, any other party to the Power Purchase Agreement or Interconnection Agreement, is in default of any of its obligations thereunder; and

(h) to the City's actual knowledge, (i) no Force Majeure Event exists under, and as defined in, the Power Purchase Agreement or Interconnection Agreement and (ii) no event or condition exists which would either immediately or with the passage of any applicable grace period or giving of notice, or both, enable either the City or Borrower to terminate or suspend its obligations under the Power Purchase Agreement or the Interconnection Agreement.

Each of the representations and warranties set forth herein shall survive the execution and delivery of this Consent and the consummation of the transactions contemplated hereby.

3. NOTICES. All notices required or permitted hereunder shall be given, in writing, and shall be effective (a) upon receipt if hand delivered, (b) upon telephonic verification of receipt if sent by facsimile and (c) if otherwise delivered, upon the earlier of receipt or three (3) Business Days after being sent registered or certified mail, return receipt requested, with proper postage affixed thereto, or by private courier or delivery service with charges prepaid, and addressed as specified below:

If to the City:
[___________________________________]
[___________________________________]
[___________________________________]
Telephone No.: [______________________]
Facsimile No.: [______________________]
Attn: [______________________________]

If to Administrative Agent:
[___________________________________]
[___________________________________]
[___________________________________]
Telephone No.: [______________________]
Facsimile No.: [______________________]
Attn: [______________________________]

If to Borrower:
[____________________________________]
[____________________________________]
[____________________________________]
Telephone No.: [______________________]
Facsimile No.: [_______________________]
Attn: [_______________________________]

Any party shall have the right to change its address for notice hereunder to any other location within the United States by giving thirty (30) days written notice to the other parties in the manner set forth above.

4. ASSIGNMENT, TERMINATION, AMENDMENT. This Consent shall be binding upon and benefit the successors and assigns of the Parties hereto and their respective successors, transferees and assigns (including without limitation, any entity that refinances all or any portion of the obligations under the Financing Agreement). The City agrees (a) to confirm such continuing obligation, in writing, upon the reasonable request of (and at the expense of) Borrower, Administrative Agent, the Lenders or any of their respective successors, transferees or assigns, and (b) to cause any successor-in-interest to the City with respect to its interest in the Power Purchase Agreement or Interconnection Agreement to assume, in writing and in form and substance reasonably satisfactory to Administrative Agent, the obligations of City hereunder. Any purported assignment or transfer of the Power Purchase Agreement or Interconnection Agreement not in conjunction with the written instrument of assumption contemplated by the foregoing clause (b) shall be null and void. No termination, amendment, or variation of any provisions of this Consent shall be effective unless in writing and signed by the parties hereto. No waiver of any provisions of this Consent shall be effective unless in writing and signed by the party waiving any of its rights hereunder.

5. GOVERNING LAW. This Consent shall be governed by the laws of the State of California applicable to contracts made and to be performed in California. The federal courts or the state courts located in California shall have exclusive jurisdiction to resolve any disputes with respect to this Consent with the City, Assignor, and the Lender or Lenders irrevocably consenting to the jurisdiction thereof for any actions, suits, or proceedings arising out of or relating to this Consent.

6. COUNTERPARTS. This Consent may be executed in one or more duplicate counterparts, and when executed and delivered by all the parties listed below, shall constitute a single binding agreement.

7. SEVERABILITY. In case any provision of this Consent, or the obligations of any of the Parties hereto, shall be invalid, illegal or unenforceable, the validity, legality and enforceability of the remaining provisions, or the obligations of the other Parties hereto, shall not in any way be affected or impaired thereby.

8. ACKNOWLEDGMENTS BY BORROWER. Borrower, by its execution hereof, acknowledges and agrees that neither the execution of this Consent, the performance by the City of any of the obligations of the City hereunder, the exercise of any of the rights of the City hereunder, or the acceptance by the City of performance of the Power Purchase Agreement by any party other than Borrower shall (1) release Borrower from any obligation of Borrower under the Power Purchase Agreement or Interconnection Agreement, (2) constitute a consent by the City to, or impute knowledge to the City of, any specific terms or conditions of the Financing Agreement, the Security Agreement or any of the other Financing Documents, or (3) except as expressly set forth in this Consent, constitute a waiver by the City of any of its rights under the Power Purchase Agreement or Interconnection Agreement. Borrower and Administrative Agent acknowledge hereby for the benefit of City that none of the Financing Agreement, the Security

Agreement, the Financing Documents or any other documents executed in connection therewith alter, amend, modify or impair (or purport to alter, amend, modify or impair) any provisions of the Power Purchase Agreement.

CITY OF PALO ALTO

APPROVED AS TO FORM

____
Senior Deputy City Attorney

APPROVED

____
City Manager

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Director of Utilities

ADMINISTRATIVE AGENT

____

BORROWER

____

Utilities Advisory Commission
Staff Report

From: Dean Batchelor, Director Utilities
Lead Department: Utilities

Meeting Date: March 6, 2024
Staff Report: 2401-2477

TITLE
Staff Recommend the Utilities Advisory Commission Recommend that the City Council Adopt a Resolution: 1) Approving the FY 2025 Wastewater Collection Utility Financial Plan 2) Amending Rate Schedules S-1 (Residential Wastewater Collection and Disposal), S-2 (Commercial Wastewater Collection and Disposal), S-6 (Restaurant Wastewater Collection and Disposal) and S-7 (Commercial Wastewater Collection and Disposal – Industrial Discharger), and 3) Approving up to a $3 million enterprise transfer loan from the Fiber Optics Fund to the Wastewater Collection Utility's Operations Reserve in FY 2024.

RECOMMENDATION
Staff request that the Utilities Advisory Commission (UAC) recommend that the City Council adopt a resolution (Attachment A):

1. Approving the Fiscal Year (FY) 2025 Wastewater Collection Financial Plan (Attachment A, Exhibit 1); and
2. Increasing Wastewater Collection Utility Rates Via the Amendment of Rate Schedules S-1 (Residential Wastewater Collection and Disposal), S-2 (Commercial Wastewater Collection and Disposal), S-6 (Restaurant Wastewater Collection and Disposal) and S-7 (Commercial Wastewater Collection and Disposal – Industrial Discharger) (Attachment A, Exhibit 2); and
3. Approving up to a $3 million enterprise transfer loan from the Fiber Optics Fund to the Wastewater Collection Utility's Operations Reserve in FY 2024.

EXECUTIVE SUMMARY
The fiscal year (FY) 2025 Wastewater Collection Utility Financial Plan (Attachment A, Exhibit 1) includes projections of the utility's costs and revenues through FY 2029. The Financial Plan anticipates costs will rise over the forecast horizon due to increasing treatment costs related to capital improvements and operational costs at the Regional Water Quality Control Plant (RWQCP), as well as increasing collection system operational and Capital Improvement Program (CIP) costs.

In 2023, the Council approved the first in a series of rate increases which incorporated expected costs for the City to accelerate its rate of sewer main replacements from 1 mile to 2.5 miles per year by FY 26 (implemented as a major sewer replacement project of 5 miles every other year). The accelerated rate of main replacement was calculated to replace all aging sewer mains within 8 years beyond their 100-year life expectancy. Additionally, in FY 2023 the Wastewater Utility accelerated by a year the most expensive sewer main replacement that the utility has ever completed (Staff Report 2301-0808, May 8, 2023 approving contract for Sanitary Sewer Replacement Project 31, WC-19001). Council approved transfers of all funds from the CIP Reserve ($3.178 million) and from the Rate Stabilization Reserve ($0.34 million) to the Operations Reserve to utilize all available funds to accelerate construction in coordination with Caltrans' repaving plans for the affected section of El Camino. Staff projected that expenditures related to Sanitary Sewer Replacement Project 31 would bring the Operations Reserve temporarily down to the minimum guideline range.

However, in FY 2023, costs were higher than forecasted, primarily for CIP-related costs (e.g., construction cost, CIP allocated costs, salaries and benefits not assigned to a specific CIP project) and transfers out to capital projects. Concurrently, revenue was lower than forecasted (primarily capacity fee revenue) and as a result, the Operations Reserve ended the year with a negative balance of $0.7 million. Additionally, in the current year, the Wastewater Utility increased rates by 9% for non-residential customers, however revenues (other than restaurants) are projected to decline by 4% from FY 2023. This may be due to wet weather and reductions in winter water usage.

In an effort to increase the currently low reserve levels, staff recommends a 15% rate increase in FY 2025, which is equivalent to $7.29 per month per residential customer. This proposal would include proceeding with a reduced-size main replacement in FY 2026 of 1.25 miles instead of 5 miles due to the low reserve and revenue levels. This would allow the highest priority mains to be replaced while allowing the reserves to replenish before the next major project. The 5-mile sewer main replacement every other year would resume with construction scheduled in FY 2028. With this schedule of main replacement, the last remaining sewer main would be 110 years old at the time it is replaced instead of 108 years old.

Staff presented a 9% preliminary wastewater rate increase to the Utilities Advisory Commission[1] (UAC) in January. Commissioners suggested staff consider a higher rate increase to reduce the amount of capital deferral and to restore reserve balances. Commissioners noted Palo Alto's favorable sewer rates compared with neighboring agencies, the need to address low reserve levels, and the need to not further defer capital. The attached Financial Plan includes an alternative with a 9% rate increase each year that considers fully deferring sewer main replacement until FY 2028. This alternative would provide sufficient funding for the last remaining sewer main to be 111 years old at the time it is replaced while maintaining Palo Alto's rates below the rates of neighboring agencies.

[1] Staff Report 2309-2080 https://www.cityofpaloalto.org/files/assets/public/v/2/agendas-minutes-reports/agendas-minutes/utilities-advisory-commission/archived-agenda-and-minutes/agendas-and-minutes-2024/01-jan-2024/01-03-2024-packet.pdf .

Operating wastewater assets past their useful life increases the likelihood of substantial pipe failures potentially resulting in additional repair and maintenance costs, sanitary sewer overflows, sinkholes, or other catastrophic impacts. Both of the alternative rate increases and their associated infrastructure delays presented here attempt to minimize ratepayer impacts while also prudently managing the City's infrastructure and maintaining an acceptable level of risk.

BACKGROUND

Every year staff presents the UAC with Financial Plans for the Electric, Gas, Water, and Wastewater Collection Utilities. The Financial Plans recommend rate adjustments if necessary to maintain the financial health of these enterprises. These Financial Plans include a comprehensive overview of the operations of each enterprise, both retrospective and prospective, and are intended to be a reference for UAC, Finance Committee, and 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 City's sewer system collects wastewater from Palo Alto residents and delivers it to the RWQCP for treatment. The City of Palo Alto runs the RWQCP, which also treats wastewater for five other partner agencies (Stanford, East Palo Alto Sanitary District, Los Altos Hills, Los Altos, and Mountain View). Some of the wastewater for certain partner agencies is also transported across the City's wastewater collection system.

The Wastewater Collection Utility has two main costs: the costs of operating the collection system and Palo Alto's share of the cost of running the RWQCP (treatment costs).[2] Both cost components have been increasing and are expected to continue to increase. Increases in collection system capital costs are primarily driving the increased collection system costs. The utility is in the process of increasing the rate of sewer main replacement projects from 1 mile to 2.5 miles per year (going from 2 miles to 5 miles per project constructed every other year) to fulfill the goal of replacing pipes near their life expectancy. Staff's experience suggests that pipe can last around 100 years in Palo Alto's underground condition. At the conclusion of the currently ongoing main replacement, there will be 136 miles of original sewer mains to be replaced or rehabilitated and most of these are vitrified clay pipe originally installed between 1950 and 1970. Staffing and inspection capacity exists to replace 2.5 miles per year on average. Reducing the size of the sewer main replacement in FY 2026 and beginning the first 5-mile main replacement project in FY 2028, the ~60 year cycle of replacement will mean the last sewer main replaced is 110 years old at the time it is replaced. Additionally, staff expects construction cost inflation to impact future main replacement costs and assumes this alone will increase CIP costs 5.4% annually.

[2] The costs associated with the RWQCP are shared among Palo Alto and the partner agencies based primarily on wastewater flows and the composition of the wastewater each agency sends to the treatment plant. Palo Alto's share varies from year to year but is roughly one third of the total cost.

The RWQCP (Treatment Plant) has been in operation since 1934. Aging equipment, new regulatory requirements, and the movement to full sustainability will require rehabilitation, replacement and new processes. Debt service for the plant is expected to increase substantially in coming years as a major rehabilitation and replacement plan adopted in 2012 (Long Range Facilities Plan[3]) is implemented. For example, the $193 million Secondary Treatment Upgrades capital project is in construction, and the $51.7 million Headworks Facility is in engineering contract negotiations. The RWQCP is also beginning an update to the Long Range Facilities Plan and plans to begin this work in 2024 and complete the plan in 2026. The results of this work will direct future CIP work at the Treatment Plant. Additionally, the plan will re-evaluate the cost of service for annual operating shares and re-evaluate the fixed allocation capacity shares for each partner.

ANALYSIS

Staff completes an annual assessment of the financial position of the City's wastewater collection utility to ensure adequate revenue to fund operations, in compliance with the cost of service requirements set forth in the California Constitution (Proposition 218). 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. The rates proposed in this Financial Plan were developed based on the 2021 Cost of Service and Rate Study completed by Raftelis Financial Consultants, Inc., the "City of Palo Alto 2021 Wastewater COS Report."[4]

The FY 2025 Wastewater Collection Financial Plan describes Council's proposed actions in detail. staff recommends increasing wastewater rates as shown in Table 1 below, effective July 1, 2024, with a system average rate increase of 15%, as shown in the amended rate schedules included as Attachment A, Exhibit 2. Additionally, staff added an alternative rate proposal with a 9% rate increase, which was the preliminary rate proposal presented to the UAC in January. This alternative is described in more detail in the FY 2025 Financial Plan (Attachment A, Exhibit 1) and outlined in the amended rate schedules shown in Attachment A, Exhibit 3. Table 2 below shows the residential bill impacts of the rate proposal compared to the alternative.

Residential customers pay a monthly fixed sewer service charge while commercial customers (other than restaurants) are billed monthly based on average winter water usage for the months of January, February and March, applied in the following July. This closely approximates non-irrigation water consumption, which represents sewer use. Restaurant customers are charged based on monthly water usage as they generally lack irrigation but are charged higher rates due to higher grease and oil discharges necessitating additional treatment costs. Currently there are

[3] Long Range Facilities Plan https://www.cityofpaloalto.org/files/assets/public/v/1/public-works/water-quality-control-plant/lrfp-final-report-08-2012.pdf

[4] A cost of service study is a study using industry-standard techniques to determine how the costs of running the utility should be recovered from its customers. Charges to each customer are set in proportion to the cost of serving that customer. https://www.cityofpaloalto.org/files/assets/public/v/1/agendas-minutes-reports/reports/city-manager-reports-cmrs/attachments/08-09-2021-id-12378-att-f-2021-wastewater-cos-report.pdf

no customers on the S-7 (Industrial) rate schedule; however, CPAU continues to maintain the S-7 rate schedule in case of future need.

Table 1: Current and Projected Wastewater Collection Charges With 15% System Average Rate Increase in FY 2025

		Current (as of 7/1/2023)	Proposed (effective 7/1/2024)	Change	
				$	%
Monthly Service Charges ($/Month)					
S-1 (Residential)	Service Charge	$ 48.64	$55.93	$ 7.29	15%
Water Quantity Rates ($/CCF)					
S-2 (Commercial)	Quantity Rates	9.08	10.44	1.36	15%
S-6 (Restaurant)	Quantity Rates	13.55	15.58	2.03	15%

<u>FY 2025 Financial Plan's Rate Adjustments for the Next Five Fiscal Years</u>
Table 2 shows the residential wastewater bill impact of the rate adjustment proposal compared with the alternative included in the Wastewater Collection Utility Financial Plan.

Table 2: Projected Residential Bill Impact, Rate Increase Percentage, Estimated Monthly Sewer Bill, and Net Difference in Monthly Bills FY 2025 to FY 2029

	Alternatives	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Estimated Bill Impact for Residential Customers ($/mo.) and Rate Increase Percentage (1)	Proposal: 15% in FY 2025	*7.29*	*5.03*	*5.48*	*5.31*	*5.02*
		15%	*9%*	*9%*	*8%*	*7%*
	Alternative: 9% in FY 2025	*4.37*	*4.77*	*5.20*	*5.66*	*6.17*
		9%	*9%*	*9%*	*9%*	*9%*
Estimated Monthly Sewer Bill ($)	Proposal: 15% in FY 2025	*55.93*	*60.96*	*66.44*	*71.75*	*76.77*
	Alternative: 9% in FY 2025	*53.01*	*57.78*	*62.98*	*68.64*	*74.81*
Net Difference in Monthly Bills ($)	15% vs. 9% in FY 2025	*2.92*	*3.18*	*3.46*	*3.11*	*1.96*

(1) estimated impact on residential wastewater monthly bill, which is currently $48.64.

The difference between the 15% and 9% scenarios is $2.92 per residential customer per month in FY 2025 and ranges from $3.46 in FY 2027 to $1.96 per month per residential customer by the end of the forecast period.

The proposal would decrease the duration the sewer main assets are operated past their estimated useful life and allow for the highest priority main to be replaced in FY 2026. The longer that wastewater assets are operated past their useful life, the greater the risk of substantial pipe failures, potentially resulting in additional repair and maintenance costs, sanitary sewer overflows, sinkholes, or other catastrophic impacts. Table 3 shows the alternate rate scenarios and estimated age of the last remaining sewer main replaced for each alternative.

Table 3: Alternate Scenarios for Wastewater Rate Changes

	FY 2025 – FY 2026 Main Replacement [a]		FY 2025	FY 2026	FY 2027	FY 2028	FY 2029	Age of Last Remaining Sewer Main Replaced
	Budget	Length (miles)						
Proposal: 15% in FY 2025	$3M	~ 1.25	15%	9%	9%	8%	7%	110 years
			$7.29	***$5.03***	***$5.48***	***$5.31***	***$5.02***	
Alternative: 9% in FY 2025	$0	0	9%	9%	9%	9%	9%	111 years
			$4.37	***$4.77***	***$5.20***	***$5.66***	***$6.17***	

a) The estimated budget for a 5-mile sewer main replacement in FY 2025 – FY 2026 is $11.6 million.

As noted above, one of the main drivers for the increase in the Wastewater Collection Utility's costs (and therefore rates) over the next several years is the cost for wastewater treatment, which is projected to increase by an average of 7.2% annually from FY 2024 to FY 2029 as the City makes several upgrades to the aging RWQCP. Increases to capital expenses begin in FY 2024 with the Joint Intercepting Sewer Rehabilitation construction, funded on a pay-as-you-go basis. The Wastewater Utility begins to pay for debt service for major projects beginning with the Primary Sedimentation Tank in FY 2025, Outfall Line Construction in FY 2027, Secondary Treatment Upgrades in FY 2029 and Headworks in FY 2030.

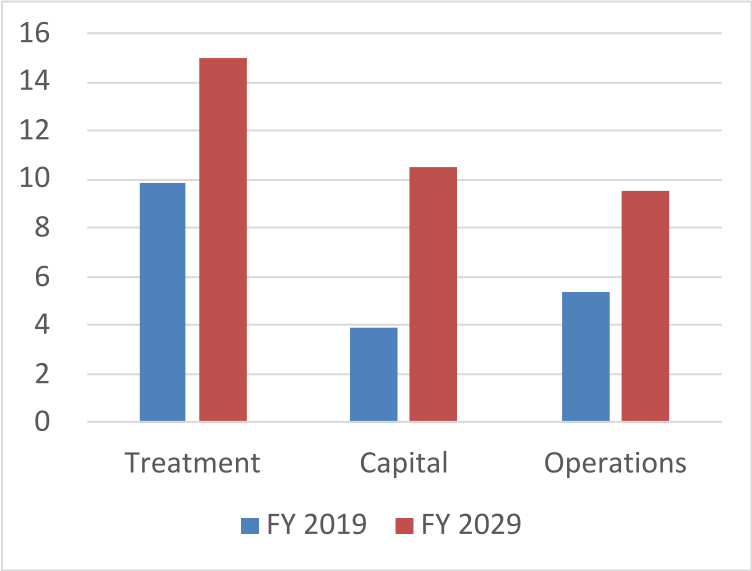
Staff anticipates Wastewater Collection operations and CIP costs (excluding costs associated with treatment) will increase by approximately 9.6% annually from FY 2024 to FY 2029. The Wastewater Collection Utility undertakes a larger main replacement project every other year. Undertaking a large main replacement project every other year will allow staff to continue replacing wastewater mains that are in poor condition, while easing scheduling difficulties for inspection coverage due to shared staffing across water, wastewater, gas, and large development services projects. Over the last few years, main replacement costs have been increasing for utilities due to economic activity in the Bay Area causing construction cost inflation. Utilities has bid one sewer project since the pandemic began. There are no indications of a decrease in construction costs in the near future.[5]

Figure 1 and 2 below illustrate the increase in the Wastewater Collection Utility's costs. RWQCP costs for the Wastewater Collection Utility are included in "Treatment," while "Capital" and "Operations" include only collection system costs. 31% of the increase from FY 2019 to FY 2029

[5] As an additional reference, the California Construction Cost index from December 2022 to December 2023 was 9.4%. See: https://www.dgs.ca.gov/RESD/Resources/Page-Content/Real-Estate-Services-Division-Resources-List-Folder/DGS-California-Construction-Cost-Index-CCCI

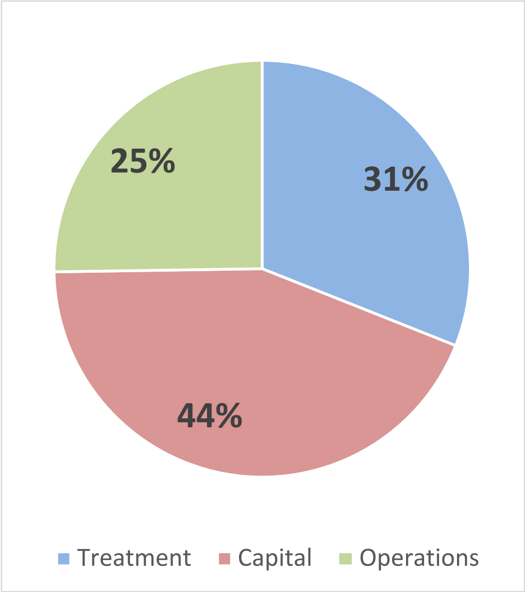
is due to treatment cost increases, 25% is due to increases in operations costs, and collection capital costs are responsible for 44% of the increase.

Figure 1: FY 2019 and FY 2029 Costs ($ Millions)*



* In Figure 1, FY 2019 Capital represents an average of capital costs in FY 2019 and FY 2020 and the FY 2029 Capital represents the capital program contribution from the Operations Reserve to the CIP Reserve.

Figure 2: Percentage of Cost Increase from FY 2019 to FY 2029 Attributed to Treatment, and Operations Costs



To promote rate stability and provide continuity in collection system CIP expenditure levels, in 2021 the Council approved a steady annual capital program contribution from the Operations Reserve to the CIP Reserve. The CIP Reserve would then absorb annual spending fluctuations, reducing the impact on the Operations Reserve. However, all of the funding was transferred out of the CIP Reserve in FY 2023 to pay for the ongoing Sanitary Sewer Replacement Project 31 on El Camino (estimated to be completed in May 2024), and the year-end FY 2023 Operations Reserve is low. In the short-term there is not sufficient funding to continue the annual Capital Program Contribution to the CIP Reserve. Furthermore, the Wastewater Collection Utility Reserves Management Practices state that if, at the end of any fiscal year, the minimum guideline is not met in the CIP or Operations Reserve, staff shall present a plan to the City Council to replenish the reserve.[6]

The attached Financial Plan recommends increasing rates necessary to cover rising costs and restore reserves over the five year forecast. Figure 3 below shows the projected CIP Reserve balances; the reserve would remain above the minimum guideline in FY 2030 and each subsequent year.

Given the low reserves, and the projected levels of revenue and expenses, there is a risk that the short-term need for cash will exceed available cash. For this reason, this Financial Plan recommends Council approve a loan transfer up to $3 million from the Fiber Optics fund in FY 2024 to cover the potential shortfall of cash in the Wastewater Utility. The Wastewater utility would repay the loan in FY 2026 at a rate equal to the City’s portfolio rate plus 0.25%

Figure 4 below shows year-end reserve balance levels for each reserve from FY 2024 projected through FY 2029. Table 4 shows reserve starting and ending balances, revenues, transfers expenses, capital program contribution and operations reserve guideline levels from FY 2024 to FY 2029.

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[6] *See* Appendix C, Wastewater Collection Utility Reserves Management Practices Section 7(b) and 5(c).

Figure 3: Projected Capital Reserve Balances, FY 2025 to FY 2029

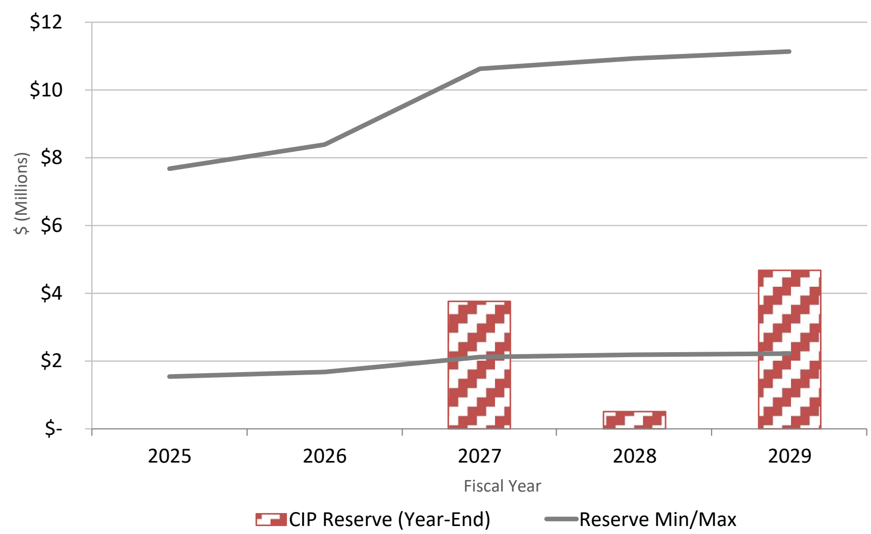

Figure 4: Wastewater Collection Utility Year-End Reserve Levels, FY 2022 to FY 2029

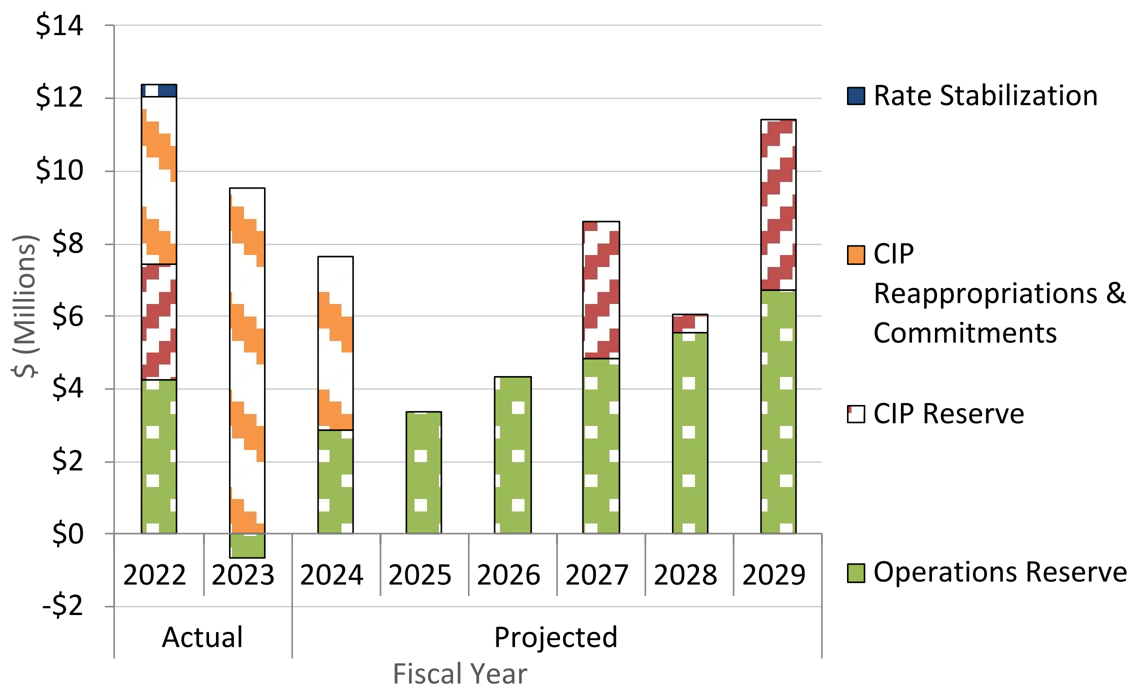

Table 4: Operations, Rate Stabilization and CIP Reserves Starting and Ending Balances, Revenues, Transfers To/(From) Reserves, Expenses, Capital Program Contribution To/(From) Reserves, and Operations Reserve Guideline Levels for FY 2024 to FY 2029 ($000)

	Fiscal Year	2024	2025	2026	2027	2028	2029
	Starting Balance						
(1)	Operations	(674)	2,875	3,371	4,342	4,837	5,568
(2)	Rate Stabilization	0	0	0	0	0	0
(3)	CIP	0	0	0	0	3,757	500
	Revenues						
(4)	Total Revenue	26,678	26,382	29,033	31,863	34,370	36,746
	Transfers						
(5)	Operations	0	0	0	0	0	0
(6)	Rate Stabilization	0	0	0	0	0	0
(7)	CIP	0	0	0	0	0	0
	CIP Reappropriations/Commitments						
	Capital Program Contribution*						
(8)	Operations	0	0	0	(10,200)	(11,659)	(11,139)
(9)	CIP	0	0	0	10,200	11,659	11,139
	Expenses						
(10)	Total Expenses (w/o CIP and Debt)	(20,308)	(21,758)	(22,859)	(21,168)	(21,980)	(24,433)
(11)	Debt Service	(129)	0	0	0	0	0
(12)	Planned CIP	(2,691)	(4,128)	(5,202)	(6,443)	(14,916)	(6,951)
	Ending Balance						
(1)+(4)+(5)+(8)+(10)+(11)+(12) thru FY 2026 (1)+(4)+(5)+(8)+(10)+(11) in FY 2027 on	Operations	2,875	3,371	4,342	4,837	5,568	6,743
(2)+(6)	Rate Stabilization	0	0	0	0	0	0
(3)+(7)+(9)+(12) in FY 2027 on	CIP	0	0	0	3,757	500	4,687
	Operations Reserve Guideline Levels						
(13)	Minimum Guideline Level	3,360	3,577	3,758	3,480	3,613	4,016
(14)	Maximum Guideline Level	8,399	8,942	9,394	8,699	9,033	10,041

* Capital Program Contribution to resume in FY 2027

* Planned CIP (item 12) is reflected as an expense in the CIP Reserve in FY 2027 – FY 2029 and does not include CIP funded through Reappropriations or Commitments reserves.

<u>Wastewater Bill Comparison with Surrounding Cities</u>

The monthly equivalent sewer bill for a Palo Alto resident is $48.64 under current rates, 26% lower than the average neighboring community. Table 5 shows the monthly sewer bills at current rates for residential customers compared to what they would be in surrounding communities. These communities are the same six cities that Palo Alto compares itself to in the annual budget across Water, Wastewater, Gas, and Electric utilities.

Table 5: Residential Monthly Equivalent Sewer Bill Comparison ($) at Current Rates

Palo Alto	Neighboring Community Average	Neighboring Communities					
		Menlo Park	Redwood City	Santa Clara	Mountain View	Los Altos	Hayward
48.64	65.38	108.83	89.28	48.28	53.10	51.47	41.29

If Council adopts a 15% rate increase in FY 2025, and assuming other agencies do not change their sewer rates, Palo Alto's residential rates would remain 14% lower than the current average neighboring community in FY 2025. Given the similar ages of treatment and collection facilities in the Bay Area, it is likely that surrounding jurisdictions will experience rate increases in the coming years. If Council adopts the 9% wastewater rate increase alternative in FY 2025, and assuming other agencies do not change their sewer rates, Palo Alto's residential rates would remain 19% lower than the current average neighboring community. Staff has no information at this time as to whether or when the surrounding communities are planning wastewater rate changes. However, as most agencies are also requiring renovations to their respective treatment plants, increases at other agencies are likely. Note that as partners in the RWQCP, Mountain View and Los Altos will be affected by similar treatment cost increases as Palo Alto.

Table 6 shows the monthly sewer bills for Commercial and Restaurant customers. Palo Alto has higher commercial sewer rates than several surrounding cities but is not the most expensive jurisdiction. Palo Alto's commercial bills are 9% higher than the neighboring community average while Palo Alto's restaurant bills are 7% below the neighboring community average. Table 8 assumes 14 units of water for the general commercial use and 38 units of water for restaurant use.

Table 6 Non-Residential Monthly Equivalent Sewer Bill Comparison ($)

	Palo Alto	Neighboring Community Average	Neighboring Communities					
			Menlo Park	Redwood City	Santa Clara	Mountain View	Los Altos	Hayward
General Commercial	127.12	116.17	147.28	117.74	82.18	166.18	89.54	94.08
Restaurant	514.90	553.44	842.08	765.70	520.60	517.18	243.02	432.06

Changes from Prior Financial Forecasts

Table 7 compares the projected overall rate changes in the current Financial Plan with the projected rate changes in the FY 2024 Financial Plans.

Table 7: Proposed/Projected Wastewater Rate Changes for FY 2025 to FY 2029

Projection	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Staff Proposal in Current Plan (FY 2025) 15% in FY 2025	15%	9%	9%	8%	7%
Alternative (FY 2025) 9% in FY 2025	9%	9%	9%	9%	9%
FY 2024 Financial Plan	9%	9%	8%	5%	N/A

Next Steps

Staff is bringing the preliminary rate projections to the Finance Committee on February 21st and staff will describe the Finance Committee's recommendations to the UAC during the March UAC meeting. Assuming the UAC and the Finance Committee support the proposed rate adjustments, staff will send notification of the potential rate increases to customers as required by Article XIIID of the State Constitution (added by Proposition 218) expected in April 2024. The City Council will consider the proposed Financial Plans and amended rate schedules with the FY 2025 budget, expected in June, at which time the public hearing required by Article XIIID of the State Constitution will be held. If Council approves the proposed rate increases, they will become effective July 1, 2024. and

FISCAL/RESOURCE IMPACT

Staff anticipates normal year revenues for the Wastewater Collection Utility will increase by approximately $3.3 million in FY 2025 as a result of a 15% rate increase. Given the low operations reserve, and the projected levels of revenue and expenses, the attached Financial Plan recommends Council approve an enterprise loan transfer up to $3 million from the Fiber Optic fund in FY 2024 to the Wastewater Collection Fund Operations Reserve. The Wastewater Utility would repay any such loan in FY 2026 at a rate equal to the City's portfolio rate plus 0.25% (the portfolio rate is expected to be higher than the current rate of 2.47% and this financial plan assumes a rate of 3%). See the FY 2025 Wastewater Collection Utility Financial Plan for a more comprehensive overview of projected cost and revenue changes for the next five years. The FY 2025 Budget is being developed concurrent with these rates and depending on final rates, adjustments to the budget may be necessary at a later time.

STAKEHOLDER ENGAGEMENT

At the January 2024 UAC meeting, staff proposed a 9% wastewater rate increase in FY 2025 and Commissioners suggested a higher rate increase to avoid deferring the sewer infrastructure investment, especially given the City's favorable rates compared to neighboring agencies, and expressed concern about the low reserve balances and the need to replenish reserves. Staff now recommends a 15% system average rate increase in FY 2025 based upon the UAC's feedback. Staff discussed the proposals with the Finance Committee on February 21, 2024 and will describe the Finance Committee's feedback to the UAC during the March UAC meeting.

ENVIRONMENTAL REVIEW

The Utilities Advisory Commission's review and recommendation to Council on the proposed FY 2025 Wastewater Collection Financial Plan and rate adjustments do not meet the definition of a project, pursuant to Section 21065 of the California Environmental Quality Act, thus no environmental review is required.

ATTACHMENTS

Attachment A: Wastewater FY25 Resolution

Attachment B: Wastewater FY25 Presentation

AUTHOR/TITLE:

Dean Batchelor, Director of Utilities

Staff: Lisa Bilir, Senior Resource Planner

Attachment A

* NOT YET APPROVED *

Resolution No. ___

Resolution of the Council of the City of Palo Alto Approving the FY 2025 Wastewater Collection Utility Financial Plan, Including Reserve Transfers, and Adjusting Wastewater Rates by Amending Rate Schedules S-1 (Residential Wastewater Collection and Disposal), S-2 (Commercial Wastewater Collection and Disposal), S-6 (Restaurant Wastewater Collection and Disposal) and S-7 (Commercial Wastewater Collection and Disposal – Industrial Discharger)

R E C I T A L S

A. Each year the City of Palo Alto ("City") 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. The City 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 a 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 ________, 2024, the City Council held a full and fair public hearing regarding the proposed rate increase and considered all protests against the proposals.

E. As required by Article XIII D, Section 6 of the California Constitution and applicable law, notice of the_________, 2024 public hearing was mailed to all City of Palo Alto Utilities wastewater customers by________, 2024.

F. The City Clerk has tabulated the total number of written protests presented by the close of the public hearing, and determined that it was less than fifty percent (50%) of the total number of customers and property owners subject to the proposed wastewater rate amendments, therefore a majority protest does not exist against the proposal.

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

SECTION 1. The Council hereby adopts the FY 2025 Wastewater Collection Utility Financial Plan.

* NOT YET APPROVED *

SECTION 2. The Council hereby approves a transfer from the Fiber Optics Fund to the Wastewater Collection Fund Operations Reserve of up to $3,000,000 in FY 2024 as described in the FY 2025 Wastewater Collection Utility Financial Plan.

SECTION 3. Pursuant to Section 12.20.010 of the Palo Alto Municipal Code, Utility Rate Schedule S-1 (Residential Wastewater Collection and Disposal) is hereby amended to read as attached and incorporated. Utility Rate Schedule S-1, as amended, shall become effective July 1, 2024.

SECTION 4. Pursuant to Section 12.20.010 of the Palo Alto Municipal Code, Utility Rate Schedule S-2 (Commercial Wastewater Collection and Disposal) is hereby amended to read as attached and incorporated. Utility Rate Schedule S-2, as amended, shall become effective July 1, 2024.

SECTION 5. Pursuant to Section 12.20.010 of the Palo Alto Municipal Code, Utility Rate Schedule S-6 (Restaurant Wastewater Collection and Disposal) is hereby amended to read as attached and incorporated. Utility Rate Schedule S-6, as amended, shall become effective July 1, 2024.

SECTION 6. Pursuant to Section 12.20.010 of the Palo Alto Municipal Code, Utility Rate Schedule S-7 (Commercial Wastewater Collection and Disposal – Industrial Discharger) is hereby amended to read as attached and incorporated. Utility Rate Schedule S-7, as amended, shall become effective July 1, 2024.

SECTION 7. The Council finds that the revenue derived from the wastewater rates approved by this resolution do not exceed the funds required to provide wastewater service, and the revenue derived from the adoption of this resolution shall be used only for the purposes set forth in Article VII, Section 2, of the Charter of the City of Palo Alto.

SECTION 8. The Council finds that 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 *

SECTION 9. The Council finds that the adoption of this resolution approving the FY 2025 Wastewater Collection Utility Financial Plan does not meet the California Environmental Quality Act's 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 review is required. The Council finds that the adoption of this resolution changing Wastewater collection 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

FY 2025 WASTEWATER COLLECTION UTILITY FINANCIAL PLAN

FY 2025 TO FY 2029

FY 2025 WASTEWATER COLLECTION UTILITY FINANCIAL PLAN

FY 2025 TO FY 2029

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SECTION 1: DEFINITIONS AND ABBREVIATIONS

CCF The standard unit of measurement for water delivered to water customers, equal to one hundred cubic feet, or roughly 748 gallons. When water usage is used to assess wastewater charges for commercial customers, it is measured in CCF.

CIP Capital Improvement Program

CPAU City of Palo Alto Utilities Department

FOG Fats, oils, and grease. When flushed into the sewer system, these materials accumulate in parts of the sewer system and create blockages.

O&M Operations and Maintenance

RWQCP Regional Water Quality Control Plant, the wastewater treatment plant owned and operated by the City of Palo Alto that serves Palo Alto and several surrounding communities.

UAC Utilities Advisory Commission

SECTION 2: EXECUTIVE SUMMARY AND RECOMMENDATIONS

This document presents a Financial Plan for the City of Palo Alto's Wastewater Collection Utility for the next five years. The 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 and long term and includes measures to mitigate and manage those risks.

SECTION 2A: OVERVIEW OF FINANCIAL POSITION

Overview

The Wastewater Collection Utility's costs include the collection system costs to collect sewage within Palo Alto, maintain and replace sewer infrastructure, and provide customer service, billing and administration as well as Palo Alto's share of the costs to treat sewage at Palo Alto's Regional Water Quality Control Plant. This Financial Plan projects total Wastewater Collection Utility costs (including Palo Alto's share of wastewater treatment costs) to increase by an average of 9.6% annually from fiscal year (FY) 2024 to FY 2029. The collection system's operations and capital costs, not including Palo Alto's share of wastewater treatment costs, are expected to grow at an average of 12.3% annually from FY 2024 to FY 2029, however, cost increases vary from year to year. These average change percentages are calculated using two-year averages for capital investment because the utility plans for one large main replacement every other year. Section 6B: Operations provides more detail about operations costs, and Section 6C: Capital Improvement Program (CIP) provides more detail about capital costs.

In 2023, the Council approved the first in a series of rate increases which incorporated expected costs for the City to accelerate its rate of sewer main replacements from 1 mile to 2.5 miles per year by FY 2026. The sustainable rate of main replacement needed to replace all sewer mains in Palo Alto within, or as close as possible to, their 100-year life expectancy is 2.5 miles per year. Additionally, in FY 2023, the Wastewater Utility began the most expensive sewer main replacement project that it has undertaken, and it was accelerated by a year (Staff Report 2301-0808, May 8, 2023 approving contract for Sanitary Sewer Replacement Project 31, WC-19001).

This project was double the cost of the utility's second largest main replacement project which occurred in 2021. It was important to coordinate the work for SSR 31 with Caltrans to limit or avoid digging into newly-paved street on El Camino. Council approved transfers of all funds from the CIP Reserve ($3.178 million) and from the Rate Stabilization Reserve ($0.34 million) to the Operations Reserve to utilize all available funds for this project. Staff projected that expenditures related to SSR 31 would bring the Operations Reserve temporarily down to the minimum guideline range.

However, in FY 2023, costs were higher than forecasted, primarily due to CIP-related costs and transfers out to capital projects, and revenue was lower than forecasted (primarily capacity fee revenue). As a result, the Operations Reserve ended the year with a negative balance of $0.7 million (discussed further in Section 5E: Risk Assessment and Reserves Adequacy). Additionally, in the current year, non-residential revenues (other than restaurants) are projected to decline by 4% from FY 2023. This may be due to wet weather conditions and reductions in winter water usage.

Staff recommends a 15% rate increase in FY 2025, or $7.29 per month per residential customer, in order to bring revenue back in line with costs, and gradually recover the reserves to within guideline ranges. As part of this recommendation, staff would defer the 5-mile main replacement planned for FY 2026 and instead proceed with a reduced-size main replacement of 1.25 miles in FY 2026 due to the low reserve and revenue levels. The 15% rate increase would allow up to $3 million in the capital budget for main replacement in FY 2025 - FY 2026. $3 million is approximately 25% of the estimated budget for a 5-mile sewer main replacement. Assuming a linear relationship between cost and pipe length replaced, this would support 1.25 miles of main replacement. Based on this mileage, the estimated age of the last remaining sewer replaced would be 110 years, instead of 108 years old.

The 5-mile sewer main replacement would resume every other year beginning with construction in FY 2028. As an alternative, staff is presenting a 9% rate increase option that includes fully deferring the 5-mile main replacement planned for FY 2026 due to the low reserves, low revenues and inflationary cost increases (Section 5F: Alternate Scenarios provides more details).

The Regional Water Quality Control Plant (RWQCP) provides wastewater treatment to Palo Alto and several surrounding communities. The RWQCP anticipates that wastewater treatment costs, a share of which are allocated to Palo Alto and passed on to wastewater collection customers, will increase by an average of 7.2% annually from FY 2024 to 2029. Debt service for treatment costs are increasing – the largest increase is for the Secondary Treatment Upgrades debt service, expected to begin in FY 2029 (See Section 6A: Wastewater Treatment Costs for more details). Rehabilitation and replacement of plant equipment at the RWQCP that has been in use for over 40 years is necessary for the City to continue to provide wastewater treatment safely and in compliance with regulatory requirements for the discharge of treated wastewater 24 hours a day. Palo Alto is in the process of applying to Valley Water's "Guiding Principle 5" grant program that awards funds to communities like Palo Alto where property taxpayers pay State Water Project property taxes but receive on average 85% of their water supply from sources other than Valley Water managed supplies. Guiding Principle 5 awards grants to each community for certain purposes including wastewater treatment environmental upgrades. Treatment costs shown in

Table 1 are offset by these grant funds from FY 2026 – FY 2029. More details are in Section 6A: Wastewater Treatment Costs.

Table 1 shows actual expenses for FY 2023 and projected expenses for FY 2024 through FY 2029. In Table 1, "Treatment" reflects Palo Alto's share of Regional Water Quality Control Plant O&M and CIP costs. "Operations" includes O&M costs for the collection system. "CIP" shown from FY 2023 to FY 2026 includes capital costs of the collection system. Excluded from this table is the increase of $4.922 in CIP commitments and reappropriations reserves at year end FY 2023, bringing total CIP Reappropriations and Commitment reserves to $9.534 million. Currently the CIP Reserve is zero. However, beginning in FY 2027, the CIP expense line shown in Table 1 reflects capital program contributions of $10.2 million per year, increasing with inflation assumed at 5.4% annually, which will be transferred from the Operations Reserve to the CIP Reserve to fund capital costs and to gradually bring the CIP Reserve back to within guideline range. Capital program contributions amounts are also shown in line 9 in Table 3 below. FY 2028 includes a larger one-time capital program contribution for the costs of the one-time pump station retrofit capital work. Table 1 CIP amounts shown in FY 2024 through FY 2026 reflect planned CIP (also shown in Table 3, line 12).

Table 1: Wastewater Collection Expenses for FY 2023 to FY 2029 ($000)*

Expense	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
	Actual	Projected					
Treatment	10,784	12,432	13,185	11,139	12,349	12,839	14,943
Operations	7,823	8,006	8,573	11,720	8,819	9,140	9,490
CIP	6,446	2,691	4,128	5,202	10,200	11,659	11,139
TOTAL	**25,052**	**23,129**	**25,887**	**28,061**	**31,368**	**33,639**	**35,572**

*Note: numbers are shown rounded to the nearest one thousand dollars.

Rate Proposal

Table 2 compares the projected overall rate changes in the current Financial Plan with the projected rate change in the FY 2024 Financial Plan. The current plan includes previously approved rate increases by the Council to accelerate the rate of main replacement, now needing a larger rate increases to cover rising costs and restore reserves; it also reflects staff's recommended adjustments described above to perform a smaller main replacement in FY 2026 to allow reserves to replenish before resuming the original replacement schedule in FY 2028. The Wastewater Collection Utility Reserves Management Practices state that if, at the end of any fiscal year, the minimum guideline is not met in the CIP or Operations Reserve, staff shall present a plan to the City Council to replenish the reserve.[1] This Financial Plan includes a plan to replenish the Operations Reserve to within the guideline range by the end of FY 2026 and gradually restore the CIP Reserve to within the guideline range by FY 2031.

[1] *See* Appendix C, Wastewater Collection Utility Reserves Management Practices Section 7(b) and 5(c).

Table 2: Proposed/Projected Wastewater Collection Rate Trajectory for FY 2025 to FY 2029

Projection	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Current Plan (FY 2025) 15% in FY 2025	15%	9%	9%	8%	7%
FY 2024 Financial Plan	9%	9%	8%	5%	N/A

Reserve Changes

Table 3 shows the starting and ending balance in the Operations, CIP and Rate Stabilization Reserves and the projected reserve transfers and capital program contributions for FY 2024 through FY 2029.

Table 3: Operations, Rate Stabilization and CIP Reserves Changes, Revenue and Guideline Levels for FY 2024 to FY 2029 ($000)

	Fiscal Year	2024	2025	2026	2027	2028	2029
	Starting Balance						
(1)	Operations	(674)	2,875	3,371	4,342	4,837	5,568
(2)	Rate Stabilization	0	0	0	0	0	0
(3)	CIP	0	0	0	0	3,757	500
	Revenues						
(4)	Total Revenue	26,678	26,382	29,033	31,863	34,370	36,746
	Transfers						
(5)	Operations	0	0	0	0	0	0
(6)	Rate Stabilization	0	0	0	0	0	0
(7)	CIP	0	0	0	0	0	0
	CIP Reappropriations/Commitments						
	Capital Program Contribution*						
(8)	Operations	0	0	0	(10,200)	(11,659)	(11,139)
(9)	CIP	0	0	0	10,200	11,659	11,139
	Expenses						
(10)	Total Expenses (w/o CIP and Debt)	(20,308)	(21,758)	(22,859)	(21,168)	(21,980)	(24,433)
(11)	Debt Service	(129)	0	0	0	0	0
(12)	Planned CIP	(2,691)	(4,128)	(5,202)	(6,443)	(14,916)	(6,951)
	Ending Balance						
(1)+(4)+(5)+(8)+(10)+(11)+(12) thru FY 2026 (1)+(4)+(5)+(8)+(10)+(11) in FY 2027 on	Operations	2,875	3,371	4,342	4,837	5,568	6,743
(2)+(6)	Rate Stabilization	0	0	0	0	0	0
(3)+(7)+(9)+(12) in FY 2027 on	CIP	0	0	0	3,757	500	4,687
	Operations Reserve Guideline Levels						
(13)	Minimum Guideline Level	3,360	3,577	3,758	3,480	3,613	4,016
(14)	Maximum Guideline Level	8,399	8,942	9,394	8,699	9,033	10,041
	* Capital Program Contribution to resume in FY 2027						

* Planned CIP (item 12) is reflected as an expense in the CIP Reserve in FY 2027 and on and does not include CIP funded through Reappropriations or Commitments reserves.

SECTION 2B: SUMMARY OF PROPOSED ACTIONS

Staff proposes the following actions for the Wastewater Collection Utility in FY 2025:

1. Approve the Fiscal Year 2025 Wastewater Collection Utility Financial Plan
2. Amend the following rate schedules to reflect an increase of 15% in FY 2025 for all customer classes to bring revenue collection closer to expenses: Rate Schedules S-1 (Residential Wastewater Collection and Disposal), S-2 (Commercial Wastewater Collection and Disposal), S-6 (Restaurant Wastewater Collection and Disposal) and S-7 (Commercial Wastewater Collection and Disposal – Industrial Discharger) See 3B for more details.

3. Approve up to a $3 million enterprise transfer loan from the Fiber Optics Fund to the Wastewater Collection Utility's Operations Reserve in FY 2024.

SECTION 3: DETAIL OF RATE AND RESERVES PROPOSALS

SECTION 3A: RATE DESIGN

The Wastewater Collection Utility's rates are evaluated and implemented in compliance with the cost of service requirements and procedural rules set forth in Article XIII D of the California Constitution (Proposition 218). Current rates are structured based on staff's annual assessment of the Wastewater Collection Utility's financial position (Staff Report 2302-0939[2])) and relied on the methodology from the *City of Palo Alto 2021 Wastewater COS Report*,[3] prepared by Raftelis Financial Consultants, Inc.

SECTION 3B: CURRENT AND PROPOSED RATES

The current rates were effective July 1, 2023, when the City increased sewer rates by 9%.

CPAU has three sewer rate schedules applicable to current customers: one for residential customers (S-1), one for non-residential customers (other than restaurants) (S-2), and one for restaurants (S-6). Restaurants have a special rate schedule because they discharge higher concentrations of grease, oil and organic components in their sewage and, therefore, discharge sewage that is relatively expensive to treat. Residential customers are billed a monthly service charge, while commercial customers other than restaurants are billed each month based on their winter month water usage (previous January through March). This closely approximates non-irrigation water consumption, which represents actual sewer use. This proxy for actual sewer use is needed because sewer customers do not generally have meters installed on their sewer connection whereas water connections are usually metered. CPAU also maintains a rate schedule for industrial dischargers (S-7), but there are currently no customers on this rate schedule.

To align revenues with costs, CPAU proposes to increase overall rates by 15% in FY 2025, by an additional 9% per year in FY 2026 and FY 2027, by 8% in FY 2028 and by 7% in FY 2029. Table 4 below summarizes the current and proposed rates for all customer classes. These rate increases will cover the increasing treatment costs resulting from improvements and upgrades to the RWQCP, as well as updated sewer main replacement cycles for collection systems capital projects, and general operations costs.

Raftelis Financial Consultants, Inc. completed a cost of service (COS) study for the Wastewater Collection Utility in 2021. Staff calculated the revenue increases needed for the Wastewater

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[2] https://cityofpaloalto.primegov.com/meeting/document/1684.pdf?name=Item%2028%20Staff%20Report

[3] https://www.cityofpaloalto.org/files/assets/public/v/1/agendas-minutes-reports/reports/city-manager-reports-cmrs/attachments/08-09-2021-id-12378-att-f-2021-wastewater-cos-report.pdf

Collection Utility based on projected revenue and expenses and applied the same increase percentage to the rates across customer classes.

Table 4: Current and Proposed Sewer Rates

		Current (as of 7/1/2023)	Proposed (effective 7/1/2024)	Change	
				$	%
Monthly Service Charges ($/Month)					
S-1 (Residential)	Service Charge	$ 48.64	$55.93	$ 7.29	15%
Water Quantity Rates ($/CCF)					
S-2 (Commercial)	Quantity Rates	9.08	10.44	1.36	15%
S-6 (Restaurant)	Quantity Rates	13.55	15.58	2.03	15%

The proposed rates for the S-7 (Industrial Discharger) rate schedule are:

1) Collection System Operation, Maintenance, and Infiltration Inflow: $5.18 per 100 cubic feet of metered water use.
2) Advanced Waste Treatment Operations and Maintenance Charge: $2.07 per 100 cubic feet of metered water use
3) $253.49 per 1000 pounds (lbs) of COD (Chemical Oxygen Demand)
4) $611.17 per 1000 lbs of SS (Suspended Solids)
5) $4,223.09 per 1000 lbs of NH_3 (Ammonia)
6) $18,528.29 per 1000 lbs of toxics (chromium, copper, cyanide, lead, nickel, silver, and zinc)

SECTION 3C: BILL IMPACT OF PROPOSED CHANGES

Table 5 below shows the bill impact of the proposed FY 2025 rate changes (effective 7/1/2024) for typical customers:

Table 5: Bill Impact of Proposed Sewer Rate Changes

	Current (as of 7/1/2023)	Proposed (effective 7/1/2024)	Change	
			$/mo.	%
S-1 (Residential)	$ 48.64	$ 55.93	$7.29	15%
S-2 (Commercial) - 14 CCF	127.12	146.16	19.04	15%
S-6 (Restaurant) - 56 CCF	758.80	872.48	113.68	15%

In FY 2025, residential customers will experience a 15% increase in bills. Commercial and Restaurant customers bill impacts will vary due to each customer's utilization of the system.

SECTION 3C: PROPOSED RESERVE TRANSFERS

At the end of FY 2023 the Wastewater Collection Fund's operations reserve was negative $0.7 million (see Figure 5: Operations Reserve Adequacy). The operations reserve not only reflects changes in revenues and expenses, but also reflects changes in capital investments in assets and liabilities. The negative operations reserve reflects certain accounting or "paper" entries for pension and other post-employment benefits liabilities as well as unrealized losses on investments (totaling $8.2 million at year end FY 2023). Excluding the impacts of these accounting entries, the wastewater collection utility's operations reserve would be positive (note: the utility continues to pay the required annual contributions to CalPERS and set aside Section 115 irrevocable trust for pension liabilities). Nevertheless, the operations reserve balance is below the guideline range and this financial plan outlines actions to bring the reserve back within the guideline range throughout the forecast period.

The wastewater utility is currently completing sanitary sewer replacement (SSR) project 31 scheduled for completion by May 2024, and has a need for cash to pay the contractor for this project. Given the low operations reserve, and the projected levels of revenue and expenses, there is a risk that this short-term need for cash will exceed available cash. For this reason, this Financial Plan recommends Council approve a transfer up to $3 million from the Fiber fund in FY 2024 to cover the potential cash shortfall in the Wastewater Utility. The Wastewater utility would repay any such loan in FY 2026 at a rate equal to the City's portfolio rate plus 0.25% (the portfolio rate is expected to be higher than the current rate of 2.47% and this financial plan assumes a rate of 3%). This will compensate the Fiber fund for the interest it would have earned plus an extra 0.25%). The need for this and future transfers will be re-evaluated once the year-end reserve balances for FY 2024 are known.

SECTION 4: UTILITY OVERVIEW

This section provides an overview of the utility and its operations. It is intended as general background information and to help readers better understand the forecasts in later sections.

SECTION 4A: WASTEWATER UTILITY HISTORY

The Wastewater Utility commenced operation in 1899 to serve Palo Alto and Stanford. In its first three decades the system grew to 60 miles of sewers. Raw sewage was discharged into Mayfield Slough at the edge of the Bay. In the 1930s, at the behest of the State Department of Health, Palo Alto built the South Bay's first wastewater treatment plant. At that time the sewer system served 20,500 Stanford and Palo Alto residents and a cannery. The plant was upgraded twice in the 1940s and 1950s to increase capacity.[4] At the same time, the postwar population and industrial boom in the 1950s required rapid expansion of the sewer system. In the first half of the 1960s Palo Alto's area doubled, as did wastewater flows, overwhelming the capacity of several of the utility's "trunk lines," which are the largest diameter main sewer lines carrying wastewater to the treatment plant. This prompted the City, in 1965, to perform the first of its sewer master plans to identify needed capacity improvements. At that point the Wastewater Utility's system comprised more than 150 miles of sewer mains.[5]

In 1968 the City signed agreements with the Cities of Mountain View and Los Altos to build a new regional treatment plant, the RWQCP, which is still in operation today. Since 1940 the City had been providing treatment services to the East Palo Alto Sanitary District through an existing agreement and was also serving Stanford University by transporting wastewater across the City's sewer system to the treatment plant. Both of these organizations became partners in the RWQCP

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[4] *Long Range Facilities Plan for the Regional Water Quality Control Plant,* August 2012, Carollo Engineers, pp 2-1 through 2-2

[5] *Wastewater Collection and Storm Drainage,* 1965, Brown and Caldwell Consulting Engineers, pp 4, 6-7, 143

as well. At the same time the Town of Los Altos Hills became the sixth partner as it signed an agreement with the City to connect the Town's sewer system to the City's sewer system to carry wastewater to the new RWQCP. The current agreements for the RWQCP extend through 2035.[6]

In the 1980s the City performed a series of studies of groundwater inflow and infiltration into the system. The studies found high rates of infiltration, estimating that as much as 40% of the water going to the RWQCP from Palo Alto's system was groundwater and stormwater rather than wastewater.[7] In some parts of Palo Alto the land surface had subsided due to groundwater pumping by the water utility, and though that practice had ceased many years earlier as the water utility switched to the Hetch Hetchy Regional Water System, parts of the city had already subsided two to five feet. This subsidence had damaged several parts of the sewer collection system, leading to reduced slopes for sewer mains that caused reductions in capacity. In response to these studies the City commenced an accelerated sewer system rehabilitation program.[8] At that point the sewer system comprised over 190 miles of mains.[9]

A Master Plan study in 1988 recommended a variety of capacity expansions, and in the 1990s the City completed about half of them. However, a 2004 Master Plan update found that the accelerated sewer rehabilitation plan started in the early 1990s had substantially reduced infiltration, easing the capacity problems that had led the to the recommended capacity increases in the 1988 study. Several of the outstanding projects were canceled and replaced with a different set of projects.[10] At the same time the City updated its hydraulic model and developed greater capacity to do system planning in-house.

SECTION 4B: CUSTOMER BASE

The City of Palo Alto's Wastewater Collection Utility provides sewer service to the residents and businesses of Palo Alto. It is distinct from the Wastewater Treatment Utility, which provides treatment services for surrounding communities in addition to Palo Alto. In effect, the Wastewater Collection Utility serves as a wholesale customer of the Wastewater Treatment Utility, and the rates charged by the Wastewater Collection Utility to its retail customers recover not only collection costs but also Palo Alto's share of Wastewater Treatment Utility Costs. Nearly 27,580 customers are connected to the sewer collection system, approximately 26,050 (94%) of which are residential and 1,530 (6%) of which are non-residential. Residential customers pay a flat fee per dwelling unit for service. Commercial customers are billed for sewer service based on their metered winter water usage while Restaurant customers are billed for sewer service based on their metered monthly water usage.

SECTION 4C: COLLECTION SYSTEM

The Wastewater Collection Utility delivers all the wastewater it collects to the Regional Water Quality Control Plant (RWQCP) operated by the City of Palo Alto under a partnership agreement with several surrounding communities. Palo Alto is responsible for 32% to 35% of the wastewater

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[6] *Long Range Facilities Plan for the Regional Water Quality Control Plant,* August 2012, Carollo Engineers, pg 2-2
[7] *Wastewater Collection System Master Plan – Capacity Assessment*, January 2004, MWH Americas, Inc., pg ES-2
[8] CMR 183:90, *Infrastructure Review and Update*, March 1, 1990
[9] *Master Plan of the Wastewater Collection System*, December 1988, Camp Dresser & McKee, Inc., pg 1-2
[10] *Wastewater Collection System Master Plan – Capacity Assessment*, January 2004, MWH Americas, Inc., pg ES-3

sent to the RWQCP. This Financial Plan does not describe the cost of running the RWQCP in detail as this cost is contained in the Wastewater Treatment Utility; however since these costs are a major driver of CPAU's sewer rates, *Section 6A: Wastewater Treatment Costs* provides some discussion of future trends in treatment costs. Treatment costs make up more than a third of the Wastewater Collection Utility's expenses as shown in Table 1 above.

To collect wastewater from its customers and deliver it to the RWQCP, CPAU owns roughly 18,000 sewer laterals (which collect wastewater from customers' plumbing systems) and 217 miles of sewer mains (which transport the waste to the treatment plant). These laterals and mains, along with the associated manholes and cleanouts, represent the vast majority of infrastructure used to collect wastewater in Palo Alto. CPAU conducts a sewer rehabilitation and replacement program to replace mains over time as they deteriorate or to increase capacity. For more discussion of this program, see *Section 6C: Capital Improvement Program (CIP)*. CIP expense accounts for less than a quarter of the utility's expenditures.

In addition to CIP, CPAU performs various maintenance activities on the sewer system. These include inspecting and repairing sewer laterals, responding to sewer overflows, regularly cleaning sections of the system heavily impacted by fats, oils, and grease (FOG), and building and replacing sewer laterals for new or redeveloped buildings. The utility also shares the costs of other operational activities (such as customer service, billing, equipment maintenance, and street restoration) with the City's other utilities. These maintenance and operations expenses, as well as associated administration, debt service, rent, and other costs, make up approximately another quarter of the utility's expenses.

SECTION 4D: COST STRUCTURE AND REVENUE SOURCES

In FY 2023, approximately 43% of the Wastewater Collection Utility costs were for treatment (capital and operations), while about 31% were for the collection system's operations. The remaining 26% were for collection system capital improvements. Figure 1 illustrates these expenditures. The utility's main source of revenue in FY 2023, shown in Figure 2, was sewer charges (96%), with the rest from connection fees and other sources (4%).

Figure 1: Cost Structure (FY 2023)

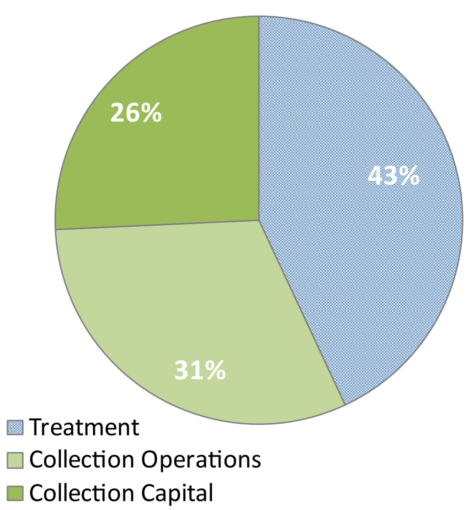
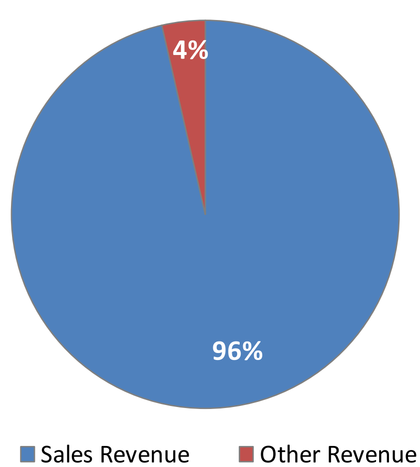


Figure 2: Revenue Structure (FY 2023)



SECTION 4E: RESERVES STRUCTURE

CPAU maintains six reserves for its Wastewater Collection Utility to manage various types of contingencies. Below is a summary of these reserves and *Appendix C: Wastewater Collection Utility Reserves Management Practices* provides more detailed definitions and guidelines for reserve management:

- **Reserve for Commitments:** A reserve equal to the utility's outstanding contract liabilities for the current fiscal year. Most City funds, including the General Fund, have a Commitments Reserve.
- **Reserve for Reappropriations:** A reserve for funds dedicated to projects reappropriated by the City Council, nearly all of which are capital projects. Most City funds, including the General Fund, have a Reappropriations Reserve.
- **Capital Improvement Program (CIP) Reserve:** The CIP reserve is used to accumulate funds for future expenditure on CIP projects and a reserve level is typically maintained in order to smooth major CIP expenditures every other year. It also acts as a contingency reserve for unexpected capital costs. This type of reserve is used in other utility funds (Electric, Gas, and Water) as well.
- **Rate Stabilization Reserve:** This reserve is 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 (Electric, Gas, and Water) as well.
- **Operations Reserve:** This is the primary contingency reserve for the Wastewater Collection Utility and is used to manage yearly variances from budget for operational costs. This type of reserve is used in other utility funds (Electric, Gas, and Water) as well.
- **Unassigned Reserve:** This reserve is for any funds not assigned to the other reserves.

SECTION 4F: COMPETITIVENESS

Table 6 shows the monthly sewer bills for residential customers compared to what they would be in surrounding communities. The average monthly sewer bill for a Palo Alto single family residential customer is $48.64 at current rates, which is lower than four of the six neighboring communities. These communities are the same six that Palo Alto compares itself to in the annual budget across Water, Wastewater, Gas, and Electric industries. In the following tables, "Menlo Park" refers to the West Bay Sanitary District.

Table 6: Residential Monthly Equivalent Sewer Bill Comparison (FY 2024 Rates) ($)

Palo Alto	Neighboring Community Average	Neighboring Communities					
		Menlo Park	Redwood City	Santa Clara	Mountain View	Los Altos	Hayward
48.64	65.38	108.83	89.28	48.28	53.10	51.47	41.29

Table 7 compares the sewer bills for two classes of non-residential customers to what they would be under surrounding communities' rate schedules. Note that other communities often have specific rates for industrial customers that discharge high intensity wastewater, such as food processors or chemical or electronics manufacturers, but Palo Alto does not currently have any customers that require these special rates. The estimate of Palo Alto commercial and restaurant monthly sewer bills are around the neighboring community average, assuming neighboring communities do not increase sewer rates. The monthly bill comparison assumes 14 CCF of water for general commercial customers and 56 CCF of water for restaurants.

Table 7: Commercial Monthly Sewer Bill Comparison (FY 2024 Rates) ($)

Customer Types	Palo Alto	Neighboring Community Average	Neighboring Communities					
			Menlo Park	Redwood City	Santa Clara	Mountain View	Los Altos	Hayward
General Commercial	127.12	115.33	147.28	117.74	82.18	166.18	84.55	94.08
Restaurant	758.80	812.27	1,240.96	1,128.40	767.20	762.16	338.18	636.72

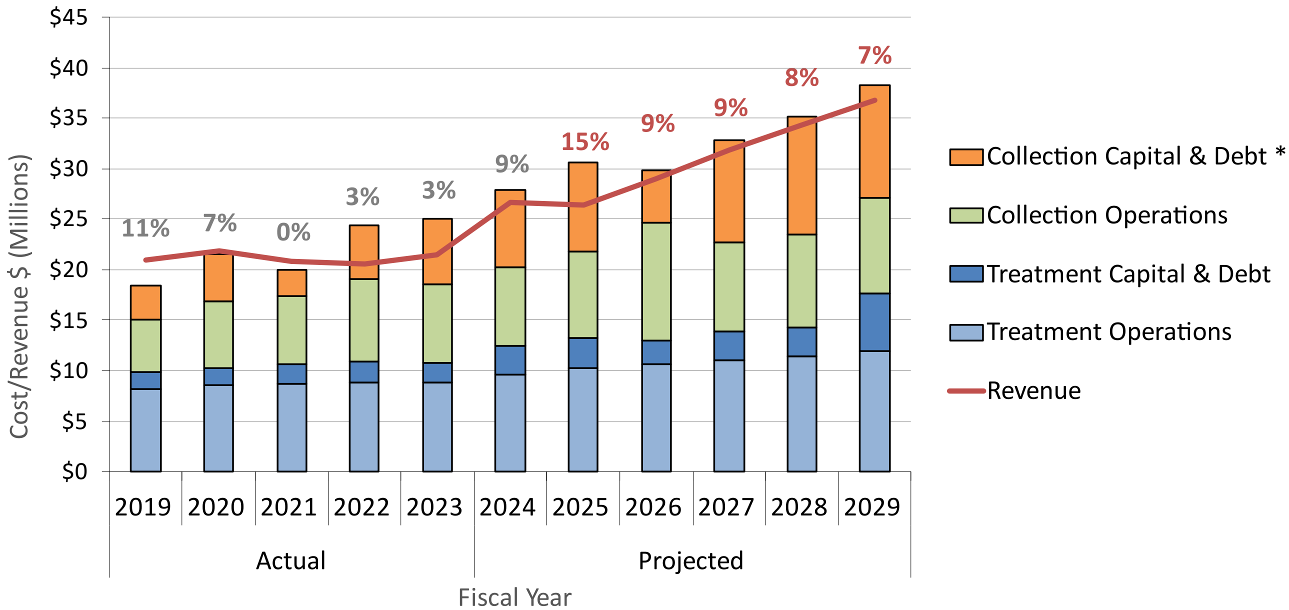
SECTION 5: UTILITY FINANCIAL PROJECTIONS

SECTION 5A: FY 2019 TO FY 2023 COST AND REVENUE TRENDS

Figure 3 shows the Wastewater Collection Utility's actual expenses and revenues for the past five years and projections through FY 2029. Treatment plant expenses (including CIP and O&M) assigned to Palo Alto's Wastewater Collection Utility increased, on average, by 2.3% annually from FY 2019 to FY 2023.

Since wastewater revenue is relatively stable, historically, revenue changes closely followed rate changes. However, during the pandemic, non-residential wastewater revenue declined by about 9% in FY 2022 and then increased by 6% in FY 2023. In the current year, non-residential revenue is projected to decline by 2% in the first six months despite the 9% rate increase. This is likely due to low winter usage in January – March of 2023 during the historically wet winter. Revenue is forecasted to recover gradually over the next three years. However, this revenue reduction increases the upward pressure on rates in FY 2025 and in future years. Connection and capacity fees grew dramatically between FY 2010 and FY 2015 and then plateaued and then declined significantly in FY 2022. Capacity fees dropped to zero in FY 2023. This is likely due to more tenant improvements permits rather than new service connection permits where the improvements are inside the buildings and the utility infrastructure remains the same. These revenue reductions contribute to the need to increase rates.

Figure 3: Wastewater Collection Utility Expenses, Revenues and Rate Changes
Actual Costs through FY 2023 and Projections through FY 2029



*CIP in the projected years include changes due to commitments/reappropriations and funds transferred to the CIP Reserve

SECTION 5B: FY 2023 RESULTS

The FY 2024 Financial Plan proposed to increase the rate of sewer main replacement from 1 mile per year to 2.5 miles per year beginning FY 2026, in order to replace the remaining 138 miles of sewer mains before they exceed their expected life. However, in FY 2023 revenues were lower than forecasted and costs were higher than forecasted; additionally, the utility proceeded a year early with a large sewer main replacement project to coordinate with Caltrans. These two factors led to low reserve levels at the end of FY 2023. The utility's revenues and reserves need time to recover and rates need to increase to support the 2.5 mile per year rate of main replacement.

Actual sewer service charge revenues for FY 2023 were similar to the forecasted level. However, capacity fee and connection fee revenue was $0.23 million lower than forecasted in the FY 2024 Financial Plan ($0.2 million actual vs. $0.45 million forecasted). Additionally, uncollectable (bad debt expense for utility bill amounts owed that are no longer collectible) were also higher than forecasted possibly resulting from the economic impacts of COVID-19 policies. Total revenues were $0.4 million lower than expected.

Treatment expenses were similar to the forecasted level ($10.8 million). Collection system capital-related costs were approximately $2.7 million higher than expected ($16 million actual compared with $13.3 million forecasted). The main factors contributing to this were CIP-related allocated costs, CIP salaries and benefits and the forecasted CIP budget, which anticipated underspending, however, the actual CIP sewer replacement bid exceeded the estimated budget. See section 6C for details.

In FY 2022, unrealized gains/losses were separated out from the Operations Reserve into a separate "Unrealized Gain/Loss on Investment" reserve. There was a subsequent adjustment to the year-end FY 2022 operations reserve balance to also move unrealized gains/losses from prior years to the separate reserve. This reduced the operations reserve by $0.135 million in FY 2023. Additionally, operating expenses were higher than expected primarily due to a transfer out to the capital projects fund. Table 8 below summarizes key reasons for the variances from forecast.

Table 8: FY 2023 Actuals vs. FY 2024 Financial Plan Forecast for FY 2023 ($000)

	Net Cost/ (Benefit)	Type of Change
Lower connection and capacity fees, higher uncollectibles	$ 391	Revenue decrease
Expenses higher than expected	$ 535	Cost increase
Higher CIP-related charges including allocated charges and CIP reappropriations/commitments	$ 2,641	Cost increase
Accounting adjustment to Operations Reserve	$ 135	Cost increase
Net Cost / (Benefit) of Variances	$ 3,703	

SECTION 5C: FY 2024 PROJECTIONS

Staff currently projects lower sales revenue compared to the FY 2024 Financial Plan ($21.9 million vs $22.7 million) due to lower sales revenue among non-residential customers, other than restaurants, as well as increased uncollectibles. Staff now anticipates other revenue from connection and capacity fees and interest to be lower than originally expected, and expects transfers in from the true-up of a shared GIS Capital Project shared between the Water, Gas, and Wastewater Collection funds to be higher than forecasted. In total, the current projection of other revenue is $0.6 million higher than the projection in the FY 24 Financial Plan. Treatment cost projections increased by $0.14 million. The current estimate of collection system costs is higher than forecasted in the FY 2024 Financial Plan by $0.36 million. This does not include CIP spending budgeted in prior years in the CIP Reappropriations and Commitments Reserves; that totals $9.5 million and primarily reflects the ongoing main replacement for Sewer Replacement Project 31. Table 9 summarizes key variances from the prior forecast.

Table 9: FY 2024 Projections vs. FY 2024 Financial Plan Forecast ($000)

	Net Cost/ (Benefit)	Type of Change
Sales revenues lower than forecast	$ 833	Revenue decrease
Other revenue higher than forecast	$ (3,615)	Revenue increase
Treatment cost increases	$ 140	Cost increase
Collection system operations and capital	$ 359	Cost increase
Net Cost / (Benefit) of Variances	$ (2,283)	

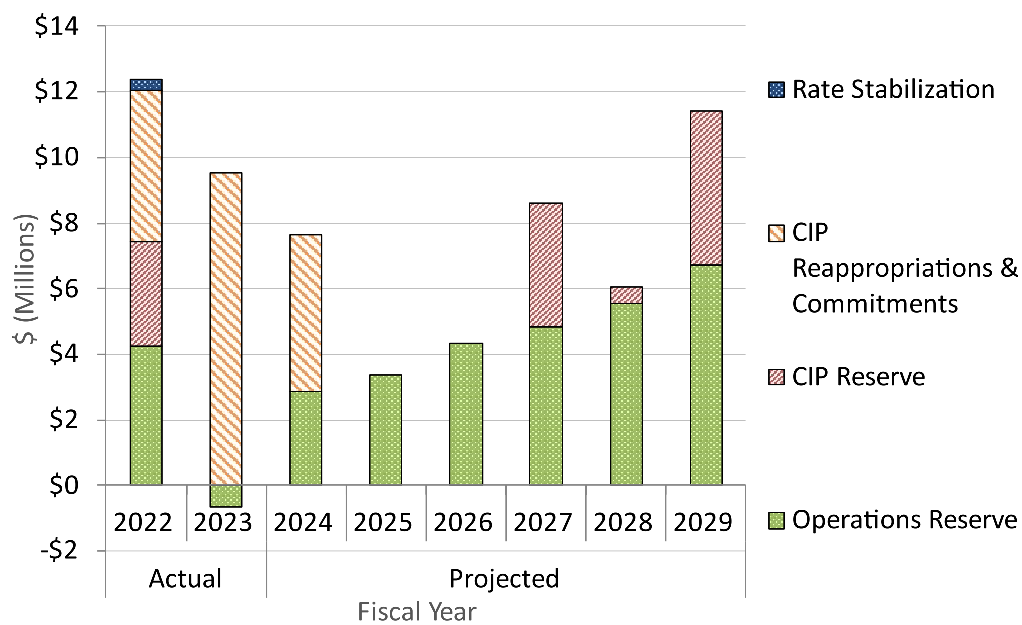
SECTION 5D: FY 2025 TO FY 2029 PROJECTIONS

As shown in Figure 3 above (and, in more detail, in *Appendix A: Wastewater Collection Financial Forecast Detail*), the Wastewater Collection Utility's total costs are projected to increase by approximately 10.1% per year on average for FY 2025 through FY 2029.

Capital costs for treatment are also increasing because the treatment plant is planning major upgrades in coming years, due to aging equipment and changing environmental regulations. The costs of the plant are shared among member agencies, with members expected to see average cost increases of around 6.5% per year over the forecast horizon. The biggest increase in Treatment costs is the addition of debt service for the Secondary Treatment Upgrades in FY 2029, which is a $193 million capital project funded through a low-interest State Revolving Fund loan, which the Wastewater Utility has included into its cost projections. (see Section 6A: Wastewater Treatment Costs

Figure 4 shows the actuals for FY 2023 and projected reserve levels through FY 2029. Figure 5 shows the movement of funds from the CIP Reserve, Operations Reserve and Rate Stabilization Reserve to the CIP Reappropriations and Commitments Reserves in FY 2023. The chart assumes that half of the CIP Reappropriations and Commitments are spent in FY 2024 and half are spent in FY 2025. The proposed rate increases will gradually bring the Operations Reserve back to within the guideline range by the end of FY 2026 and allow the CIP Reserve to also be replenished gradually by FY 2031.

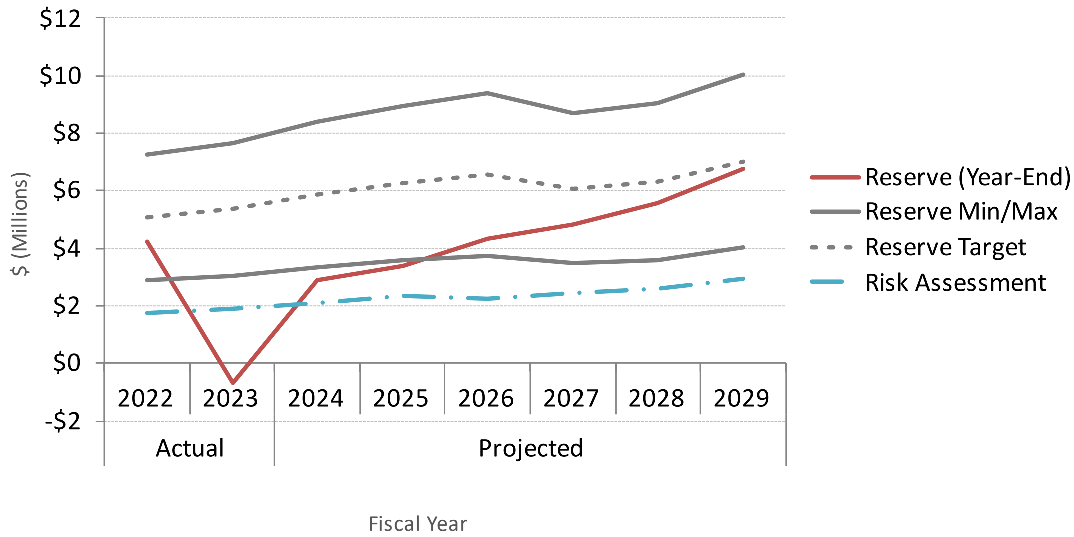
Figure 4: Wastewater Collection Utility Year-End Reserves Levels, FY 2023 to FY 2029



SECTION 5E: RISK ASSESSMENT AND RESERVES ADEQUACY

The Operations Reserve, which is the Wastewater Collection Utility's primary contingency reserve, is expected to return to within the reserve guideline levels by the end of FY 2026 and remain within the guideline range for the rest of the forecast period, as shown in Figure 5 below. The proposed annual rate increases in this Financial Plan are intended to maintain a steady rate trajectory and keep the Operations Reserve within the guideline range in the long term.

Figure 5: Operations Reserve Adequacy



Staff performs an annual assessment of risks for the Wastewater Collection Utility. Table 10 summarizes the risk assessment calculation for the Wastewater Collection Utility through FY 2029. The risk assessment includes the revenue shortfall that could accrue due to:

1. the maximum observed budget-to-actual variance in one year during the past five years; and
2. an increase of 10% in treatment costs.

Staff is proposing to allow the Wastewater Operations Reserve to be below the guideline range for three fiscal years (FY 2023 through FY 2025). This Financial Plan projects the Wastewater Utility's primary contingency reserve, the Operations Reserve, to be below guideline levels at the end of FY 2023 through FY 2025 and then return to within the guideline range by the end of FY 2026 and increase to approximately target levels by the end of the forecast period. Per the Reserves Management Practices (Appendix C) any rate plan that involves returning the Operations Reserve to within guideline levels in more than one year requires Council approval. Table 10 shows the Operations Reserve ending balances alongside the risk assessment values and Figure 5 shows the Operations Reserve ending balances alongside the minimum, maximum, and target guidelines. In case costs exceed available reserves during the FY 2023-2025 timeframe, staff is requesting Council approval to transfer up to $3 million from the Fiber fund to the Wastewater Utility. The Wastewater Utility could additionally explore other short-term financing options if necessary. The Operations Reserve is projected to be adequate to manage these levels of risk from FY 2026 through FY 2029.

Table 10: Wastewater Collection Risk Assessment for FY 2024 to FY 2029

	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Total Revenue ($000)	$22,049	$25,308	$27,902	$30,673	$33,398	$35,748
Max. Historical Budget-to-Actual variance	4%	4%	4%	4%	4%	4%
Budget-to-Actual Risk ($000)	882	1,012	1,116	1,227	1,336	1,430
Treatment Budget ($000)	12,432	13,185	11,139	12,349	12,839	14,943
Treatment Cost Contingency @10% ($000)	1,243	1,319	1,114	1,235	1,284	1,494
Total Risk Assessment Value ($000)	2,125	2,331	2,230	2,462	2,620	2,924
Projected Operations Reserve Level ($000)	2,875	3,371	4,342	4,837	5,568	6,743

SECTION 5F: ALTERNATE SCENARIOS

This Financial Plan includes an alternate rate trajectory scenario as shown in Table 11 below. Staff brought this item to the Finance Committee for discussion on February 20, 2024 (Staff Report 2312-2468). Staff will describe the Finance Committee's feedback to the UAC during the March UAC meeting.

Table 11 shows the rate projections of the alternative that would increase rates 9% in FY 2025 and fully defer the first 5-mile Sanitary Sewer Replacement (SSR) construction in FY 2026. This alternative includes a 5-mile sewer main replacement every two years beginning in FY 2028.

Table 12 to 14 shows the monthly bill impacts of the recommended and alternative rate increase scenario for residential, commercial and restaurant customers in FY 2025 to FY 2029.

Table 11: Wastewater Rate Changes and Residential Monthly Bill Impacts

	FY 2025 – FY 2026 Main Replacement [a]		FY 2025	FY 2026	FY 2027	FY 2028	FY 2029	Age of Last Remaining Sewer Main Replaced
	Budget	Length (miles)						
REcommendation: 15% in FY 2025	$3M	~1.25	*15%*	*9%*	*9%*	*8%*	*7%*	110 years
			$7.29	***$5.03***	***$5.48***	***$5.31***	***$5.02***	
Alternate: 9% in FY 2025	$0	0	*9%*	*9%*	*9%*	*9%*	*9%*	111 years
			$4.37	***$4.77***	***$5.20***	***$5.66***	***$6.17***	

a) **The estimated budget for a 5-mile sewer main replacement in FY 2025 – FY 2026 is $11.6 million.**

Table 12: Residential Monthly Bill Impact, S-1
(calculated from FY 2024 residential monthly bill of $48.64/mo)

Rate Scenarios	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
15% in FY 2025	$7.29	$5.03	$5.48	$5.31	$5.02
9% in FY 2025	4.37	4.77	5.20	5.66	6.17

Table 13: Commercial Monthly Bill Impact, S-2, 14 CCF (calculated from FY 2024 commercial monthly bill of $127.12/mo)

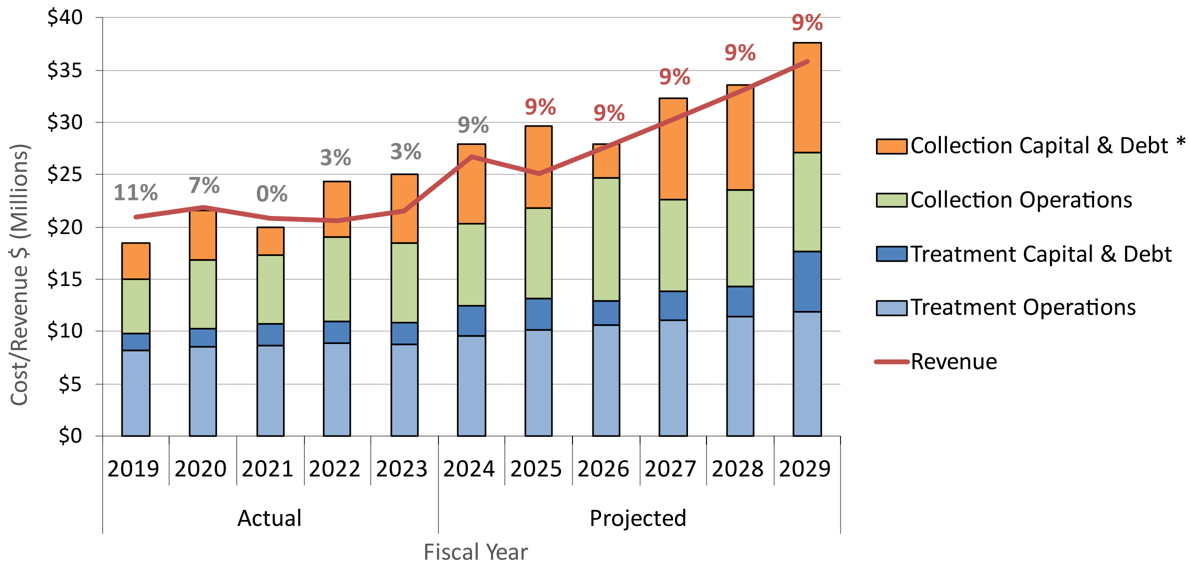
Rate Scenarios	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
15% in FY 2025	$19.04	$13.02	$14.28	$13.86	$13.02
9% in FY 2025	11.34	12.46	13.58	14.70	16.10

Table 14: Restaurant Monthly Bill Impact, S-6, 56 CCF (calculated from FY 2024 restaurant monthly bill of $758.80/mo)

Rate Scenarios	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
15% in FY 2025	$113.68	$78.40	$85.12	$82.88	$77.84
9% in FY 2025	67.76	73.92	80.64	87.92	95.76

The following figures show the expenses, revenues and rate changes chart as well as operations reserve and CIP Reserve Year-end Balances for the alternative of a 9% increase in FY 2025.

Figure 6: Wastewater Collection Utility Expenses, Revenues and Rate Changes – 9% increase in FY 2025



*CIP in the projected years include changes due to commitments/reappropriations and funds transferred to the CIP Reserve

Figure 7: Wastewater Collection Operations Reserve Year End Balances – 9% increase in FY 2025

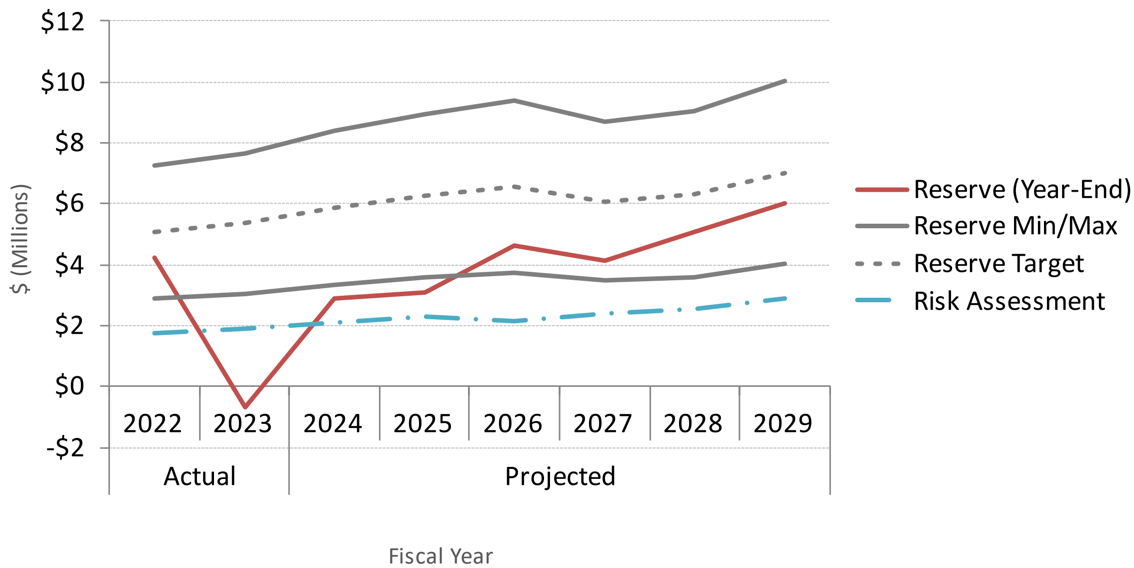
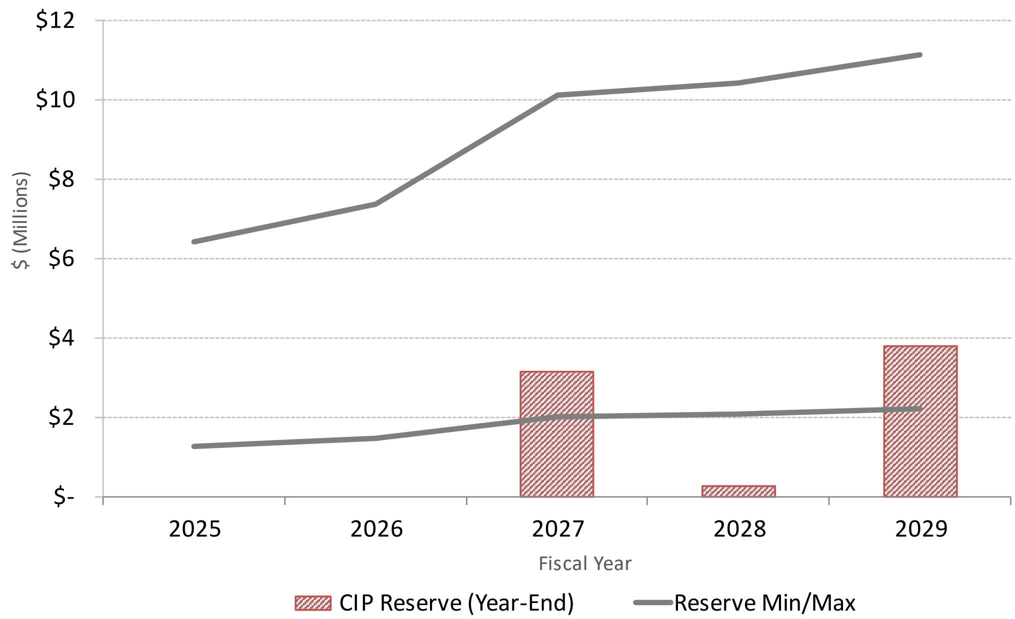


Figure 8: Wastewater Collection CIP Reserve Year End Balances – 9% increase in FY 2025



SECTION 5G: LONG-TERM OUTLOOK

In the longer term (5 to 35 years), there are several factors that could potentially increase costs for the Wastewater Collection Utility. Section 2A: Overview of Financial Position discusses the acceleration of sewer main replacement projects, with alternative main replacement schedules shown in Section 5F: Alternate Scenarios. Another factor is major upgrades at the RWQCP, for which the Wastewater Utility will pay its share as part of treatment costs. More details are in Section 6A: Wastewater Treatment Costs.

SECTION 6: DETAILS AND ASSUMPTIONS

SECTION 6A: WASTEWATER TREATMENT COSTS

Treatment expenses represent the Wastewater Collection Utility's share of the costs of operating the RWQCP. According to the agreements between Palo Alto and its partner agencies, these charges are calculated using a formula that considers the amount of wastewater, the organic material and ammonia levels, and the total suspended solids it contains. The Wastewater Collection Utility's assessed share of the RWQCP's revenue requirement is projected to be 32% for FY 2025. Mountain View is the other large agency served by the RWQCP (42% of the revenue requirement estimated for FY 2025) with the smaller agencies (Stanford, Los Altos, East Palo Alto, and Los Altos Hills) making up the remaining share of the total treatment costs.

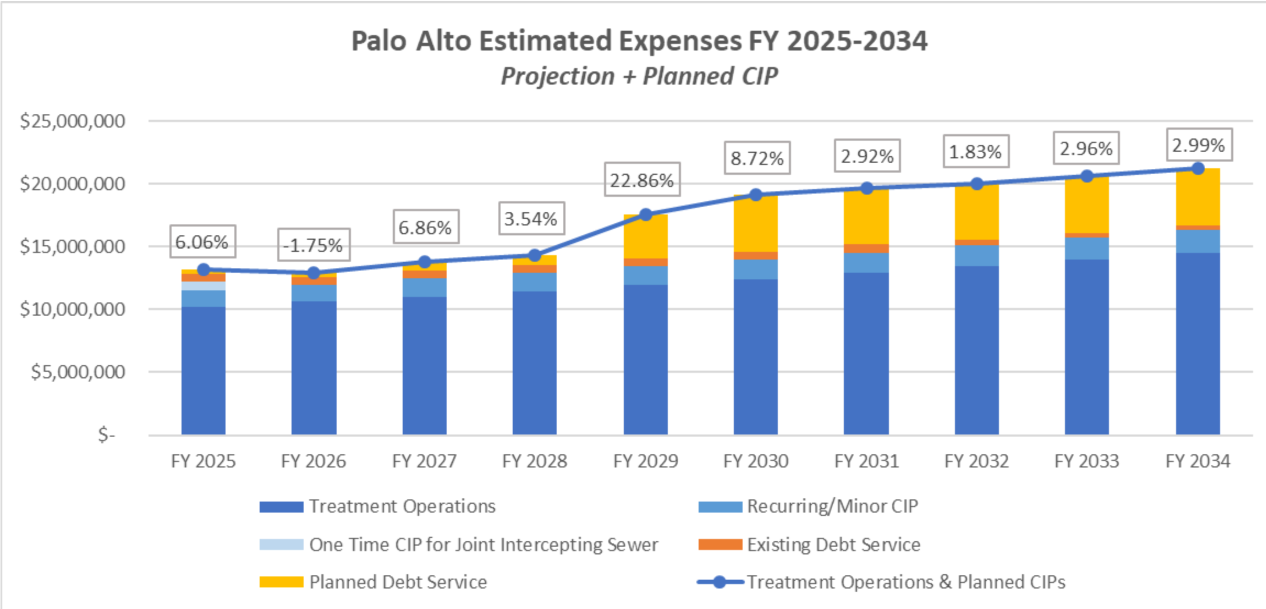
Based on detailed project cost estimates provided by RWQCP staff, overall treatment costs are estimated to increase by an average of 7.2% per year from FY 2024 through FY 2029. Wastewater Treatment Fund costs are increasing due to major plant rehabilitation and rising salary and benefit costs as well as increased staffing needed to support capital programs. Additional expense increases include sludge hauling services costs, maintenance materials costs and rent. Commodity and utility rates to operate the facility are also anticipated to increase in FY 2025 for electric, water, and natural gas rates.

The largest increase in the treatment costs is the repayment of the Secondary Treatment Upgrades through a low-interest Clean Water State Revolving Fund Loan. Loan payments are expected to begin in FY 2029. Slow reimbursement for the Secondary Treatment Upgrades capital project during construction has created a cashflow issue for the RWQCP. This will increase treatment costs in the short-term beyond the projected levels shown below as the Wastewater Treatment fund will owe other City funds for the loss on shared return on investment on cash.

The RWQCP completed a Long-Range Facilities Plan in 2012 which has guided the CIP needs of the Treatment Plant. Currently, the RWQCP is beginning an update to the Long-Range Facilities Plan and plans to begin this work in 2024 and complete the plan in 2026. The results of this work will direct future CIP work at the Treatment Plant. Additionally, the plan will re-evaluate the cost of service for annual operating shares and re-evaluate the fixed allocation capacity shares for each partner.

Palo Alto’s share of treatment operations and maintenance costs is expected to increase by an average of 4.6% per year from FY 2024 through FY 2029. Capital projects and debt are increasing at an average of 15% per year from FY 2024 through FY 2029. Increases to capital expenses begin in FY 2024 with the Joint Intercepting Sewer Rehabilitation construction, funded on a pay-as-you-go basis. The Wastewater Utility begins to pay for debt service for major projects beginning with the Primary sedimentation Tank in FY 2025, Outfall Line Construction in FY 2027, Secondary Treatment Upgrades in FY 2029 and Headworks in FY 2030. Figure 9 below shows the estimated costs of treatment expenses for Palo Alto.

Figure 9: Palo Alto's Share of Wastewater Treatment Expenses (Projection & Planned CIP)



Grant Funding

Santa Clara Valley Water District (Valley Water) is the groundwater manager for Santa Clara County. Valley Water developed the "GP5 Program" grant program for communities and/or organizations, like the City of Palo Alto, where property taxpayers pay State Water Project property taxes but receive on average 85% of their water supply from sources other than Valley Water managed supplies. GP5 refers to Guiding Principle 5, a principle of the Valley Water Board that awards grants to each community at a dollar amount up to the State Water Project property taxes paid by property owners in their respective service areas. The grants must fund conservation programs, potable recycled water, non-potable recycled water (including salinity reductions), options to purchase wastewater, purified water, wastewater treatment plant environmental upgrades, Advanced Metering Infrastructure (AMI) updates, or dedicated environmental-focused activities.

The RWQCP is currently in the process of applying for this grant funding for Palo Alto's portion of certain qualifying Wastewater Treatment capital projects. These are estimated to include:

- Joint Intercepting Sewer Rehabilitation
- Outfall Line Construction
- 12kV Loop Electrical Improvements and
- Headworks

The estimated funding available to Palo Alto through this grant program is $11.2 million through FY 2033. This Financial Plan assumes those funds begin to be received as an offset to Palo Alto's treatment costs in FY 2026, which allows for a year of delays in the process of being awarded the grant funding. In total, this Financial Plan assumes $7.4 million of the funds are received during the 5-year planning period as shown in the following table.

Table 15: GP5 Grant Funding Assumed to Offset Palo Alto's Treatment Costs

	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
GP5 Grants ($'000)	-	1,815	1,494	1,494	2,667

SECTION 6B: OPERATIONS

Operations costs include the Customer Service, Distribution Operations, Engineering, and Allocated Charges categories in *Appendix A: Wastewater Collection Financial Forecast Detail*. Debt service, rent, and transfers are also included in this category. Customer Service costs are primarily related to the call center and collections on delinquent accounts. The Distribution Operations category includes preventative and corrective maintenance on sewer mains and laterals, investigation of sewer overflows, regular cleaning of heavily impacted sections of the sewer system, and services shared with other utilities (such as street restoration and equipment maintenance). Allocated Charges include the costs of accounting, purchasing, legal, and other administrative functions provided by the City's General Fund staff, as well as shared communications services and Utilities Department administrative overhead and billing system maintenance costs. A portion of these costs are allocated to operations costs and a portion to capital costs.

This Financial Plan anticipates operations costs will increase by approximately 3.5% annually from FY 2024 to FY 2029 based on preliminary assumptions for non-salary and benefit cost categories from Palo Alto's Office of Management and Budget. This includes an assumption of a 7.5% increase to salaries and benefits costs in FY 2024 and a 3-4% increase annually in subsequent years.

SECTION 6C: CAPITAL IMPROVEMENT PROGRAM (CIP)

The Wastewater Collection Utility's CIP consists of the following programs:

- The Sanitary Sewer Replacement/Rehabilitation (SSR) Program, under which the Wastewater Collection Utility replaces aging sewer mains.
- Customer Connections, which covers the cost when the Wastewater Collection Utility installs new laterals or upgrades existing laterals at a customer's request in response to development or redevelopment. CPAU charges a fee to these customers to cover the cost of these projects.
- Ongoing Projects, which covers the cost of replacing deteriorated manholes and sewer laterals, addressing unplanned replacement needs, performing hydraulic analysis, replacing antiquated software, as well as the cost of capitalized tools and equipment.

The Sanitary Sewer Replacement and Rehabilitation Program funds the replacement of deteriorating sewer mains to increase capacity or improve pipe condition in various parts of the sewer system. The sewer system consists of 216 miles of mains, and CPAU uses a variety of tools to establish which sections need to be replaced. The 2004 Master Plan study identified wastewater mains with capacity deficiency, and they have been corrected in past CIP projects. A new master plan study is underway and will update the existing wastewater model, given the many development projects which have introduced additional flow in the collection system since 2004. The master plan project was approved at the November 27, 2023 Council Meeting and the consultant is currently under contract. The new study includes flow-monitoring data to reflect current condition and re-assessment of the system capacity. For condition assessment, maintenance statistics (such as records of the location and number of sewer overflows on the system) and video recording of sewer mains during routine cleaning and inspection can reveal areas with deteriorating pipe. CPAU uses a structural rating system to grade the pipe defects. The video-inspection data and maintenance records are used to plan and prioritize sewer main replacement and rehabilitation.

Utilities also coordinates with the Public Works street maintenance program to avoid cutting into newly repaved streets. Major goals of the replacement program are to minimize sewer overflows and reduce groundwater and rainwater infiltration. As clay pipe deteriorates, roots start intruding into the cracks or pipe joints to create blockages, permitting groundwater or rainwater to infiltrate the system, and potentially cause structural damage such as broken or collapsed pipe. Some level of infiltration is expected on any sewer system, but if there is too much, the combined flow of wastewater and groundwater/rainwater can overwhelm the capacity of various parts of the sewer system. Reducing infiltration can reduce the need to expand the system to accommodate increased flow, as well as reducing unnecessary amounts of water to be treated at the treatment plant. To achieve this goal, deteriorating mains are either replaced with new HDPE pipe or rehabilitated with a plastic lining when replacement is not feasible. Staff has been replacing/rehabilitating the mains as needed according to their condition. In addition, Wastewater Operations' routine maintenance continues to stay on schedule to minimize sewer overflows.

Utilities Engineering has been consistently replacing aging sewer mains since the early 1990s. The proactive replacement program keeps the collection system in good condition. Between 1990 and 2022, 80 miles or 37% of the collection system has been replaced or rehabilitated (the darker green-colored lines shown in the attached map in *Appendix D: Map (CPA Wastewater Collection System - Sewer Mains Replaced or Rehabilitated since 1990)*.

A routine replacement program is recommended to keep the system reliable. Each SSR project in recent years has had approximately a $4 to $5 million budget to cover design and construction. This project scope and frequency allowed staff to replace 1 mile per year of wastewater mains that were in poor condition that potentially would collapse to create sewer overflow or street sink hole and to reduce groundwater and rainwater infiltration through cracks or leaking joints.

As part of the FY 2024 financial plan, staff recommended an accelerated CIP program to increase the replacement rate from 1 mile to 2.5 miles per year (from 2 miles to 5 miles per project constructed every other year) to fulfil the goal of replacing pipes near their life expectancy. Staff's proposal attempted to minimize rate impacts while also prudently managing the City's infrastructure and maintaining an acceptable level of risk. The FY 2024 financial plan proposed to begin the accelerated main replacement starting in FY 2026, however due to unforeseen reductions in revenue and increases in operating expenses this financial plan proposes to begin the accelerated CIP replacement rate in FY 2028. Additionally, in 2025, storm damage to a sewer pipe at Arastradero Creek needs to be repaired for an estimated $0.3 million.

With the completion of SSR 31 there will be 136 miles of sewer main remaining to be replaced before the end of its useful life.

This Financial Plan includes one alternative rate trajectory of 9% in FY 2025 described in detail in Section 5F:Alternate Scenarios. Under the alternative, deferring the 5-mile project planned for FY 2026 and adding one additional project to the end of the ~60 year replacement cycle will mean the last main is approximately 110-111 years old before it is replaced. Staff recommends a higher rate increase of 15% in FY 2025 to raise revenues to pay for a reduced-size main replacement of 1 mile (instead of 5 miles) with construction in FY 2026. With the inclusion of this project in FY 2026, the last remaining main would be approximately 110 years old when it is replaced.

The most recent SSR project, SSR 31 includes sewer main replacement on El Camino Real in Caltrans Right of Way and Page Mill Road in Santa Clara County Right of Way. Construction began the end of July 2023 with completion anticipated in May 2024. SSR 31's schedule was accelerated to complete sewer replacement prior to Caltrans' street improvement project on El Camino Real, to avoid digging into the newly-paved street. SSR 31's accelerated schedule and work in El Camino Real resulted in higher than anticipated construction costs. Over the last few years, main replacement costs have been increasing for utilities due to economic activity in the Bay Area causing construction cost inflation. Utilities has bid one sewer project since the pandemic began. There are no indications of a dip in construction costs in the near future. Therefore, future CIP spending assumes an inflation rate of about 5.4% annually, which will significantly increase CIP costs over the forecast period.

The costs for Customer Connections and on-going projects are projected to remain steady through the end of the forecast period. Actual expenses for these projects fluctuate annually depending on how many defective laterals and manholes are discovered during routine maintenance, as well as how much development and redevelopment is going on that prompts the replacement or upgrade of sewer laterals. Property owners pay a fee for sewer lateral replacement or expansion during redevelopment, so when the number of projects increases, so does fee revenue.

Table 16 displays anticipated CIP spending for the 5-year financial forecast period, assuming the accelerated replacement rate of CIP projects will start in FY 2028.

Table 16: Projected CIP Spending, FY 2024 to FY 2029 ($,000)

Project Category	FY 2024 Budget*	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Sewer Rehab/Augmentation	8,965	1,314	2,314	3,476	11,868	3,827
One-Time Projects	-	-	-	-	2,000	-
Ongoing Projects	1,719	1,126	1,150	1,177	1,205	1,225
Customer Connections	350	450	450	450	450	450
Allocated Overhead	1,191	1,239	1,288	1,340	1,394	1,449
TOTAL	12,225	4,128	5,202	6,443	16,916	6,951

Aside from Customer Connections, the CIP plan for FY 2024 to FY 2029 is funded by sewer rates and capacity fees. *Appendix B: Wastewater Collection Utility Capital Improvement Program (CIP) Detail* shows the details of the plan.

Figure 10 below shows the projected CIP Reserve balances from FY 2025 through FY 2029. Figure 11 below shows the projected CIP expenditures fluctuating from year to year with the staggered main replacement schedule. The utility will resume capital program contributions as soon as possible and this is projected to be in FY 2027. This will gradually re-establish the CIP Reserve within the guideline range by FY 2031. Until FY 2027 the CIP Reserve is expected to remain empty. Appendix A: Wastewater Collection Financial Forecast Detail shows the amount of the rate-funded CIP Reserve contributions under "Expenses" for FY 2024 through FY 2029.

Figure 10: Projected CIP Reserve Balances, FY 2025 to FY 2029 ($,000)

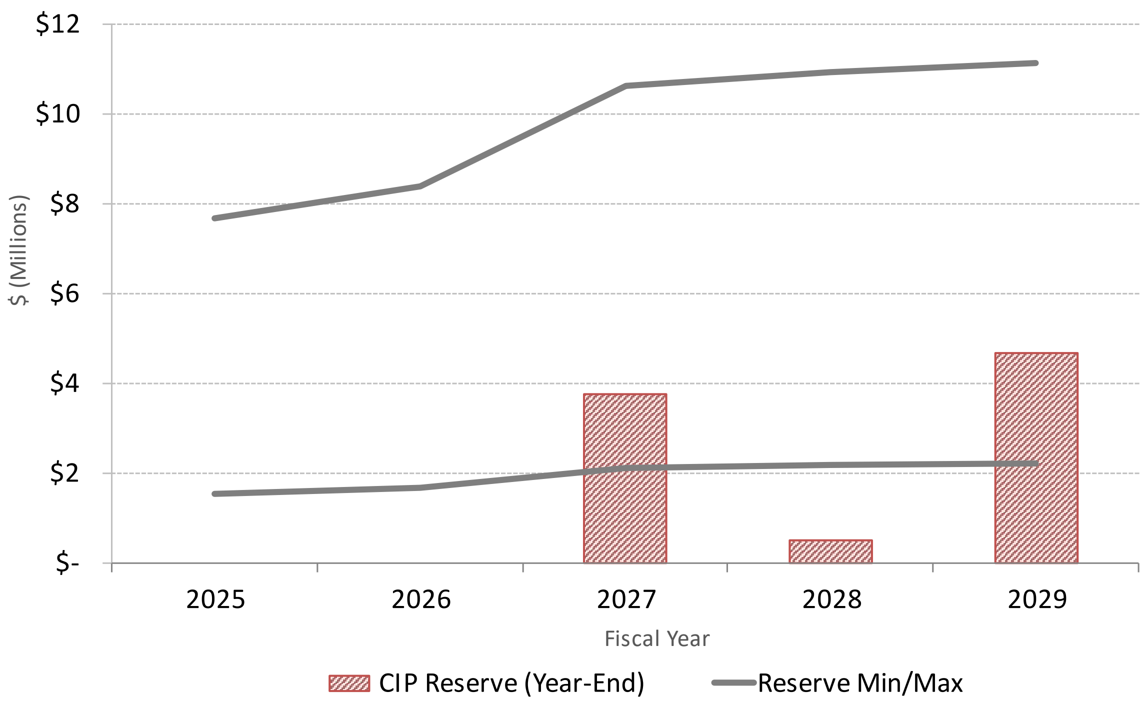
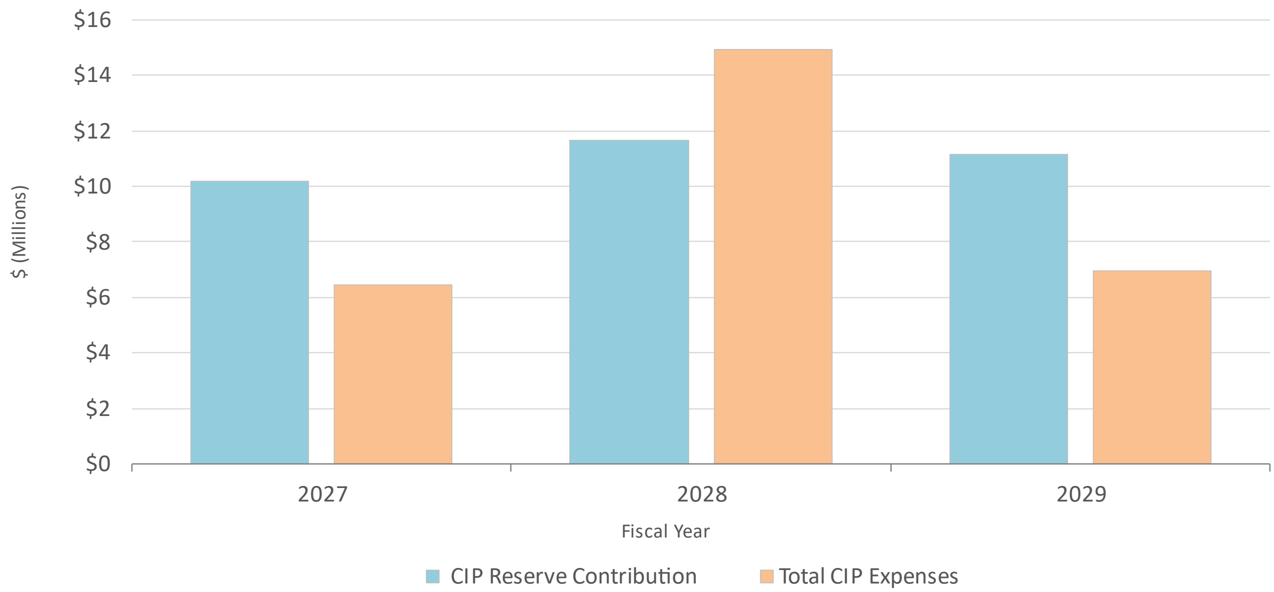


Figure 11: Projected CIP Expenditure, and Projected Capital Program Contribution, FY 2027 to FY 2029 ($000)



SECTION 6D: DEBT SERVICE

The Wastewater Collection Utility currently pays its share of one bond issuance, the 1999 Utility Revenue Bonds, Series A, which is due to be retired in FY 2024. This $17.7 million issuance refinanced various earlier Storm Drain, Wastewater Treatment, and Wastewater Collection Utility bond issuances. The Wastewater Collection Utility's share of the issuance was roughly $1.9 million. This amount represented the second refinancing of the remaining principal of a 1990 bond issuance, which itself was a refinancing of a 1985 issuance that financed a variety of improvements to the sewer system. The cost of debt service for the Wastewater Collection Utility's share of this bond issuance for the financial forecast period is roughly $129,000 per year. The 1999 Utility Revenue Bonds include two covenants stating that 1) the Wastewater Collection Utility will maintain a debt coverage ratio of 125% of debt service, and 2) that the City will maintain "Available Reserves"[11] equal to five times the annual debt service. The current Financial Plan maintains compliance with both covenants throughout the forecast period. Table 17, below, shows compliance with the first covenant.

[11] Available Reserves as defined in the 1999 Utility Revenue Bonds included reserves for the Water, Wastewater Treatment, Wastewater Collection, Refuse, Storm Drain, Electric, and Gas Utilities

Table 17: Debt Service Coverage Ratio ($000)

	FY 2024
Revenues	21,915
Expenses (excl. CIP and Debt Service)	20,308
Net Revenues	1,606
Debt Service	129
Coverage Ratio	1243%

Table 18, below, shows the available reserves in relation to the debt service for the Wastewater Collection utility in FY 2024.

Table 18: Debt Service Minimum Reserves ($000)

	FY 2024
Wastewater Collection and Water Utilities [a]	20,313
Debt Service [b]	129
Reserves Ratio [c]	157x

a) CIP, Rate Stabilization, Operations and Unassigned Reserves
b) Wastewater Collection and Water Utility's share of the debt service on the 1999 Utility Revenue Bonds
c) Calculated using combined Wastewater Collection and Water Utility reserves. The actual reserves ratio for the 1999 Utility Revenue Bonds is calculated based on the combined Water, Wastewater Treatment, Wastewater Collection, Refuse, Storm Drain, Electric, and Gas Utilities reserves and total debt service and is higher than shown here.

The Wastewater Collection Utility's reserves (but not its net revenues) are also considered security for the Storm Drain and Wastewater Treatment Utilities' shares of the debt service on the 1999 bonds. Throughout the term of the bonds there remains a small risk that the Wastewater Collection Utility's reserves could be called upon to make a debt service payment on behalf of one of those utilities if it cannot meet its debt service obligations. Staff does not foresee this occurring based on the current financial condition of those utilities. If the Wastewater Collection Utility's reserves were used this way, any amounts advanced would have to be repaid by the borrowing utility.

SECTION 6E: OTHER REVENUES

Other revenues are from capacity and connection fees and income from interest and transfers in. These revenues fluctuate from year to year. This plan forecasts other revenues using a three-year average of actual capacity and connection fee revenue from FY 2021 – FY 2023 and assuming no inflation throughout the forecast period.

SECTION 7: COMMUNICATIONS PLAN

In FY 2025, the communications strategy for the wastewater collection utility will address the following primary areas: cost drivers, cost containment measures, infrastructure upgrades, increasing wastewater treatment costs, maintenance and operations related to safety, and how these necessary activities impact the rates this year. Communication about wastewater rate adjustments will highlight the important infrastructure upgrades that are occurring at the Regional Water Quality Control Plant (RWQCP) as well as increased capital improvement projects (CIP) to improve our wastewater collection utility services. These infrastructure upgrades are necessary to replace aging wastewater collection mains and sanitary sewer treatment equipment at the RWQCP. Financial reserves are also below minimum guidelines due to higher capital improvement program costs, lower revenue than forecasted, and higher transfers out to capital projects. Some projects will be deferred as the fund increases revenues to a sustainable level.

Staff update the utilities webpages with information on the progress of wastewater projects to keep customers apprised of the status and accomplishments of capital improvement projects. Customers can find project schedules, maps, overviews of the work being done, and project manager contact information at the Utilities Projects webpage[12]. Promotional activities about wastewater infrastructure upgrades and environmental service improvements, operations, safety, CPAU and customer responsibilities for wastewater system maintenance, include the use of bill inserts, ads in local print publications, email newsletters and social media.

An important communications topic for the wastewater utility is avoiding sewer back-ups due to FOG (fats, oil and grease), trash and other hazardous materials being dumped down drains and toilets. These items can clog sewer lines, cause sewer overflows, pollute San Francisco Bay, and create a health and safety risk to humans. Safety topics are emphasized year-round. Staff continue to educate customers about the utility's gas-sewer line cross-bore inspection program, including the importance of calling 811 before digging and contacting CPAU prior to clearing sewer lines in the event of a sewer back-up.

While print materials and webpages feature prominently, CPAU is increasing the outreach emphasis on more direct communication with customers, including through use of social media, email newsletters, digital ads and videos. Staff attend community outreach events, safety and emergency preparedness fairs, business and neighborhood meetings. CPAU continually seeks out new opportunities to engage with the public to spread awareness about important safety topics and inform the community about project improvements such as at the RWQCP.

[12] https://www.cityofpaloalto.org/Departments/Utilities/Utilities-Services-Safety/Utilities-Projects

APPENDICES

Appendix A: Wastewater Collection Financial Forecast Detail

Appendix B: Wastewater Collection Utility Capital Improvement Program (CIP) Detail

Appendix C: Wastewater Collection Utility Reserves Management Practices

Appendix E: Map (CPA Wastewater Collection System - Sewer Mains Replaced or Rehabilitated since 1990)

Appendix E: Sample of Wastewater Collection Outreach Materials

APPENDIX A: WASTEWATER COLLECTION FINANCIAL FORECAST DETAIL

CITY OF PALO ALTO

Wastewater Collection Financial Details

($'000)

		Actual					Projected					
	Fiscal Year	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
1	**% Change in Retail Rate**	**11%**	**7%**	**0%**	**3%**	**3%**	**9%**	**15%**	**9%**	**9%**	**8%**	**7%**
2												
3	Retail Sales Revenue	19,342	20,335	19,817	19,778	20,694	21,915	25,447	28,074	30,880	33,363	35,712
4	Connection & Capacity Fees	594	686	502	203	219	308	308	308	308	308	308
5	Other Revenues & Transfers In	545	394	404	486	387	4,294	460	477	494	512	530
6	Interest	446	406	43	141	168	161	167	174	181	188	195
7	**REVENUES**	**20,928**	**21,820**	**20,765**	**20,608**	**21,467**	**26,678**	**26,382**	**29,033**	**31,863**	**34,370**	**36,746**
8												
9	Treatment	9,843	10,234	10,542	9,479	10,784	12,432	13,185	11,139	12,349	12,839	14,943
10	Allocated Charges (Operating)	1,038	1,640	1,865	3,251	2,158	2,275	2,370	2,467	2,556	2,651	2,755
11	Customer Service	306	366	430	407	414	486	507	527	546	566	589
12	Distribution Operations	2,855	3,461	3,413	3,697	4,054	4,278	4,500	4,656	4,806	4,985	5,181
13	Engineering (Operating)	329	339	351	261	273	292	304	316	327	339	352
14	Debt Service	128	128	127	128	129	129	-	-	-	-	-
15	Rent	320	332	252	257	268	275	283	290	298	306	314
16	Other/ Transfers Out	364	467	342	229	526	270	609	3,463	286	293	299
17	Capital *	3,307	4,582	2,526	5,225	6,446	2,691	4,128	5,202	10,200	11,659	11,139
18	**EXPENSES**	**18,489**	**21,550**	**19,848**	**22,933**	**25,052**	**23,129**	**25,887**	**28,061**	**31,368**	**33,639**	**35,572**
19												
20	**INTO / (OUT OF) RESERVES**	**2,439**	**271**	**917**	**(2,325)**	**(3,585)**	**3,549**	**496**	**971**	**495**	**732**	**1,174**
21												
22	Ending Operations Reserve ^	5,390	5,661	6,578	4,252	(674)	2,875	3,371	4,342	4,837	5,568	6,743
23	Ending Commitments & Reappropriations	5,732	4,775	830	4,612	9,534	4,767	-	-	-	-	-
24	Ending CIP Reserve	978	978	3,178	3,178	-	-	-	-	3,757	500	4,687
25	Ending Rate Stabilization Reserve	342	342	342	342	-	-	-	-	-	-	-
26	Unassigned Reserves	-	-	-	-	-	-	-	-	-	-	-
27												
28	**Operations Reserve Guidelines**											
29	Max (150 Days Treatment/O&M Exp)	7,426	8,673	7,977	7,277	7,646	8,399	8,942	9,394	8,699	9,033	10,041
30	Target (105 Days Treatment/O&M Exp)	5,198	6,071	5,584	5,094	5,353	5,879	6,259	6,576	6,089	6,323	7,029
31	Min (60 Days Treatment/O&M Exp)	2,971	3,469	3,191	2,911	3,059	3,360	3,577	3,758	3,480	3,613	4,016
32	Short Term Risk Assessment Value	2,047	2,251	1,853	1,740	1,911	2,125	2,331	2,230	2,462	2,620	2,924
33												

* Capital for FY 2021 - FY 2022 and FY 2027 - FY 2029 represents CIP funding from the Operations Reserve to the CIP Reserve

34 ^ FY 2023 Operations Reserve Accounting Adjustment of ($135,000)

APPENDIX B: WASTEWATER COLLECTION UTILITY CAPITAL IMPROVEMENT PROGRAM (CIP) DETAIL

Fiscal Year		2024			2025	2026	2027	2028	2029
Project #	Project Name	Carryover From FY23 (A)	Current Year Estimate (B)	Current Year Funding (B-A)					
WC-17001	SSR/A - Project 30	240,022	542,363	302,341	-	-	-	-	-
WC-19001	SSR/A - Project 31	8,436,225	8,108,426	(327,799)	-	-	-	-	-
WC-20000	SSR/A - Project 32	-	-	-			-	-	-
WC-20001	SSR/A - Project 33	-	-	-	1,000,000	2,000,000	3,162,000	9,553,878	-
WC-22001	SSR/A - Project 34	-	-	-	-	-	-	-	3,512,716
WC-22002	SSR/A - Project 35	-	-	-	-	-	-	-	-
WC-22003	SSR/A - Project 36	-	-	-	-	-	-	-	-
WC-22004	SSR/A - Project 37	-	-	-	-	-	-	-	-
WC-22005	SSR/A - Project 38	-	-	-	-	-	-	-	-
WC-22006	SSR/A - Project 39	-	-	-	-	-	-	-	-
Wastewater Pump Station Retrofit		-	-	-	-	-	-	2,000,000	-
Subtotal Sewer Rehab/Augmentation		**8,676,247**	**8,650,789**	**(25,458)**	**1,000,000**	**2,000,000**	**3,162,000**	**11,553,878**	**3,512,716**
WC-13002	Fusion & Gen Equip/Tools	68,481	50,157	(18,324)	50,000	50,000	50,000	50,000	50,000
WC-15002	WW System Improvements	604,002	700,000	95,998	200,000	200,000	200,000	200,000	200,000
WC-99013	Sewer/Manhole Rehab	168,829	968,829	800,000	875,500	900,000	927,000	955,000	975,000
Subtotal Ongoing Projects		**841,312**	**1,718,986**	**877,674**	**1,125,500**	**1,150,000**	**1,177,000**	**1,205,000**	**1,225,000**
Unallocated Salaries and Benefits		-	314,000	314,000	314,000	314,000	314,000	314,000	314,000
Total Project Expenses		**9,517,559**	**10,683,775**	**1,166,216**	**2,439,500**	**3,464,000**	**4,653,000**	**13,072,878**	**5,051,716**
WC-80020	Sewer System Extensions	16,143	350,000	333,857	450,000	450,000	450,000	450,000	450,000
Total Customer Connections		**16,143**	**350,000**	**333,857**	**450,000**	**450,000**	**450,000**	**450,000**	**450,000**
Total CIP Allocated Charges		**-**	**1,191,237**	**1,191,237**	**1,238,886**	**1,288,442**	**1,339,980**	**1,393,579**	**1,449,322**
Total CIP Expenses		**9,533,701**	**12,225,012**	**2,691,311**	**4,128,386**	**5,202,442**	**6,442,980**	**14,916,457**	**6,951,038**
Connection Fees				217,989	217,989	217,989	217,989	217,989	217,989
Capacity Fees				90,118	90,118	90,118	90,118	90,118	90,118
Total CIP Funding				**308,107**	**308,107**	**308,107**	**308,107**	**308,107**	**308,107**
Net CIP Costs				**2,383,204**	**3,820,280**	**4,894,335**	**6,134,873**	**14,608,350**	**6,642,931**
CIP Reserve Beginning Balance				-	-	-	-	3,757,020	499,564
CIP Reserve Contribution				**-**	**-**	**-**	**10,200,000**	**11,659,000**	**11,138,655**
CIP Reserve (Year-End)				-	-	-	3,757,020	499,564	4,687,181
Reserve Minimum				923,256	1,534,513	1,675,646	2,125,539	2,185,625	2,224,618
Reserve Maximum				4,616,280	7,672,566	8,378,229	10,627,694	10,928,125	11,123,092

APPENDIX C: WASTEWATER COLLECTION UTILITY RESERVES MANAGEMENT PRACTICES

The following reserves management practices shall be used when developing the Wastewater Collection 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. Reserves

The Wastewater Collection Utility's Fund Balance is reserved for the following purposes:

a) For existing contracts, as described in Section 3 (Reserve for Commitments)
b) For operating and capital budgets re-appropriated from previous years, as described in Section 4 (Reserve for Re-appropriations)
c) For cash flow management and contingencies related to the Wastewater Collection Utility's Capital Improvement Program (CIP), as described in Section 5 (CIP Reserve)
d) For rate stabilization, as described in Section 6 (Rate Stabilization Reserve)
e) For operating contingencies, as described in Section 7 (Operations Reserve)
f) 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 8 (Unassigned Reserves).

Section 3. Reserve for Commitments

At the end of each fiscal year the Reserve for Commitments will be set to an amount equal to the total remaining spending authority for all contracts in force for the Wastewater Collection Utility at that time.

Section 4. Reserve for Re-appropriations

At the end of each fiscal year the Reserve for Re-appropriations will be set to an amount equal to the amount of all remaining capital and non-capital budgets, if any, that will be re-appropriated to the following fiscal year in accordance with Palo Alto Municipal Code Section 2.28.090.

Section 5. 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)[13] CIP budget, for 48 months of budgeted CIP expenses[14]

b) Changes in Reserves: Staff is authorized to transfer funds between the CIP Reserve and the Reserve for Commitments when funds are added or removed from to that reserve 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.
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, return the funds to ratepayers, or designate a specific use of the 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 6. Rate Stabilization Reserve

Funds may be added to the Rate Stabilization Reserve by action of the City Council and held to manage the trajectory of future year rate increases. Withdrawal of funds from the Rate Stabilization Reserve requires Council action. If there are funds in the Rate Stabilization Reserve at the end of any fiscal year, any subsequent Wastewater Collection Utility Financial Plan must result in the withdrawal of all funds from this Reserve by the end of the Financial Planning Period.

[13] Each month is calculated based upon 1/12 of the annual budget.
[14] For example, in the Financial Plan for FY 2022, the 48 month period to use to derive the annual average is FY 2022 through FY 2025. In the FY 2023 Financial Plan, the 48 month period to use to derive the annual average would be FY 2023 through FY 2026 etc.

Section 7. Operations Reserve

The Operations Reserve is used to manage normal variations in costs and as a reserve for contingencies. Any portion of the Wastewater Collection Utility's Fund Balance not included in the reserves described in Section 3-Section 6 above will be included in the Operations Reserve unless this reserve has reached its maximum level as set forth in Section 7(d) below. Staff will manage the Operations Reserve according to the following practices:

a) The following guideline levels are set forth for the 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.

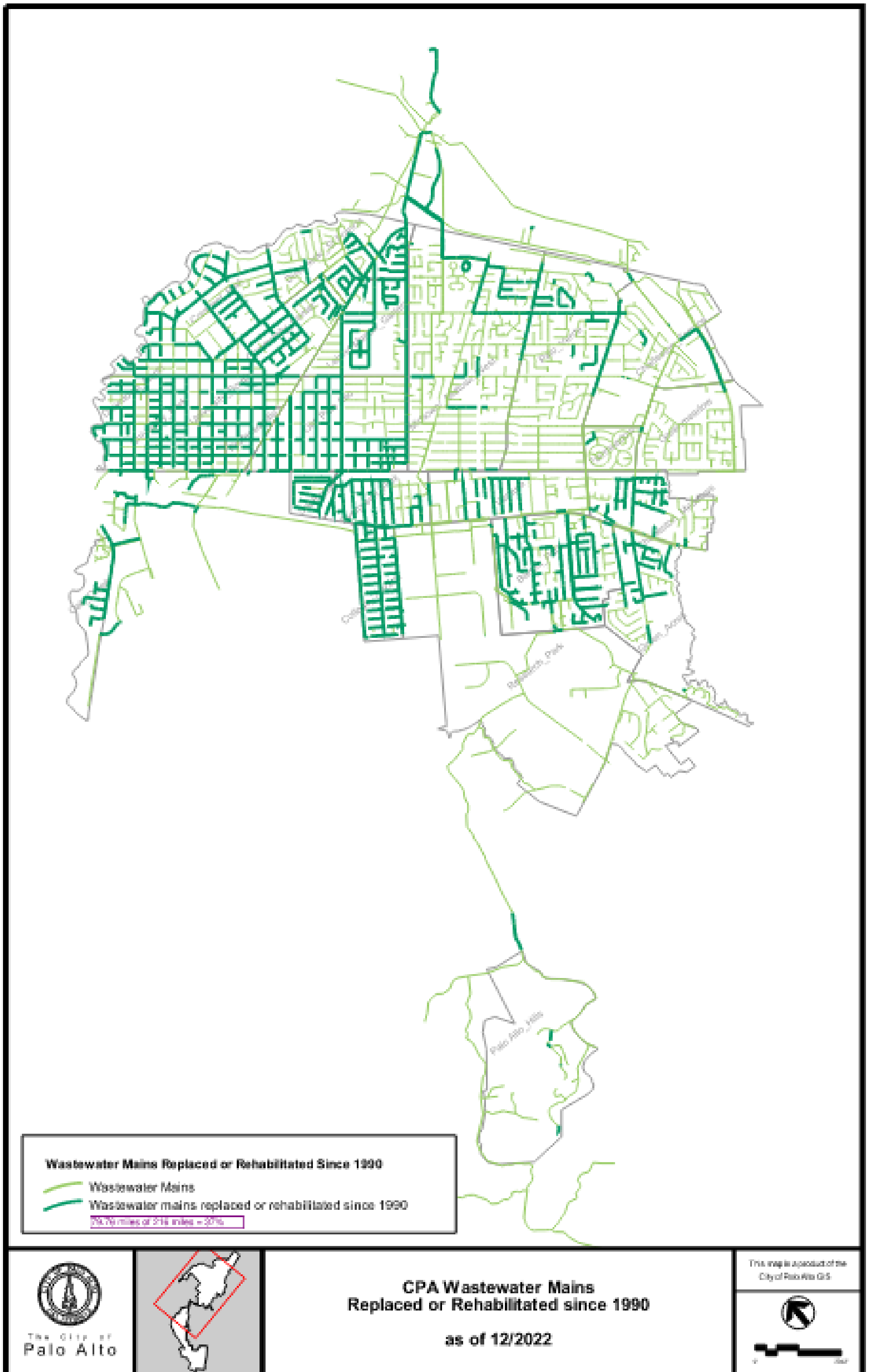
Minimum Level	60 days of O&M and commodity expense
Target Level	105 days of O&M and commodity expense
Maximum Level	150 days of O&M and commodity expense

b) Minimum Level: If, at the end of any fiscal year, the funds remaining in the 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, and the Council may adopt, an alternative plan that takes longer than one year to replenish the reserve.
c) Target Level: If, at the end of any fiscal year, the Operations Reserve is higher or lower than the target level, any Financial Plan created for the Wastewater Collection Utility shall be designed to return the Operations Reserve to its target level within four years.
d) Maximum Level: If, at any time, the Operations Reserve reaches its maximum level, no funds may be added to this reserve. Any further increase in the Wastewater Collection Utility's Fund Balance shall be automatically included in the Unassigned Reserve described in Section 8, below.

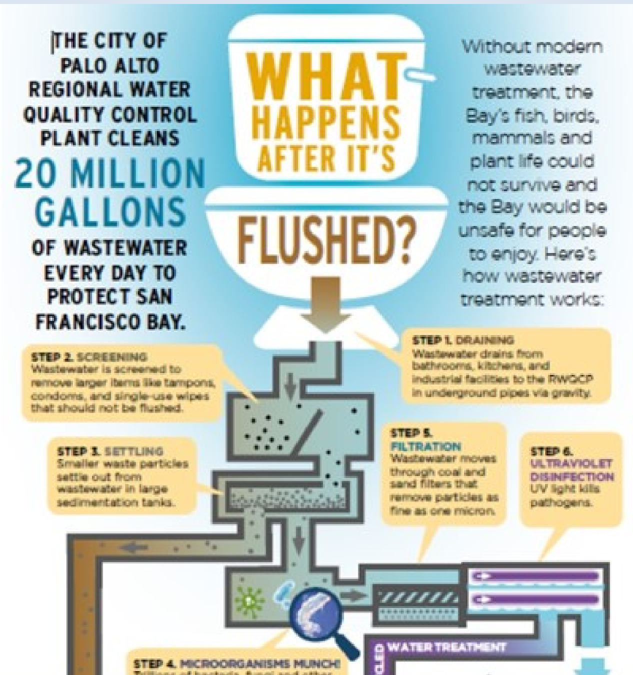
Section 8. Unassigned Reserve

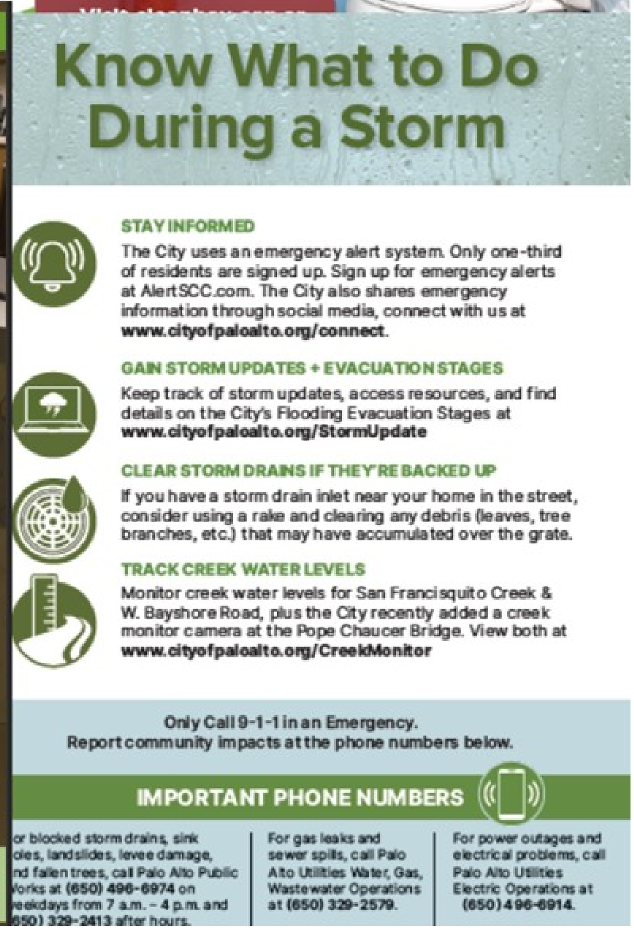
If the Operations Reserve reaches its maximum level, any further additions to the Wastewater Collection Utility's Fund Balance will be held in the Unassigned Reserve. If there are any funds in the Unassigned Reserve at the end of any fiscal year, the next Financial Plan presented to the City Council must include a plan to assign them to a specific purpose or return them to the Wastewater Collection 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 2015, and the next Financial Planning Period is FY 2016 through FY 2020, the Financial Plan shall include a plan to return or assign any funds in the Unassigned Reserve by the end of FY 2016. Staff may present an alternative plan that retains these funds or returns them over a longer period of time.

APPENDIX D: MAP (CPA WASTEWATER COLLECTION SYSTEM - SEWER MAINS REPLACED OR REHABILITATED SINCE 1990)



APPENDIX E: SAMPLE OF WASTEWATER COLLECTION OUTREACH MATERIALS





RESIDENTIAL WASTEWATER COLLECTION AND DISPOSAL

UTILITY RATE SCHEDULE S-1

A. APPLICABILITY:

This schedule applies to each Occupied Domestic Dwelling unit.

B. TERRITORY:

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

C. RATES:

Per Month

Each Occupied Domestic Dwelling unit... $~~48.64~~55.93

D. SPECIAL NOTES:

1. Any dwelling unit being individually served by a Water, Gas, or Electric Meter will be considered continuously occupied.

2. For two or more Occupied Domestic Dwelling units served by one Water Meter, the monthly Wastewater charge will be calculated by multiplying the current Wastewater rate by the number of dwelling units.

3. Each developed separate lot shall have a separate service lateral to a sanitary main or manhole.

{End}

COMMERCIAL WASTEWATER COLLECTION AND DISPOSAL

UTILITY RATE SCHEDULE S-2

A. APPLICABILITY:

This schedule applies to all commercial establishments other than those served under Utility Rate Schedule S-1 (Residential Wastewater Collection and Disposal), Rate Schedule S-6 (Restaurant Wastewater Collection and Disposal) or Rate Schedule S-7 (Commercial Establishments Wastewater Disposal – Industrial Discharger).

B. TERRITORY:

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

C. RATES:

Quantity Rate, per 100 cubic feet (See Section D.1) .... $~~9.08~~10.44

D. SPECIAL NOTES:

1. The monthly charge for the quantity rate set forth in Section C of this rate schedule will be based upon the average Water usage for the months of January, February and March, and applied in the following July. If a Water Meter is identified as exclusively serving irrigation landscaping, such Meter will be exempted from Wastewater charge calculations. Customers without an applicable usage history will be rebuttably presumed to have usage of 4.8 ccf per month until such time as such usage may reasonably be established by the City of Palo Alto Utilities Department.

2. The City of Palo Alto Utilities Department may require Wastewater Metering facilities, in which case Service will be governed by terms of a special agreement between the City and the Customer.

{End}

RESTAURANT WASTEWATER COLLECTION AND DISPOSAL

UTILITY RATE SCHEDULE S-6

A. APPLICABILITY:

This schedule applies to all restaurants.

B. TERRITORY:

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

C. RATES:

Quantity Rates, per 100 cubic feet of monthly metered Water usage ....$ 1~~3.55~~5.58

D. SPECIAL NOTES:

1. The City of Palo Alto Utilities Department may require Wastewater Metering facilities, in which case Service will be governed by terms of a special agreement between the City and the Customer.

{End}

COMMERCIAL WASTEWATER COLLECTION AND DISPOSAL – INDUSTRIAL DISCHARGER

UTILITY RATE SCHEDULE S-7

A. APPLICABILITY:

This schedule applies to any establishment requiring sampling of industrial discharges in excess of 25,000 gallons per day, or special discharge monitoring, as defined in Rule 23, Section C.

B. TERRITORY:

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

C. RATES:

1. Collection System Operation, Maintenance, and Infiltration Inflow:
   $ ~~4.51~~5.18 per 100 cubic feet of metered water use.

2. Advanced Waste Treatment Operations and Maintenance Charge:
   $ 2.07~~1.80~~ per 100 cubic feet of metered water use

3. $253.49~~20.43~~ per 1000 pounds (lbs) of COD (Chemical Oxygen Demand)
4. $ 611.17~~531.46~~ per 1000 lbs of SS (Suspended Solids)
5. $ 4,223.09~~3,672.26~~ per 1000 lbs of NH_3 (Ammonia)
6. $ 18,528.29~~16,111.56~~ per 1000 lbs of toxics (chromium, copper, cyanide, lead, nickel, silver, and zinc)

D. SPECIAL NOTES:

1. Water usage will be determined as defined in Rule 23, Section C. If a Water Meter is identified as exclusively serving irrigation landscaping, such Meter will be exempted from Wastewater charge calculations.

2. The City of Palo Alto Utilities Department may require Wastewater Metering facilities, in which case Service will be governed by terms of a special agreement between the City of Palo Alto and the Customer.

3. Charges for large discharges will be determined on the basis of sampling as outlined in Utilities Rule 23, Section C. However, for purposes of arriving at an accurate flow estimate, discharge Meters, if installed, can be utilized to measure outflow for billing purposes. Annual charges will be determined and allocated monthly for billing purposes.

{End}

RESIDENTIAL WASTEWATER COLLECTION AND DISPOSAL

UTILITY RATE SCHEDULE S-1

A. APPLICABILITY:

This schedule applies to each Occupied Domestic Dwelling unit.

B. TERRITORY:

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

C. RATES:

Per Month

Each Occupied Domestic Dwelling unit.. $~~48.64~~53.01

D. SPECIAL NOTES:

1. Any dwelling unit being individually served by a Water, Gas, or Electric Meter will be considered continuously occupied.

2. For two or more Occupied Domestic Dwelling units served by one Water Meter, the monthly Wastewater charge will be calculated by multiplying the current Wastewater rate by the number of dwelling units.

3. Each developed separate lot shall have a separate service lateral to a sanitary main or manhole.

{End}

COMMERCIAL WASTEWATER COLLECTION AND DISPOSAL

UTILITY RATE SCHEDULE S-2

A. APPLICABILITY:

This schedule applies to all commercial establishments other than those served under Utility Rate Schedule S-1 (Residential Wastewater Collection and Disposal), Rate Schedule S-6 (Restaurant Wastewater Collection and Disposal) or Rate Schedule S-7 (Commercial Establishments Wastewater Disposal – Industrial Discharger).

B. TERRITORY:

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

C. RATES:

Quantity Rate, per 100 cubic feet (See Section D.1) .... $9.89~~08~~

D. SPECIAL NOTES:

1. The monthly charge for the quantity rate set forth in Section C of this rate schedule will be based upon the average Water usage for the months of January, February and March, and applied in the following July. If a Water Meter is identified as exclusively serving irrigation landscaping, such Meter will be exempted from Wastewater charge calculations. Customers without an applicable usage history will be rebuttably presumed to have usage of 4.8 ccf per month until such time as such usage may reasonably be established by the City of Palo Alto Utilities Department.

2. The City of Palo Alto Utilities Department may require Wastewater Metering facilities, in which case Service will be governed by terms of a special agreement between the City and the Customer.

{End}

RESTAURANT WASTEWATER COLLECTION AND DISPOSAL

UTILITY RATE SCHEDULE S-6

A. APPLICABILITY:

This schedule applies to all restaurants.

B. TERRITORY:

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

C. RATES:

Quantity Rates, per 100 cubic feet of monthly metered Water usage ....$ 14.76~~3.55~~

D. SPECIAL NOTES:

1. The City of Palo Alto Utilities Department may require Wastewater Metering facilities, in which case Service will be governed by terms of a special agreement between the City and the Customer.

{End}

COMMERCIAL WASTEWATER COLLECTION AND DISPOSAL – INDUSTRIAL DISCHARGER

UTILITY RATE SCHEDULE S-7

A. APPLICABILITY:

This schedule applies to any establishment requiring sampling of industrial discharges in excess of 25,000 gallons per day, or special discharge monitoring, as defined in Rule 23, Section C.

B. TERRITORY:

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

C. RATES:

1. Collection System Operation, Maintenance, and Infiltration Inflow:
   $ 4.9~~5~~1 per 100 cubic feet of metered water use.

2. Advanced Waste Treatment Operations and Maintenance Charge:
   $ 1.96~~80~~ per 100 cubic feet of metered water use

3. $240.26~~20.43~~ per 1000 pounds (lbs) of COD (Chemical Oxygen Demand)
4. $ 579.29~~31.46~~ per 1000 lbs of SS (Suspended Solids)
5. $ 4,002.76~~3,672.26~~ per 1000 lbs of NH_3 (Ammonia)
6. $ 17,561.60~~6,111.56~~ per 1000 lbs of toxics (chromium, copper, cyanide, lead, nickel, silver, and zinc)

D. SPECIAL NOTES:

1. Water usage will be determined as defined in Rule 23, Section C. If a Water Meter is identified as exclusively serving irrigation landscaping, such Meter will be exempted from Wastewater charge calculations.

2. The City of Palo Alto Utilities Department may require Wastewater Metering facilities, in which case Service will be governed by terms of a special agreement between the City of Palo Alto and the Customer.

3. Charges for large discharges will be determined on the basis of sampling as outlined in Utilities Rule 23, Section C. However, for purposes of arriving at an accurate flow estimate, discharge Meters, if installed, can be utilized to measure outflow for billing purposes. Annual charges will be determined and allocated monthly for billing purposes.

{End}

CITY OF PALO ALTO

WASTEWATER COLLECTION UTILITY FINANCIAL PROJECTIONS

March 6, 2024

www.cityofpaloalto.org

Wastewater Proposal

- Staff Recommendation: 15% rate increase in FY 25, **$7.29** per residential customer per month
  - Reduced-size sewer replacement $1M in FY 25 and $2M in FY 26
  - $2M Pump station retrofit in FY 28
- Alternative 9% rate increase in FY 25, $4.37 per residential customer per month
  - Defer FY 25 and FY 26 of planned sewer replacement
  - Defer pump station retrofit
- Both staff recommendation and alternative resume 2.5 miles per year of sewer main replacement in FY 28

Rate Projections:

Fiscal Year	2024	2025	2026	2027	2028	2029
Staff Recommendation	9%	15%	9%	9%	8%	7%
Alternative	9%	9%	9%	9%	9%	9%
FY 2024 Financial Plan	9%	9%	9%	8%	5%	5%

Summary of Proposal and Alternative Residential Bill Impacts

	Alternatives	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Estimated Bill Impact for Residential Customers ($/mo.) and Rate Increase Percentage (1)	Proposal: 15% in FY 2025	7.29	5.03	5.48	5.31	5.02
		15%	9%	9%	8%	7%
	Alternative: 9% in FY 2025	4.37	4.77	5.20	5.66	6.17
		9%	9%	9%	9%	9%
Estimated Monthly Sewer Bill ($)	Proposal: 15% in FY 2025	55.93	60.96	66.44	71.75	76.77
	Alternative: 9% in FY 2025	53.01	57.78	62.98	68.64	74.81
Net Difference in Monthly Bills ($)	15% vs. 9% in FY 2025	2.92	3.18	3.46	3.11	1.96

(1) estimated impact on residential wastewater monthly bill, which is currently $48.64.

Wastewater Alternatives & Residential Bill Impacts

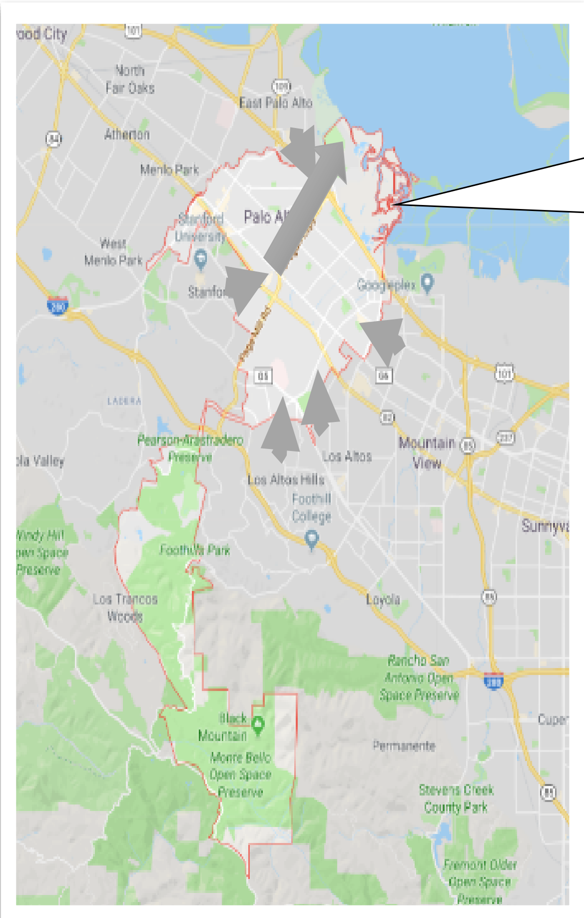
	FY 2025 – FY 2026 Main Replacement [a]		FY 2025	FY 2026	FY 2027	FY 2028	FY 2029	Age of Last Remaining Sewer Main Replaced
	Budget	Length (miles)						
Proposal: 15% in FY 2025	$3M	~ 1.25	15%	9%	9%	8%	7%	110 years
			$7.29	***$5.03***	***$5.48***	***$5.31***	***$5.02***	
Alternative: 9% in FY 2025	$0	0	9%	9%	9%	9%	9%	111 years
			$4.37	***$4.77***	***$5.20***	***$5.66***	***$6.17***	

a) The estimated budget for a 5-mile sewer main replacement in FY 2025 – FY 2026 is $11.6 million.

Wastewater Projections

- FY 2023 Year End Ops Reserve below minimum guideline and below zero, at -$0.7M, due to:
  - $3M – higher CIP-related (including admin costs)
  - $0.5M – revenue lower than forecasted
  - $0.3M – higher transfers out to capital projects
- Sanitary Sewer Replacement 31 moved up a year from FY 2024 to FY 2023 due to coordination with CalTrans; $9.3M in the reappropriations reserve for this project
- Current year revenue projected to be $0.7M below projection due to non-residential revenue declines as a result of wet weather and reductions in winter water usage
- Recommend reduced size sewer main replacement (construction in FY 2026)
- Reductions temporary as the Wastewater Collection fund increases revenues to sustainable level by the end of the forecast period

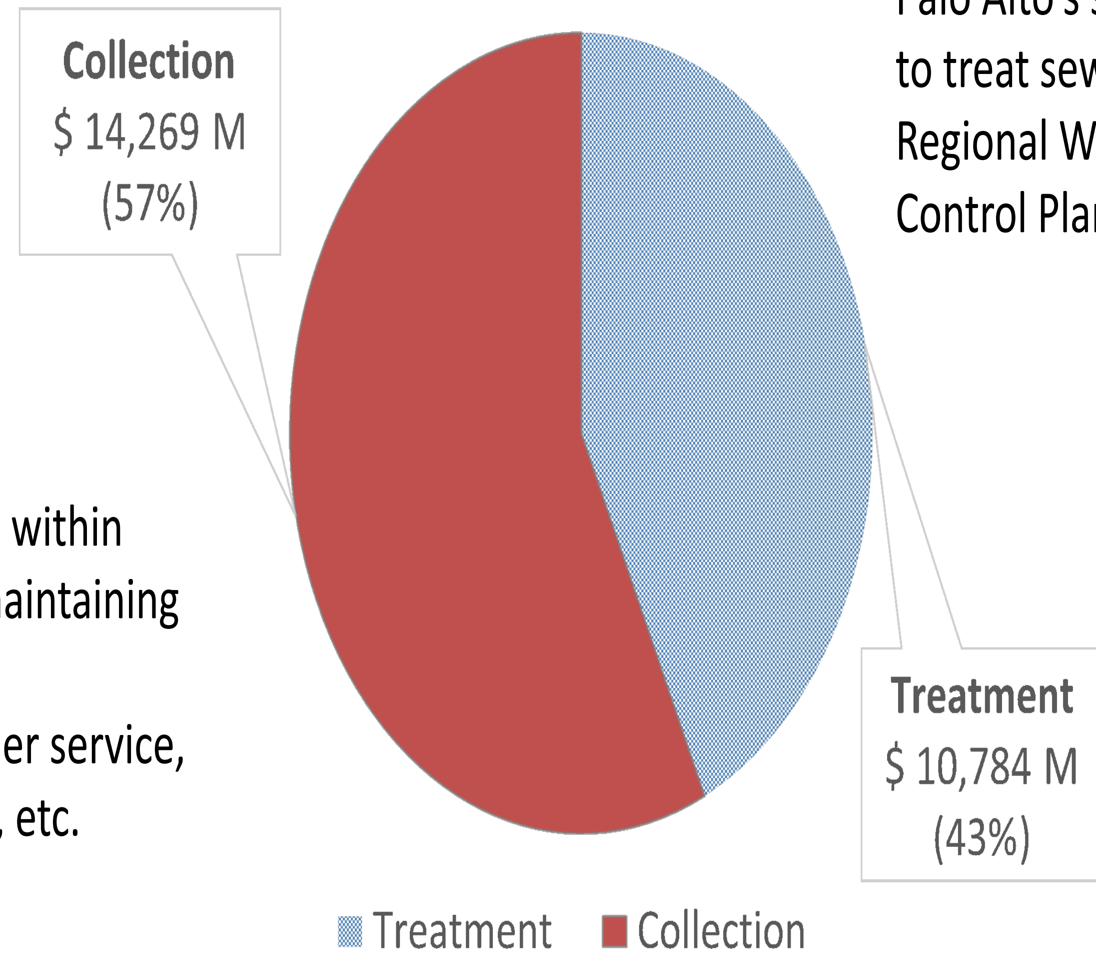
Wastewater Utility Basics



- Treatment Plant has five partners: Stanford, East Palo Alto, Los Altos Hills, Los Altos, and Mountain View
- Wastewater drains from partner systems through the City of Palo Alto Collection System, and into the City of Palo Alto Regional Water Quality Control Plant (RWQCP) for treatment
- City of Palo Alto Utilities Department manages collection system, Public Works manages the RWQCP

CITY OF PALO ALTO

Wastewater Utility Cost Structure



Palo Alto's share of the cost to treat sewage at Palo Alto's Regional Water Quality Control Plant

Cost to collect sewage within Palo Alto, including: maintaining and replacing sewer infrastructure, customer service, billing, administration, etc.

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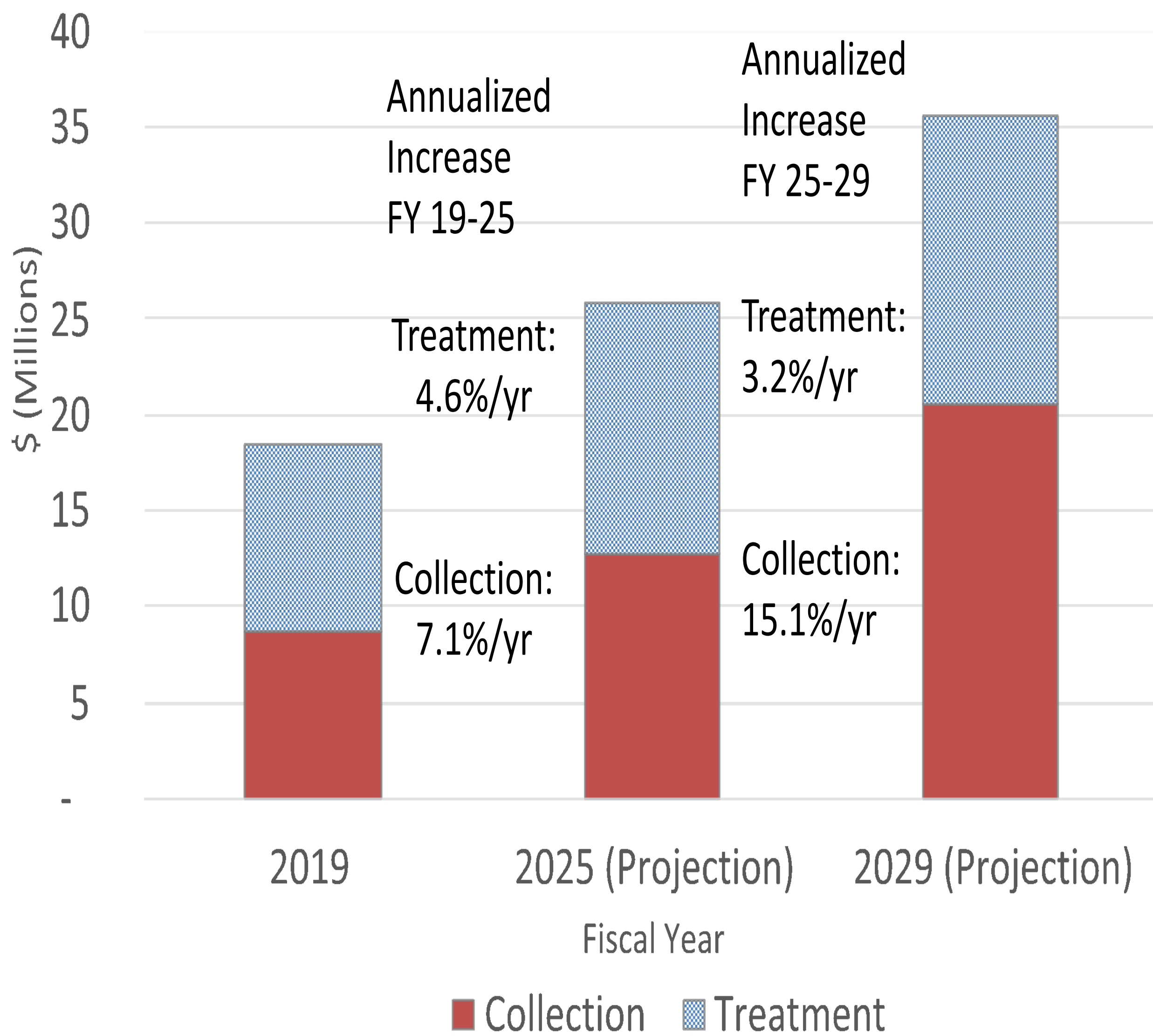
Long Term Cost Trends



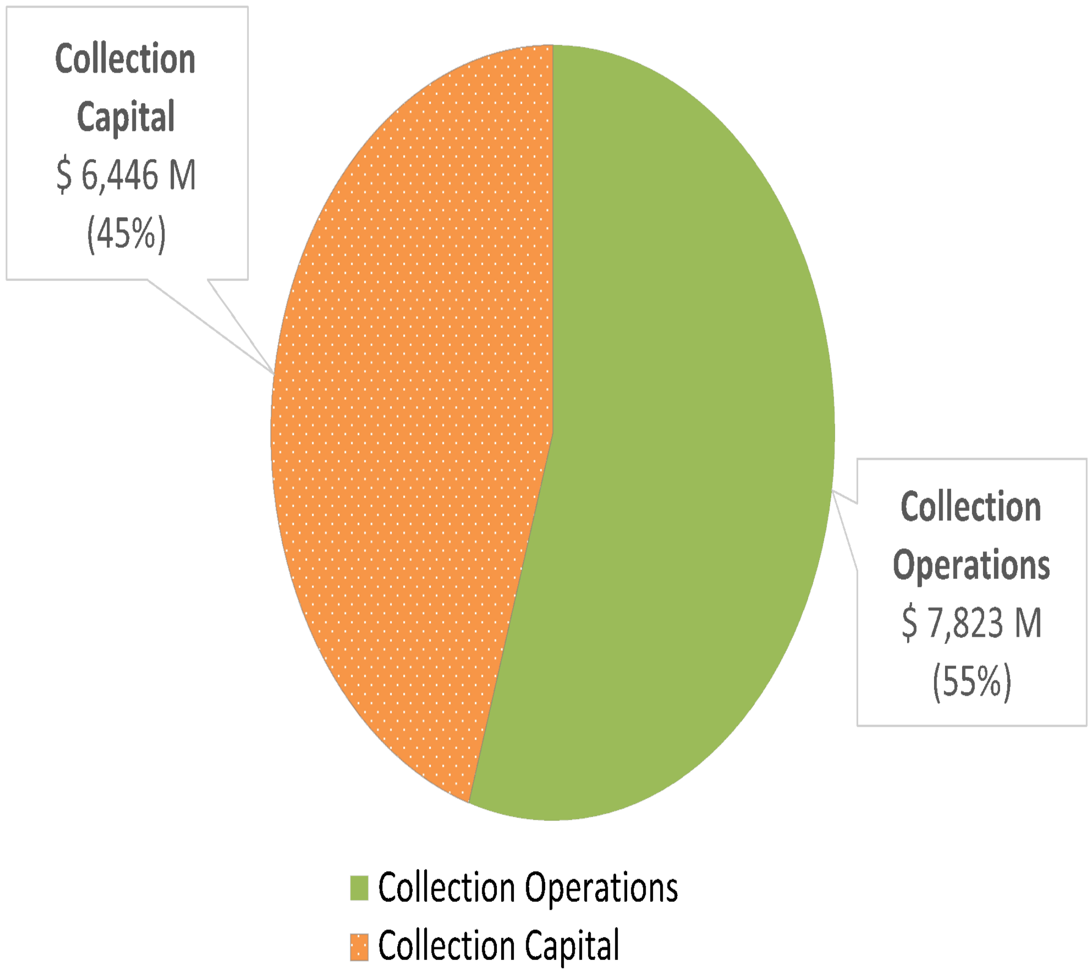
Note: Collection Capital reflects Two-Year Average

CITY OF PALO ALTO

Treatment Cost Drivers

- Regional Water Quality Control Plant needs rehabilitation
- Long Range Facilities Plan completed in 2012, currently being updated including partner cost-share re-evaluation
- Near Term Major Projects:
  - Sedimentation Tank ($19.4M)
  - Outfall Pipeline ($17.8M)
  - Laboratory/Operations Center ($48.5M)
  - Secondary Treatment Upgrades ($193M)
- Applying for grant funding from Valley Water (estimated $11.2M available to Palo Alto from 2024 through 2033);
- Forecast assumes $7.4M available from FY 26 – FY 29

Wastewater Collection Costs



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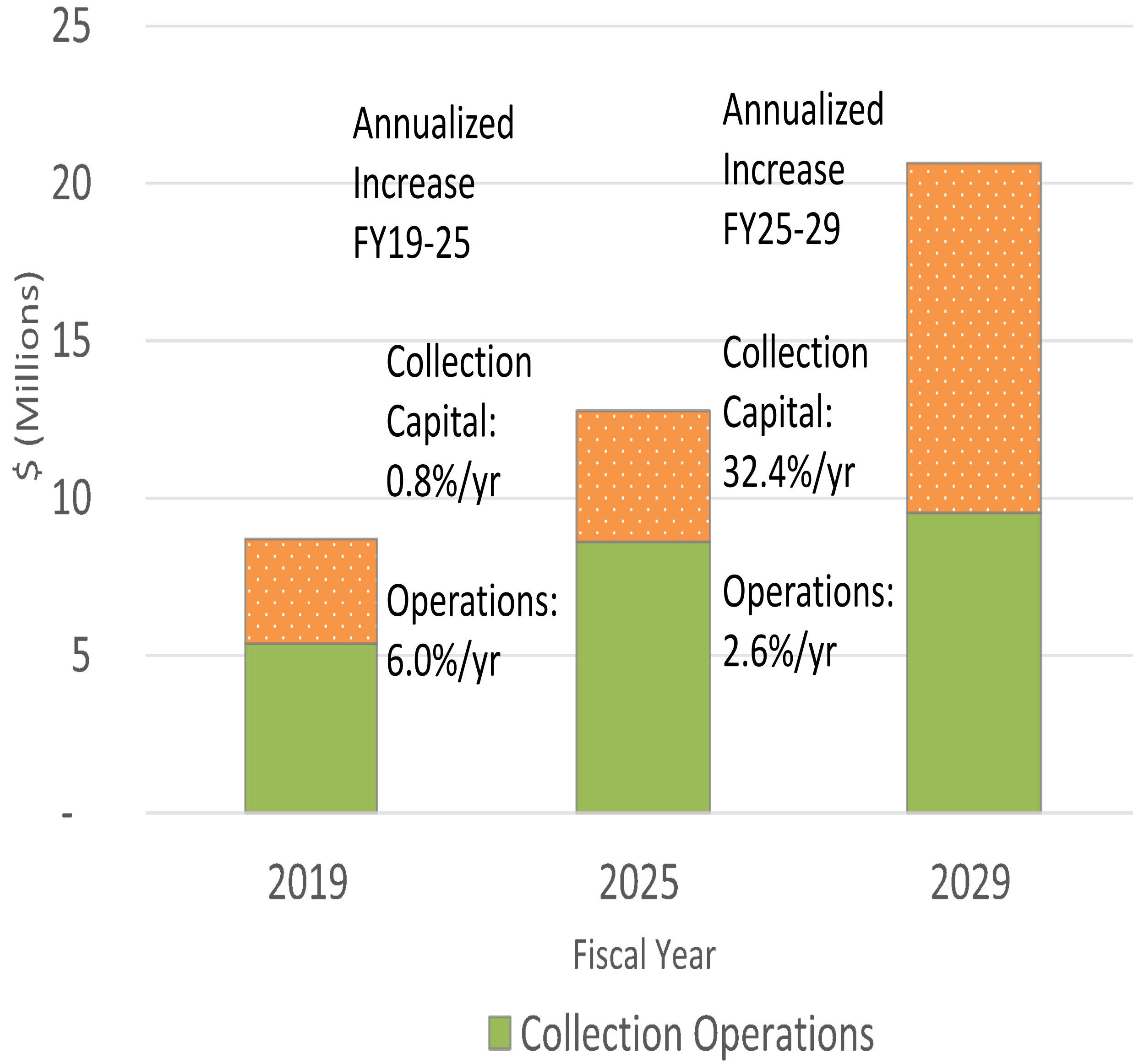
Wastewater Collection Cost Trends



Reflects Reduced-Size Sewer Replacement in FY 2025 and FY 2026

Note: Capital & Debt Service reflects two-year average

CITY OF PALO ALTO

OPERATIONS/CAPITAL COST DRIVERS

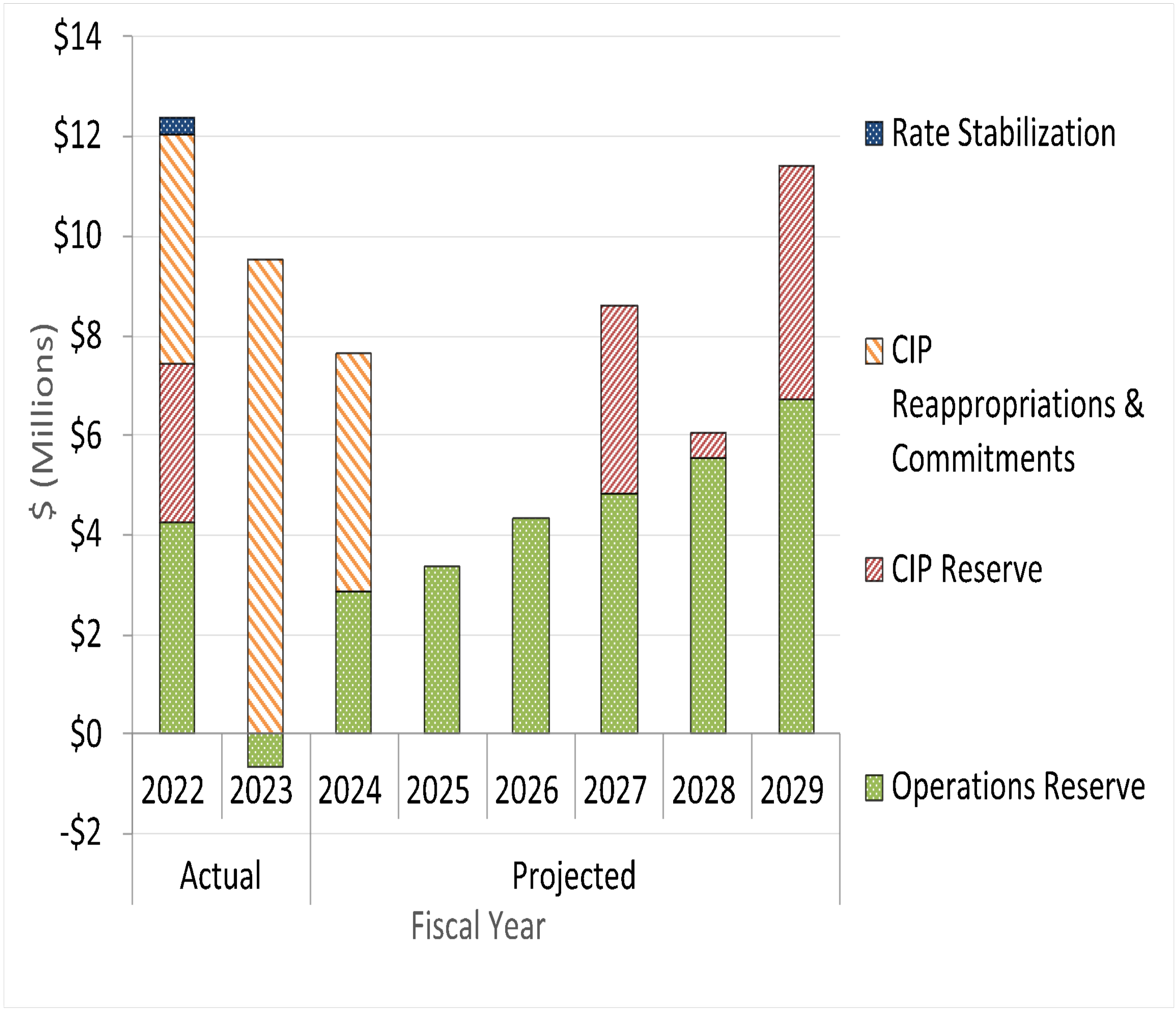
Operational Costs

- Salary and benefit costs for existing staff
- 3-4% annual inflation for other operating costs
- Revenue reduction expected in current year $700K, estimated recovery by FY 2027
- Lower connection, capacity fees and interest income

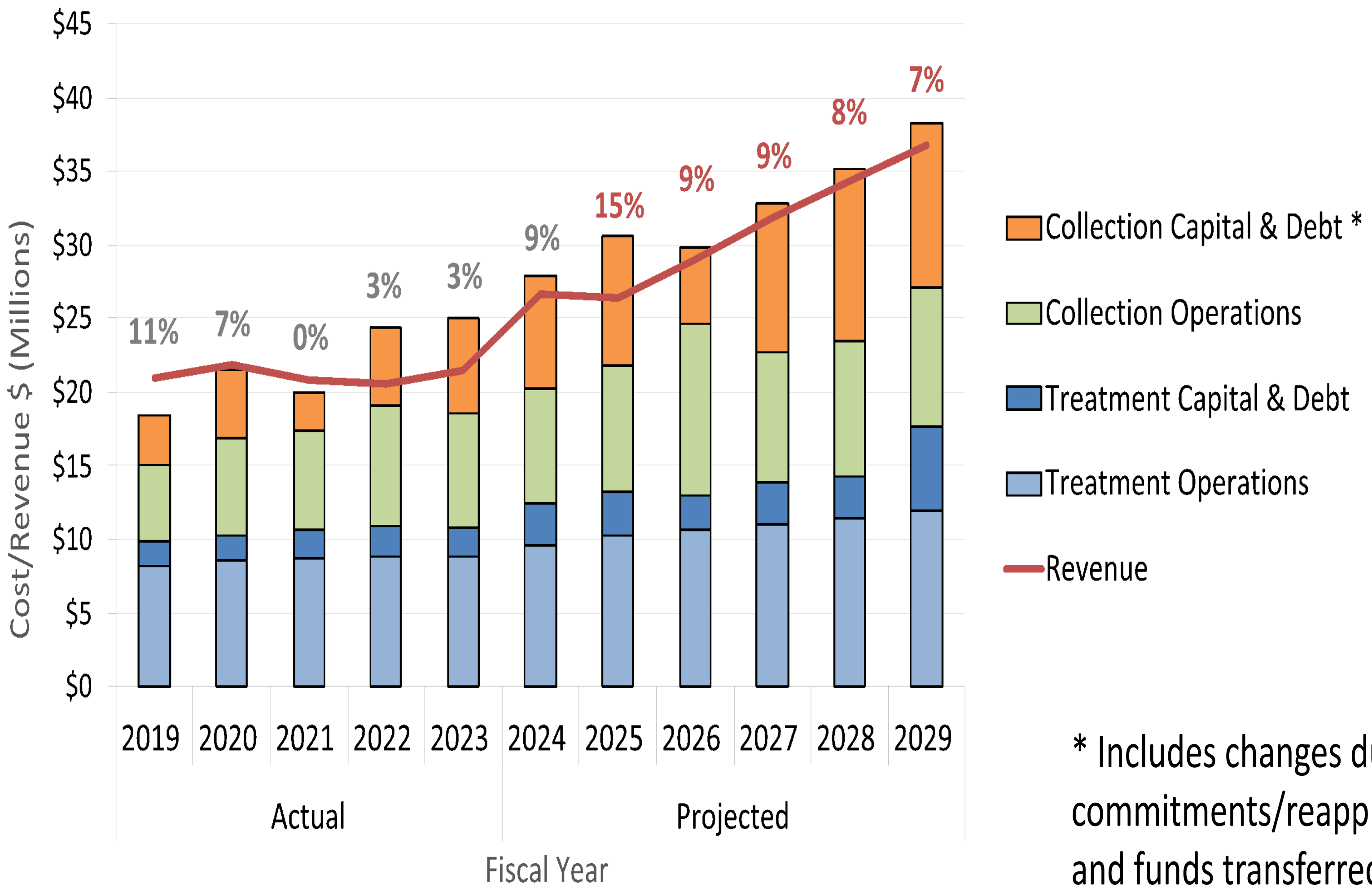
Capital Costs

- Underground construction cost increases
- Allocated cost increases
- Sanitary Sewer Replacements at the rate of 2.5 miles per year after fund recovers

Wastewater Reserve Projections



Preliminary Wastewater Cost and Revenue Projections



* Includes changes due to commitments/reappropriations and funds transferred to the CIP Reserve

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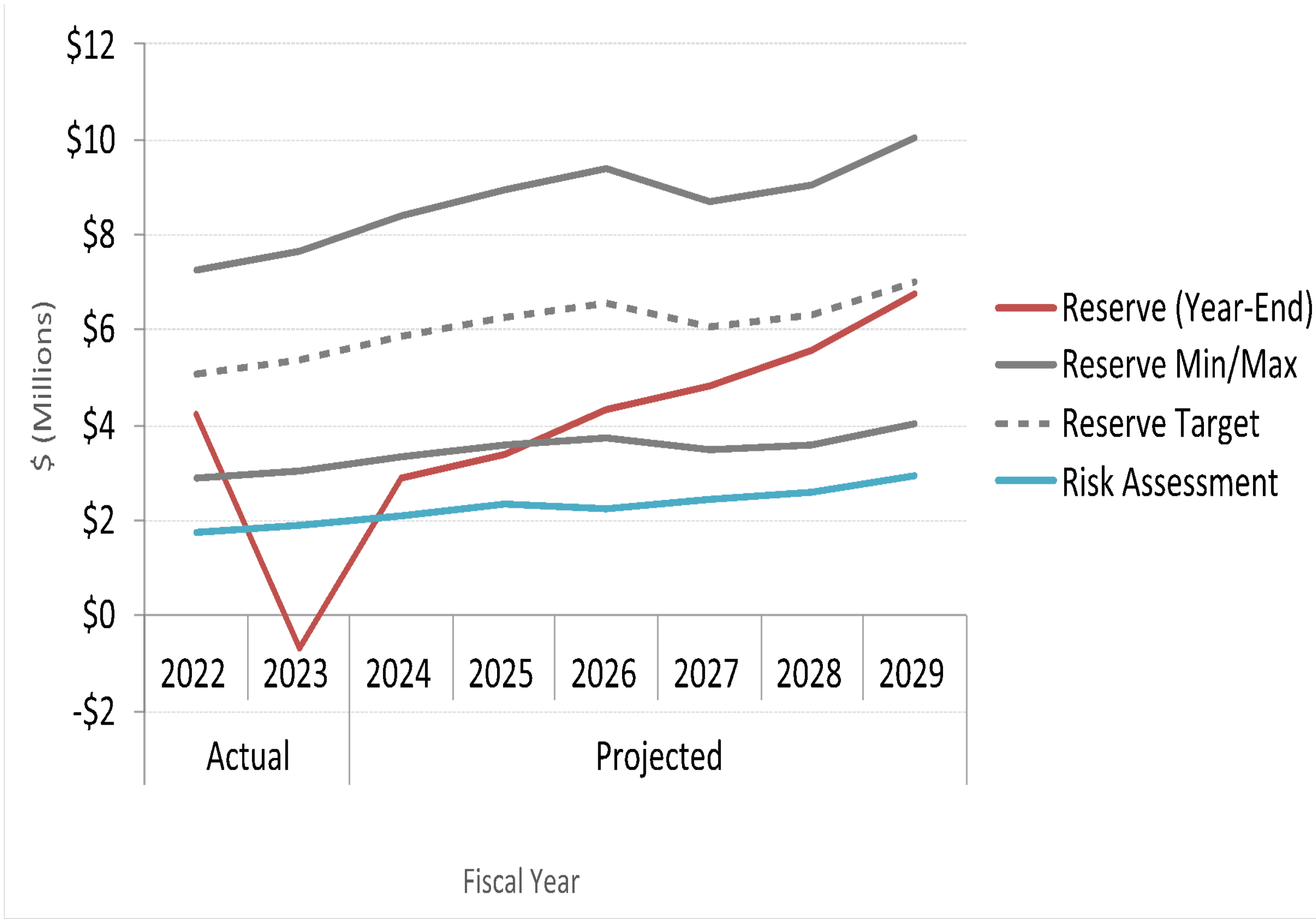
Wastewater Operations Reserve Projections



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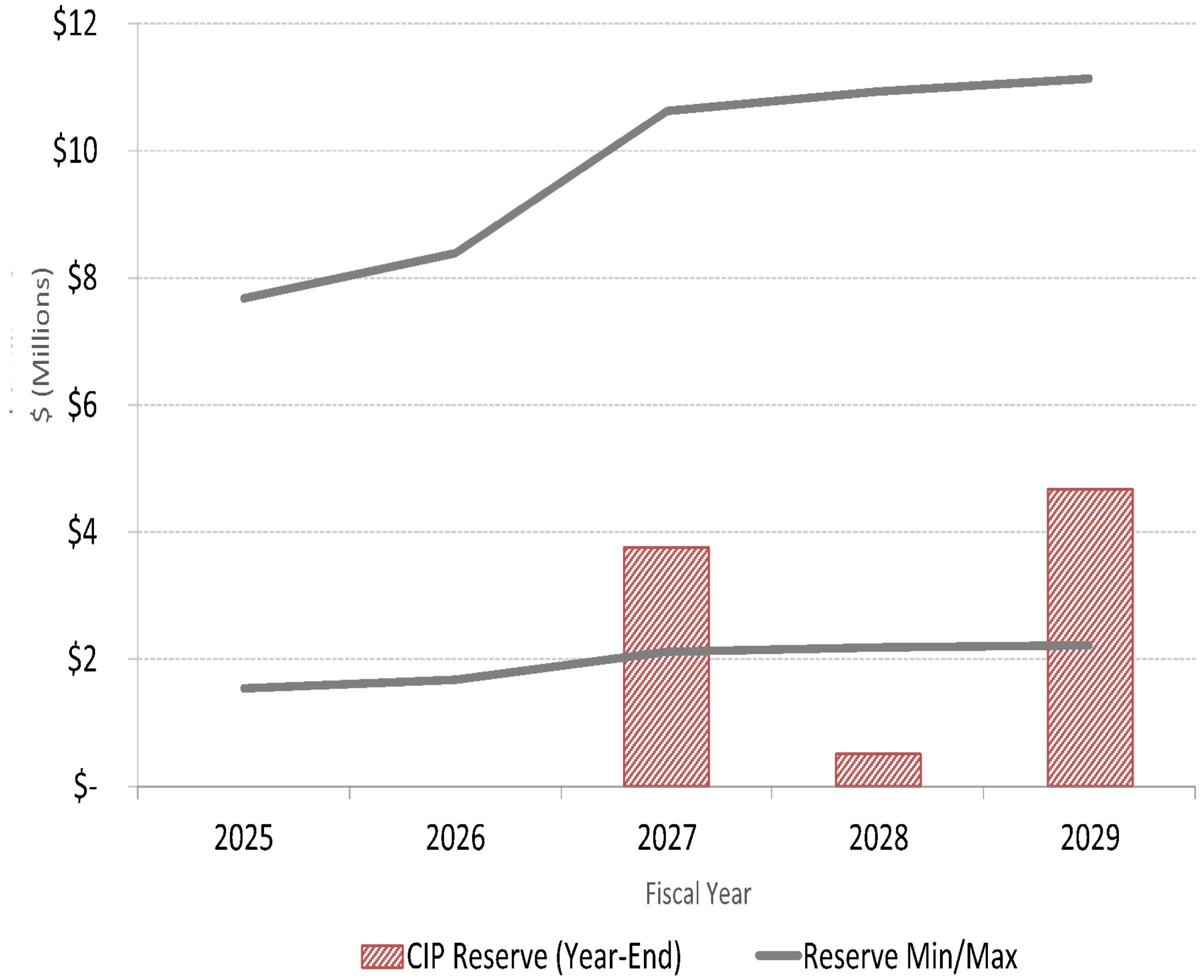
Wastewater CIP Reserve Projections



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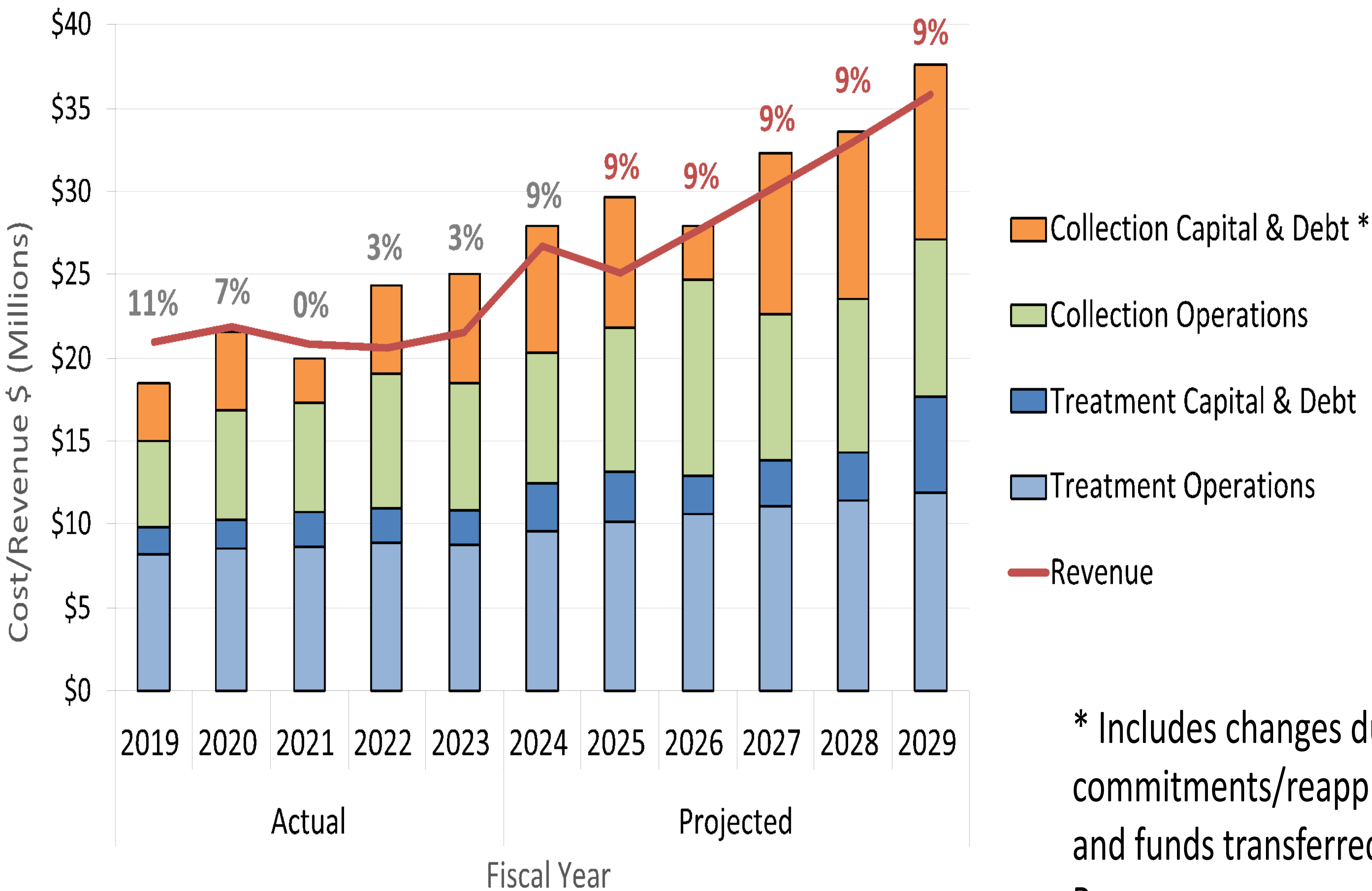
ALTERNATIVE Preliminary Wastewater Projections

9% in FY25



* Includes changes due to commitments/reappropriations and funds transferred to the CIP Reserve

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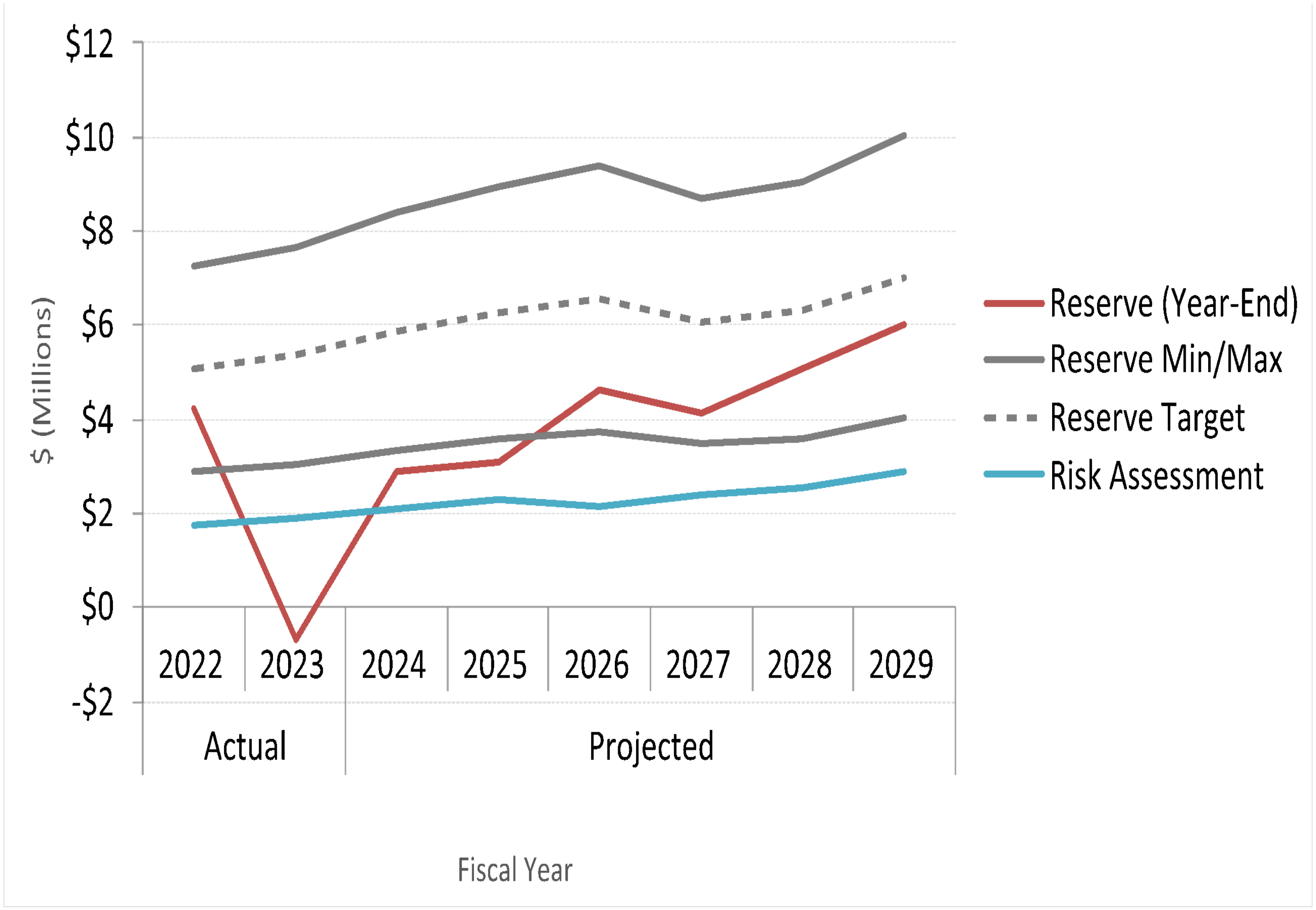
ALTERNATIVE: Wastewater Operations Reserve Projection

9% in FY25



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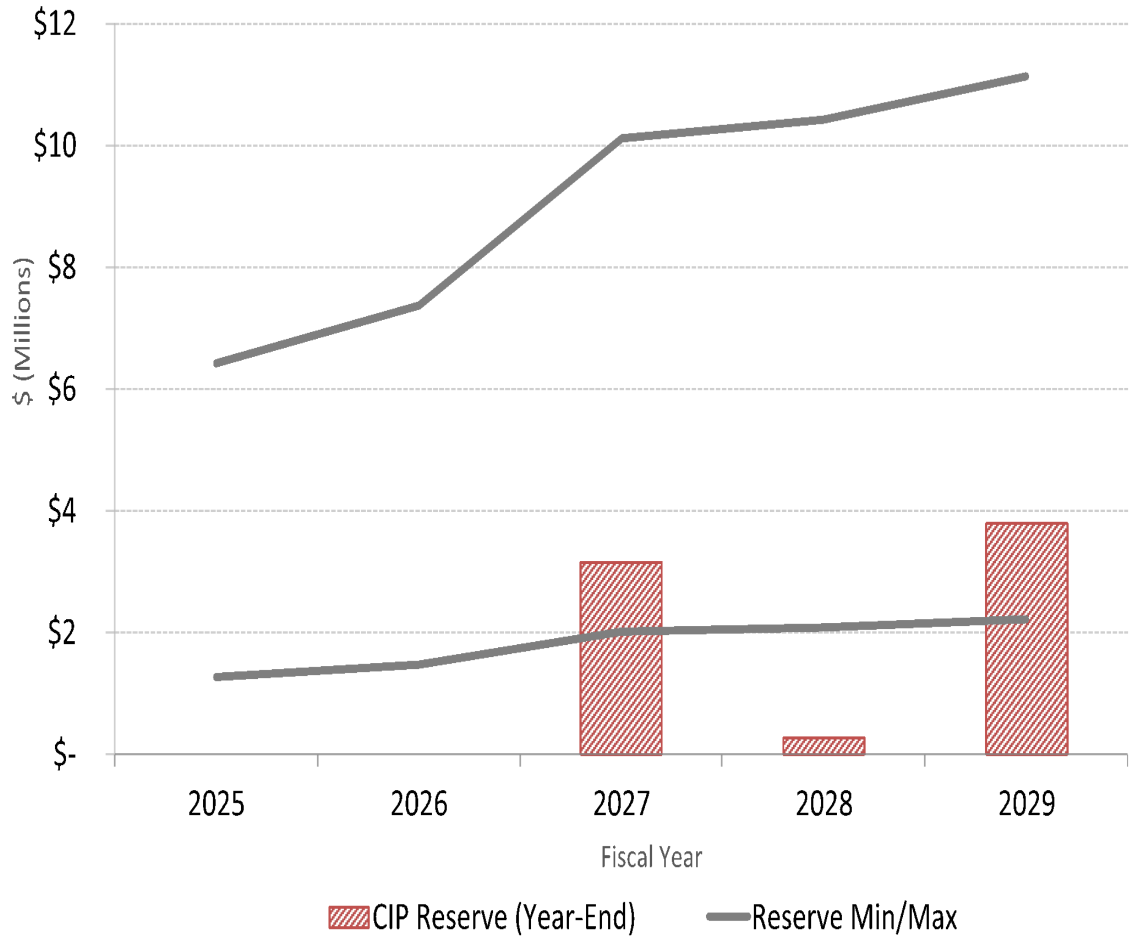
ALTERNATIVE: Wastewater CIP Reserve Projection

9% in FY25



Reduced-Size Sewer Replacement: $1M in FY 2025 and $2M in FY 2026

CITY OF PALO ALTO

WASTEWATER MONTHLY RESIDENTIAL BILL ($) NOVEMBER 2023

Palo Alto is 26% below comparison city average

Palo Alto	Neighboring Community Average	Neighboring Communities					
		Menlo Park	Redwood City	Santa Clara	Mountain View	Los Altos	Hayward
48.64	65.38	108.83	89.28	48.28	53.10	51.47	41.29

CITY OF PALO ALTO

WASTEWATER MONTHLY NON-RESIDENTIAL BILL ($) NOVEMBER 2023

Commercial: Palo Alto is 9% higher than comparison city average
Restaurant: Palo Alto is 7% below comparison city average

	Palo Alto	Neighboring Community Average	Neighboring Communities					
			Menlo Park	Redwood City	Santa Clara	Mountain View	Los Altos	Hayward
General Commercial	127.12	116.17	147.28	117.74	82.18	166.18	89.54	94.08
Restaurant	514.90	553.44	842.08	765.70	520.60	517.18	243.02	432.06

CITY OF PALO ALTO

RECOMMENDATION

Staff requests that the UAC recommend that the City Council Adopt a resolution approving:

- The Fiscal Year 2025 Wastewater Collection Financial Plan
- Increasing Wastewater Collection Utility Rates Via the Amendment of Rate Schedules S-1 (Residential Wastewater Collection and Disposal), S-2 (Commercial Wastewater Collection and Disposal), S-6 (Restaurant Wastewater Collection and Disposal) and S-7 (Commercial Wastewater Collection and Disposal – Industrial Discharger)
- Approving up to a $3 million enterprise transfer loan from the Fiber Optics Fund to the Wastewater Collection Utility's Operations Reserve in FY 2024

CITY OF PALO ALTO

Utilities Advisory Commission
Staff Report

From: Dean Batchelor, Director Utilities
Lead Department: Utilities

Meeting Date: March 6, 2024
Staff Report: 2401-2474

TITLE

Staff Recommends the Utilities Advisory Commission Recommend that the City Council Adopt a Resolution: 1) Approving the Fiscal Year (FY) 2025 Electric Financial Plan and Accepting the 2024 City of Palo Alto Electric Cost of Service and Rate Study, and 2) Amending E-1 (Residential Electric Service), E-2 (Residential Master-Metered and Small Non-Residential Electric Service), E-2-G (Residential Master-Metered and Small Non-Residential Green Power Electric Service), E-4 (Medium Non-Residential Electric Service), E-4-G (Medium Non-Residential Green Power Electric Service), E-4 TOU (Medium Non-Residential Time of Use Electric Service), E-7 (Large Non-Residential Electric Service), E-7-G (Large Non-Residential Green Power Electric Service), E-7 TOU (Large Non-Residential Time of Use Electric Service), E-NSE (Net Metering Net Surplus Electricity Compensation), and E-EEC (Export Electricity Compensation)

RECOMMENDATION

Staff recommends that the Utilities Advisory Commission (UAC) recommend the City Council Adopt a Resolution (Attachment A):

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

i. Up to $26 million from the Distribution Operations Reserve to the Supply Operations Reserve;
ii. Up to $30 million from the Supply Operations Reserve to the Electric Special Projects Reserve; and
iii. Up to $5 million from the Distribution Operations Reserve to the CIP Reserve;

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

EXECUTIVE SUMMARY

The FY 2025 Electric Utility Financial Plan includes projections of the utility's costs and revenues through FY 2028. Staff is seeking rate changes that vary significantly by customer class but that in aggregate result in little change (around an 0.5% increase) to total electric utility revenue in FY 2025. To ensure that electric rates continue to represent the Utility's cost to serve customers, the City engaged the services of a consultant to prepare a cost of service analysis (COSA), which was completed in February 2024 (Attachment A, Exhibit 2) The COSA showed the need for different changes by customer class ranging from a 6% decrease for small non-residential customers (E-2) to a 2% increase for the residential class as a whole. However, recommended changes to the tier structure and the addition of a fixed charge result in a range of changes for residential customers depending on usage, with the median residential customer seeing an 8% increase.

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

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

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

BACKGROUND

Every year staff presents the 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 and 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.

ANALYSIS

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 move towards adequate cost recovery. This year's proposed rates are based on the models developed in the attached February 8 2024 City of Palo Alto Electric Cost of Service and Rate Study by EES Consulting (Exhibit 2 to the attached resolution).

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

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

1. Staff proposes amending the Electric Utility Reserves Management Practices (Appendix B to the Financial Plan) to direct staff to transfer to the CIP reserve, at the end of each fiscal

year, any budgeted capital investment that remains unspent, uncommitted, and which is not proposed for reappropriation to the following fiscal year, and to clarify how the Cap and Trade Program Reserve is adjusted each year .

2. Staff proposes the following reserve transfers for the Electric Utility for FY 2024:
    a. Up to $20 million from the Electric Special Projects Reserve to the Supply Operations Reserve;
    b. Up to $17 million from the Supply Operations Reserve to the Hydroelectric Stabilization Reserve;
    c. Up to $58 million from the Supply Operations Reserve to the Distribution Operations Reserve; and
3. Staff proposes the following reserve actions for the Electric Utility for FY 2025:
    a. Up to $26 million from the Distribution Operations Reserve to the Supply Operations Reserve
    b. Up to $30 million from the Supply Operations Reserve to the Electric Special Projects Reserve, and
    c. Up to $5 million from the Distribution Operations Reserve to the CIP Reserve
4. Staff proposes the following rate actions effective July 1, 2024 (FY 2025):
    a. Changing retail electric rates E-1 (Residential Electric Service), E-2 (Small Non-Residential Electric Service), E-4 (Medium Non-Residential Electric Service), E-4 TOU (Medium Non-Residential Time of Use Electric Service), E-7 (Large Non-Residential Electric Service), and E-7 TOU (Large Non-Residential Time of Use Electric Service) by varying percentages depending on rate schedule and consumption resulting in an overall revenue increase of 0.5% effective July 1, 2024;
    b. An increase to the Export Electricity Compensation (E-EEC-1) rate to reflect 2023 avoided cost, effective July 1, 2024;
    c. An increase to the Net Surplus Electricity Compensation (E-NSE-1) rate to reflect current projections of FY 2024 avoided cost, effective July 1, 2024; and
    d. An update to the Residential Master-Metered and Small Non-Residential Green Power Electric Service (E-2-G), the Medium Non-Residential Green Power Electric Service (E-4-G), and the Large Non-Residential Green Power Electric Service (E-7-G) rate schedules to reflect modified distribution and commodity components, effective July 1, 2024.

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

The $58 million interfund transfer from the Supply Operations Reserve to the Distribution Operations Reserve in FY 2024, followed by the return of $26 million in FY 2025 is related to the timing of debt issuance associated with major capital expenses, as described in the Executive Summary and in Section 3D (Proposed Reserve Transfers) of the attached FY 2025 Electric Utility Financial Plan. This will require a one-year $20 million additional loan from the Electric Special

Projects Reserve in FY 2024 rather than the $10 million repayment of a previous loan that was approved in the FY 2024 Electric Utility Financial Plan. However, this Financial Plan includes repayment of the total $30 million in outstanding Electric Special Projects Reserve loans in FY 2025.

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

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

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

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

Table 2 shows the proposed and projected electric rates for FY 2025 through FY 2029. As noted above staff is proposing a set of rate changes consistent with the attached February 8 2024 City of Palo Alto Electric Cost of Service and Rate Study by EES Consulting (GDS Associates) that result in an approximately 0.5% increase in revenue for FY 2025. The rate changes by customer class and customer usage are discussed further in this report.

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

Projection	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Current	-6% to +8%[1]	5%	5%	5%	5%
Last Year	5%	5%	5%	5%	N/A

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

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

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

	Mid-year FY 2023	Current	Proposed	Projected			
		FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Estimated Bill Impact ($/mo) *							
Base Bill Only	$63.73	$76.82	$80.66	$85.02	$89.63	$94.49	$99.62
With Hydro Rate Adjuster	$83.37	$76.82	No Hydro Rate Adjuster forecasted				

* Estimated impact on median monthly residential electric bill

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

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

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

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

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

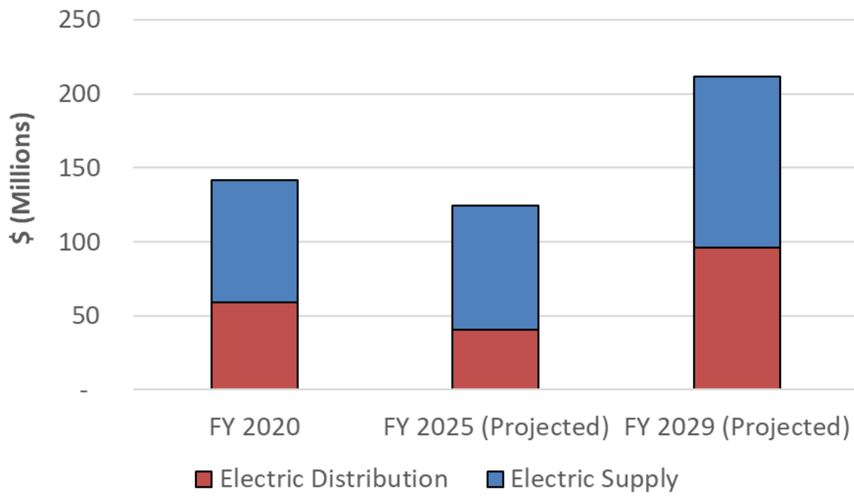


Figure 2 shows distribution costs. Operational costs increased about 6% per year from FY 2020 to FY 2025. Due to higher than anticipated staff vacancies, more expensive external contracts have been needed to complete necessary electric system maintenance. Salary and benefit costs have increased, and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

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

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

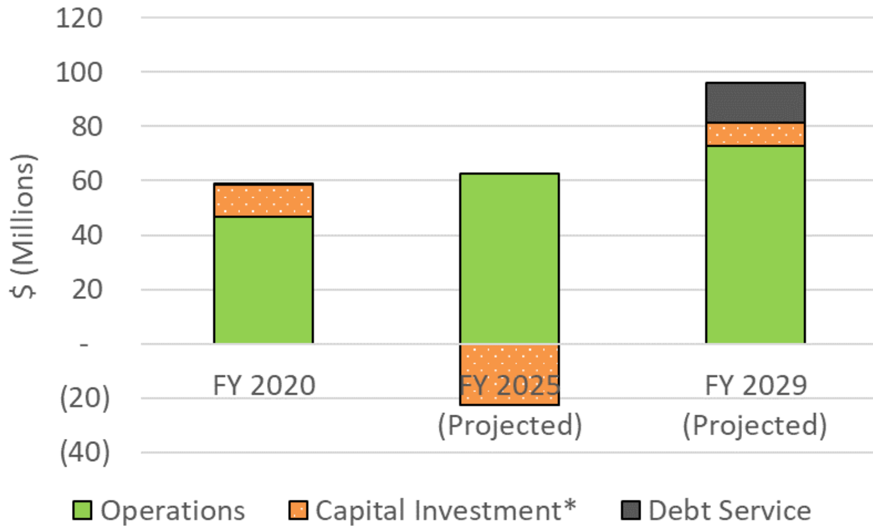
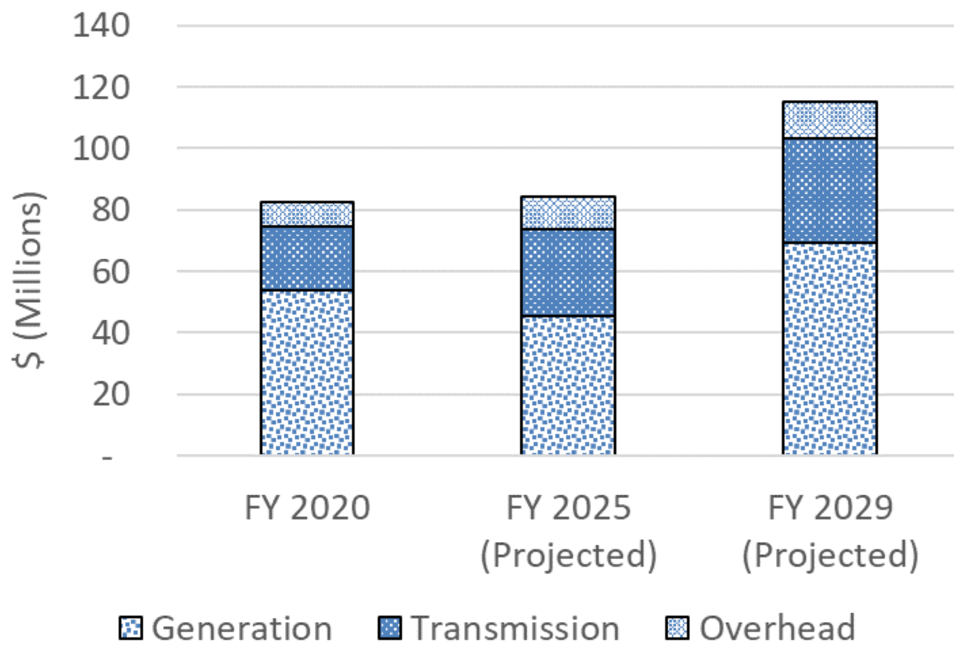


Figure 3 shows commodity costs did not increase significantly from FY 2020 to FY 2025 but as noted above, this is because FY 2025 generation expenses are projected to be lower than usual due to surplus resource adequacy and REC sales revenues that are not expected to continue through the forecast period.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

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 also seeks to achieve cost savings in electric supply and overhead wherever feasible.

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



Staff recognizes the importance of managing operating costs and maximizing efficiency to minimize rate increases. As discussed above, staff is working on cost containment measures related to transmission and renewable energy costs. As reflected in the Utilities Strategic Plan, staff regularly explores additional ways to effectively use available resources, particularly across divisions.

Electric Bill Comparison with Surrounding Cities

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

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

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

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

Staff is updating its methodology for commercial customer rate comparisons and will provide an update at a later date.

<u>Proposed Rate Changes</u>

Staff engaged the services of a consultant to review and revise the Electric Utility's Cost of Service study and rates. This study, the February 8, 2024 City of Palo Alto Electric Cost of Service and Rate Study by EES Consulting (GDS Associates), examined how the City's costs are allocated among the residential and commercial classes and recommended some realignments. In general costs increased more for residential than non-residential customer classes due to changes in consumption patterns compared to those reflected in the current rates. In addition, increased usage in the residential class led to some recommended changes to the current tiered rate design, increasing the Tier 1 allowance and narrowing the difference between the tiers. Lastly, the minimum bill included in the current rate schedules is recommended to be replaced with a modest fixed charge.

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

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

Table 5: Current and Proposed Electric Rates

	Current Rates	Proposed Rates (7/1/2024)	Change	
			$	%
E-1 (Residential)				
Tier 1 Energy ($/kWh)	0.17522	0.19337	0.01815	10%
Tier 2 Energy ($/kWh)	0.24666	0.20335	-0.04331	-18%
Customer Charge ($/day)		0.15250	0.15250	
E-2 & E-2-G (Small Non-Residential)				
Summer Energy ($/kWh)	0.26560	0.25211	-0.01349	-5%
Winter Energy ($/kWh)	0.18626	0.16415	-0.02211	-12%
Customer Charge ($/day)		0.18410	0.18410	
E-4 & E-4-G (Medium Non-Residential)				
Summer Energy ($/kWh)	0.16363	0.15387	-0.00976	-6%
Winter Energy ($/kWh)	0.12667	0.11018	-0.01649	-13%
Summer Demand ($/kW)	36.82668	45.29000	8.46332	23%
Winter Demand ($/kW)	24.16296	23.73000	-0.43296	-2%
Customer Charge ($/day)		3.73900	3.73900	
E-7 & E-7-G (Large Non-Residential)				
Summer Energy ($/kWh)	0.14561	0.13570	-0.00991	-7%
Winter Energy ($/kWh)	0.09856	0.08797	-0.01059	-11%
Summer Demand ($/kW)	39.08286	40.36000	1.27714	3%
Winter Demand ($/kW)	21.71270	27.79000	6.07730	28%
Customer Charge ($/day)		17.12210	17.12210	

Table 6 shows the impact of the proposed July 1, 2024 rate changes on the residential and non-residential bills for various consumption levels. The rate changes vary by customer class due to the completion of a cost of service analysis as noted above. The rate change for the median residential customer is 8%. Because of the addition of a customer charge and the changes in the design of the tiers for the E-1 customer class usage in this class varies widely depending on consumption, generally increasing for customers who use less electricity and decreasing for those who use more. This trend is expected to continue when the utility moves to time of use rates, which provides prices that vary by time of day rather than by how much electricity a customer uses in a month. It is worth noting, however, that increases among low users, while large in percentage terms, are arguably nominal in absolute dollar terms (not more than $10.63 per month, most low users will see lower increases).

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

Rate Schedule	Usage (kWh/mo)	Peak Demand (kW-mo)	Bill under Current Rates ($/mo)	Bill Under Rates Proposed 7/1/24 ($/mo)	Change	
					$/mo	%
E-1 (Residential)	300	N/A	$52.57	$62.65	$10.08	19%
	(Summer Median) 365	N/A	$66.46	$75.22	$8.76	13%
	(Winter Median) 453	N/A	$88.16	$92.24	$4.07	5%
	650	N/A	$136.75	$135.61	($1.14)	-1%
	1200	N/A	$272.42	$257.34	($15.07)	-6%
E-2 (Small Non-Residential)	1,000	N/A	$225.93	$213.73	($12.20)	-5%
E-4 (Medium Non-Residential)	160,000	274	$31,580	$30,693	($887)	-3%
	500,000	856	$98,680	$95,667	($3,014)	-3%
E-7 (Large Non-Residential	2,000,000	3,424	$348,247	$340,864	($7,383)	-2%

Net Energy Metering Buyback Rates

The City operates two Net Energy Metering (NEM) programs. Solar customers served by the CPAU's original NEM program, NEM 1, are compensated at retail rates for net electricity they export to the grid, and solar customers served by the NEM successor program, or NEM 2 (effective after the City reached its NEM 1 cap at the end of 2017), are compensated at the Export Electricity Compensation (E-EEC-1) rate for exported electricity. Customers on the NEM 1 program who have chosen to have the value of any annual net generation they produced over the past 12 months credited back to their account do so under the Net Metering Net Surplus Electricity Compensation (E-NSE-1) rate. Both surplus compensation rates are based on the City's renewable energy costs, but the calculation methodologies differ slightly to reflect the different characteristics of the NEM programs they are used for and the different regulations applicable to those programs. More detail on these rates is included in Section 3B (Current and Proposed Rates) of the FY 2025 Electric Utility Financial Plan.

Staff proposes to change the E-NSE-1 rate to $0.1427/kWh based on updated cost calculations reflecting the current electricity market prices. Staff proposes to change the Export Electricity Compensation (E-EEC-1) compensation rate to $0.1420/kWh based on projected market prices.

Table 8: NEM Compensation Rates – Current vs. Proposed

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

Palo Alto Green (PAG) Program

The Palo Alto Green (PAG) program provides CPAU's commercial customers an opportunity to voluntarily pay a premium to receive renewable electricity credits to match their energy usage. Under this program, CPAU staff purchase and retire Green-e certified RECs in the wholesale market on behalf of PAG customers. This enables participating commercial customers to claim credit for the REC purchases in order to satisfy their corporate sustainability goals and meet federal "green certification" requirements. In the past year the wholesale cost of Green-e certified RECs in the Western US market has remained relatively flat at around $7.00/REC. As such, the PAG rate premium should remain at $7.5 per 1,000 kWh block (.75 cents/kWh), which includes both the price of the RECs and the administrative overhead.

TIMELINE

The Finance Committee is scheduled to review the FY 2025 Electric Financial Plan[2] in April 2024. The City Council will consider adopting the Financial Plan and rate amendments as part of the FY 2025 budget review and adoption process.

FISCAL/RESOURCE IMPACT

FY 2025 revenues are projected to remain very close to FY 2024 levels if Council adopts this report's recommendations. The City is a non-residential utility customer and can expect a decrease in estimated City utility expenses of about $160,000, approximately $85,000 of that being in the General Fund. Street light expenses (which are paid from the General Fund) are projected to decrease by about $180,000. Resource impacts to City departments and funds of the recommended rate adjustments are programmed in the FY 2025 Proposed Operating Budget. If the final rates adopted by Council in June differ from those proposed in this report, further adjustments may be brought forward as part of the annual budget process.

STAKEHOLDER ENGAGEMENT

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

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

ENVIRONMENTAL REVIEW

The UAC's review and recommendation to the City Council on the FY 2024 Electric Financial Plans and rate adjustments does not meet the California Environmental Quality Act's definition of a project, pursuant to Public Resources Code Section 21065, thus no environmental review is required.

ATTACHMENTS

Attachment A: Resolution of the Council of the City of Palo Alto Approving the Fiscal Year 2025 Electric Utility Financial Plan and Reserve Transfers, Amending the Electric Utility Reserves Management Practices, and Amending Utility Rates
Attachment A, Exhibit 1: February 8, 2024 City of Palo Alto Electric Cost of Service and Rate Study by EES Consulting (GDS Associates)
Attachment A, Exhibit 2: Proposed FY 2025 Electric Utility Financial Plan
Attachment A, Exhibit 3: Proposed Electric Rate Schedules
Attachment B: Proposed Amended Electric Utility Reserves Management Practices
Attachment C: Presentation

AUTHOR/TITLE:

Dean Batchelor, Director of Utilities
Jonathan Abendschein, Assistant Director, Utilities

Yet to be Passed

Resolution No. ____

Resolution of the Council of the City of Palo Alto Approving the Fiscal Year 2025 Electric Utility Financial Plan and Accepting the 2024 City of Palo Alto Electric Cost of Service and Rate Study, and Amending Utility Rate Schedules E-1 (Residential Electric Service), E-2 (Residential Master-Metered and Small Non-Residential Electric Service), E-2-G (Residential Master-Metered and Small Non-Residential Green Power Electric Service), E-4 (Medium Non-Residential Electric Service), E-4-G (Medium Non-Residential Green Power Electric Service), E-4 TOU (Medium Non-Residential Time of Use Electric Service), E-7 (Large Non-Residential Electric Service), E-7-G (Large Non- Residential Green Power Electric Service), E-7 TOU (Large Non-Residential Time of Use Electric Service), E-NSE (Net Surplus Electricity Compensation Rate), and E-EEC (Export Electricity Compensation)

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 June 17, 2024, 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:

<u>SECTION 1</u>. The Council hereby approves the FY 2025 Electric Utility Financial Plan (Exhibit A), including the

amended Electric Utility Reserves Management Practices in Appendix B of the Financial Plan.

SECTION 2. The Council hereby approves the following transfers to be made by the end of FY 2024, as described in the FY 2025 Electric Utility Financial Plan:

a. A transfer of up to $20 million from the Electric Special Projects Reserve to the Supply Operations Reserve; and
b. A transfer of up to $17 million from the Supply Operations Reserve to the Hydroelectric Stabilization Reserve; and
c. A transfer of up to $58 million from the Supply Operations Reserve to the Distribution Operations Reserve

SECTION 3. The Council hereby approves the following transfers to be made by the end of FY 2025, as described in the FY 2025 Electric Utility Financial Plan:

a. A transfer of up to $26 million from the Distribution Operations Reserve to the Supply Operations Reserve; and
b. A transfer of up to $30 million from the Supply Operations Reserve to the Electric Special Projects Reserve; and
c. A transfer of up to $5 million from the Distribution Operations Reserve to the CIP Reserve

SECTION 4. Pursuant to Section 12.20.010 of the Palo Alto Municipal Code, Utility Rate Schedule E-1 (Residential Electric Service) is hereby amended to read as attached and incorporated. Utility Rate Schedule E-1, as amended, shall become effective July 1, 2024.

SECTION 5. Pursuant to Section 12.20.010 of the Palo Alto Municipal Code, Utility Rate Schedule E-2 (Residential Master-Metered and Small Non-Residential Electric Service) is hereby amended to read as attached and incorporated. Utility Rate Schedule E-2, as amended, shall become effective July 1, 2024.

SECTION 6. 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, 2024.

SECTION 7. Pursuant to Section 12.20.010 of the Palo Alto Municipal Code, Utility Rate Schedule E-4 (Medium Non-Residential Electric Service) is hereby amended to read as attached and incorporated. Utility Rate Schedule E-4, as amended, shall become effective July 1, 2024.

SECTION 8. 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, 2024.

SECTION 9. Pursuant to Section 12.20.010 of the Palo Alto Municipal Code, Utility Rate Schedule E-4 TOU (Medium Non-Residential Time of Use Electric Service) is hereby amended to read as attached and incorporated. Utility Rate Schedule E-4 TOU, as amended, shall become effective July 1, 2024.

SECTION 10. Pursuant to Section 12.20.010 of the Palo Alto Municipal Code, Utility Rate Schedule E-7 (Large Non-Residential Electric Service) is hereby amended to read as attached and incorporated. Utility Rate Schedule E-7, as amended, shall become effective July 1, 2024.

SECTION 11. 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, 2024.

SECTION 12. Pursuant to Section 12.20.010 of the Palo Alto Municipal Code, Utility Rate Schedule E-7 TOU (Large Non-Residential Time of Use Electric Service) is hereby amended to read as attached and incorporated. Utility Rate Schedule E-7 TOU, as amended, shall become effective July 1, 2024.

SECTION 13. Pursuant to Section 12.20.010 of the Palo Alto Municipal Code, Utility Rate Schedule E-NSE (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, 2024.

SECTION 14. 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, 2024.

SECTION 15. 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.

Attachment A

SECTION 16. The Council finds that approving the Financial Plan and Reserve transfers 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 CEQA Guidelines 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

PREPARED BY EES CONSULTING

City of Palo Alto

Electric Cost of Service and Rate Study
DRAFT 8

February 8, 2024

EES Consulting
a GDS Associates Company

EES Consulting
a GDS Associates Company

Amber Gschwend, Managing Director
amber.gschwend@gdsassociates.com

February 8, 2024

Mr. Micah Babbitt
City of Palo Alto
250 Hamilton Avenue
Palo Alto, CA 94301

SUBJECT: Electric Cost of Service and Rate Study – DRAFT 8

Dear Mr. Babbitt:

Please find attached the draft report for the Electric Cost of Service and Rate Study performed for the City of Palo Alto (City).

We appreciate all of the help you and your staff have provided in conjunction with this study. Please feel free to contact me directly with any questions or comments.

Very truly yours,

Amber Gschwend
Managing Director, EES Consulting

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www.eesconsulting.com

Contents

1 Executive Summary

The City of Palo Alto (City) retained EES Consulting (EES), a GDS Associates Company, to perform an electric cost of service analysis (COSA) and rate study as part of its ongoing efforts to maintain fiscally prudent and fair, cost-based rates for its electric customers. The purpose of this report is to discuss the data inputs, assumptions and results that were part of developing the rate study. A comprehensive rate study generally consists of three separate, yet interrelated analyses. These three analyses are the revenue requirement, the COSA, and the rate design.

1.1 REVENUE REQUIREMENT

A revenue requirement analysis compares the overall revenues of the utility to its expenses and helps determine whether an overall adjustment to rate levels is required. For this analysis, a "cash basis" method was used for determining the City's revenue requirement. Recorded annual operating expenses for Fiscal Year (FY) 2021-22 as well as the FY 2022-23, FY 2023-24, and FY 2024-25 approved and budget forecasts provided by the City were used to determine the revenue requirement. The study relies on the proposed FY2024-25 budget for the revenue requirement study.

If the City's rates currently in effect remain unchanged, FY 2024-25 revenues from all sources would equal $219.3 million, while budgeted expenses and reserve contributions are $215.5 million.[1] The revenue adjustment necessary to avoid surplus funds is a 2.2% decrease. Table 1.1 summarizes the FY 2024-25 revenue requirement.

TABLE 1.1: SUMMARY OF THE REVENUE REQUIREMENT – FY2024-25

Power Supply (Commodity)	$115,533,652
Distribution	$28,005,465
Customer Accounts and Services	$12,608,722
Administration and General	$7,698,473
Capital Projects Funded from Rates	$6,500,000
Debt Service	$4,770,582
General Fund Transfer	$15,121,000
Reserve Contribution	$25,333,578
Total Expenses	**$215,571,473**
Other Revenues	$50,984,335
Total Revenue Required from Rates (Revenue Requirement)	$164,587,138
Revenue Based on Rates Currently in Effect	$168,321,326
Additional Rate Revenue Needed (Surplus)	($3,734,187)
Net Required Rate Revenue Increase (Decrease)	**(2.2%)**

[1] Expenses exclude capital expenses reimbursed by connection fees or other direct reimbursement agreements.

1.1.1 Rate Classes

Part of the revenue requirement analysis includes an analysis of revenue from current retail rates ($168.3 million in Table 1.1). These revenues are calculated for each rate class to later determine if each class is collecting its assigned revenue goal (determined by the COSA). The following rate classes are modeled in the Revenue Requirement Study and COSA:

E-1 Residential: All residential customers, excluding master-metered multifamily customers.

E-2 Small Commercial: Electric service for small commercial customers and master-metered multifamily customers. Any customer with energy usage over 8,000 kWh per month for three consecutive months would be moved to E-4 (see below), while any E-4 customer with energy usage below 6,000 kWh per month for 12 consecutive months would be switched to E-2. When analyzing customer load data this study used the rate schedule designation for each customer in the utility billing system to determine whether the customer currently fell into the E-2 or E-4 class.

E-4 Medium Commercial: Demand metered electric service for commercial customers with a maximum demand below 1,000 kilowatts per month and usage over 8,000 kWh per month.

E-7 Large Commercial: Demand metered electric service for commercial customers with a maximum demand of at least 1,000 kilowatts per month per site, and who have sustained this demand level for at least 3 consecutive months during previous 12-month period.

Street and Traffic Lights: This class applies to all street and highway lighting installations that the City of Palo Alto Utilities Department elects to operate and maintain, generally lights owned by the City, the County, or another government entity and located on public streets.

For purposes of the analysis in this study, customers are assigned to a customer class without regard to whether they participate in Palo Alto Green, Net Energy Metering, Time of Use Metering or Low Income programs.

Master-metered multi-family customers are treated as commercial customers rather than residential customers.

1.2 COST OF SERVICE ANALYSIS

A COSA is concerned with the equitable allocation of the revenue requirement to the various customer classes of service. The revenue requirement shown in Table 1-1 for the City was functionalized, classified and allocated. Specifically:

- **Functionalization** is the attribution of each cost line-item to Power Supply (Commodity) (purchase or production of electric energy), Transmission (transmitting electric energy via power lines rated for 115 kiloVolts (kV) and above),[2] Distribution (moving electric energy from supply or transmission infrastructure to end users via power lines rated for less than 115 kV), and Customer (primarily costs associated with metering and billing). The City does not own any power lines that would be categorized as Transmission, so there were no costs allocated to this function.

- **Classification** is the determination of whether the costs associated with a functionalized line item are most appropriately allocated based on energy use (kWh), demand (kW-- the maximum usage of energy over a specified period of time), or customer (simply having a service account).
- **Allocation** is the process of using the classification for each functionalized line item to assign costs to each customer class. For example, a cost item classified as "energy use" might be allocated based on an annual kWh allocator. This means that the line-item cost is directly correlated to the quantity of energy used by each customer class annually. Another example of an energy-based allocator for energy classified costs would be kWh used in the month of January. This process is described in more detail in the section titled "Cost of Service Analysis."

Table 1-2 shows the results of the COSA. It shows the revenues that would be realized in FY 2024-25 without any rate changes (i.e. keeping the rates currently in effect), the share of the FY 2024-25 revenue requirement that should be allocated to each rate class as determined by the COSA, and the surplus/(deficiency) in revenue if current rates are left unchanged. Without a rate change, FY 2024-25 revenues will be slightly more than allocated FY 2024-25 costs for some classes of service. The variance between revenues and costs is greater for some classes than others. The last column of Table 1-2 shows the increase or decrease in revenue required for each rate class.

The results of the COSA are summarized in Table 1.2 and the COSA methodology is described in more detail below in the "Cost of Service Analysis" section of this report.

TABLE 1.2: SUMMARY OF COST OF SERVICE ANALYSIS FOR FY 2024-25 TEST YEARS

	Projected Revenues under Current Rates	Net Revenue Requirement	Projected Surplus/ (Deficiency) in Revenue Based on Current Rates	Revenue Increase/ (Decrease) Needed[3]
Residential E-1	$27,309,759	$27,852,514	-$542,755	2.0%
Small Commercial E-2	$11,784,676	$11,067,556	$717,121	-6.1%
Medium Commercial E-4	$67,707,023	$65,186,601	$2,520,422	-3.7%
Large Commercial E-7	$59,295,683	$58,473,708	$821,975	-1.4%
Street and Traffic Lighting	$2,224,184	$2,006,759	$217,425	-9.8%
TOTAL	**$168,321,326**	**$164,587,138**	**$3,734,187**	**-2.2%**

[2] Note that the Transmission function is for costs associated with moving electric energy over CPAU-owned transmission lines. Payments for transmission service on lines owned by other utilities are included in the Power Supply (Commodity) function.

[3] Projected FY 2024-25 revenue surplus/(deficiency) divided by projected FY 2024-25 revenue based on rates currently in effect.

The projected cost of service allocation has changed across rate classes since the study completed in 2016. The primary drivers for the changes include the following:

1. Updated electric usage information (more detail provided in Section 4.4 Cost of Service Results).
2. Increase in Residential usage results in more costs assigned to residential class.
    a. Decreased Commercial usage, yielding Residential contributing a greater percentage of total energy usage.
    b. Increased residential usage as a class is due to higher average electric usage. Average residential usage increased from 457 kWh/mo in 2019 to 526 kWh/mo in FY2020-2021. The increased average use may be from multiple factors including increased adoption of electric vehicles and air conditioning, electrification, or the work from home trend beginning at the start of the 2020 pandemic.
3. The current E-1 (residential) rate structure includes a two-tier energy rate. Tier 1 energy rates apply to kWh usage up to 330 kWh per month. Tier 2 energy rates apply to usage above 330 kWh per month. COSA. The ratio of the Tier 2 rate to the Tier 1 rate has declined over time due to changes in the utility's costs, but this means that the increase in Tier 2 usage relative to Tier 1 usage has not resulted in as significant an increase in residential rate revenue in recent years than would otherwise be expected. This results in an even greater increase needed for the residential class than would be required just based on the average residential usage increase alone.
4. Streetlights have lower expenses due to newer LED bulbs requiring less in operations and maintenance costs.

1.3 EXISTING RATES OVERVIEW

The rates for residential and commercial customers are designed to take into account differences in energy costs for various generating resources as well as the impacts seasonal changes in energy use and peak demand have on the utility's distribution capacity needs.

The E-1 (Residential) rate is an inclining 2-tier metered rate. Electric use below a certain threshold is charged at one rate per kWh and each kWh used in excess of that threshold is charged at a higher rate. The rates at each tier are comprised of a Commodity rate (which captures Power Supply charges and purchased transmission service) and a Distribution rate. In addition, E-1 customers pay a separate "public benefits charge" on a per kWh basis for all energy consumed, regardless of tier.

The E-2 (Small Commercial) is a seasonal metered rate. For purposes of this rate, the year is divided into two seasons, each of which has a different rate per kWh used. The summer season (period) is defined as May 1 through October 31. The winter period is November 1 through April 30. The higher rate that is applicable during the summer reflects the higher cost of energy during summer months, and the cost of the extra infrastructure needed to meet the City's seasonal non-residential peak, which occurs in the summer (unlike the residential class, which peaks in the winter). Due to the diversity of usage characteristics within the E-2 customer class, the seasonal structure better captures these seasonal distribution cost variations than a tiered rate structure would. The rates for each season are comprised of a "commodity" rate and a "distribution" rate. Additionally, E-2 customers pay the "public benefits charge" at the same rate as is charged to E-1 customers.

The E-4 (Medium Commercial) and E-7 (Large Commercial) rates are seasonal metered rates, but for each season there is both an Energy Charge (measuring consumption in kWh) and a Demand Charge (measuring, in kW, the peak energy delivered in the highest 15-minute period of the day). Because the infrastructure costs of meeting the peak demand are collected through the Demand Charge, the rate variations between seasons only reflect seasonal variation in the utility's costs. The Energy Charge and the Demand Charge for each season are each comprised of a "commodity" rate and a "distribution" rate. Additionally, E-4 and E-7 customers pay the "public benefits charge" at the same rate as is charged to other customers

TOU rates are made available to E-4 and E-7 customers; these rates reflect both seasonal and hourly demand and energy cost of service. TOU rates are applied to electricity usage and demand as measured during 3 periods: peak, mid-peak, and off peak. TOU rates differ between seasons as well. Customers on the regular E-4 or E-7 rate schedules may opt to be billed according to the TOU rate schedule if desired. TOU rates are meant to reflect the hourly and seasonally varying costs of providing electric service and need to be adjusted as those costs change over time.

1.4 RATE DESIGN

1.4.1 Distribution Rates

The allocation of distribution costs is based on an analysis of the average and excess monthly energy and capacity costs associated with that rate class: the 'Average and Excess' method. The Average and Excess method compares the average capacity and energy used against the maximum capacity and energy used over the season (the "excess"). This captures the level of system capacity required to serve the customer during peak times as opposed to average times.

As mentioned, the distribution rate design for E-1 consists of a 2-tier rate. The Tier 1 distribution rate recovers the cost of providing distribution capacity to each customer. The Tier 1 rate includes costs associated with the capacity requirements during the lower usage months: May through October. This level of capacity is used year-round. The additional costs associated with the distribution capacity needed to serve higher winter demands is collected through the Tier 2 distribution rate.

For E-2 costs associated with demand-related system costs (such as transformers or lines) were separated into seasons using the average and excess demand information from the COSA. The methodology assigns costs associated with average demand to both seasons, while costs related to the distribution capacity required to serve peak demands is allocated to the summer season.[4] For the E-4 and E-7 rates the demand-related system costs are recovered through demand charges.

The recommended rate design for each rate class includes a monthly customer charge. This customer charge is based on a portion of the utility's fixed costs for metering and billing. The customer charge ensures that even for customers who consume zero or negative energy, the customer charge would recover the meter reading and billing costs.

[4] Summer is May 1-October 31. Commercial customers have higher usage during summer whereas residential customers have higher usage during winter.

1.4.2 Commodity Rates

The City purchases wholesale electricity from a variety of resources including, for example, hydropower, wind resources, or market transactions. Each resource provides benefit to the utility and its ratepayers in the form of energy, capacity, or renewable attributes. All California utilities are required to meet capacity requirements (known as resource adequacy) determined by the CPUC (California Public Utility Commission) and the CEC (California Energy Commission). These requirements ensure that the grid, as a whole, can meet electric demands across various electric usage scenarios. The City's capacity costs are directly impacted by how and when electric customers consume electricity. Lastly, the City does not own its own transmission lines to transfer energy from the generators it contracts with to the City's distribution system and therefore purchases transmission services from others. The commodity rates reflect the cost of providing energy, capacity, renewable energy, and purchased transmission service to end-use customers.

In the case of E-1, the lower Tier 1 commodity rate recovers costs associated with lower cost energy resources. The higher Tier 2 commodity rate recovers higher cost resources.

The current rate design for non-residential classes remains largely the same in the proposals. Commodity rates for rate classes E-2 (Small Commercial), E-4 (Medium Commercial), and E-7 (Large Commercial), are determined such that the costs for each generating resource are assigned to the season in which the costs are incurred. Demand rates are calculated by allocating average capacity costs to both summer and winter rates. Because summer peaks drive capacity costs for the utility, the costs of meeting capacity requirements are allocated to the summer (peak demand) season.

1.5 RECOMMENDATION

Based on the projected revenue requirement and COSA analysis, the following observations can be made for the City:

- The City needs a small rate decrease to match FY 2024-25 revenue and expenses.

- Revenues for each rate class should be aligned with the costs allocated to that rate class.
- Rate design recommendations include:
    - Adjust the E-1 Tier 1 quantity of kWh for increased average usage within this class, as discussed in Section 5.1.
    - Implement a monthly customer charge for all classes to recover billing and metering costs.
    - Adjust TOU periods for optional TOU rates to better align with marginal energy and system peak demand costs.
    - Consider additional rate assistance for low-income households as E-1 rates transition to flat rate design and a minimum bill is implemented. Low-income program funds are collected through the Public Benefits Charge paid by all customers.

TABLE 1.3: RECOMMENDED RATES

	Commodity	Distribution	PBC	Total
Residential (E-1)				
Tier 1 (up to 461 kWh), $/kWh	$0.10270	$0.08518	$0.00549	$0.19337
Tier 2 (> 461 kWh), $/kWh	$0.13311	$0.08272	$0.00549	$0.22132
Customer Charge, $/month				$4.64
Small Commercial (E-2)				
Summer, $/kWh	$0.14926	$0.09735	$0.00549	$0.25210
Winter, $/kWh	$0.09242	$0.06623	$0.00549	$0.16414
Customer Charge, $/month				$5.60
Medium Commercial (E-4)				
Summer, $/kWh	$0.12318	$0.02520	$0.00549	$0.15387
Winter, $/kWh	$0.07949	$0.02520	$0.00549	$0.11018
Summer, $/kW-month	$10.98	$34.31		$45.29
Winter, $/kW-month	$2.57	$21.16		$23.73
Customer Charge, $/month				$113.73
Medium Commercial (E-4 TOU)				
Summer Peak (4-9 pm)	$0.17038	$0.02538	$0.00549	$0.20125
Summer Mid Peak (2-4 pm and 9-11 pm)	$0.14041	$0.02538	$0.00549	$0.17128
Summer Off Peak (all other hours)	$0.10556	$0.02538	$0.00549	$0.13643
Winter Peak (4-9 pm)	$0.11976	$0.02500	$0.00549	$0.15025
Winter Mid Peak (9 am -2 pm)	$0.09452	$0.02500	$0.00549	$0.12501
Winter Off Peak (all other hours)	$0.06525	$0.02500	$0.00549	$0.09574
Summer Peak Period Demand, $/kW-month	$9.72	$17.18		$26.90
Summer Max Demand, $/kW-month	$1.29	$17.18		$18.47
Winter Peak Period Demand, $/kW-month	$1.30	$10.73		$12.03
Winter Max Demand, $/kW-month	$1.30	$10.73		$12.03
Customer Charge, $/month				$113.73
Large Commercial (E-7)				
Summer, $/kWh	$0.12659	$0.00362	$0.00549	$0.13570
Winter, $/kWh	$0.07894	$0.00354	$0.00549	$0.08797
Summer, $/kW-month	$11.95	$28.41		$40.36
Winter, $/kW-month	$2.79	$25.00		$27.79
Customer Charge, $/month				$520.80

	Commodity	Distribution	PBC	Total
Large Commercial (E-7 TOU)				
Customer Charge, $/month				$520.80
Summer Peak (4-9 pm)	$0.18019	$0.00362	$0.00549	$0.18930
Summer Mid Peak (2-4 pm and 9-11 pm)	$0.14850	$0.00362	$0.00549	$0.15761
Summer Off Peak (all other hours)	$0.11164	$0.00362	$0.00549	$0.12075
Winter Peak (4-9 pm)	$0.12104	$0.00354	$0.00549	$0.13007
Winter Mid Peak (9 am -2 pm)	$0.09552	$0.00354	$0.00549	$0.10455
Winter Off Peak (all other hours)	$0.06594	$0.00354	$0.00549	$0.07497
Summer Peak Period Demand, $/kW-month	$11.28	$14.71		$25.99
Summer Max Demand, $/kW-month	$1.45	$14.71		$16.16
Winter Peak Period Demand, $/kW-month	$1.45	$12.99		$14.44
Winter Max Demand, $/kW-month	$1.45	$12.99		$14.44

2 Overview of Rate Setting Principles

EES Consulting (EES), a GDS Associates Company, was retained by the City of Palo Alto (City) to perform a comprehensive electric cost of service and rate study. Performing an electric rate study is necessary to assure that City rates are structured to be fair, equitable and based on the cost of providing service to all City customers. Further, on September 1, 2021, the City's Utilities Advisory Commission approved an Electric Rate Policy[5] which includes 5 guidelines for electric cost of service and rate-making:

1. Rates must be based on the cost of providing service.
2. The effect of any recommended rate design changes on low-income customers should be considered, to the extent permissible within a cost-based rate structure.
3. Rates should not create unnecessary barriers to building and vehicle electrification, including public EV charging, while remaining cost-based.
4. Rates should not create unnecessary barriers to on-site generation and storage while simultaneously avoiding subsidies between customer classes.
5. The COSA and rate design should support a transition to more time variant rates (such as TOU, seasonal, etc.) as advanced metering infrastructure (AMI) is deployed.

This Study was prepared while considering the above guidelines. In conducting a cost of service and rate study, three inter-related analyses are performed:

1. **Revenue Requirement Analysis:** This analysis examines the various sources and uses of funds for the utility and determines the overall revenue required to operate the utility.
2. **Cost of Service Analysis (COSA):** The COSA is used to determine the fair and equitable allocation of the total revenue requirement to the various customer classes of service (e.g. residential, small non-residential, medium non-residential, etc.). This analysis provides a determination of the level of revenue responsibility of each class of service and the adjustments from current revenues required to meet the cost of service.
3. **Rate Design Analysis:** The third analysis involves evaluating the rate design options available and designing rate schedules that can be applied to each rate class to equitably collect revenues that match the cost to serve each customer in that class.

2.1 OVERVIEW AND ORGANIZATION OF REPORT

This report is divided into sections that follow these three analyses. This first section is a generic discussion of the theory and financial principles behind setting rates. This is followed by a section discussing the development of the revenue requirement analysis for the City. The next section discusses the COSA. Finally, rate design options are presented in the fourth and final section. A technical appendix is attached

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[5] https://www.cityofpaloalto.org/files/assets/public/agendas-minutes-reports/agendas-minutes/utilities-advisory-commission/archived-agenda-and-minutes/agendas-and-minutes-2021/09-01-2021-special/id-13426-item-3.pdf

at the end of this report that provides details of the various analyses. The schedules contained in the technical appendix are referenced throughout the report.

The purpose of this section of the report is to provide a brief overview of the fundamentals of cost identification and allocation for purposes of developing electric rates. From this base-level of knowledge, more insight and understanding can be obtained from the following sections of the report that discuss the specifics of the Revenue Requirement, Cost of Service, and Rate Design analyses mentioned above.

2.2 OVERVIEW OF REVENUE REQUIREMENT

The revenue requirement is the amount of revenue required to be collected from retail rates in order for the utility to cover costs. The revenue requirement includes all electric department expenses (operating and non-operating) less non-rate revenue such as interest income or other unrelated credits. For this study, a cash basis was used to determine the City's electric utility revenue requirement. The cash basis methodology aligns with the City's electric utility budgeting process. Revenue projections and expenses for fiscal year 2024-25 are the basis for the revenue requirement study.

2.3 COST OF SERVICE OVERVIEW

After the total revenue requirement has been determined, the requirement is allocated across the various classes[6] of service based on a cost-based methodology that reflects cost causation between customer characteristics and the Commodity (also known as Power Supply) costs (purchase or generation of the electric commodity and purchased transmission service) and Distribution (delivery of electric service across City-owned distribution line). A COSA begins by assigning each cost in a utility's revenue requirement into major categories such as Commodity, Transmission, Distribution and Customer. This is called "functionalization." Next, the functionalized costs are classified to specific categories, such as demand-related, energy-related, costs based on the portion of the utility's rate base (its distribution assets and general plant assets) serving each customer type, services provided to customers (purchase and delivery/distribution of power), customer-related or a direct assignment of costs to one or more class. This classification is the basis for developing the COSA unit costs (average cost-based rates in terms of $/kWh, $/kW, or $/customer). Allocation factors are factors that add to 100% across all service classes. An example of an allocation factor is the share of the total number of customers or the share of retail sales. These factors are used to spread costs to each class of service. Once the revenue requirement has been allocated to each class of service a determination of the necessary revenue goal for each class can be made.

2.4 RATE DESIGN ANALYSIS

The final step in the rate study process is to design rates for each class of service. Rates can be structured in many ways, but ultimately, they should reflect the types of costs that the utility incurs to serve the

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[6] The relevant classes of service for the City of Palo Alto include E-1, E-2, E-4, E-7, and lighting and streetlights. Classes of service can mean rate classes or just customer type such as residential, small general service, industrial etc. In this study, all residential customers are included in E-1, all small general service are in E-2, and E-4 and E-7 include both non-TOU and TOU customers within each respective class.

customer (e.g. demand-, energy- and customer-related costs), and should collect the required level of revenues to safely and reliably operate the utility.

The Power Supply (Commodity) rate design options can provide accurate, cost-based prices for the cost of power supply. Specifically, electric utility rate design should reflect the power supply cost structure and how each class of service is responsible for its fair share of each power supply cost component. Given appropriate prices, consumers can then make informed decisions regarding their electricity use.

The distribution portion of retail rates should be developed such that each ratepayer is responsible for their fair share of the electric distribution service provided. Distribution rates can be bundled with Power Supply (Commodity) rates or unbundled and shown separately as the City has continued to do. Depending on the unique nature of each utility, class of service, or utility goals distribution rate design can vary. While the COSA provides average distribution costs for each class, the rates that are implemented may be designed a number of ways. Regardless of rate design choice, retail rates should follow best practices[7] for rate design which include:

- Promote efficient use of energy and competing products and services
- Simplicity, easy to understand, publicly acceptable, and feasible to implement
- Recovers the revenue requirement
- Provides stability and minimizes adverse impacts on customers
- Fairly apportions cost of service among different consumers

Rate design recommendations are presented in Section 5.

[7] Summarized from Bonbright's Eight Criteria of Sound Rate Structure.

3 Development of the Revenue Requirements

This section of the report presents the development of the electric revenue requirement for the City. Simply stated, a revenue requirement analysis compares the overall revenues of the utility to its expenses and determines the overall adjustment to rate levels that is required.

3.1 OVERVIEW OF THE CITY'S REVENUE REQUIREMENT METHODOLOGY

The City utilizes the "cash basis" approach for determining its revenue requirement. In summary, the components of its revenue requirement include the elements shown in Table 3-1.

TABLE 3-1: ELEMENTS OF A CASH BASIS REVENUE REQUIREMENT

+	Operation and Maintenance Expenses (O&M)	
	✓	Power Supply Expense
	✓	Distribution Expense
	✓	Customer Accounting Expenses
	✓	Administrative and General Expense
+	Capital Improvements funded from Rates	
+	Debt Service (Interest and Principal)	
+	General Fund Transfer	
	=	Total Revenue Requirement
	-	Transfers from Reserves
	-	Miscellaneous Revenue Sources
	=	Net Revenues Required from Rates

From this basic analytical framework, the next step in determining the revenue requirement is to select a time period over which to project revenue and expenses. In the case of the City, a fiscal year test period was utilized (July through June) rather than a calendar year test period. The recommended rate changes are for July 1, 2024; therefore, the 2024-25 fiscal year (July 2024 through June 2025), was chosen as the test period for the COSA.

The next step in the analysis was to translate the City budgeted costs into the system used by the Federal Electric Regulatory Commission (FERC), the FERC System of Accounts. A summary of the FY 2024-25 revenue requirement (using the FERC System of Accounts) is provided in Schedule 1.4, and the details are shown in Schedule 3.1.

3.2 POWER SUPPLY COSTS (COMMODITY)

As with most electric utilities, the major expense associated with operating the utility is power supply. Approximately $115.5 million, or 54 percent of the FY 2024-25 total revenue requirement of the utility, is power supply costs, as shown in Schedule 3.1. Power supply costs include costs from renewable and non-renewable resources, including Western Area Power Administration (WAPA), Northern California Power Agency (NCPA) resources and power purchase agreements. In addition, power supply costs include California Independent System Operator (CAISO) transmission and ancillary charges. The City's proposed FY 2024-25 Operating Budget was used for power supply expenses.

3.3 OTHER OPERATIONS AND MAINTENANCE COSTS

The City's proposed FY 2024-25 Operating Budget determines the other operations and maintenance (O&M) costs. Total FY 2024-25 O&M costs (excluding power supply) are projected to be $48.3 million. As shown in Schedules 1.4 and 3.1, this is made up of the following:

- Distribution O&M costs of $28.0 million. These costs include maintenance of distribution system infrastructure such as lines, transformers, meters, and substations.
- Customer Service-related costs of $12.6 million. These costs include meter reading, billing, key account representatives and general customer service.
- Administrative and general costs of $7.7 million. These costs include functions like accounting, benefit overhead, insurance, and other types of administrative overhead.

FY 2024-25 O&M and Power Supply (Commodity) costs together total $163.8 million, as shown in Schedules 1.4 and 3.1.

3.4 GENERAL FUND TRANSFER

The City calculates the equity transfer from its Electric Utility based on a methodology adopted by Council in 2009,[8] which has remained unchanged since then. The methodology includes a risk and tax adjustment to PG&E's approved return on equity (ROE). Through the budgeting process, the City has identifed PG&E's ROE for calendar year 2023 at 10.0%. Using the recommended tax adjustment (70%) and risk adjustment (85%), the City's calculated ROR is 6.1% for FY 2024-25. The total rate base of $248 million means that the General Fund Transfer is projected to be $15.1 million.

3.5 RATE-FUNDED CAPITAL IMPROVEMENT PROGRAM (CIP)

For FY 2024-25, the budgeted CIP is $6.5 million, as shown in Schedules 1.4 and 3.1. This excludes any capital expenses reimbursed by customers through connection fees or reimbursement agreements.

3.6 TRANSFER FROM RESERVES

In its FY 2024-25 proposed budget, the City plans to contribute approximately $25.3 million to reserves. This contribution is necessary to replenish reserve levels recently withdrawn due to differences between the timing of the commencement of the utility's grid modernization capital project and the timing of the

[8] City of Palo Alto City Manager's Report (CMR) 280:09, "Adoption of an Ordinance Adopting the Fiscal Years 2010 and 2011 Budget, Including the Fiscal Year 2010 Capital Improvement Program, Changes to the Municipal Fee Schedule, Utility Rates and Charges, Equity Transfer Methodology Change and Changes to Compensation Plans," June 15, 2009 and CMR 260:09, "Recommendation to City Council to Change the Methodology Used to Calculate the Equity Transfer from Utilities Funds to the General Fund," May 26, 2009. https://portal.laserfiche.com/Portal/DocView.aspx?id=46024&repo=r-704298fc&searchid=7d78969f-7381-4bf1-ab9c-06cabaec6e19

first debt issuance associated with that project. See the FY 2024-25 Electric Utility Financial Plan for more detail.

3.7 MISCELLANEOUS REVENUES

The City receives additional operating and non-operating revenues and contributions, which are distinct from ratepayer revenues. These come in the form of carbon allowance revenues, interest revenues, miscellaneous service revenues, rents and other revenue. Service revenues received from connections and other fees offset the costs of those services. Interest revenues represent interest on the utility's reserves. Miscellaneous service revenues also include minor revenue sources like pole attachment fees for other utilities such as telecommunications, transfers from other City-owned utilities for shared services, and charges for damaged utility property. Other revenues include wholesale sales of surplus energy. For FY 2024-25 the projection for such revenues and contributions is $51.0 million, as shown in Schedules 1.4 and 3.1.

3.8 SUMMARY OF REVENUE REQUIREMENT

Once all of the components of the cash basis revenue requirement have been determined, the parts can be summed to equal the total revenue requirement. The City's revenue requirement for the FY 2024-25 test period is summarized in Table 3-2. More detail on the individual components of the revenue requirement can be found in Schedules 1.4 and 3.1.

TABLE 3-2: SUMMARY OF THE REVENUE REQUIREMENT – FY: 2024 -25

Purchased Power	$115,533,652
Distribution	$28,005,465
Customer Accounts and Services	$12,608,722
Administration and General	$7,698,473
Capital Projects Funded from Rates	$6,500,000
Debt Service	$4,770,582
General Fund Transfer	$15,121,000
Reserve Contribution	$25,333,578
Total Expenses	**$215,571,473**
Other Revenues	$50,984,335
Total Revenue Required from Rates (Revenue Requirement)	$164,587,138
Revenue Based on Rates Currently in Effect	$168,321,326
Additional Rate Revenue Needed (Surplus)	($3,734,187)
Net Required Rate Revenue Increase (Decrease)	**(2.2%)**

3.9 RECOMMENDATION

The City's revenues are slightly more than its cost obligations in FY 2024-25 using current rates; therefore, a rate reduction is recommended. It is important to note that the City's revenue-to-cost balance needs to be continually monitored. The City regularly reviews revenue requirements to update retail rates and ensure financial objectives are met.

4 Cost of Service Analysis

The objective of the cost of service analysis (COSA) is to allocate the costs in the revenue requirement to each customer class of service to determine the cost to serve those customers. An essential principle of cost allocation is the concept of cost-causation. Cost-causation evaluates which customer or group of customers causes the utility to incur a cost by linking system facility investments and the operating costs to serve certain facilities to the way customers use those facilities and services. This section of the report will discuss the general approach used to apportion the City's costs, and will provide a summary of the results.

4.1 CUSTOMER CLASSES

A primary input into the COSA is the classes of service. Classes can be modeled by each rate schedule; however, rate schedules for similar customers may also be combined in the COSA. Combining rate schedules recognizes that those groups of customers have similar usage characteristics. For example, E-4 Medium Commercial and TOU-E-4 Medium Commercial customers are likely to have similar load characteristics. The following rate classes are modeled in the COSA:

E-1 Residential: All residential customers, excluding from master-metered multifamily customers..

E-2 Small Commercial: Electric service for small commercial customers and master-metered multifamily customers. Any customer with energy usage over 8,000 kWh per month for three consecutive months would be moved to E-4 (see below), while any E-4 customer with energy usage below 6,000 kWh per month for 12 consecutive months would be switched to E-2. When analyzing customer load data this study used the rate schedule designation for each customer in the utility billing system to determine whether the customer currently fell into the E-2 or E-4 class.

E-4 Medium Commercial: Demand metered electric service for commercial customers with a maximum demand below 1,000 kilowatts per month and usage over 8,000 kWh per month.

E-7 Large Commercial: Demand metered electric service for commercial customers with a maximum demand of at least 1,000 kilowatts per month per site, and who have sustained this demand level for at least 3 consecutive months during previous 12-month period.

Street and Traffic Lights: This class applies to all street and highway lighting installations that the City of Palo Alto Utilities Department elects to operate and maintain, generally lights owned by the City, the County, or another government entity and located on public streets.

For purposes of the analysis in this study, customers are assigned to a customer class without regard to whether they participate in Palo Alto Green, Net Energy Metering, Time of Use Metering or Low Income programs.

Master-metered multi-family customers are treated as commercial customers rather than residential customers.

4.2 COSA GENERAL PRINCIPLES

A COSA study allocates the costs of providing utility service to the various customer classes served by the utility based upon the cost-causal relationship associated with specific expense items. This approach is taken to develop a fair and equitable designation of costs to each class of service. Because the majority of costs are not incurred by any one type of customer, the COSA allocates joint and common costs among the various classes using factors appropriate to each type of expense. The COSA is the second step in a traditional three-step process for developing electric service rates, after development of the revenue requirement but before designing rates.

This COSA is performed using the embedded cost methodology. Embedded costs reflect the actual costs incurred by the utility and closely track the expenses kept in its accounting records.

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

- Functionalization
- Classification
- Allocation

Functionalization separates costs into major categories that reflect the different services provided to customers. The functional categories for the City are Power Supply (Commodity) and Distribution. Shared service costs (generally overhead) that will be allocated across both functional categories are also identified in this phase.

Classification determines the portion of each cost that is related to identified "classifiers" (cost-causal factors). Table 4-3 shows the classifiers used in this analysis. Generally, costs are classified as one or more of: demand-related (related to the class of service's peak energy usage over a given period), energy-related (related to the total energy used by the class of service over a given period), and customer-related (costs incurred as a result of receiving service, regardless of the energy use or peak demand), though there are some other classifiers. Power Supply (Commodity) costs are related to generating and supplying power to customers on the system and are often demand- or energy-related. The distribution system is designed to extend service to all customers attached to the system and to meet the peak demand requirement of each customer, meaning that costs are often demand-related. Some operational costs, such as billing, are generally customer-related. Costs can also be classified based on system revenues or directly assigned to a customer or group of customers if appropriate (for example, for street lighting customers).

Allocation of costs to specific classes of service happens after those costs have been classified. Allocation factors are chosen to allocate the costs assigned to each classification, and the share of costs allocated to each class of service are based on the class's contribution to the specific allocation factor selected. For example, certain Power Supply (Commodity) costs might be classified as partially demand-related and partially energy-related. The demand-related Power Supply (Commodity) costs would be allocated to the classes of service using each class's contribution to the annual system peak demand (the highest demand for the system as a whole at any time during the year), while the energy-related costs would be allocated to classes based on their annual energy usage. In this example, the allocation factors are 1) each class of service's contribution to the annual system peak demand and 2) the annual energy usage of each class of service. An analysis of customer requirements, and usage characteristics is completed to develop allocation factors reflecting each of the classifiers employed within the COSA.

4.3 FUNCTIONALIZATION OF COSTS

As discussed above, the first step in the COSA process following finalization of the revenue requirement is to functionalize the revenue requirement.

Certain types of costs in the revenue requirement (primarily O&M costs associated with various types of capital assets) are allocated based on the use of the underlying capital assets by customer class. To determine this, the underlying capital assets of the utility (the "rate base") are functionalized into cost categories and allocated to customer classes. The functionalization, classification, and allocation of the rate base will be used as a basis for functionalization, classification, and allocation of certain types of operating expenses in the revenue requirement, such as maintenance of the capital assets included in the rate base.

In the City's case, the rate base and revenue requirement are functionalized into Power Supply (Commodity), Distribution, and Shared Services functional categories. Schedule 3.1 shows the functional category for each cost in the revenue requirement, while Schedule 3.3 shows the results of the functionalization and classification of each cost. Schedules 4.1 and 4.2 show the same information for the rate base. The functional categories are described in more detail below:

- ***Power Supply (Commodity).*** The Power Supply functional category includes all power-related services that are obtained by the utility through generation and direct purchase. The City purchases power from a variety of renewable and hydroelectric generating sources, as well as purchasing power in the energy markets. The transmission services that the City must acquire to deliver the purchased power supply to the service area are included in purchased power costs.

- ***Distribution.*** Distribution services include all services required to move the electricity from the point of interconnection between the transmission system and the distribution system to the end user of the power. These include substations, primary and secondary poles and conductors, line transformers, services and meters as well as customer costs and any direct assignment items.

- ***Shared Services.*** Shared services include assets used across multiple functions or costs that apply across multiple functions, such as facilities used for general management of the operation or insurance or benefits costs. Assets and costs in the shared services category are not shown in the attached schedules as a separate functional category. Instead, they are allocated across the Power Supply (Commodity) and Distribution functions as overhead.

4.4 CLASSIFICATION AND ALLOCATION OF COSTS

The next step in performing a COSA is to classify and allocate the functionalized expenses. The classifications and allocations are directly related to specific consumption behavior or system configuration measurements such as coincident peak (CP) or non-coincident peak (NCP)[9] demand, energy

[9] Coincident peak represents the customer class's contribution to the system peak demand (i.e. its demand coincident with, or at the time of, the system peak), while non-coincident peak represents the customer class's peak

consumption, or number of customers. Each cost in the revenue requirement will be classified into one or more categories and will then be allocated to customer classes of service based on a specific allocator. For example, 7% of the costs associated with the Calaveras hydroelectric generating resource were classified into the demand classification and 93% were classified into the energy classification, with the demand classifier allocated to classes of service based on each class's CP demand, and the energy portion of the cost allocated based on each class's annual energy consumption.

The classification and allocation factors used for each component of the rate base and revenue requirement are shown in Tables 4-1 and4-2 and are discussed in more detail below. Descriptions of each factor are included in Table 4-3.

The following are the specific classifiers used in the City's COSA within the Power Supply and Distribution functions. As noted earlier, the Shared Services function is spread across the Power Supply and Distribution functions as overhead, so it does not have its own classifiers:

- **Power Supply (Commodity) Function**

  Within this study, Power Supply (Commodity) function costs are classified to demand and energy based on discussion with the City staff related to cost causation. The specific classifiers used for the Power Supply (Commodity) function include:

  - ***Energy***. Energy-related costs are those that vary with the total amount of electricity consumed by a customer. Electricity usage measured in kWh is used in this portion of the analysis. Energy costs are the costs of consumption over a specified period of time, such as a month or year.

  - ***Demand***. Demand-related costs are those that vary with the maximum demand or the maximum rates of energy supplied to classes of service. Customer and system demands for this analysis were measured in kW. Demand costs are generally related to the size (capacity) of facilities needed to meet a customer's maximum demand at any point in time. Resource capacity costs are functionalized as demand. When referring to customer peak electricity use or requirements, the term demand is used. When referring to resource attributes, the term capacity is used.

  In order to classify Power Supply (Commodity) costs, each resource or type of cost was evaluated based on how the City is charged and whether the resource provides energy or capacity[10] to the City. Power purchase agreements for the output from the Western Area Power Administration (WAPA) and Calaveras hydroelectric generating resources and all renewable resources provide differing amounts of energy and capacity, and so were classified according to the relative market value of the energy and capacity provided by each resource. An analysis of the amount of capacity and energy provided

demand regardless of when it occurs. A customer class's demand at the time of the system peak demand may be lower than its peak demand, which may occur at some other time of the year.

[10] When referring to a generating resource, "capacity" refers to its potential generating capacity regardless of whether it is actually generating energy. Capacity must be held to meet customer peak demand, regardless of whether it is used to generate energy at all times of the year. Capacity costs are usually assigned to the demand classifier.

by each resources was done, and the market value of each of those was calculated based on historical energy and capacity prices. The market value is used rather than actual operating expenses since the resources generate revenues that offset their operating expenses, and the actual cost to Palo Alto depends on the market value for energy, and capacity less the individual resource cost. The ratio of energy to capacity value was used to classify the cost of the resource and assign resource costs to energy or demand.

Costs associated with services provided to the City by Northern California Power Agency (NCPA) (such as scheduling generating resources and interacting with the California Independent System Operator (CAISO) on the City's behalf) are classified as energy costs because these services are necessitated by City's energy purchases. Purchases of energy from marketers[11] are classified as energy-related costs, while purchases of capacity are classified as demand-related costs.[12] CAISO transmission costs are classified as energy-related costs, as this is the way those costs are allocated to distribution utilities by the CAISO, and the CAISO transmission costs therefore vary with the total City system energy.

- **Distribution Function**

Distribution services include all services required to get energy supply from the point of interconnection between the transmission system and the utility's service area to the end user of the power. Most distribution costs are split between demand and customer components. The demand component is the cost of facilities like distribution substations, lines, or line transformers built to serve a particular peak demand. The customer component is the cost of facilities that varies with the number of customers, such as meters. The following are the specific classifiers used for the City's distribution function:

- ***Demand***. Demand-related costs are those that vary with the maximum demand or the maximum rates of energy supplied to classes of service. Customer and system demands for this analysis are measured in kW. Demand costs are generally related to the size of facilities needed to meet a customer's maximum demand at any point in time.

- ***Customer***. Customer-related costs are those that vary with the number of customers. Customer costs may be weighted to account for differences in the cost of providing services to those customers. For example, the service drop and metering associated with serving a large commercial customer is more costly and requires substantially more work and material than the service and meter for a small residential customer.

- ***Direct Assignment***. Some costs are directly assigned to specific classes of service. Costs associated with providing account representatives to large customers are allocated directly to those classes of service. Direct maintenance costs associated with streetlights and traffic signals are directly

[11] City purchases energy and capacity from various marketers and other agencies (BP Energy Company, Cargill Power Markets, Exelon Generation Co., Iberdrola Renewables, Nextera Energy Marketing, Pacificorp, Powerex, Shell Energy North America, and Turlock Irrigation District) through its Electric Master Agreements.

[12] Energy purchases require that energy is delivered to the system during some specified period of time, while capacity purchases enable the City to count generating capacity from a specific generating unit owned by another agency or marketer toward the generating capacity requirements imposed on it by the CAISO.

allocated to the streetlight / traffic signal class. Schedules 3.5 and 4.4 provide the background information for all directly assigned costs associated with the revenue requirement and rate base.

The methodology for functionalization, classification, and allocation of the City's rate base is summarized in Table 4-1 and in Technical Appendix Schedule 4.1. The results of the process for the rate base can be found in Schedule 4.2. The same information for the revenue requirement can be found in Table 7, Schedule 3.1, and Schedule 3.3. More detail on the classification and allocation factor codes used in the classification and allocation process can be found in Table 8. Schedule 6.1 shows how each code is used to separate costs into functions (power supply and distribution) and classifications (demand, energy, customer, and direct assignment). Schedule 6.2 shows the way each code then allocates the costs within each classification across classes of service.

TABLE 4-1: RATE BASE FUNCTIONALIZATION, CLASSIFICATION AND ALLOCATION

FERC Account	Asset Description	Functionalization Category	Classification and Allocation Factor Code[13]
	Distribution Plant		
361.0	Structures and Improvements	Distribution	NCPP
362.0	Station Equipment – Distribution	Distribution	NCPP
363.0	Storage & Battery Equipment	Distribution	NCPP
364.0	Poles, Towers & Fixtures	Distribution	100% DP
365.0	Overhead Conductor & Devices	Distribution	100% DC
366.0	Underground Conduit	Distribution	100% DC
367.0	Underground Conductors	Distribution	100% DC
368.0	Line Transformers	Distribution	100% DT
369.0	Services	Distribution	SERV
370.0	Meters	Distribution	CUSTM
371.0	Installations on Customer Premises	Distribution	CUSTM
373.0	Street Lighting Systems	Distribution	DA1
	General Plant		
390.0	Structures & Improvements	Shared Services	GPLT
391.0	Office Furniture & Equipment	Shared Services	GPLT
392.0	Transportation Equipment	Shared Services	GPLT
394.0	Tools, Shop & Garage Equipment	Shared Services	GPLT
397.0	Communication Equipment	Shared Services	GPLT
398.0	Miscellaneous Equipment	Shared Services	GPLT
399.0	Other Tangible Property – EV Charging	Shared Services	GPLT
	Accumulated Depreciation		
	Distribution Plant	Distribution	RBD-NoDA
	General Plant	Shared Services	RBGP
	Street Lighting	Distribution	DA1

[13] See Table 4.3 for more detail and fully spelled-out acronyms

FERC Account	Asset Description	Functionalization Category	Classification and Allocation Factor Code[13]
	Working Capital		
	90 Days Distribution O&M	Shared Services	OMWOP
	90 Days of Commodity Cost	Power Supply	OMP
	1/12 Purchased Transmission Charges	Power Supply	OMPT
	Construction Work in Progress		
	Construction Work in Progress	Distribution	RBD

TABLE 4-2: REVENUE REQUIREMENT FUNCTIONALIZATION, CLASSIFICATION AND ALLOCATION

FERC Account	Plant Description	Functionalization Category	Classification and Allocation Factor Code[14]
	Power Purchases		
555.70	Western Power Purchases	Power Supply	WEST
555.71	Contra Surplus Energy	Power Supply	kWh
555.72	NCPA Pooling	Power Supply	kWh
555.73	NCPA Facilities	Power Supply	kWh
555.74	Local Capacity Purchase	Power Supply	CP12
555.76	Renewable Energy	Power Supply	REN
555.77	Carbon Neutral Purchases (RECs)	Power Supply	kWh
555.78	Market Power Purchases	Power Supply	kWh
555.80	TANC & Calveras O&M	Power Supply	CALA
555.90	CVP O&M	Power Supply	WEST
555.15	Resource Management Admin	Power Supply	kWh
	Other		
555.10	Surplus Energy	Power Supply	kWh
555.30	Carbon Allowance Revenues	Power Supply	kWh
	Distribution		
580.0	Operations Supervision and Engineering	Distribution	RBD
586.0	Meters	Distribution	CUSTW
587.0	Customer Installations	Distribution	CUSTW
588.0	Miscellaneous Distribution	Distribution	RBD-NoDA
589.0	Rents	Distribution	RBD-NoDA
590.0	Maintenance Supervision and Engineering	Distribution	RBD-NoDA
593.0	Maintenance of Overhead Lines	Distribution	RBOH
594.0	Maintenance Of Underground Lines	Distribution	RBUG
596.0	Street Lighting & Signal Systems	Distribution	DA1
598.0	Maintenance of Misc. Distribution Plant	Distribution	RBD
598.1	Communication O&M	Distribution	RBD-NoDA
	Customer Service, Accounts & Sales		
901.0	Supervision	Distribution	CUSTW
902.0	Meter Reading Expenses	Distribution	CUSTMR
903.0	Cust. Records Collection Expense	Distribution	REV
904.0	Uncollectable Accounts	Distribution	REV
906.0	Customer Service & Information	Distribution	CUST
907.0	Customer Communication & Education	Distribution	CUST
910.0	Misc. Customer Service & Information	Distribution	CUST
916.0	Misc. Sales Expense	Distribution	CUST
906.1	Key Accounts	Distribution	OM
906.2	Energy Efficiency & Demand-Side Management (DSM)	Distribution	DSMEE

[14] See Table 4.3 for more detail.

FERC Account	Plant Description	Functionalization Category	Classification and Allocation Factor Code[14]
906.3	Low Income Residential Energy Assistance Program	Distribution	DSMEE
	Administrative and General (A&G) Expenses		
920.0	Salaries	Shared Services	OMAG
921.0	Office Supplies and Expense	Shared Services	OMAG
923.0	Outside Services	Shared Services	OMAG
924.0	Property Insurance	Shared Services	NETPLT
925.0	Injuries and Damages	Shared Services	OMAG
926.0	Employee Pension and Benefits	Shared Services	OMAG
927.0	Franchise Requirements	Shared Services	OMAG
930.2	Miscellaneous General Expense	Shared Services	OMAG
930.3	Environmental Fees	Shared Services	OMAG
932.0	Maintenance of General Plant & Communication Equipment	Shared Services	OMAG
935.0	Cost Plan Charges	Shared Services	OMAG
	Interest and Debt Service Expense		
427.0	Interest and Debt Service Electric	Shared Services	NETPLT
	Capital Projects From Rates		
	Distribution	Distribution	RBD-NoDA Services
	Other Contributions		
	General Fund Transfer	Shared Services	GF
	Other Transfers In/Out	Shared Services	NETPLT
	Reserve Contribution	Shared Services	RContr
	Misc. & Other Revenues and Income		
451.0	Connect / Re-Connect Fees	Shared Services	OMAG
419/424	Dividends from Affiliates, Interest	Power Supply	WEST
415/416	Income from Equity Investments	Shared Services	OM
421.0	Misc. Income (RA Sales & Surplus Sales)	Power Supply	kWh
421.1	Public Benefits Revenue	Power Supply	kWh

TABLE 4-3: CLASSIFICATION AND ALLOCATION FACTORS

Factor Code	Factor Name	Classification	Allocation Basis
Rate Base Classification and Allocation Factors			
NCPP	Non-coincident Peak - Primary	100% Demand	The total peak kW demand, regardless of when it occurs.
100% DP	100% Demand (Poles, Towers, Fixtures)	100% Demand	The total peak kW demand, regardless of when it occurs.
100% DC	100% Demand (Overhead and Underground Conduit)	100% Demand	The total peak kW demand, regardless of when it occurs.
100% DT	100% Demand (Transformers)	100% Demand	The total peak kW demand, regardless of when it occurs.
SERV	Services[15]	100% Customer	# customers weighted for the cost of installing and replacing services
CUSTM	Customers weighted for accounting / metering	100% Customer	# customers weighted for cost of installing, maintaining and reading meters, billing, and account management
DA1	Street Light Rate Base Assignment	100% Direct Assignment	Street lighting assets allocated directly to street light customer class of service
GPLT	Gross Plant	71.7% Demand, 21.1% Customer 7.2% Direct Assignment	Allocated on the Basis of Gross Plant (w/o General Plant & Intangible)
RBD-ST	Rate Base: Distribution Adjusted for Street Light Direct Assignments	61.8% Demand, 24.3% Customer 13.9% Direct Assignment	Classified and allocated to classes of service based on the value of all operational and shared services assets assigned to each class of service. Used for accumulated depreciation
RBD-NoDA	As Distribution Ratebase without DA Street Lighting	71.7% Demand, 28.3% Customer	Allocated as Distribution Rate Base without DA Street Lighting
RBD-NoDA Services	As Distribution Ratebase without DA Street Lighting or Services	97.8 Demand, 2.2% Customer	As Distribution Rate Base without DA Street Lighting or Services
RBGP	Rate Base - General Plant	71.7% Demand, 21.1% Customer, 7.20% Direct Assignment	On the Basis of General Plant Rate Base
RContr		50.7% Demand, 33.9% Energy 15.4% Customer	Based on Commodity and Distribution Split

[15] This is a technical term referring to the connection from the line transformer to the customer's electrical panel.

Factor Code	Factor Name	Classification	Allocation Basis
OMWOP	O&M without Power Supply	51.6% Demand, 17.7% Energy, 27.7% Customer 3.0% Direct Assignment	Allocated based on O&M without Power Supply costs
OMP	O&M: Purchase Power	9.3% Demand, 90.7% Energy	Allocated based on Purchased Power costs
OMPT	O&M: Purchased Transmission	100% Energy	Allocated based on Purchased Transmission costs
RBD	Rate Base: Distribution	71.7% Demand, 21.1% Customer 7.2% Direct Assignment	Classified and allocated to classes of service based on the net book value of all shared services assets and other capital assets assigned to each class of service.
Revenue Requirement Classification and Allocation Factors			
WEST	Western Base Resource allocation	16% Demand, 84% Energy	Western Base Resource costs. Classified according to the relative market value of the capacity and energy provided by the resource, and allocated to classes of service based on each class's energy consumption and coincident peak demand.
kWh	Energy consumption (kWh)	100% Energy	Energy consumption of each class of service in kWh
CP12	12-month Coincident Peak	100% Demand	Customer class of service's contribution to the utility's annual system peak demand
CALA	Calaveras Hydroelectric Resource allocation	7% Demand, 93% Energy	Calaveras hydroelectric resource costs. Classified according to the relative market value of the capacity and energy provided by the resource, and allocated to classes of service based on each class's energy consumption and coincident peak demand.
REN	Renewable Power Purchase Agreements	3% Demand, 97% Energy	Renewable Power Purchase Agreement costs. Classified according to the relative market value of the capacity and energy provided by the resource, and allocated to classes of service based on each class's energy consumption and coincident peak demand.
RBD	Distribution Rate Base	71.7% Demand, 21.1% Customer, 7.2% Direct Assignment	On the Basis of Distribution Rate Base
RBD-NoDA	Distribution Rate Base Excluding Street Lighting and Traffic Signals	71.7% Demand, 28.3% Customer	Used for allocation of most distribution system infrastructure O&M costs other than street light/traffic signal maintenance. Classified and allocated to classes of service based on the net book value of all shared services assets and other capital assets assigned to each class of service, excluding street lighting and traffic signals.

Factor Code	Factor Name	Classification	Allocation Basis
RBD-NoDA Services	As Distribution Rate Base without DA Street Lighting or Services	97.8 Demand, 2.2% Customer	As Distribution Rate Base without Direct Assignment to Street Lighting and excluding Services (FERC 369)
DA1	Street Light and Traffic Signal Direct Assignment	100% Direct Assignment	Costs associated with operating and maintaining streetlight and traffic signal assets
GF	General Fund Allocator	4% Demand 95% Energy 1% Customer	Allocator for General fund Contributions based on Surplus Sales
RContr	Reserves Contribution	50.7% Demand, 33.9% Energy 15.4% Customer	Based on Commodity and Distribution split
RBOH	Rate Base (Overhead Lines)	100% Demand	Used for allocation of maintenance costs for overhead lines. Classified and allocated to classes of service based on the net book value of overhead lines assigned to each class of service.
RBUG	Rate Base (Underground Lines)	100% Demand	On the Basis of all Underground Rate Base
REV	Retail Revenues	100% Demand	Share of retail rate revenue
CUSTW	Customers weighted for accounting / metering	100% Customer	# customers weighted for cost of installing, maintaining and reading meters, billing, and account management
CUSTMR	Customers weighted for meter reading	100% Customer	# customers weighted for cost of reading meters
CREDIT	Credit and Collections	100% Customer	# customers weighted for credit and collections costs
CUST SERV	Customer Service	100% Customer	# customers weighted for customer service costs
CUST	Actual Customers	100% Customer	Actual (unweighted) customer count
OMAG	O&M omitting A&G and Power Supply	Shared Services	On the basis of all other O&M costs allocated to each class of service excluding A&G and Power Supply. Allocated to Power supply Function (12.6% Energy) and Distribution Function (48.7% Demand, 31.5% Customer, 7.2% Direct Assignment)
OM	All O&M	Shared Services	Allocated on the basis of all other O&M costs in the revenue requirement. Allocated to Power Supply Function (4.9% Demand, 12.6% Energy) and Distribution Function (48.7% Demand, 31.5% Customer, 7.2% Direct Assignment)
DSRE	Demand-Side Renewable Energy Allocator	Power Supply	Allocated based on PV Partners solar rebate budget allocation

Factor Code	Factor Name	Classification	Allocation Basis
DSMEE	DSM / EE Allocator	Power Supply	Based on historical residential / non-residential program expenditures. Residential direct assignment, non-residential based on annual kWh. No allocation to Street/Traffic Lights
NETPLT	Net Plant	78.4% Demand, 18.2% Customer, 3.4% Direct Assignment	Allocated on the basis of the net book value of all capital assets (initial cost less accumulated depreciation) assigned to each class of service.

4.5 COST OF SERVICE RESULTS

Given the key assumptions listed above, the COSA was completed. Schedules 3.4 and 4.3 in the appendix show the functionalized and classified rate base and revenue requirement allocated to each class of service. These schedules are calculated by multiplying the applicable classification and allocation factors to each cost in the revenue requirement or rate base.

Given the above assumptions regarding the COSA, the various costs were classified and allocated to the customer classes of service. Table 4-4 provides the COSA results. Summary data and additional detail is presented in Schedules 1.1 and 1.2.

TABLE 4-4: SUMMARY OF COST OF SERVICE ANALYSIS FOR FY 2024-25 TEST YEAR

	Projected Revenues under Current Rates	Net Revenue Requirement	Projected Surplus/ (Deficiency) in Revenue Based on Current Rates	Revenue Increase/ (Decrease) Needed[16]
Residential E-1	$27,309,759	$27,852,514	-$542,755	2.0%
Small Commercial E-2	$11,784,676	$11,067,556	$717,121	-6.1%
Medium Commercial E-4	$67,707,023	$65,186,601	$2,520,422	-3.7%
Large Commercial E-7	$59,295,683	$58,473,708	$821,975	-1.4%
Residential E-1	$2,224,184	$2,006,759	$217,425	-9.8%
TOTAL	**$168,321,326**	**$164,587,138**	**$3,734,187**	**-2.2%**

The results show that with present rates, the City would collect surplus revenues in FY 2024-25. As discussed previously in the report, the amount of additional revenue required varies by class of service. While customers on Rate Schedule E-7 are paying close to cost of service already, the E-1 rate class will need a rate increase. The varying cost requirements are a result of changes in customer usage

[16] Projected FY 2024-25 revenue surplus/(deficiency) divided by projected FY 2024-25 revenue based on rates currently in effect.

characteristics since the last COSA and rate redesign. These changing consumption patterns affect use of the system and the way costs are allocated among customers.

As described throughout this section, costs are allocated to customers based on their consumption patterns, particularly energy consumption and peak demand. As customer consumption patterns change, some of the utility's costs change as well, but others are fixed over the short term. For example, some charges to the utility, like market energy purchases, are directly related to energy consumption. These costs decrease as customer energy consumption decreases, usually in real-time. If a customer class uses less energy, fewer of these costs will be allocated to them and their revenue requirement will decrease. Other costs only change slowly over time, such as the amount of distribution capacity the utility builds and maintains. These costs are largely fixed and change over the long term with changes in peak demand or energy use. The majority of the City of Palo Alto's costs change slowly over the long term.

Rates for each customer class are set based on the energy and peak demand patterns over the study period. If energy use and peak demand decrease or increase after the rate study is completed, costs that change only over the long term might not change. When a subsequent COSA is performed, different revenue adjustments may need to be made for each customer class. The impacts to each class required as a result of the analysis done in the COSA are described below:

- Energy consumption and demand has increased for the E-1 (Residential)[17] class of service. The share of costs allocated to this customer class increased as a result. Revenues need to increase more than average for this class of service.
- Small Commercial (E-2) needs a larger rate decrease due to an updated assessment of the cost allocation factors for customer service costs for this customer class.
- The Medium Commercial (E-4) annual load factor has remained consistent with the previous COSA; however, energy usage and demand usage has decreased. This results in less cost allocation to E-4.
- Large Commercial (E-7) load factors[18] have increased. The share of costs allocated to this class decreased as a result.
- The streetlight and traffic signal class reflects lower maintenance costs and capital expenditures allocated to lighting.

The table below compares usage data from this study (FY 2023-24) with the previous COSA (FY 2016-17). Note that E-18 (City Accounts) were combined with commercial classes in the last COSA (FY 2016-17). Rather than developing separate E-18 rates, the City included City Accounts in the appropriate commercial classes based on individual customer demand size as described in the retail rate schedules. Retail sales data and number of customers was provided by the City. Billed demand[19] for applicable classes was also provided by the City. Not all classes have meters that measure demand, therefore, for classes without

[17] While this class of service is named "Residential Electric Service," it does not include 100% of residential use. Some master-metered multi-family residential buildings take service under other rate schedules.
[18] See previous footnote.

[19] Billed demand refers to the maximum measured kW in any given month. Billed demand is based on a customer's maximum demand regardless of the time of the utility system peak (non-coincident demand at the meter).

billed demand, demands are calculated using load factor data calculated from an appropriate City feeder (i.e. a feeder[20] that is mostly serving residential customers is used to calculate monthly load factors).

TABLE 4-5: COMPARISON OF LOAD CHARACTERISTICS

	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	City Accounts E-18	Street & Traffic Lights	Total
Retail Sales, MWh							
FY2016-17	153,030	70,451	320,995	394,322	29,231	1,897	969,926
Forecast FY2024-25	133,053	53,238	295,255	348,505	0	1,893	831,944
Peak Demand (12NCP, kW)[1]							
FY2016-17	304,102	190,983	773,606	747,738	76,890	5,371	2,098,690
Forecast FY2024-25	264,621	143,933	764,019	607,389	0	5,359	1,785,322
Load Factor[2] **Average Monthly**							
FY2016-17	69%	51%	54%	74%	53%	50%	
Forecast FY2024-25	69%	51%	49%	78%	NA	50%	
Customers							
FY2016-17	25,341	3,073	736	66	123	1	29,339
Forecast FY2024-25	26,100	3,183	837	71	0	2	30,193

When examining the results, it is important to note that the inter-class cost allocation is based on usage data estimates and usage pattern assumptions. Since these can vary from year to year, the results of applying this COSA may deviate from these allocations over time. To avoid these deviations, the COSA model can be updated when necessitated by significant changes to customer consumption patterns or the City's costs. This study utilizes the FY 2020-21 and FY2021-22 historic years and the City's forecasted load growth to estimate FY2024-25 loads. The historic data includes usage patterns that have continued since the pandemic. This data best reflects the near-term usage characteristics. It is recommended to revisit the load characteristics in future COSA studies.

[20]A feeder is the part of the distribution system which connects the power supply to the area where power is to be distributed (and eventually to individual customers).

5 Rate Design

The final step in the rate study process is to design rates for each class of service. It is important to note that the results of the revenue requirement and COSA study are dependent on forecasted usage data estimates and usage pattern assumptions. Actual electricity usage patterns may differ from forecast. For this study, rates are developed based on the forecasted usage and observed historical usage patterns for each rate class.

As part of the electric cost of service study, a rate design analysis is prepared to update the City's current and recommended rate schedules. The City's existing rate model and methodologies are largely preserved for each rate classes. In some cases, rate components for existing schedules have recommended updates. This section of the report summarizes the rate design analysis for FY 2024-25 electric rates. Table 5-1 summarizes the recommended rate adjustments by class. These rate adjustments are taken directly from the COSA results.

TABLE 5-1: RATE ADJUSTMENT RECOMENDATION OVERVIEW

	Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/ Traffic Lights
Current Rate Revenue	$168,321,326	$27,309,759	$11,784,676	$67,707,023	$59,295,683	$2,224,184
Rate Revenue Goal	$164,583,349	$27,852,514	$11,067,651	$65,184,561	$58,471,865	$2,006,759
Rate Adjustment	-2.2%	2.0%	-6.1%	-3.7%	-1.4%	-9.8%

Table 5-2 summarizes the current rate design for each rate schedule and recommended rate design updates.

TABLE 5-2: RATE DESIGN RECOMMENDATION OVERVIEW

Rate Schedule	Current Rate Design	Recommended Rate Design
Residential E-1	Energy Only Tiered Rate with 2 Inclining Blocks	• Add Customer Charge • Increase Tier 1 kWh to average summer usage
Small Commercial E-2	Seasonal Rates energy charge only	• Update Seasonal Costs • Add Customer Charge
Medium Commercial E-4	Seasonal with Energy and Demand Charges	• Update Seasonal Costs • Add Customer Charge • Adjust kW billing methodology
Medium Commercial E-4-TOU	6-period TOU Energy and Demand Rates	• Update TOU Periods • Commodity Rate Based on updated Marginal Cost • Add Customer Charge
Large Commercial E-7	Seasonal with Energy and Demand Charge	• Update Seasonal Costs • Add Customer Charge
Large Commercial E-7-TOU	6-period TOU with Energy and Demand Charge	• Update TOU Periods • Commodity Rate Based on updated Marginal Cost • Add Customer Charge • Adjust kW billing methodology

5.1 CUSTOMER CHARGE AND MINIMUM BILL

Table 5-2 recommends adding monthly customer charges to each rate schedule.[21] The recommended customer charges recover the cost of metering and billing in each class. Customer charge bill impacts to low-income customers are addressed in section 5.2 below.

5.2 RESIDENTIAL E-1

The current rate design is based on a 2-tier inclining block rate as described in Table 5-3. The costs allocated to Tier 1 include the cost of maintaining and replacing the distribution capacity used year-round, while the costs allocated to Tier 2 represent the cost of maintaining and replacing the distribution capacity used only in the winter, which is when residential consumption peaks. Local capacity costs (resource adequacy) are allocated to Tier 2 as well. The current break point between Tier 1 and Tier 2 is 330 kWh per month. An analysis of residential consumption for CY 2020 shows the average summer residential consumption is 461 kWh per month. This is most representative of the current annual year-round usage. Therefore, the recommended rate design change is to increase the Tier 2 threshold to 461 kWh per month.

TABLE 5-3: RESIDENTIAL E-1 TIERED ENERGY RATE DESIGN

	Current Rates	Recommended Rate Design
Tier 1 kWh	330	461
Tier 2 kWh	Above 330	Above 461

It is recommended that the City implement a monthly customer charge.[21] This customer charge recovers customer-specific costs such as billing and meter reading. Additionally, a customer charge is a way to improve cost of service recovery within each class; low users pay their share of costs. Low-income programs would continue to be available to mitigate rate impacts to vulnerable customers.

Table 5-4 shows the recommended rates preserving the tiered rate structure.

TABLE 5-4: RECOMMENDED E-1 RATES

	Commodity	Distribution	PBC	Total
Current Rates				
Tier 1 (up to 330 kWh), $/kWh	$0.09999	$0.06954	$0.00568	$0.17521
Tier 2 (> 330 kWh), $/kWh	$0.13873	$0.10225	$0.00568	$0.24666
Recommended Rate				
Tier 1 (up to 461 kWh), $/kWh	$0.10270	$0.08518	$0.00549	$0.19337

[21] A monthly customer charge can be referred to as a facilities charge, fixed charge, basic charge, fixed delivery charge or other nomenclature. This study refers to the customer charge as fixed or facilities charge. All of these are essentially the same type of rate meant to recover a portion of fixed costs incurred just to serve a customer.

	Commodity	Distribution	PBC	Total
Tier 2 (> 461 kWh), $/kWh	$0.13311	$0.08272	$0.00549	$0.22133
Customer Charge, $/month				$4.64
COSA Rate Adjustment				**2.0%**

The above rates are based on the cost of service for each rate component. Table 5-5 summarizes the components for the recommended rate design.

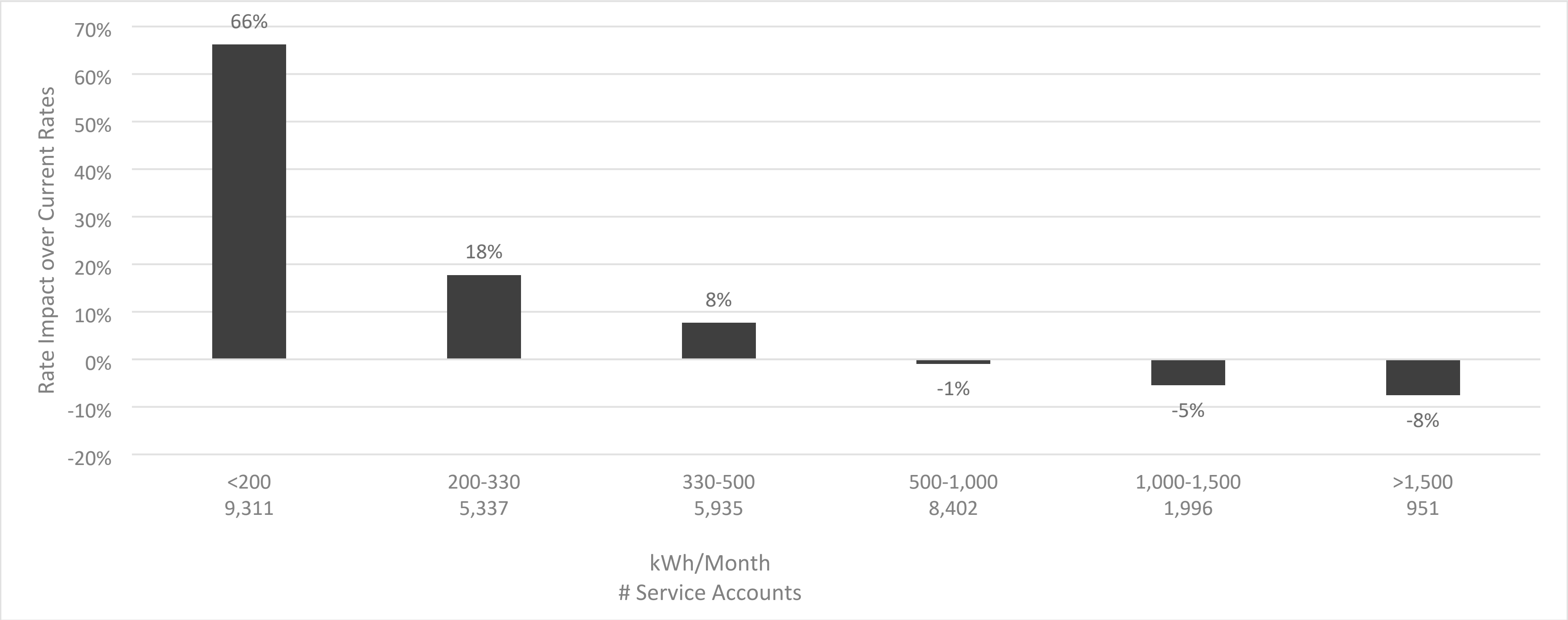
TABLE 5-5: COST BASIS FOR RECOMMENDED RATES

Rate Component	Cost-Basis	Reasoning
Commodity Tier 1	Average Energy Costs	Full cost recovery of energy-related power supply purchases
Commodity Tier 2	Average Energy Costs plus Local Capacity Costs	Higher-users contribute more to demand costs than customers in lower tiers. Customers in higher tiers use more energy in summer months which directly impact the utility's capacity costs
Distribution Tier 1	All Customer-Related Distribution Costs less Customer Charge Revenue plus Average demand-related distribution costs	Average demand-related costs are recovered even at lower usage levels.
Distribution Tier 2	Average and Excess Demand-Related Costs	Average demand-related costs plus Excess demand-related costs collected for usage over the Tier 1 kWh. Excess demand is related to higher usage levels.
Customer Charge	Recovers Fixed Customer Metering and Billing Costs	All customers should pay for their fixed costs independent of usage.

5.2.1 E-1 Bill Impacts

The figures below show impacts of the recommended rates. As expected, the customers in the lowest usage tier (<200 kWh/month) experience the greatest impact. Note that the bill impacts are calculated in reference to the current rate level and rate structure. The average customer using less than 200 kWh/month would experience a 68% bill increase.

FIGURE 5-1: BILL IMPACTS



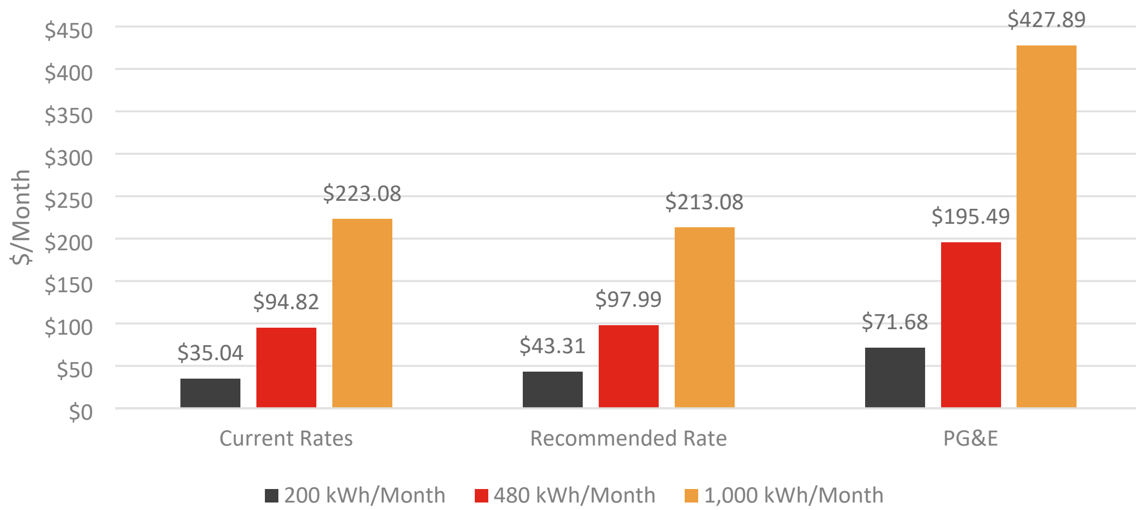
While the monthly bills increase by a large percentage for the 200 kWh/month and less group, the actual dollar increase is smaller, averaging less than $3.40/month (Figure 5-4).

FIGURE 5-2: BILL IMPACTS, $/MONTH

5.2.2 Bill Comparison with PG&E

Figure 5-3 compares the current and recommended E-1 rates to PG&E current rates for a range of consumption levels: low, average, and high use. Regardless of usage, PG&E current rates are approximately twice the recommended rate level for Palo Alto E-1 rates.

FIGURE 5-3: E-1 BILL COMPARISON: PALO ALTO AND PG&E, AVERAGE BILL



Note that the PG&E baseline allowance for Tier 1 is 198 and 228 kWh/mo (winter and summer respectively). PG&E current rates are 36 cents/kWh and 45 cents/kWh Tier 1 and Tier 2 respectively.

5.2.3 Rate Impacts for Low-Income E-1 (RAP)

One particular concern related to rate design change is the impact on low-income customers. This section presents bill impacts to customers currently participating in the City's Rate Assistance Program (RAP). The RAP program provides bill discounts of 25% to qualifying customers. Discounts are paid from the Public Benefits Charge (PBC) fund.[22] All customers pay into the PBC fund through the PBC charge, which is implemented via a variable rate (applied to kWh consumption).

As a group, participating RAP customers use less energy than non-RAP customers on average. Most RAP customers, (495 out of 817 or 61%), use 330 kWh or less per month and 78% use less than 461 kWh per month on average. As such, the inclusion of a minimum bill or monthly customer charge will disproportionately affect RAP customers. The charts below compare RAP bill impacts for current and recommended rates. Because these customers receive rate assistance, the bill impact (%) and the dollar per month impact are lower compared to the E-1 class as a whole (see previous figures).

[22] California Code, Public Utilities Code - PUC § 385

FIGURE 5-4 RAP CUSTOMER BILL IMPACTS

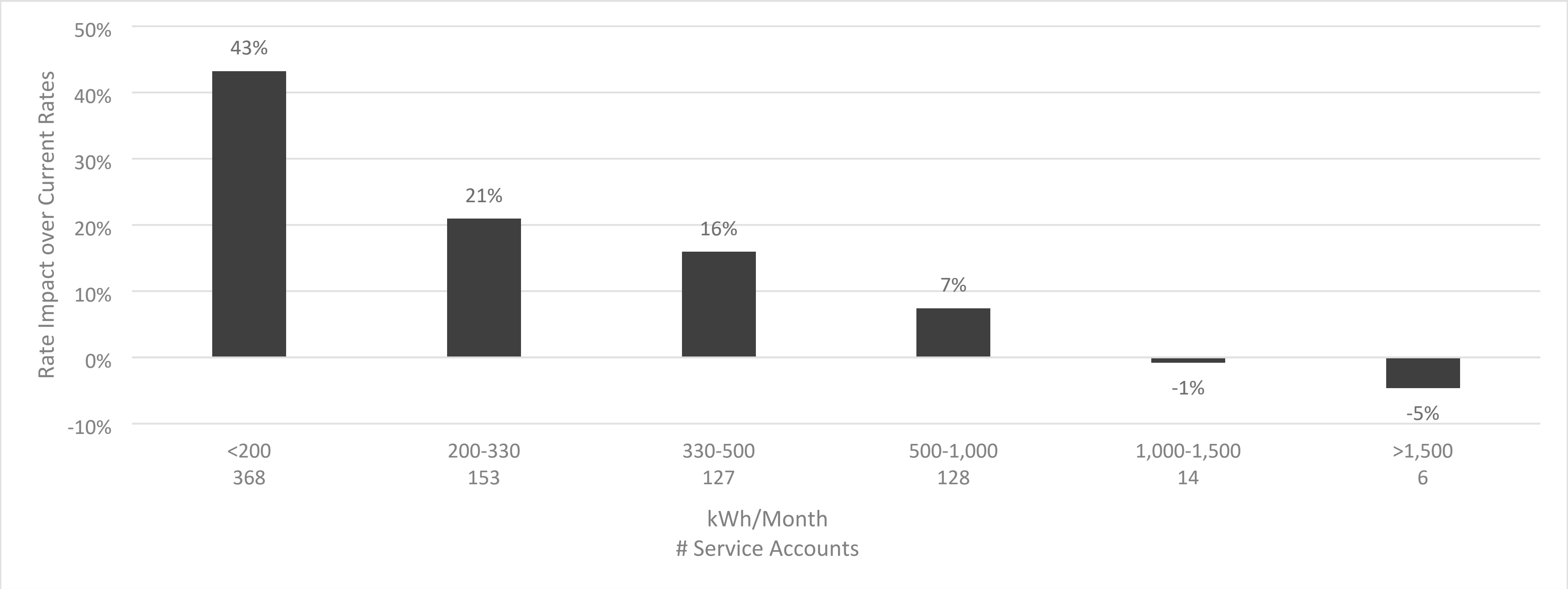
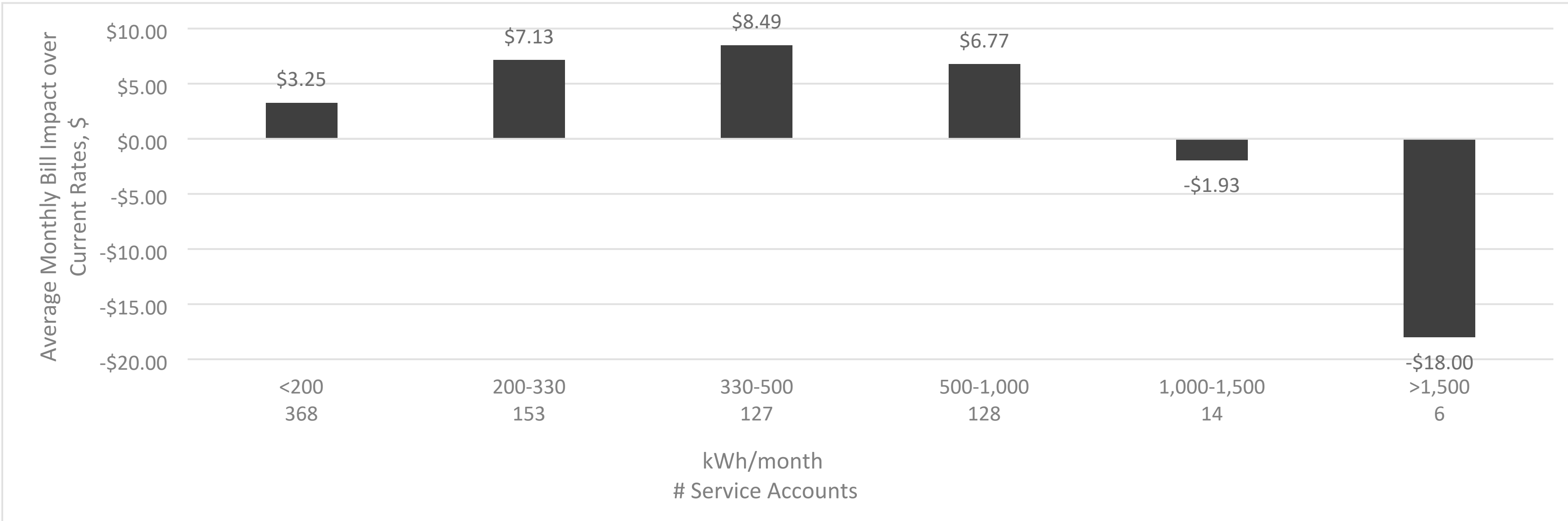


FIGURE 5-5 RAP CUSTOMER BILL IMPACTS, $/MONTH



The table below shows the average monthly bill increase and rate assistance needed to eliminate adverse bill impacts from the recommended rates. Also shown are the smallest estimated bill impacts (minimum, or "Min") and highest estimated bill impacts (maximum, or "Max"). For example, if the recommended tiered energy rate is implemented, it is estimated that the average monthly bill for a RAP customer is $5.19 higher compared with current rate levels and rate design. The customer with the largest bill decrease will see an average of $32.75 less on their monthly bills while the customer with the largest bill increase will see an increase of $11.68/month on average. If all RAP bill increases are mitigated with additional assistance, the City can expect to increase RAP funding by $51,000 per year. This rate assistance would both support the 2% rate level increase and the rate design change. The City would fund this incremental increase to program spending with the PBC fund if necessary.

TABLE 5-6: LOW INCOME MONTHLY BILL IMPACT AND RATE ASSISTANCE NEED ESTIMATES

	Impacts
Recommended Tiered Energy Rate	Average Bill Impact: $5.19 Min: -$32.75 Max: $11.68 Rate Assist. Need: $51,000/yr

5.3 SMALL COMMERCIAL E-2

The current E-2 rate is a seasonal rate with energy charges only. The seasonal Commodity component of the rate is based on actual seasonal Commodity costs. Distribution demand costs are split into summer and winter based on the average and excess method where summer receives a higher allocation consistent with higher summer peak demands. Distribution customer costs are shared equally across seasons. Table 5-7 shows the current and recommended rates.

TABLE 5-7: CURRENT AND RECOMMENDED E-2 RATES

	Commodity	Distribution	PBC	Total
Current Rates				
Summer, $/kWh	$0.14216	$0.11775	$0.00568	$0.26559
Winter, $/kWh	$0.10196	$0.07861	$0.00568	$0.18625
Recommended Rates				
Summer, $/kWh	$0.14926	$0.09735	$0.00549	$0.25211
Winter, $/kWh	$0.09242	$0.06623	$0.00549	$0.16415
Customer Charge, $/month				$5.60
COSA Rate Adjustment				-6.1%

Just as in the E-1 rate design, the recommended customer charge recovers customer billing and meter reading costs.

Figures 5-6 and 5-7 illustrate the monthly bill impact from a percent change perspective as well as dollar amount. While the lowest usage groups experience high bill impacts from a % change perspective, the dollar amount is less than $2 per month on average.

FIGURE 5-6: E-2 BILL IMPACTS

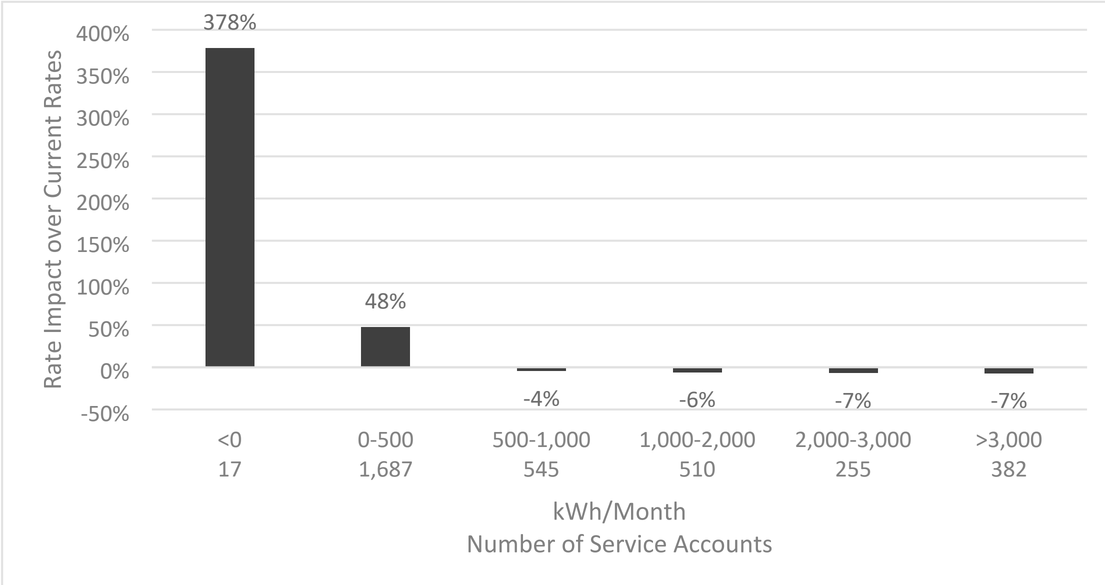
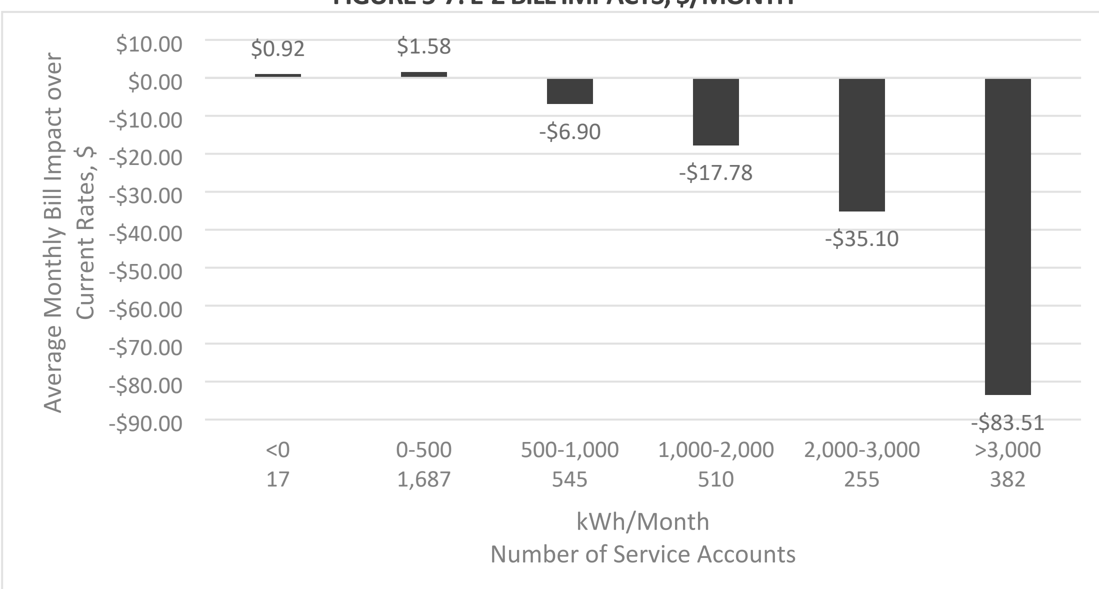


FIGURE 5-7: E-2 BILL IMPACTS, $/MONTH



5.4 MEDIUM COMMERCIAL E-4

The E-4 rate schedule, as shown in Table 5-8, is seasonal with a demand component. As mentioned previously, there is also an optional TOU option for E-4.

The default E-4 rate separates Commodity costs into summer and winter seasons based on actual seasonal costs. Local capacity costs (resource adequacy) are allocated to summer rates only. Other demand-related Commodity costs are allocated to both summer and winter based on kW. Distribution customer costs are the same across seasons. Billing and metering costs are collected through the customer charge. Distribution demand costs are allocated to each season based on average and excess where summer receives a larger allocation.

TABLE 5-8: CURRENT AND RECOMMENDED E-4 RATES

	Commodity	Distribution	PBC	Total
Current Rates				
Summer, $/kWh	$0.13157	$0.02638	$0.00568	$0.16363
Winter, $/kWh	$0.09461	$0.02638	$0.00568	$0.12667
Summer, $/kW-month	$5.28	$31.54		$36.82
Winter, $/kWh-month	$3.29	$20.87		$24.16
Recommended Rates				
Summer, $/kWh	$0.12318	$0.02520	$0.00549	$0.15387
Winter, $/kWh	$0.07949	$0.02520	$0.00549	$0.11018
Summer, $/kW-month	$10.98	$34.31		$45.29
Winter, $/kW-month	$2.57	$21.16		$23.73
Customer Charge, $/month				$113.73
COSA Rate Adjustment				**-1.9%**

Summer demand rates are increased significantly due to local capacity costs equaling a larger share of total power-related demand costs.

5.5 E-4 TOU

As solar has penetrated the market, daytime prices have become the lowest priced time to purchase energy. Table 5-9 compares the current and recommended TOU periods. The peak period is both the maximum priced energy period (for purchases of wholesale energy), and the City's system peak has occurred within this period in each month over the previous 3 years. Capacity requirements are set based on system peaks during this time period. The mid peak period represents mid-afternoon and or late evening periods when energy costs are lower. Off peak periods represent all other hours and the lowest energy prices. All weekends and federal holidays are considered off peak.

TABLE 5-9: PRESENT AND RECOMMENDED TOU PERIODS

Current TOU Periods			Recommended TOU Periods		
	Summer	Winter		Summer	Winter
Energy & Demand			**Energy**		
Peak	12 – 6 PM M-F	8 AM- 9 PM M-F	Peak	4-9 PM M-F	4-9 PM M-F
Mid Peak	8 AM-12 PM, 6 PM- 9 PM M-F	None	Mid Peak	2-4 PM & 9-11 PM, M-F	9 AM-2 PM M-F
Off Peak	9 PM- 8 AM M-F All Day Sat & Sun	All Other Hours	Off Peak	All Other Hours	All Other Hours
			Demand		
			Peak	4-9 PM M-F	4-9 PM M-F
			Max Peak	All Hours	All Hours

To illustrate why it is recommended to shift TOU periods, Table 5-10 compares the marginal cost of energy for the current and recommended TOU periods. These values are calculated by averaging hourly market prices over each period. These costs represent the value of energy if the City were to sell or purchase wholesale energy within these time periods. The recommended TOU periods maintain the current seasons where Summer is May 1- October 31. Table 5-10 shows that the current TOU periods do not have a pricing differential in winter months. Also, under the current structure, summer mid peak is the most expensive period.

TABLE 5-10: CURRENT AND RECOMMENDED TOU MARGINAL COSTS

	Marginal Cost, $/MWh
Current TOU Periods	
Summer Peak (noon -6 pm M-F)	$57.61
Summer Mid Peak (8 am - noon & 6 pm - 9 pm M-F	$73.81
Summer Off Peak (9pm - 8 am M-F, all day Sat & Sun)	$62.24
Winter Peak (8 am - 9 pm M-F)	$48.00
Winter Off Peak (all other times)	$48.00
Recommended TOU Periods	
Summer Peak (4-9 pm)	$81.29
Summer Mid Peak (2-4 pm and 9 am - 11 pm)	$66.99
Summer Off Peak (all other hours)	$50.36
Winter Peak (4-9 pm)	$63.51
Winter Mid Peak (9 am -2 pm)	$50.13
Winter Off Peak (all other hours)	$34.60

The recommended TOU rates adjust both the TOU periods and the demand billing methodology as shown in Table 5-11 below. The marginal costs from Table 5-10 (recommended TOU periods) are used to determine the commodity rate for each period.

The current method applies demand charges for each TOU period. This design choice will incentivize customers to reduce demand during both peak and mid peak periods. However, demand rates contain largely fixed costs. The recommended rate provides a simplification where customers are still able to reduce costs by shifting usage away from peak periods, and the City will collect a larger share of its fixed distribution costs with a non-TOU demand charge. Said another way, the peak demand charge recovers the associated commodity costs plus a share of distribution costs attributed to maximum demand in summer months. The non-TOU demand charge collects distribution demand costs for average demand consumption.

TABLE 5-11: CURRENT AND RECOMMENDED E-4 TOU RATES

	Commodity	Distribution	PBC	Total
Current Rates				
Summer Peak (noon -6 pm M-F)	$0.12020	$0.02636	$0.00568	$0.15224
Summer Mid Peak (8 am - noon & 6 pm - 9 pm M-F)	$0.15204	$0.02636	$0.00568	$0.18408
Summer Off Peak (9pm - 8 am M-F, all day Sat & Sun)	$0.09229	$0.02636	$0.00568	$0.12433
Winter Peak (8 am - 9 pm M-F)	$0.14744	$0.02636	$0.00568	$0.17948
Winter Off Peak (all other times)	$0.12619	$0.02636	$0.00568	$0.15823
Summer Peak Period Demand, $/kW-month	$3.22	$10.85		$14.07
Summer Mid Peak Period Demand, $/kW-month	$1.11	$10.85		$11.96
Summer Off Peak Demand, $/kW-month	$1.11	$10.85		$11.96
Winter Peak Period Demand, $/kW-month	$1.83	$11.63		$13.46
Winter Off-Peak Demand, $/kW-month	$1.83	$11.63		$13.46
Recommended Rates				
Customer Charge, $/month				$113.73
Summer Peak (4-9 pm)	$0.17038	$0.02538	$0.00549	$0.20125
Summer Mid Peak (2-4 pm and 9-11 pm)	$0.14041	$0.02538	$0.00549	$0.17128
Summer Off Peak (all other hours)	$0.10556	$0.02538	$0.00549	$0.13643
Winter Peak (4-9 pm)	$0.11976	$0.02500	$0.00549	$0.15025
Winter Mid Peak (9 am -2 pm)	$0.09452	$0.02500	$0.00549	$0.12501
Winter Off Peak (all other hours)	$0.06525	$0.02500	$0.00549	$0.09574
Summer Peak Period Demand, $/kW-month	$9.72	$17.18		$26.90
Summer Max Demand, $/kW-month	$1.29	$17.18		$18.47
Winter Peak Period Demand, $/kW-month	$1.30	$10.73		$12.03
Winter Max Demand, $/kW-month	$1.30	$10.73		$12.03

Since the majority of commodity-related demand costs are from local resource adequacy purchases (capacity), the commodity portion is low in winter months and off-peak summer periods. High summer peak period demand charges reflect the marginal costs for demand requirements during the most expensive periods. The local RA cost is based on the City's system peak demand, which occurs during the 4 pm to 9 pm peak period in the summer.

The TOU rate designs allocate costs seasonally using the same methodology as the underlying non-TOU rate designs, but they also take into account hourly variations in energy prices. Most generating capacity costs are allocated to the summer peak periods, since the City's system peak demand occurs during that time. Most of the City's resource adequacy (generating capacity) costs result from requirements imposed by the CAISO based on the City's annual system peak demand. Resource Adequacy costs are allocated to the peak periods based on the impact peak demand has on those costs.

5.6 LARGE COMMERCIAL E-7

The E-7 rate schedule is seasonal with a demand component. The E-7 rate separates Commodity costs into summer and winter seasons based on actual seasonal costs. Local RA (capacity costs) are allocated to summer rates only. Other power-demand costs are allocated to both summer and winter based on kW.

Billing and metering costs are recovered through the recommended customer charge. Other Distribution customer costs are the same across seasons. Distribution demand costs are allocated to each season based on average and excess where summer receives a larger allocation consistent with higher summer usage which drives distribution system costs. Note that distribution demand costs are spread more evenly across seasons due to flatter seasonal load profiles for E-7 customers.

TABLE 5-12: CURRENT AND RECOMMENDED E-7 RATES

	Commodity	Distribution	PBC	Total
Current Rates				
Summer, $/kWh	$0.13917	$0.00075	$0.00568	$0.14560
Winter, $/kWh	$0.09212	$0.00075	$0.00568	$0.09855
Summer, $/kW-month	$6.03	$33.05		$39.08
Winter, $/kWh-month	$3.46	$18.25		$21.71
Recommended Rates				
Summer, $/kWh	$0.12659	$0.00362	$0.00549	$0.13570
Winter, $/kWh	$0.07894	$0.00354	$0.00549	$0.08797
Summer, $/kW-month	$11.95	$28.41		$40.36
Winter, $/kW-month	$2.79	$25.00		$27.79
Customer Charge, $/month				$520.80
COSA Rate Adjustment				-1.4%

5.6.1 E-7 TOU

The recommended TOU rates adjust both the TOU periods and the demand billing methodology in the same manner as the recommended E-4 TOU rate.

TABLE 5-13: CURRENT AND RECOMMENDED E-7 TOU RATES

	Commodity	Distribution	PBC	Total
Current Rates				
Summer Peak (noon -6 pm M-F)	$0.14457	$0.00075	$0.00568	$0.15100
Summer Mid Peak (8 am - noon & 6 pm - 9 pm M-F)	$0.18205	$0.00075	$0.00568	$0.18848
Summer Off Peak (9pm - 8 am M-F, all day Sat & Sun)	$0.11171	$0.00075	$0.00568	$0.11814
Winter Peak (8 am - 9 pm M-F)	$0.09697	$0.00075	$0.00568	$0.10340
Winter Off Peak (all other times)	$0.08323	$0.00075	$0.00568	$0.08966
Summer Peak Period Demand, $/kW-month	$3.86	$11.08		$14.94
Summer Mid-Peak Period Demand, $/kW-month	$1.13	$11.08		$12.21
Summer Off-Peak Demand, $/kW-month	$1.13	$11.08		$12.21
Winter Peak Period Demand, $/kW-month	$1.78	$9.22		$11.00
Winter Off-Peak Demand, $/kW-month	$1.78	$9.22		$11.00
Recommended Rates				
Customer Charge, $/month				$520.80
Summer Peak (4-9 pm)	$0.18019	$0.00362	$0.00549	$0.18930
Summer Mid Peak (2-4 pm and 9-11 pm)	$0.14850	$0.00362	$0.00549	$0.15761
Summer Off Peak (all other hours)	$0.11164	$0.00362	$0.00549	$0.12075
Winter Peak (4-9 pm)	$0.12104	$0.00354	$0.00549	$0.13007
Winter Mid Peak (9 am -2 pm)	$0.09552	$0.00354	$0.00549	$0.10455
Winter Off Peak (all other hours)	$0.06594	$0.00354	$0.00549	$0.07497
Summer Peak Period Demand, $/kW-month	$11.28	$14.71		$25.99
Summer Max Demand, $/kW-month	$1.45	$14.71		$16.16
Winter Peak Period Demand, $/kW-month	$1.45	$12.99		$14.44
Winter Max Demand, $/kW-month	$1.45	$12.99		$14.44

The ratio of distribution demand costs collected through the Peak Period Demand charge to those collected through the Max Demand charge is determined based on load profile data. The Max Demand charge collects costs that were allocated based on the non-coincident peak (NCP) of the customer class. Just over half (52%) of all costs allocated under the recommended rate design are based on customer maximum peak (NCP). Therefore, 52% of demand-related distribution costs are collected through the Max Demand charge. The remaining 48% are collected through the Peak Demand charge. For summer demand charges these calculations coincidentally resulted in an identical distribution demand charge for both the Peak and Max Demand charge.. Table 5-14 illustrates the demand billing determinants assuming the entire E-7 class is on the TOU schedule.

TABLE 5-14: TOU E-7 BILLED DEMAND ASSUMPTIONS

	Share of Total Billed Demand		Estimated Class Billing Determinant, kW	
	Summer	Winter	Summer	Winter
Peak Demand	48.2%	48.0%	283,362	280,165
Max Peak Demand (NCP)	51.8%	52.0%	304,237	303,152

5.7 PUBLIC BENEFITS CHARGE

Public Utilities Code Section 385 requires all POUs to have a public benefits charge built into their rates. The rate must recover revenue equal to a set percentage of all other sales revenue based on a formula in that law. Most California POUs have interpreted this formula to require collection of an additional 2.85% of sales revenue for this purpose, as has the City. The revenue collected must be spent on a specified set of energy efficiency and other demand-side measures, including: 1) demand side-management services to promote efficiency and conservation, 2) new investment in renewable energy and technologies, 3) research and development programs for the public interest, and 4) services and discounts for low income electricity customers.

The public benefits charge is collected as a flat charge assessed on every kWh that results in the revenue level described above. The FY 2024-25 Public Benefits Charge is calculated at $0.00568/kWh.

5.8 STREET LIGHTING AND TRAFFIC SIGNALS

The City's electric utility also provides lighting and traffic signal maintenance services, which are captured in the E-14 Street Lights schedule. These services are primarily provided to the City itself, but also to a few other governmental agencies. Table 5-17 shows the updated lighting rates based on current rates adjusted by the 9.8% rate reduction. Maintenance Class A indicates that the City provides electricity and switching service only. Maintenance Class C indicates that the City supplies electricity, switching, and maintains the lighting system including lamps and glassware.

TABLE 5-17: SCHEDULE E-14 RECOMMENDED RATES

Maintenance Class	Lamp Rating	Current Rate $/mo.	Recommended Rate $/mo.
A	HPS 100W	$6.21	$5.60
A	HPS 200W	$11.46	$10.34
A	HPS 250W	$14.08	$12.70
A	HPS 310W	$17.42	$15.72
A	HPS 400W	$22.43	$20.24
C	Mercury-Vapor 400W	$35.83	$32.33
C	HPS 70W	$32.97	$29.75
C	HPS 100W	$34.55	$31.17
C	HPS 150W	$37.17	$33.54
C	HPS 250W	$42.42	$38.27
C	LED 70W-EQ	$29.48	$26.60
C	LED 100W-EQ	$30.68	$27.68
C	LED 150W-EQ	$31.77	$28.66
C	LED 250W-EQ	$34.78	$31.38

6 Technical Appendix

CITY OF PALO ALTO

Cost of Service Schedules

Date:	February 8, 2024
Version:	3rd Draft
Test Period:	FY: 2025
Production Peak Allocation Method:	Average and Excess Method (AE)
Transmission Peak Allocation Method:	Average and Excess Method (AE)
Distribution System Allocation Method:	100% Demand

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For questions about this model:
amber.gschwend@gdsassociates.com

City of Palo Alto - 100% Demand
SUMMARY OF PRESENT AND PROPOSED RATE REVENUE
BY CUSTOMER CLASS
Schedule 1.1

Forecast Year: 2025	Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Revenues - Present Rate	$168,321,326	$27,309,759	$11,784,676	$67,707,023	$59,295,683	$2,224,184
Less Allocated Revenue Requirement	$164,587,138	$27,852,514	$11,067,556	$65,186,601	$58,473,708	$2,006,759
Difference	$4,034,187	-$242,755	$717,121	$2,520,422	$821,975	$217,425
Revenue To Cost Ratio	**102.3%**	**98.1%**	**106.5%**	**103.9%**	**101.4%**	**110.8%**
		16.9%	6.7%	39.6%	35.5%	1.2%
% Increase Retail Rates to Equal Allocated Cost	**-2.22%**	**2.0%**	**-6.1%**	**-3.7%**	**-1.4%**	**-9.8%**
Rate Base	$247,977,170	$40,100,933	$16,740,604	$108,987,533	$74,010,673	$8,137,426
Rate Of Return, %	1.6%	-0.6%	4.3%	2.3%	1.1%	2.7%
Rate Of Return, $	$4,034,187	-$242,755	$717,121	$2,520,422	$821,975	$217,425
Modified Debt Service Coverage Ratio						
Unit Cost: Present Rates ($/kWh)	**$0.202**	**$0.20526**	**$0.221**	**$0.229**	**$0.170**	**$1.175**

Unit Cost Summary

Unit Cost: Present Rates ($/kWh)	**$0.202**	**$0.2053**	**$0.2214**	**$0.2293**	**$0.1701**	**$1.1748**
Unit Cost: COSA Rates ($/kWh)	**$0.198**	**$0.2093**	**$0.2079**	**$0.2208**	**$0.1678**	**$1.0600**
Difference from Present Rates	-2.22%	1.99%	-6.09%	-3.72%	-1.39%	-9.78%

City of Palo Alto - 100% Demand
FUNCTIONALIZATION AND CLASSIFICATION OF REVENUE REQUIREMENT SUMMARY
BY CUSTOMER CLASS
Schedule 1.2

Forecast Year: 2025	Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Power Supply						
Demand (PD)	$12,059,111	$1,525,512	$853,735	$5,178,050	$4,481,269	$20,546
Energy (PE)	$85,775,612	$13,664,488	$5,622,166	$30,235,026	$36,079,503	$174,429
Direct Assignment (PDA)	$0	$0	$0	$0	$0	$0
Distribution						
Demand (DD)	$48,672,424	$7,211,559	$3,827,858	$21,189,930	$16,221,785	$221,292
Energy (DE)	$0	$0	$0	$0	$0	$0
Customer (DC)	$16,489,682	$5,450,955	$763,798	$8,583,596	$1,691,151	$182
Direct Assignment (DDA)	$1,590,310	$0	$0	$0	$0	$1,590,310
Total	**$164,587,138**	**$27,852,514**	**$11,067,556**	**$65,186,601**	**$58,473,708**	**$2,006,759**
Total Cost / Function						
Production	$97,834,723	$15,190,000	$6,475,900	$35,413,076	$40,560,772	$194,975
Transmission	$0	$0	$0	$0	$0	$0
Distribution	$66,752,416	$12,662,515	$4,591,655	$29,773,526	$17,912,936	$1,811,784
Total Cost / Function	**$164,587,138**	**$27,852,514**	**$11,067,556**	**$65,186,601**	**$58,473,708**	**$2,006,759**
Total Cost / Classifier						
Demand	$60,731,534	$8,737,071	$4,681,592	$26,367,979	$20,703,054	$241,837
Energy	$85,775,612	$13,664,488	$5,622,166	$30,235,026	$36,079,503	$174,429
Customer	$16,489,682	$5,450,955	$763,798	$8,583,596	$1,691,151	$182
Direct Assignment	$1,590,310	$0	$0	$0	$0	$1,590,310
Total Cost / Classifier	**$164,587,138**	**$27,852,514**	**$11,067,556**	**$65,186,601**	**$58,473,708**	**$2,006,759**
check	0	0	0	0	0	0

City of Palo Alto - 100% Demand
FUNCTIONALIZATION AND CLASSIFICATION OF RATE BASE SUMMARY
BY CUSTOMER CLASS
Schedule 1.3

	Historic Year: 2021	Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Power Supply							
	Demand (PD)	$2,837,950	$358,268	$200,664	$1,218,428	$1,055,861	$4,729
	Energy (PE)	$27,397,411	$4,370,785	$1,780,313	$9,681,321	$11,506,983	$58,008
	Direct Assignment (PDA)	$0	$0	$0	$0	$0	$0
Transmission							
	Demand (TD)	$0	$0	$0	$0	$0	$0
	Energy (TE)	$0	$0	$0	$0	$0	$0
	Direct Assignment (TDA)	$0	$0	$0	$0	$0	$0
Distribution							
	Demand (DD)	$169,721,240	$24,953,594	$13,477,543	$74,374,253	$56,268,738	$647,113
	Energy (DE)	$0	$0	$0	$0	$0	$0
	Customer (DC)	$40,593,025	$10,418,286	$1,282,084	$23,713,532	$5,179,090	$32
	Direct Assignment (DDA)	$7,427,544	$0	$0	$0	$0	$7,427,544
	Total	**$247,977,170**	**$40,100,933**	**$16,740,604**	**$108,987,533**	**$74,010,673**	**$8,137,426**
Total Cost / Function							
	Production	$30,235,360	$4,729,053	$1,980,977	$10,899,749	$12,562,844	$62,737
	Transmission	$0	$0	$0	$0	$0	$0
	Distribution	$217,741,809	$35,371,880	$14,759,627	$98,087,785	$61,447,829	$8,074,689
	Total Cost / Function	**$247,977,170**	**$40,100,933**	**$16,740,604**	**$108,987,533**	**$74,010,673**	**$8,137,426**
Total Cost / Classifier							
	Demand	$172,559,190	$25,311,861	$13,678,207	$75,592,680	$57,324,599	$651,842
	Energy	$27,397,411	$4,370,785	$1,780,313	$9,681,321	$11,506,983	$58,008
	Customer	$40,593,025	$10,418,286	$1,282,084	$23,713,532	$5,179,090	$32
	Direct Assignment	$7,427,544	$0	$0	$0	$0	$7,427,544
	Total Cost / Classifier	**$247,977,170**	**$40,100,933**	**$16,740,604**	**$108,987,533**	**$74,010,673**	**$8,137,426**
	check	0	0	0	0	0	0

City of Palo Alto - 100% Demand

SUMMARY OF REVENUE REQUIREMENT COST ALLOCATION
Schedule 1.4

Forecast Year: 2025	Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Power Purchases	$77,938,853	$12,076,773	$5,064,877	$28,518,196	$32,109,436	$169,570
Transmission/Ancillary Services Purchases	$28,377,775	$4,538,512	$1,815,971	$10,071,340	$11,887,704	$64,248
Other	-$4,111,816	-$657,611	-$263,126	-$1,459,293	-$1,722,476	-$9,309
Total Production	$115,533,652	$18,089,382	$7,470,671	$41,860,681	$47,858,233	$254,685
Total Distribution	$28,005,465	$4,890,155	$1,850,538	$12,549,763	$7,458,839	$1,256,169
Total Operation & Maintenance	**$143,539,117**	**$22,979,538**	**$9,321,209**	**$54,410,444**	**$55,317,072**	**$1,510,854**
Total O&M w/o Purchased Power Supply & A&G	**$40,614,187**	**$7,715,792**	**$2,785,933**	**$17,280,750**	**$11,539,837**	**$1,291,875**
Total Customer Service, Accounts & Sales	$12,608,722	$2,825,637	$935,395	$4,730,987	$4,080,998	$35,706
Total Administrative & General	$7,698,473	$1,455,847	$527,903	$3,281,415	$2,187,225	$246,083
Total O&M plus A&G	**$163,846,313**	**$27,261,021**	**$10,784,507**	**$62,422,846**	**$61,585,295**	**$1,792,643**
Total Taxes	$0	$0	$0	$0	$0	$0
Total Interest / Debt Service Expense	$4,770,582	$767,840	$323,639	$2,150,357	$1,352,040	$176,706
Total Capital Projects Funded From Rates	$6,500,000	$1,056,184	$519,787	$2,792,253	$2,107,800	$23,976
Revenue Requirement Before Other Revenues	**$215,571,473**	**$36,012,298**	**$14,344,364**	**$83,466,601**	**$79,583,924**	**$2,164,286**
Revenue Req. Before Taxes and Other Revenues	**$215,571,473**	**$36,012,298**	**$14,344,364**	**$83,466,601**	**$79,583,924**	**$2,164,286**
Total Other Revenues	$50,984,335	$8,159,783	$3,276,809	$18,279,999	$21,110,216	$157,528
REVENUE REQUIREMENT for COST ALLOCATION	**$164,587,138**	**$27,852,514**	**$11,067,556**	**$65,186,601**	**$58,473,708**	**$2,006,759**

City of Palo Alto - 100% Demand

SUMMARY OF RATE BASE COST ALLOCATIONS
Schedule 1.5

Historic Year: 2021	Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Total Transmission Plant	$0	$0	$0	$0	$0	$0
Total Distribution Plant	$350,285,324	$55,478,957	$22,215,541	$153,581,897	$92,838,756	$26,170,173
Total Transmission & Distribution	$350,285,324	$55,478,957	$22,215,541	$153,581,897	$92,838,756	$26,170,173
Total General Plant	$47,223,629	$7,479,382	$2,994,983	$20,705,105	$12,516,034	$3,528,125
Total Plant Before General Plant & Intangible	**$350,285,324**	**$55,478,957**	**$22,215,541**	**$153,581,897**	**$92,838,756**	**$26,170,173**
Total Gross Plant in Service	**$397,508,952**	**$62,958,339**	**$25,210,523**	**$174,287,002**	**$105,354,790**	**$29,698,298**
Total Accumulated Depreciation	$188,823,622	$29,369,777	$11,053,181	$80,221,345	$46,210,884	$21,968,435
Total Net Plant	**$208,685,330**	**$33,588,562**	**$14,157,342**	**$94,065,657**	**$59,143,905**	**$7,729,863**
Total Working Capital	$39,291,839	$6,512,371	$2,583,262	$14,921,877	$14,866,767	$407,563
TOTAL RATE BASE	**$247,977,170**	**$40,100,933**	**$16,740,604**	**$108,987,533**	**$74,010,673**	**$8,137,426**

City of Palo Alto - 100% Demand

SUMMARY OF HISTORIC LOAD DATA
Schedule 1.6

Historic Year: 2021	Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Recorded Load Data						
Energy Sales (kWh)	815,778,523	161,545,337	45,675,813	242,402,726	364,257,301	1,897,346
Total Billing Capacity (kW)	1,297,123	0	0	669,694	627,429	0
Avg. Monthly Billing Capacity (kW)	108,094	0	0	55,808	52,286	0
Number of Customers	29,647	25,600	3,147	828	70	2
Ratio of NCP to Avg. Billing Capacity	0%	0%	0%	101%	96%	0%
Rate Classes NCP Demand at Meter	143,946	26,353	9,983	56,601	50,402	607
Estimates Based on Recorded Data						
Annual NCP Load Factor	65%	70%	52%	49%	82%	36%
Rate Classes CP Demand at Input Voltage	129,587	21,580	6,696	48,905	52,406	0
Annual CP Load Factor	72%	85%	78%	57%	79%	0%
Average On-Peak kWh as a % of Total kWh	0%	59%	59%	59%	59%	59%
Average Off-Peak kWh as a % of Total kWh	0%	41%	41%	41%	41%	41%

City of Palo Alto - 100% Demand

SUMMARY OF FORECAST LOAD DATA
Schedule 1.7

Forecast Year: 2025	Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Forecast Load Data						
Energy Sales (kWh)	831,943,836	133,052,833	53,237,722	295,255,415	348,504,639	1,893,227
Total Billing Capacity (kVa)	1,371,408	0	0	764,019	607,389	0
Avg. Monthly Billing Capacity (kVa)	114,284	0	0	63,668	50,616	0
Number of Customers	30,193	26,100	3,183	837	71	2
Ratio of NCP to Avg. Billing	192%	0%	0%	98%	94%	0%
Rate Classes NCP Demand at Meter	144,419	22,568	11,434	62,252	47,558	606
Forecast Based on Recorded and Forecast Data						
Annual NCP Load Factor	294%	67%	53%	54%	84%	36%
Rate Classes CP Demand at Input Voltage	137,082	16,462	9,311	61,491	49,449	367
Annual CP Load Factor	352%	92%	65%	55%	80%	59%
On-Peak kWh as a % of Total kWh	297%	59%	59%	59%	59%	59%
Off-Peak kWh as a % of Total kWh	203%	41%	41%	41%	41%	41%

City of Palo Alto - 100% Demand

SUMMARY OF POWER SUPPLY COSTS
Schedule 1.8

Forecast Year: 2025	Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Forecast Power Supply						
Power Purchases						
NCPA Pooling	$10,148,225	$1,623,025	$649,412	$3,601,629	$4,251,182	$22,976
NCPA Facilities	$2,542,371	$406,606	$162,693	$902,294	$1,065,022	$5,756
Local Capacity Purchase	$7,486,559	$945,117	$529,355	$3,214,232	$2,785,379	$12,476
Load Advance	$0	$0	$0	$0	$0	$0
Carbon Neutral Purchases (REC)	$9,741	$1,558	$623	$3,457	$4,081	$22
Market Power Purchases	$8,892,531	$1,422,200	$569,057	$3,155,981	$3,725,161	$20,133
PA Green Comm Purch	$0	$0	$0	$0	$0	$0
Transmission/Ancillary Services Purchases						
Transmission Purchases	$28,377,775	$4,538,512	$1,815,971	$10,071,340	$11,887,704	$64,248
Open	$0	$0	$0	$0	$0	$0
Open	$0	$0	$0	$0	$0	$0
Low Carbon Fuel G&A	-$4,111,816	-$657,611	-$263,126	-$1,459,293	-$1,722,476	-$9,309
Total Power Supply	**$66,674,227**	**$10,411,115**	**$4,316,935**	**$24,220,078**	**$27,579,622**	**$146,478**

City of Palo Alto - 100% Demand

SUMMARY OF REVENUES AT PRESENT RATES
Schedule 1.9

Forecast Year: 2025	Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Revenues:						
Customer Charge Revenues	$0	$0	$0	$0	$0	$0
Energy Revenues	$123,566,578	$27,309,759	$11,784,676	$43,647,477	$40,824,665	$0
Demand Revenues	$42,530,564	$0	$0	$24,059,546	$18,471,018	$0
Surcharge	$2,224,184	$0	$0	$0	$0	$2,224,184
Total Revenues	**$168,321,326**	**$27,309,759**	**$11,784,676**	**$67,707,023**	**$59,295,683**	**$2,224,184**
Average Charge:						
Customer Charge $ / Per Customer / Month		$0.00	$0.00	$0.00	$0.00	$0.00
Average Energy + Demand Charge $ / kWh		$0.205	$0.221	$0.229	$0.170	$0.000
Average Energy Charge $ / kWh		$0.205	$0.221	$0.148	$0.117	$0.000
Demand Charge $ / kVa or kW		$0.00	$0.00	$31.49	$30.41	$0.00

City of Palo Alto - 100% Demand
SUMMARY OF REVENUE REQUIREMENT UNIT COSTS
BY CUSTOMER CLASS
Schedule 2.1

Forecast Year: 2025	Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Billing Determinants						
Total kW	1,371,408	0	0	764,019	607,389	0
Total Demand (kW)	1,785,322	264,621	143,933	764,019	607,389	5,359
Total Energy (kWh)	831,943,836	133,052,833	53,237,722	295,255,415	348,504,639	1,893,227
Average Monthly Customers	30,193	26,100	3,183	837	71	2

Functional Cost	Total Cost	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Power Supply						
Demand (PD)	$12,059,111	$1,525,512	$853,735	$5,178,050	$4,481,269	$20,546
$/kW	$6.75	$5.76	$5.93	$6.78	$7.38	$3.83
Energy (PE)	$85,775,612	$13,664,488	$5,622,166	$30,235,026	$36,079,503	$174,429
$/kWh	$0.103	$0.103	$0.106	$0.102	$0.104	$0.092
Direct Assignment (PDA)	$0	$0	$0	$0	$0	$0
$/kW	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
$/kWh	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
Distribution						
Demand (DD)	$48,672,424	$7,211,559	$3,827,858	$21,189,930	$16,221,785	$221,292
$/kW	$27.26	$27.25	$26.59	$27.73	$26.71	$41.29
Energy (DE)	$0	$0	$0	$0	$0	$0
$/kWh	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
Customer (DC)	$16,489,682	$5,450,955	$763,798	$8,583,596	$1,691,151	$182
$/Customer/Month	$46	$17	$20	$855	$1,989	$8
Direct Assignment (DDA)	$1,590,310	$0	$0	$0	$0	$1,590,310
$/kW	$0.89	$0.00	$0.00	$0.00	$0.00	$296.74
$/kWh	$0.002	$0.000	$0.000	$0.000	$0.000	$0.840
Total	**$164,587,138**	**$27,852,514**	**$11,067,556**	**$65,186,601**	**$58,473,708**	**$2,006,759**
Total						
$/kW	**$34.91**	**$33.02**	**$32.53**	**$34.51**	**$34.09**	**$341.87**
$/kWh	**$0.10501**	**$0.10270**	**$0.10560**	**$0.10240**	**$0.10353**	**$0.93213**
$/Customer/Month	**$45.51**	**$17.40**	**$20.00**	**$854.60**	**$1,989.31**	**$7.54**
Melded kW/kWh in $/kWh	0.1780	0.1684	0.1935	0.1917	0.1629	1.0599
Melded kW/Cust in $/Cust/M	$217.52	$45.30	$142.56	$3,479.85	$26,342.39	$75,817.26

City of Palo Alto - 100% Demand

SUMMARY OF RATE BASE UNIT COST
BY CUSTOMER CLASS
Schedule 2.2

Forecast Year: 2025	Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Billing Determinants						
Total kVa	1,371,408	0	0	764,019	607,389	0
Total Demand (kW)	1,785,322	264,621	143,933	764,019	607,389	5,359
Total Energy (kWh)	831,943,836	133,052,833	53,237,722	295,255,415	348,504,639	1,893,227
Average Monthly Customers	30,193	26,100	3,183	837	71	2

Functional Cost	Total Cost	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Power Supply						
Demand (PD)	$2,837,950	$358,268	$200,664	$1,218,428	$1,055,861	$4,729
$/kW		$1.35	$1.39	$1.59	$1.74	$0.88
Energy (PE)	$27,397,411	$4,370,785	$1,780,313	$9,681,321	$11,506,983	$58,008
$/kWh	$0.033	$0.033	$0.033	$0.033	$0.033	$0.031
Direct Assignment (PDA)	$0	$0	$0	$0	$0	$0
$/kW	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
$/kWh	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
Distribution						
Demand (DD)	$169,721,240	$24,953,594	$13,477,543	$74,374,253	$56,268,738	$647,113
$/kW		$94.30	$93.64	$97.35	$92.64	$120.75
Energy (DE)	$0	$0	$0	$0	$0	$0
$/kWh	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
Customer (DC)	$40,593,025	$10,418,286	$1,282,084	$23,713,532	$5,179,090	$32
$/Customer/Month		$33	$34	$2,361	$6,092	$1
Direct Assignment (DDA)	$7,427,544	$0	$0	$0	$0	$7,427,544
$/kW		$0.00	$0.00	$0.00	$0.00	$1,385.93
$/kWh		$0.000	$0.000	$0.000	$0.000	$3.923
Total	**$247,977,170**	**$40,100,933**	**$16,740,604**	**$108,987,533**	**$74,010,673**	**$8,137,426**

Prepared By EES Consulting, Inc.

City of Palo Alto
INPUT REVENUE REQUIREMENT
Schedule 3.1

FERC Account		Year 2025 Cost, $	Function	Classification & Allocation Factor	Classification & Allocation Method
	Operation & Maintenance Expense				
	Power Purchases				
555.70	Western Power Purchases	$7,903,405	P	WEST	Western Cost (84% E, 16% D)
555.71	Contra Surplus Energy	-$13,328,841	P	kWh	Annual Energy (kWh)
555.72	NCPA Pooling	$10,148,225	P	kWh	Annual Energy (kWh)
555.73	NCPA Facilities	$2,542,371	P	kWh	Annual Energy (kWh)
555.74	Local Capacity Purchase	$7,486,559	P	CP12	12 Coincident Utility Peak
555.75	Load Advance	$0	P	kWh	Annual Energy (kWh)
555.76	Renewable Energy	$37,130,836	P	REN	Renewable (92% E, 3% D)
555.77	Carbon Neutral Purchases (REC)	$9,741	P	kWh	Annual Energy (kWh)
555.78	Market Power Purchases	$8,892,531	P	kWh	Annual Energy (kWh)
555.79	PA Green Comm Purch	$0	P	kWh	Annual Energy (kWh)
555.80	TANC & Calveras O&M	$6,816,709	P	CALA	Calaveras Cost (93% E, 7% D)
555.90	CVP O&M	$7,000,000	P	WEST	Western Cost (84% E, 16% D)
555.791	EMA Purchases	$0	P	kWh	Annual Energy (kWh)
556.00	Energy Risk Mgmt	$0	P	kWh	Annual Energy (kWh)
X555	Budget True-up	$0	P	kWh	Annual Energy (kWh)
555.15	Resource Management Admin	$3,337,316	P	kWh	Annual Energy (kWh)
	Transmission/Ancillary Services Purchases				
XXXX	Transmission Purchases	$28,377,775	P	kWh	Annual Energy (kWh)
	Other				
555.10	Surplus Energy	$13,328,841	P	kWh	Annual Energy (kWh)
555.20	Low Carbon Fuel G&A	$0	P	kWh	Annual Energy (kWh)
555.30	Carbon Allowance Revenues	-$4,111,816	P	kWh	Annual Energy (kWh)
555.40	open	$0	P	kWh	Annual Energy (kWh)
555.45	Allocated G&A	$0	P	kWh	Annual Energy (kWh)
555.50	Renewable Energy Salaries & General	$0	P	DSRE	Demand-Side Renewable Energy Allocator
	Total Purchased Power	$115,533,652			
	Total Production	$115,533,652			

Prepared By EES Consulting, Inc.

City of Palo Alto
INPUT REVENUE REQUIREMENT
Schedule 3.1

FERC Account		Year 2025 Cost, $	Function	Classification & Allocation Factor	Classification & Allocation Method
	Operation & Maintenance Expense				
	Distribution				
580.00	Op. Supervision & Engineering	$11,890,278	D	RBD	On the Basis of Distribution Rate Base
581.00	Load Dispatching	$0	D	RBSE	On the Basis of Station Equipment Rate Base
582.00	Line and Station Expenses	$0	D	RBSE	On the Basis of Station Equipment Rate Base
583.00	Overhead Lines	$0	D	RBOH	On the Basis of all Overhead Rate Base
584.00	Underground Lines	$0	D	RBUG	On the Basis of all Underground Rate Base
585.00	Street Lighting & Signal System	$0	D	DA1	Direct Assignment for Streetlights
586.00	Meters	$7,396	D	CUSTW	Customers Weighted for Accounting/Metering
587.00	Customer Installations	$1,153,617	D	CUSTW	Customers Weighted for Accounting/Metering
588.00	Misc. Distribution	$1,889,789	D	RBD-noDA	As Distribution Ratebase without DA Street Lighting
589.00	Rents	$6,733,141	D	RBD-noDA	As Distribution Ratebase without DA Street Lighting
590.00	Maint. Supervision & Engineering	$4,769,435	D	RBD-noDA	As Distribution Ratebase without DA Street Lighting
591.00	Maint. of Structures	$0	D	RBSE	On the Basis of Station Equipment Rate Base
592.00	Maint. of Station Equipment	$0	D	RBSE	On the Basis of Station Equipment Rate Base
XXXX	Maint. of Structures and Equipment	$0	D	RBSE	On the Basis of Station Equipment Rate Base
593.00	Maint. of Overhead Lines	$4,538,857	D	RBOH	On the Basis of all Overhead Rate Base
594.00	Maint. Of Underground Lines	$80,123	D	RBUG	On the Basis of all Underground Rate Base
XXXX	Maint. of Lines	$0	D	RBUG	On the Basis of all Underground Rate Base
595.00	Maint. of Line Transformers	$0	D	RBTR	On the Basis of all Transformer Rate Base
XXXX	Maint. of Line Transformers - Underground	$0	D	RBTR	On the Basis of all Transformer Rate Base
596.00	Maint. of Street Lighting & Signal System	$603,558	D	DA1	Direct Assignment for Streetlights
597.00	Maint. of Meters	$0	D	CUSTM	Customers Weighted for Meters and Services
598.00	Maint. of Misc. Distribution Plant	-$3,882,192	D	RBD	On the Basis of Distribution Rate Base
598.10	Communications	$221,461	D	RBD-noDA	As Distribution Ratebase without DA Street Lighting
	Total Distribution	$28,005,465			
	Total Operation & Maintenance	$143,539,117			

Prepared By EES Consulting, Inc.

City of Palo Alto
INPUT REVENUE REQUIREMENT
Schedule 3.1

FERC Account	Operation & Maintenance Expense	Year 2025 Cost, $	Function	Classification & Allocation Factor	Classification & Allocation Method
	Customer Service, Accounts, & Sales				
901.00	Supervision	$2,584,782	D	CUSTW	Customers Weighted for Accounting/Metering
902.00	Meter Reading	$694,215	D	CUSTMR	Customers Weighted for Meter Reading
903.00	Customer Records Collection	$968,331	D	REV	On The Basis of Revenue
904.00	Uncollectable Accounts	$1,727,779	D	REV	On The Basis of Revenue
905.00	Misc. Customer Accounts (Customer Deposits)	$0	D	CUST	Actual Customers
906.00	Customer Service & Information	-$744,743	D	CUST	Actual Customers
907.00	Customer Communication & Education	$122,716	D	CUST	Actual Customers
908.00	Customer Assistance	$0	D	CUST	Actual Customers
910.00	Misc. Customer Service & Information	$270,056	D	CUST	Actual Customers
912.00	Demonstrating & Selling	$0	D	CUST	Actual Customers
913.00	Advertising	$0	D	CUST	Actual Customers
916.00	Misc. Sales Expenses	$295,823	D	CUSTW	Customers Weighted for Accounting/Metering
917.00	Sales Expenses	$0	D	OM	On the Basis of All O&M
906.10	Key Accounts	$0	D	OM	On the Basis of All O&M
906.20	Energy Efficiency, DSM& Low Income Program	$6,689,764	D	DSMEE	DSM / EE Allocator:
906.30	Low Income Residential Energy Assistance Program	$0	D	DSMEE	DSM / EE Allocator:
	Total Customer Service, Accounts & Sales	$12,608,722			
	Total O&M w/o Purchased Power Supply & A&G	$40,614,187			
	Administrative & General				
920.00	Administrative & General Salaries	$2,840,007	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
921.00	Office Supplies	$110,579	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
922.00	Administrative Transfer - Credit	$0	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
923.00	Outside Services & Pension Credit	$637,787	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
924.00	Property Insurance	$230,547	SS	NETPLT	On the Basis of Net Plant
925.00	Injuries and Damages	$179,837	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
926.00	Employee Pension & Benefits	$2,346,975	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
927.00	Franchise Requirements	$23,187	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
928.00	Regulatory Expense	$0	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
929.00	Duplicate Charge - Credit	$0	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
XXXX	General Advertising	$0	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
930.00	Misc. General Expense	$0	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
930.10	General Advertising	$0	SS	OM	On the Basis of All O&M
930.20	Misc. General Expense	$111,099	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
930.30	Environmental	$2,034	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
931.00	COVID Expenses	$0	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
932.00	Maint. of General Plant & Communication Equipment	$7,022	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
933.00	Transportation	$0	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
935.00	Cost Plan Charges	$1,209,398	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
	Total Administrative & General	$7,698,473			
	Total O&M plus A&G	$163,846,313			

Prepared By EES Consulting, Inc.

City of Palo Alto
INPUT REVENUE REQUIREMENT
Schedule 3.1

FERC Account		Year 2025 Cost, $	Function	Classification & Allocation Factor	Classification & Allocation Method
	Operation & Maintenance Expense				
	Depreciation				
403.00	Generation Plant	$0	P	RBG	On the Basis of Generation Rate Base
403.44	Transmission Plant	$0	T	RBT	On the Basis of Transmission Rate Base
403.45	Distribution Plant	$0	D	RBD	On the Basis of Distribution Rate Base
403.46	General Plant	$0	SS	RBGP	On the Basis of General Plant Rate Base
403.80	Amortization of Plant	$0	D	RBD	On the Basis of Distribution Rate Base
XXXX	Amortization of Loss on Refunding	$0	D	RBD	On the Basis of Distribution Rate Base
XXXX	Miscellaneous Intangible Plant	$0	SS	RBIG	On the Basis of Intangible Plant Rate Base
	Total Depreciation	$0			
	Interest and Debt Service Expense				
427.00	Interest and Debt Service Electric	$4,770,582	D	NETPLT	On the Basis of Net Plant
428.00	Amortization of Debt Discount	$0	SS	NETPLT	On the Basis of Net Plant
429.00	Other Interest Expense	$0	SS	NETPLT	On the Basis of Net Plant
XXXX	Annual LT Debt Service	$0	SS	GPLT	Intangible)
XXXX	Annual ST Debt Service (AMI)	$0	SS	NETPLT	On the Basis of Net Plant
XXXX	Accelerated Debt Reduction - LT Debt	$0	SS	GPLT	Intangible)
XXXX	Ind A Interest Expense	$0	T	DA3	Direct Assignment for Ind A___________________________
	Total Interest / Debt Service Expense	$4,770,582			
	Capital Projects Funded From Rates				
	Production	$0	P	RBG	On the Basis of Generation Rate Base
	Transmission	$0	T	RBT	On the Basis of Transmission Rate Base
	Distribution	$6,500,000	D	RBD-noDA Services	Services
	General	$0	SS	GPLT	Intangible)
	Retirements	$0	SS	NETPLT	On the Basis of Net Plant
	Open	$0	SS	NETPLT	On the Basis of Net Plant
	Total Capital Projects Funded From Rates	$6,500,000			
	Other Contributions				
	General Fund Transfer to/(from)	$15,121,000	SS	GF	General Fund transfer based on other Revenues
	Reserves	$23,800,000	SS	Rcontr	Based on production and delivery split
	Debt Service Coverage Requirement	$0	SS	NETPLT	On the Basis of Net Plant
	Other transfers out	$1,533,578	SS	NETPLT	On the Basis of Net Plant
	Transfers In	$0	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
	Reserve Alloc Reapp	$0	D	OMP	On the Basis of Purchased Power O&M
	Margin Requirement	$0	SS	OM	On the Basis of All O&M
	Total Other Contributions	$40,454,578			
	Revenue Requirement Before Other Revenues	$215,571,473			
	Revenue Req. Before Taxes and Other Revenues	$215,571,473			

Prepared By EES Consulting, Inc.

City of Palo Alto
INPUT REVENUE REQUIREMENT
Schedule 3.1

FERC Account	Operation & Maintenance Expense	Year 2025 Cost, $	Function	Classification & Allocation Factor	Classification & Allocation Method
	Other Revenues				
450.00	Late Charges	$0	SS	OM	On the Basis of All O&M
451.00	Connect / Re-Connect Fees	$1,447,561	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
453.00	Misc Revenue	$0	SS	OM	On the Basis of All O&M
454.00	Joint Use Pole Attachment Income	$0	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
456.00	Misc Revenue (Other)	$0	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
457.00	Transfer Credits	$0	SS	OM	On the Basis of All O&M
458.00	Hydro Adjuster	$0	SS	OM	On the Basis of All O&M
419&424	Dividends from Affiliates, Interest	$7,000,000	P	WEST	Western Cost (84% E, 16% D)
448.00	Interdepartmental Sales	$0	SS	OM	On the Basis of All O&M
415&416	Income (Loss) from Equity Investments	$699,559	P	kwh	Annual Energy (kWh)
XXXX	Open	$0	SS	OMAG	On the Basis of O&M (w/o Power Supply and A&G)
449.00	Other Revenues	$274,394	P	kwh	Annual Energy (kWh)
456.20	Investment Income	$0	SS	OM	On the Basis of All O&M
421.00	Misc Income (RA Sales & Surplus Sales)	$37,045,073	P	kwh	Annual Energy (kWh)
421.10	Public Benefits Revenue	$4,517,748	P	kwh	Annual Energy (kWh)
	Total Other Revenues	$50,984,335			
	REVENUE REQUIREMENT for COST ALLOCATION	$164,587,138			

Prepared By EES Consulting, Inc.

City of Palo Alto
PROJECTED REVENUE REQUIREMENTS
Schedule 3.2

	Total 2021 Expenses	2022	2023	2024	2025	2026
Operation & Maintenance Expense						
Power Purchases						
Western Power Purchases	$6,687,852	$9,394,901	$8,394,847	$9,285,966	$7,903,405	$9,701,222
Contra Surplus Energy		-$5,205,273	$0	-$1,475,608	-$13,328,841	-$12,853,694
NCPA Pooling	$10,320,035	$4,132,334	$5,415,717	$5,440,093	$10,148,225	$10,111,288
NCPA Facilities	$2,312,749	$2,388,368	$2,436,135	$2,484,858	$2,542,371	$2,595,329
Local Capacity Purchase	$3,028,409	$5,906,575	$5,286,310	$6,544,573	$7,486,559	$9,462,041
Load Advance						
Renewable Energy	$38,702,755	$35,700,546	$34,990,114	$35,427,070	$37,130,836	$38,650,038
Carbon Neutral Purchases (REC)	$1,108,277	$0	$492,577	$128,608	$9,741	$20,331
Market Power Purchases	$0	$13,137,319	$22,769,940	$18,163,843	$8,892,531	$8,490,473
PA Green Comm Purch	$0					
TANC & Calveras O&M	$3,842,277	$5,483,163	$5,616,183	$6,263,875	$6,816,709	$6,398,793
CVP O&M	$807,716	$7,000,000	$7,000,000	$7,000,000	$7,000,000	$7,000,000
EMA Purchases	$3,822,940					
Energy Risk Mgmt	$20,064					
Budget True-up		$8,984,011				
Resource Management Admin	$1,922,591	$2,824,303	$2,991,189	$3,100,525	$3,337,316	$3,474,146
Transmission/Ancillary Services Purchases						
Transmission Purchases	$23,199,086	$20,397,767	$25,498,017	$27,280,567	$28,377,775	$29,964,562
Other						
Surplus Energy	$2,994,684	$5,205,273	$0	$1,475,608	$13,328,841	$12,853,694
Low Carbon Fuel G&A	$0					
Carbon Allowance Revenues	$0	-$6,118,830	-$5,285,256	-$5,700,281	-$4,111,816	-$4,231,477
open	$0					
Allocated G&A	$6,843,179					
Renewable Energy Salaries & General	$466,530					
Total Purchased Power	$106,079,144	$109,230,458	$115,605,773	$115,419,697	$115,533,652	$121,636,745
Total Production	$106,079,144	$109,230,458	$115,605,773	$115,419,697	$115,533,652	$121,636,745

Prepared By EES Consulting, Inc.

City of Palo Alto
PROJECTED REVENUE REQUIREMENTS
Schedule 3.2

	Total 2021 Expenses	2022	2023	2024	2025	2026
Operation & Maintenance Expense						
Distribution						
Op. Supervision & Engineering	$10,003,968	$7,776,271	$11,253,181	$11,612,313	$11,890,278	$12,187,535
Load Dispatching				$0	$0	$0
Line and Station Expenses				$0	$0	$0
Overhead Lines				$0	$0	$0
Underground Lines				$0	$0	$0
Street Lighting & Signal System	$112,680			$0	$0	$0
Meters	$0	$7,000	$7,000	$7,223	$7,396	$7,581
Customer Installations	-$940,288	$1,038,229	$1,091,805	$1,126,648	$1,153,617	$1,182,457
Misc. Distribution	$565,477	$1,596,973	$1,788,532	$1,845,611	$1,889,789	$1,937,034
Rents	$6,137,322	$6,069,000	$6,182,562	$6,329,377	$6,733,141	$7,002,466
Maint. Supervision & Engineering	$3,492,774	$4,444,812	$4,513,883	$4,657,938	$4,769,435	$4,888,671
Maint. of Structures	$0	$0	$0	$0	$0	$0
Maint. of Station Equipment				$0	$0	$0
Maint. of Structures and Equipment				$0	$0	$0
Maint. of Overhead Lines	$2,360,521	$1,581,321	$4,295,659	$4,432,750	$4,538,857	$4,652,328
Maint. Of Underground Lines	$16,644	$75,171	$75,830	$78,250	$80,123	$82,126
Maint. of Lines				$0	$0	$0
Maint. of Line Transformers				$0	$0	$0
Maint. of Line Transformers - Underground				$0	$0	$0
Maint. of Street Lighting & Signal System	$0	$310,880	$571,219	$589,449	$603,558	$618,647
Maint. of Meters				$0	$0	$0
Maint. of Misc. Distribution Plant		$1,163,077	-$926,128	-$3,892,006	-$3,882,192	-$3,932,002
Communications	$167,606	$388,899	$209,595	$216,284	$221,461	$226,998
Total Distribution	$21,916,704	$24,451,633	$29,063,136	$27,003,837	$28,005,465	$28,853,843
Total Operation & Maintenance	$127,995,848	$133,682,092	$144,668,909	$142,423,534	$143,539,117	$150,490,587

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City of Palo Alto
PROJECTED REVENUE REQUIREMENTS
Schedule 3.2

	Total 2021 Expenses	2022	2023	2024	2025	2026
Operation & Maintenance Expense						
Customer Service, Accounts, & Sales						
Supervision	$1,261,028	$1,834,721	$1,939,798	$2,009,325	$2,584,782	$2,688,174
Meter Reading	$415,884	$492,765	$520,986	$539,660	$694,215	$721,983
Customer Records Collection	$585,885	$687,337	$726,702	$752,748	$968,331	$1,007,064
Uncollectable Accounts	$625,505	$757,029	$757,029	$757,029	$1,727,779	$1,727,779
Misc. Customer Accounts (Customer Deposits)	$0	$0	$0	$0	$0	$0
Customer Service & Information	-$296,500	-$528,631	-$558,906	-$578,939	-$744,743	-$774,533
Customer Communication & Education	$0	$87,106	$92,095	$95,396	$122,716	$127,625
Customer Assistance	$0	$0	$0	$0	$0	$0
Misc. Customer Service & Information		$191,690	$202,668	$209,932	$270,056	$280,858
Demonstrating & Selling		$0	$0	$0	$0	$0
Advertising		$0	$0	$0	$0	$0
Misc. Sales Expenses	$114,500	$209,980	$222,006	$229,963	$295,823	$307,656
Sales Expenses		$0	$0	$0	$0	$0
Key Accounts		$0	$0	$0	$0	$0
Energy Efficiency, DSM& Low Income Program		$4,086,083	$6,179,462	$6,693,931	$6,689,764	$5,766,493
Low Income Residential Energy Assistance Program		$0	$0	$0	$0	$0
Total Customer Service, Accounts & Sales	$2,706,301	$7,818,080	$10,081,840	$10,709,045	$12,608,722	$11,853,099
Total O&M w/o Purchased Power Supply & A&G	$24,623,005	$32,269,713	$39,144,976	$37,712,882	$40,614,187	$28,853,843
Administrative & General						
Administrative & General Salaries	$1,261,556	$1,848,292	$2,143,425	$2,207,728	$2,840,007	$2,953,607
Office Supplies	$200,741	$82,457	$83,457	$85,961	$110,579	$115,003
Administrative Transfer - Credit	$0	$0	$0	$0	$0	$0
Outside Services & Pension Credit	$311,036	$431,250	$481,354	$495,795	$637,787	$663,299
Property Insurance	$163,810	$167,000	$174,000	$179,220	$230,547	$239,769
Injuries and Damages	$45,187	$81,310	$135,727	$139,799	$179,837	$187,030
Employee Pension & Benefits	$1,645,824	$1,495,593	$1,771,322	$1,824,461	$2,346,975	$2,440,854
Franchise Requirements	$20,077	$17,500	$17,500	$18,025	$23,187	$24,115
Regulatory Expense	$0	$0	$0	$0	$0	$0
Duplicate Charge - Credit	$0	$0	$0	$0	$0	$0
General Advertising	$0			$0	$0	$0
Misc. General Expense	$0	$0	$0	$0	$0	$0
General Advertising	$1,332			$0	$0	$0
Misc. General Expense	$25,454	$83,849	$83,849	$86,364	$111,099	$115,543
Environmental	$5,390	$1,535	$1,535	$1,581	$2,034	$2,115
COVID Expenses	$0	$0	$0	$0	$0	$0
Maintenance of General Plant	$31,830	$2,033	$5,300	$5,459	$7,022	$7,303
Transportation				$0	$0	$0
Cost Plan Charges		$1,521,278	$1,121,467	$1,173,264	$1,209,398	$1,271,312
Total Administrative & General	$3,712,238	$5,732,098	$6,018,937	$6,217,658	$7,698,473	$8,019,950
Total O&M plus A&G	$134,414,387	$147,232,270	$160,769,685	$159,350,237	$163,846,313	$170,363,636

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City of Palo Alto
PROJECTED REVENUE REQUIREMENTS
Schedule 3.2

	Total **2021** Expenses	**2022**	**2023**	**2024**	**2025**	**2026**
Operation & Maintenance Expense						
Depreciation						
Generation Plant				$0	$0	$0
Transmission Plant				$0	$0	$0
Distribution Plant	$6,403,152			$0	$0	$0
General Plant	$2,233,509			$0	$0	$0
Amortization of Plant				$0	$0	$0
Amortization of Loss on Refunding				$0	$0	$0
Miscellaneous Intangible Plant				$0	$0	$0
Total Depreciation	$8,636,661	$0	$0	$0	$0	$0
Interest and Debt Service Expense						
Interest and Debt Service Electric	$8,068,219	$8,068,219	$8,502,737	$8,275,943	$4,770,582	$7,873,314
Amortization of Debt Discount				$0	$0	$0
Other Interest Expense				$0	$0	$0
Annual LT Debt Service				$0	$0	$0
Annual ST Debt Service (AMI)				$0	$0	$0
Accelerated Debt Reduction - LT Debt				$0	$0	$0
Ind A Interest Expense				$0	$0	$0
Total Interest / Debt Service Expense	$8,068,219	$8,068,219	$8,502,737	$8,275,943	$4,770,582	$7,873,314
Capital Projects Funded From Rates						
Production	$0	**$0**	$0	$0	$0	$0
Transmission	$0	$0	$0	$0	$0	$0
Distribution	-$2,080	$22,508,996	$21,991,316	$25,508,299	$6,500,000	$25,643,701
General	$0	$0	$0	$0	$0	$0
Retirements	$0	$0	$0	$0	$0	$0
Open	$0	$0	$0	$0	$0	$0
Total Capital Projects Funded From Rates	-$2,080	$22,508,996	$21,991,316	$25,508,299	$6,500,000	$25,643,701
Other Contributions						
General Fund Transfer to/(from)	-$367,473	$14,138,000	$14,221,000	$15,119,000	$15,121,000	$15,550,000
Reserves	$7,443,994			-$4,500,000	$23,800,000	
Debt Service Coverage Requirement						
Other transfers out		$334,713	$351,449	$363,046	$1,533,578	$14,594,921
Transfers In						
Reserve Alloc Reapp				-$6,200,000		
Margin Requirement		-$661,616	-$568,039	-$587,742		
Total Other Contributions	$7,076,521	$13,811,097	$14,004,410	$4,194,305	$40,454,578	$30,144,921
Revenue Requirement Before Other Revenues	$158,193,708	$191,620,582	$205,268,147	$197,328,783	$215,571,473	$234,025,573
Revenue Req. Before Taxes and Other Revenues	$158,193,708	$191,620,582	$205,268,147	$197,328,783	$215,571,473	$234,025,573

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City of Palo Alto
PROJECTED REVENUE REQUIREMENTS
Schedule 3.2

	Total **2021** Expenses	**2022**	**2023**	**2024**	**2025**	**2026**
Operation & Maintenance Expense						
Other Revenues						
Late Charges	$1,658			$0	$0	$0
Connect / Re-Connect Fees	$170,799	$853,087	$1,850,000	$1,850,000	$1,447,561	$1,447,561
Misc Revenue	$465,178			$0	$0	$0
Joint Use Pole Attachment Income				$0	$0	$0
Misc Revenue (Other)	$51,580					
Transfer Credits	$6,183,933					
Hydro Adjuster		$1,288,015	$23,979,772			
Dividends from Affiliates, Interest	-$307,000	$7,000,000	$7,000,000	$7,000,000	$7,000,000	$7,000,000
Interdepartmental Sales	$4,035,716					
Income (Loss) from Equity Investments	$682,703	$1,619,919	$1,323,004	$1,741,050	$699,559	$801,144
Open						
Other Revenues	$357,575	$488,778	$500,975		$274,394	$281,313
Investment Income	$561,981					
Misc Income (RA Sales & Surplus Sales)	$0	$18,529,188	$17,751,851	$18,801,694	$37,045,073	$23,470,737
Public Benefits Revenue	$4,279,271	$4,086,083	$6,179,462	$4,902,000	$4,517,748	$4,583,987
Total Other Revenues	$16,483,393	$33,865,070	$58,585,063	$34,294,744	$50,984,335	$37,584,742
REVENUE REQUIREMENT for COST ALLOCATION	$141,710,315	$157,755,512	$146,683,084	$163,034,040	$164,587,138	$196,440,831

City of Palo Alto - 100% Demand
REVENUE REQUIREMENT COST ALLOCATION
FUNCTIONALIZATION AND CLASSIFICATION
Schedule 3.3

Prepared By EES Consulting, Inc.

	Allocation Date 2025 Total Expenses	Power Supply Demand PD	Energy PE	Direct Assignment PDA	Transmission Demand TD	Energy TE	Direct Assignment TDA	Distribution Demand DD	Energy DE	Customer DC	Direct Assignment DDA
Operation & Maintenance Expense											
Power Purchases	$0										
Western Power Purchases	$7,903,405	$1,264,545	$6,638,860	$0	$0	$0	$0	$0	$0	$0	$0
Contra Surplus Energy	-$13,328,841	$0	-$13,328,841	$0	$0	$0	$0	$0	$0	$0	$0
NCPA Pooling	$10,148,225	$0	$10,148,225	$0	$0	$0	$0	$0	$0	$0	$0
NCPA Facilities	$2,542,371	$0	$2,542,371	$0	$0	$0	$0	$0	$0	$0	$0
Local Capacity Purchase	$7,486,559	$7,486,559	$0	$0	$0	$0	$0	$0	$0	$0	$0
Load Advance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Renewable Energy	$37,130,836	$1,172,553	$35,958,283	$0	$0	$0	$0	$0	$0	$0	$0
Carbon Neutral Purchases (REC)	$9,741	$0	$9,741	$0	$0	$0	$0	$0	$0	$0	$0
Market Power Purchases	$8,892,531	$0	$8,892,531	$0	$0	$0	$0	$0	$0	$0	$0
PA Green Comm Purch	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TANC & Calveras O&M	$6,816,709	$477,170	$6,339,539	$0	$0	$0	$0	$0	$0	$0	$0
CVP O&M	$7,000,000	$1,120,000	$5,880,000	$0	$0	$0	$0	$0	$0	$0	$0
EMA Purchases	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Energy Risk Mgmt	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Budget True-up	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Resource Management Admin	$3,337,316	$0	$3,337,316	$0	$0	$0	$0	$0	$0	$0	$0
Transmission/Ancillary Services Purchases	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transmission Purchases	$28,377,775	$0	$28,377,775	$0	$0	$0	$0	$0	$0	$0	$0
Other	$0										
Surplus Energy	$13,328,841	$0	$13,328,841	$0	$0	$0	$0	$0	$0	$0	$0
Low Carbon Fuel G&A	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Carbon Allowance Revenues	-$4,111,816	$0	-$4,111,816	$0	$0	$0	$0	$0	$0	$0	$0
open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Allocated G&A	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Renewable Energy Salaries & General	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Purchased Power	$115,533,652	$11,520,826	$104,012,826	$0	$0	$0	$0	$0	$0	$0	$0
Total Production	$115,533,652	$11,520,826	$104,012,826	$0	$0	$0	$0	$0	$0	$0	$0

REVENUE REQUIREMENT COST ALLOCATION
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	Allocation Date 2025 Total Expenses	Power Supply			Transmission			Distribution			
		Demand PD	Energy PE	Direct Assignment PDA	Demand TD	Energy TE	Direct Assignment TDA	Demand DD	Energy DE	Customer DC	Direct Assignment DDA
Operation & Maintenance Expense											
Distribution											
Op. Supervision & Engineering	$11,890,278	$0	$0	$0	$0	$0	$0	$8,530,111	$0	$2,504,017	$856,151
Load Dispatching	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Line and Station Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Overhead Lines	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Underground Lines	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Street Lighting & Signal System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Meters	$7,396	$0	$0	$0	$0	$0	$0	$0	$0	$7,396	$0
Customer Installations	$1,153,617	$0	$0	$0	$0	$0	$0	$0	$0	$1,153,617	$0
Misc. Distribution	$1,889,789	$0	$0	$0	$0	$0	$0	$1,355,739	$0	$534,050	$0
Rents	$6,733,141	$0	$0	$0	$0	$0	$0	$4,830,370	$0	$1,902,771	$0
Maint. Supervision & Engineering	$4,769,435	$0	$0	$0	$0	$0	$0	$3,421,603	$0	$1,347,832	$0
Maint. of Structures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Maint. of Station Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Maint. of Structures and Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Maint. of Overhead Lines	$4,538,857	$0	$0	$0	$0	$0	$0	$4,538,857	$0	$0	$0
Maint. Of Underground Lines	$80,123	$0	$0	$0	$0	$0	$0	$80,123	$0	$0	$0
Maint. of Lines	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Maint. of Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Maint. of Line Transformers - Underground	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Maint. of Street Lighting & Signal System	$603,558	$0	$0	$0	$0	$0	$0	$0	$0	$0	$603,558
Maint. of Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Maint. of Misc. Distribution Plant	-$3,882,192	$0	$0	$0	$0	$0	$0	-$2,785,093	$0	-$817,565	-$279,534
Communications	$221,461	$0	$0	$0	$0	$0	$0	$158,877	$0	$62,584	$0
Total Distribution	$28,005,465	$0	$0	$0	$0	$0	$0	$20,130,587	$0	$6,694,703	$1,180,175
Total Operation & Maintenance	$143,539,117	$11,520,826	$104,012,826	$0	$0	$0	$0	$20,130,587	$0	$6,694,703	$1,180,175

REVENUE REQUIREMENT COST ALLOCATION
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	Allocation Date 2025 Total Expenses	Power Supply Demand PD	Power Supply Energy PE	Power Supply Direct Assignment PDA	Transmission Demand TD	Transmission Energy TE	Transmission Direct Assignment TDA	Distribution Demand DD	Distribution Energy DE	Distribution Customer DC	Distribution Direct Assignment DDA
Operation & Maintenance Expense											
Customer Service, Accounts, & Sales											
Supervision	$2,584,782	$0	$0	$0	$0	$0	$0	$0	$0	$2,584,782	$0
Meter Reading	$694,215	$0	$0	$0	$0	$0	$0	$0	$0	$694,215	$0
Customer Records Collection	$968,331	$0	$0	$0	$0	$0	$0	$968,331	$0	$0	$0
Uncollectable Accounts	$1,727,779	$0	$0	$0	$0	$0	$0	$1,727,779	$0	$0	$0
Misc. Customer Accounts (Customer Deposits)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer Service & Information	-$744,743	$0	$0	$0	$0	$0	$0	$0	$0	-$744,743	$0
Customer Communication & Education	$122,716	$0	$0	$0	$0	$0	$0	$0	$0	$122,716	$0
Customer Assistance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Misc. Customer Service & Information	$270,056	$0	$0	$0	$0	$0	$0	$0	$0	$270,056	$0
Demonstrating & Selling	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Advertising	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Misc. Sales Expenses	$295,823	$0	$0	$0	$0	$0	$0	$0	$0	$295,823	$0
Sales Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Key Accounts	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Energy Efficiency, DSM& Low Income Program	$6,689,764	$0	$6,689,764	$0	$0	$0	$0	$0	$0	$0	$0
Low Income Residential Energy Assistance Program	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Customer Service, Accounts & Sales	$12,608,722	$0	$6,689,764	$0	$0	$0	$0	$2,696,110	$0	$3,222,849	$0
Total O&M w/o Purchased Power Supply & A&G	$40,614,187	$0	$6,689,764	$0	$0	$0	$0	$22,826,696	$0	$9,917,552	$1,180,175
Administrative & General											
Administrative & General Salaries	$2,840,007	$0	$467,792	$0	$0	$0	$0	$1,596,191	$0	$693,500	$82,525
Office Supplies	$110,579	$0	$18,214	$0	$0	$0	$0	$62,150	$0	$27,002	$3,213
Administrative Transfer - Credit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Outside Services & Pension Credit	$637,787	$0	$105,053	$0	$0	$0	$0	$358,460	$0	$155,741	$18,533
Property Insurance	$230,547	$0	$0	$0	$0	$0	$0	$180,763	$0	$41,927	$7,858
Injuries and Damages	$179,837	$0	$29,622	$0	$0	$0	$0	$101,075	$0	$43,914	$5,226
Employee Pension & Benefits	$2,346,975	$0	$386,582	$0	$0	$0	$0	$1,319,088	$0	$573,106	$68,199
Franchise Requirements	$23,187	$0	$3,819	$0	$0	$0	$0	$13,032	$0	$5,662	$674
Regulatory Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Duplicate Charge - Credit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General Advertising	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Misc. General Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General Advertising	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Misc. General Expense	$111,099	$0	$18,300	$0	$0	$0	$0	$62,442	$0	$27,129	$3,228
Environmental	$2,034	$0	$335	$0	$0	$0	$0	$1,143	$0	$497	$59
COVID Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Maint. of General Plant & Communication Equipment	$7,022	$0	$1,157	$0	$0	$0	$0	$3,947	$0	$1,715	$204
Transportation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Cost Plan Charges	$1,209,398	$0	$199,206	$0	$0	$0	$0	$679,727	$0	$295,322	$35,143
Total Administrative & General	$7,698,473	$0	$1,230,079	$0	$0	$0	$0	$4,378,017	$0	$1,865,515	$224,862
Total O&M plus A&G	$163,846,313	$11,520,826	$111,932,669	$0	$0	$0	$0	$27,204,714	$0	$11,783,067	$1,405,037

REVENUE REQUIREMENT COST ALLOCATION
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		Power Supply			**Transmission**			**Distribution**			
	Allocation Date 2025 **Total** **Expenses**	Demand PD	Energy PE	Direct Assignment PDA	Demand TD	Energy TE	Direct Assignment TDA	Demand DD	Energy DE	Customer DC	Direct Assignment DDA
Operation & Maintenance Expense											
Depreciation											
Generation Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transmission Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Distribution Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Amortization of Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Amortization of Loss on Refunding	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Miscellaneous Intangible Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Depreciation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Interest and Debt Service Expense		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Interest and Debt Service Electric	$4,770,582	$0	$0	$0	$0	$0	$0	$3,740,419	$0	$867,570	$162,593
Amortization of Debt Discount	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Interest Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Annual LT Debt Service	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Annual ST Debt Service (AMI)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Accelerated Debt Reduction - LT Debt	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Ind A Interest Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Interest / Debt Service Expense	$4,770,582	$0	$0	$0	$0	$0	$0	$3,740,419	$0	$867,570	$162,593
Capital Projects Funded From Rates			$0	$0	$0	$0	$0	$0	$0	$0	$0
Production	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Distribution	$6,500,000	$0	$0	$0	$0	$0	$0	$6,354,628	$0	$145,372	$0
General	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Retirements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Capital Projects Funded From Rates	$6,500,000	$0	$0	$0	$0	$0	$0	$6,354,628	$0	$145,372	$0
Other Contributions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General Fund Transfer to/(from)	$15,121,000	$332,171	$14,430,225	$0	$0	$0	$0	$241,294	$0	$104,835	$12,475
Reserves	$23,800,000	$1,326,114	$8,067,926	$0	$0	$0	$0	$10,742,536	$0	$3,663,424	$0
Debt Service Coverage Requirement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other transfers out	$1,533,578	$0	$0	$0	$0	$0	$0	$1,202,416	$0	$278,894	$52,268
Transfers In	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Reserve Alloc Reapp	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Margin Requirement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Other Contributions	$40,454,578	$1,658,285	$22,498,151	$0	$0	$0	$0	$12,186,246	$0	$4,047,153	$64,743
Revenue Requirement Before Other Revenues	$215,571,473	$13,179,111	$134,430,820	$0	$0	$0	$0	$49,486,007	$0	$16,843,161	$1,632,374
Revenue Req. Before Taxes and Other Revenues	$215,571,473	$13,179,111	$134,430,820	$0	$0	$0	$0	$49,486,007	$0	[illegible]	[illegible]

February 2024

REVENUE REQUIREMENT COST ALLOCATION
FUNCTIONALIZATION AND CLASSIFICATION
Schedule 3.3

Prepared By EES Consulting, Inc.

	Allocation Date 2025 Total Expenses	Power Supply Demand PD	Power Supply Energy PE	Power Supply Direct Assignment PDA	Transmission Demand TD	Transmission Energy TE	Transmission Direct Assignment TDA	Distribution Demand DD	Distribution Energy DE	Distribution Customer DC	Distribution Direct Assignment DDA
Operation & Maintenance Expense											
Other Revenues		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Late Charges	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Connect / Re-Connect Fees	$1,447,561	$0	$238,435	$0	$0	$0	$0	$813,584	$0	$353,479	$42,064
Misc Revenue	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Joint Use Pole Attachment Income	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Misc Revenue (Other)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transfer Credits	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Hydro Adjuster	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Dividends from Affiliates, Interest	$7,000,000	$1,120,000	$5,880,000	$0	$0	$0	$0	$0	$0	$0	$0
Interdepartmental Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Income (Loss) from Equity Investments	$699,559	$0	$699,559	$0	$0	$0	$0	$0	$0	$0	$0
Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Revenues	$274,394	$0	$274,394	$0	$0	$0	$0	$0	$0	$0	$0
Investment Income	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Misc Income (RA Sales & Surplus Sales)	$37,045,073	$0	$37,045,073	$0	$0	$0	$0	$0	$0	$0	$0
Public Benefits Revenue	$4,517,748	$0	$4,517,748	$0	$0	$0	$0	$0	$0	$0	$0
Total Other Revenues	$50,984,335	$1,120,000	$48,655,209	$0	$0	$0	$0	$813,584	$0	$353,479	$42,064
REVENUE REQUIREMENT for COST ALLOCATION	$164,587,138	$12,059,111	$85,775,612	$0	$0	$0	$0	$48,672,424	$0	$16,489,682	$1,590,310

Prepared By EES Consulting, Inc.

City of Palo Alto - 100% Demand
REVENUE REQUIREMENT COST ALLOCATION
BY CUSTOMER
Schedule 3.4

Operation & Maintenance Expense	Allocation Date 2025 Total Expenses	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Power Purchases						
Western Power Purchases	$7,903,405	$1,221,404	$514,251	$2,899,059	$3,251,553	$17,138
Contra Surplus Energy	-$13,328,841	-$2,131,707	-$852,949	-$4,730,438	-$5,583,570	-$30,177
NCPA Pooling	$10,148,225	$1,623,025	$649,412	$3,601,629	$4,251,182	$22,976
NCPA Facilities	$2,542,371	$406,606	$162,693	$902,294	$1,065,022	$5,756
Local Capacity Purchase	$7,486,559	$945,117	$529,355	$3,214,232	$2,785,379	$12,476
Load Advance	$0	$0	$0	$0	$0	$0
Renewable Energy	$37,130,836	$5,898,903	$2,383,976	$13,265,097	$15,499,495	$83,364
Carbon Neutral Purchases (REC)	$9,741	$1,558	$623	$3,457	$4,081	$22
Market Power Purchases	$8,892,531	$1,422,200	$569,057	$3,155,981	$3,725,161	$20,133
PA Green Comm Purch	$0	$0	$0	$0	$0	$0
TANC & Calveras O&M	$6,816,709	$1,074,134	$439,424	$2,454,783	$2,833,221	$15,148
CVP O&M	$7,000,000	$1,081,791	$455,469	$2,567,680	$2,879,881	$15,179
EMA Purchases	$0	$0	$0	$0	$0	$0
Energy Risk Mgmt	$0	$0	$0	$0	$0	$0
Budget True-up	$0	$0	$0	$0	$0	$0
Resource Management Admin	$3,337,316	$533,743	$213,564	$1,184,421	$1,398,031	$7,556
Transmission/Ancillary Services Purchases						
Transmission Purchases	$28,377,775	$4,538,512	$1,815,971	$10,071,340	$11,887,704	$64,248
Other						
Surplus Energy	$13,328,841	$2,131,707	$852,949	$4,730,438	$5,583,570	$30,177
Low Carbon Fuel G&A	$0	$0	$0	$0	$0	$0
Carbon Allowance Revenues	-$4,111,816	-$657,611	-$263,126	-$1,459,293	-$1,722,476	-$9,309
open	$0	$0	$0	$0	$0	$0
Allocated G&A	$0	$0	$0	$0	$0	$0
Renewable Energy Salaries & General	$0	$0	$0	$0	$0	$0
Total Purchased Power	$115,533,652	$18,089,382	$7,470,671	$41,860,681	$47,858,233	$254,685
Total Production	$115,533,652	$18,089,382	$7,470,671	$41,860,681	$47,858,233	$254,685

City of Palo Alto - 100% Demand
REVENUE REQUIREMENT COST ALLOCATION
BY CUSTOMER
Schedule 3.4

Prepared By EES Consulting, Inc.

Operation & Maintenance Expense	Allocation Date 2025 Total Expenses	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Distribution						
Op. Supervision & Engineering	$11,890,278	$1,883,208	$754,097	$5,213,269	$3,151,370	$888,335
Load Dispatching	$0	$0	$0	$0	$0	$0
Line and Station Expenses	$0	$0	$0	$0	$0	$0
Overhead Lines	$0	$0	$0	$0	$0	$0
Underground Lines	$0	$0	$0	$0	$0	$0
Street Lighting & Signal System	$0	$0	$0	$0	$0	$0
Meters	$7,396	$3,442	$525	$2,981	$448	$0
Customer Installations	$1,153,617	$536,899	$81,846	$464,880	$69,951	$41
Misc. Distribution	$1,889,789	$333,523	$124,004	$908,672	$518,476	$5,115
Rents	$6,733,141	$1,188,310	$441,813	$3,237,512	$1,847,281	$18,225
Maint. Supervision & Engineering	$4,769,435	$841,742	$312,959	$2,293,299	$1,308,526	$12,910
Maint. of Structures	$0	$0	$0	$0	$0	$0
Maint. of Station Equipment	$0	$0	$0	$0	$0	$0
Maint. of Structures and Equipment	$0	$0	$0	$0	$0	$0
Maint. of Overhead Lines	$4,538,857	$667,042	$360,611	$1,989,683	$1,504,397	$17,125
Maint. Of Underground Lines	$80,123	$11,775	$6,366	$35,123	$26,557	$302
Maint. of Lines	$0	$0	$0	$0	$0	$0
Maint. of Line Transformers	$0	$0	$0	$0	$0	$0
Maint. of Line Transformers - Underground	$0	$0	$0	$0	$0	$0
Maint. of Street Lighting & Signal System	$603,558	$0	$0	$0	$0	$603,558
Maint. of Meters	$0	$0	$0	$0	$0	$0
Maint. of Misc. Distribution Plant	-$3,882,192	-$614,870	-$246,214	-$1,702,139	-$1,028,927	-$290,043
Communications	$221,461	$39,085	$14,532	$106,486	$60,759	$599
Total Distribution	$28,005,465	$4,890,155	$1,850,538	$12,549,763	$7,458,839	$1,256,169
Total Operation & Maintenance	$143,539,117	$22,979,538	$9,321,209	$54,410,444	$55,317,072	$1,510,854

City of Palo Alto - 100% Demand
REVENUE REQUIREMENT COST ALLOCATION
BY CUSTOMER
Schedule 3.4

Prepared By EES Consulting, Inc.

Operation & Maintenance Expense	Allocation Date 2025 Total Expenses	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Customer Service, Accounts, & Sales						
Supervision	$2,584,782	$1,202,969	$183,384	$1,041,606	$156,731	$93
Meter Reading	$694,215	$323,102	$49,255	$279,762	$42,096	$0
Customer Records Collection	$968,331	$157,109	$67,796	$389,510	$341,120	$12,795
Uncollectable Accounts	$1,727,779	$280,328	$120,967	$694,997	$608,656	$22,831
Misc. Customer Accounts (Customer Deposits)	$0	$0	$0	$0	$0	$0
Customer Service & Information	-$744,743	-$643,788	-$78,513	-$20,646	-$1,747	-$50
Customer Communication & Education	$122,716	$106,081	$12,937	$3,402	$288	$8
Customer Assistance	$0	$0	$0	$0	$0	$0
Misc. Customer Service & Information	$270,056	$233,448	$28,470	$7,486	$634	$18
Demonstrating & Selling	$0	$0	$0	$0	$0	$0
Advertising	$0	$0	$0	$0	$0	$0
Misc. Sales Expenses	$295,823	$137,677	$20,988	$119,210	$17,938	$11
Sales Expenses	$0	$0	$0	$0	$0	$0
Key Accounts	$0	$0	$0	$0	$0	$0
Energy Efficiency, DSM& Low Income Program	$6,689,764	$1,028,709	$530,112	$2,215,660	$2,915,283	$0
Low Income Residential Energy Assistance Program	$0	$0	$0	$0	$0	$0
Total Customer Service, Accounts & Sales	$12,608,722	$2,825,637	$935,395	$4,730,987	$4,080,998	$35,706
Total O&M w/o Purchased Power Supply & A&G	$40,614,187	$7,715,792	$2,785,933	$17,280,750	$11,539,837	$1,291,875
Administrative & General						
Administrative & General Salaries	$2,840,007	$539,538	$194,811	$1,208,382	$806,940	$90,336
Office Supplies	$110,579	$21,008	$7,585	$47,050	$31,419	$3,517
Administrative Transfer - Credit	$0	$0	$0	$0	$0	$0
Outside Services & Pension Credit	$637,787	$121,165	$43,749	$271,369	$181,216	$20,287
Property Insurance	$230,547	$37,107	$15,640	$103,920	$65,340	$8,540
Injuries and Damages	$179,837	$34,165	$12,336	$76,518	$51,098	$5,720
Employee Pension & Benefits	$2,346,975	$445,873	$160,991	$998,604	$666,853	$74,654
Franchise Requirements	$23,187	$4,405	$1,591	$9,866	$6,588	$738
Regulatory Expense	$0	$0	$0	$0	$0	$0
Duplicate Charge - Credit	$0	$0	$0	$0	$0	$0
General Advertising	$0	$0	$0	$0	$0	$0
Misc. General Expense	$0	$0	$0	$0	$0	$0
General Advertising	$0	$0	$0	$0	$0	$0
Misc. General Expense	$111,099	$21,106	$7,621	$47,271	$31,567	$3,534
Environmental	$2,034	$386	$140	$865	$578	$65
COVID Expenses	$0	$0	$0	$0	$0	$0
Maint. of General Plant & Communication Equipment	$7,022	$1,334	$482	$2,988	$1,995	$223
Transportation	$0	$0	$0	$0	$0	$0
Cost Plan Charges	$1,209,398	$229,759	$82,959	$514,581	$343,630	$38,469
Total Administrative & General	$7,698,473	$1,455,847	$527,903	$3,281,415	$2,187,225	$246,083
Total O&M plus A&G	$163,846,313	$27,261,021	$10,784,507	$62,422,846	$61,585,295	$1,792,643

City of Palo Alto - 100% Demand
REVENUE REQUIREMENT COST ALLOCATION
BY CUSTOMER
Schedule 3.4

Prepared By EES Consulting, Inc.

Operation & Maintenance Expense	Allocation Date 2025 Total Expenses	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Depreciation						
Generation Plant	$0	$0	$0	$0	$0	$0
Transmission Plant	$0	$0	$0	$0	$0	$0
Distribution Plant	$0	$0	$0	$0	$0	$0
General Plant	$0	$0	$0	$0	$0	$0
Amortization of Plant	$0	$0	$0	$0	$0	$0
Amortization of Loss on Refunding	$0	$0	$0	$0	$0	$0
Miscellaneous Intangible Plant	$0	$0	$0	$0	$0	$0
Total Depreciation	$0	$0	$0	$0	$0	$0
Interest and Debt Service Expense						
Interest and Debt Service Electric	$4,770,582	$767,840	$323,639	$2,150,357	$1,352,040	$176,706
Amortization of Debt Discount	$0	$0	$0	$0	$0	$0
Other Interest Expense	$0	$0	$0	$0	$0	$0
Annual LT Debt Service	$0	$0	$0	$0	$0	$0
Annual ST Debt Service (AMI)	$0	$0	$0	$0	$0	$0
Accelerated Debt Reduction - LT Debt	$0	$0	$0	$0	$0	$0
Ind A Interest Expense	$0	$0	$0	$0	$0	$0
Total Interest / Debt Service Expense	$4,770,582	$767,840	$323,639	$2,150,357	$1,352,040	$176,706
Capital Projects Funded From Rates						
Production	$0	$0	$0	$0	$0	$0
Transmission	$0	$0	$0	$0	$0	$0
Distribution	$6,500,000	$1,056,184	$519,787	$2,792,253	$2,107,800	$23,976
General	$0	$0	$0	$0	$0	$0
Retirements	$0	$0	$0	$0	$0	$0
Open	$0	$0	$0	$0	$0	$0
Total Capital Projects Funded From Rates	$6,500,000	$1,056,184	$519,787	$2,792,253	$2,107,800	$23,976
Other Contributions						
General Fund Transfer to/(from)	$15,121,000	$2,420,039	$971,840	$5,421,506	$6,260,895	$46,720
Reserves	$23,800,000	$4,260,379	$1,640,551	$9,988,374	$7,843,259	$67,436
Debt Service Coverage Requirement	$0	$0	$0	$0	$0	$0
Other transfers out	$1,533,578	$246,834	$104,039	$691,266	$434,634	$56,805
Transfers In	$0	$0	$0	$0	$0	$0
Reserve Alloc Reapp	$0	$0	$0	$0	$0	$0
Margin Requirement	$0	$0	$0	$0	$0	$0
Total Other Contributions	$40,454,578	$6,927,252	$2,716,430	$16,101,145	$14,538,789	$170,961
Revenue Requirement Before Other Revenues	$215,571,473	$36,012,298	$14,344,364	$83,466,601	$79,583,924	$2,164,286
Revenue Req. Before Taxes and Other Revenues	$215,571,473	$36,012,298	$14,344,364	$83,466,601	$79,583,924	$2,164,286

City of Palo Alto - 100% Demand
REVENUE REQUIREMENT COST ALLOCATION
BY CUSTOMER
Schedule 3.4

Prepared By EES Consulting, Inc.

Operation & Maintenance Expense	Allocation Date 2025 Total Expenses	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Other Revenues						
Late Charges	$0	$0	$0	$0	$0	$0
Connect / Re-Connect Fees	$1,447,561	$275,004	$99,296	$615,916	$411,300	$46,045
Misc Revenue	$0	$0	$0	$0	$0	$0
Joint Use Pole Attachment Income	$0	$0	$0	$0	$0	$0
Misc Revenue (Other)	$0	$0	$0	$0	$0	$0
Transfer Credits	$0	$0	$0	$0	$0	$0
Hydro Adjuster	$0	$0	$0	$0	$0	$0
Dividends from Affiliates, Interest	$7,000,000	$1,081,791	$455,469	$2,567,680	$2,879,881	$15,179
Interdepartmental Sales	$0	$0	$0	$0	$0	$0
Income (Loss) from Equity Investments	$699,559	$111,882	$44,767	$248,275	$293,052	$1,584
Open	$0	$0	$0	$0	$0	$0
Other Revenues	$274,394	$43,884	$17,559	$97,383	$114,946	$621
Investment Income	$0	$0	$0	$0	$0	$0
Misc Income (RA Sales & Surplus Sales)	$37,045,073	$5,924,690	$2,370,615	$13,147,385	$15,518,512	$83,871
Public Benefits Revenue	$4,517,748	$722,532	$289,103	$1,603,360	$1,892,525	$10,228
Total Other Revenues	$50,984,335	$8,159,783	$3,276,809	$18,279,999	$21,110,216	$157,528
REVENUE REQUIREMENT for COST ALLOCATION	$164,587,138	$27,852,514	$11,067,556	$65,186,601	$58,473,708	$2,006,759

Prepared By EES Consulting, Inc.

City of Palo Alto - 100% Demand
REVENUE REQUIREMENT COST ALLOCATION
DIRECT ASSIGNMENT BY CUSTOMER
Schedule 3.5

Operation & Maintenance Expense	Allocation Date 2024 Total Expenses	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Power Purchases						
Western Power Purchases	$0	$0	$0	$0	$0	$0
Contra Surplus Energy	$0	$0	$0	$0	$0	$0
NCPA Pooling	$0	$0	$0	$0	$0	$0
NCPA Facilities	$0	$0	$0	$0	$0	$0
Local Capacity Purchase	$0	$0	$0	$0	$0	$0
Load Advance	$0	$0	$0	$0	$0	$0
Renewable Energy	$0	$0	$0	$0	$0	$0
Carbon Neutral Purchases (REC)	$0	$0	$0	$0	$0	$0
Market Power Purchases	$0	$0	$0	$0	$0	$0
PA Green Comm Purch	$0	$0	$0	$0	$0	$0
TANC & Calveras O&M	$0	$0	$0	$0	$0	$0
CVP O&M	$0	$0	$0	$0	$0	$0
EMA Purchases	$0	$0	$0	$0	$0	$0
Energy Risk Mgmt	$0	$0	$0	$0	$0	$0
Budget True-up	$0	$0	$0	$0	$0	$0
Resource Management Admin	$0	$0	$0	$0	$0	$0
Transmission/Ancillary Services Purchases						
Transmission Purchases	$0	$0	$0	$0	$0	$0
Other						
Surplus Energy	$0	$0	$0	$0	$0	$0
Low Carbon Fuel G&A	$0	$0	$0	$0	$0	$0
Carbon Allowance Revenues	$0	$0	$0	$0	$0	$0
open	$0	$0	$0	$0	$0	$0
Allocated G&A	$0	$0	$0	$0	$0	$0
Renewable Energy Salaries & General	$0	$0	$0	$0	$0	$0
Total Purchased Power	$0	$0	$0	$0	$0	$0
Total Production	$0	$0	$0	$0	$0	$0

City of Palo Alto - 100% Demand
REVENUE REQUIREMENT COST ALLOCATION
DIRECT ASSIGNMENT BY CUSTOMER
Schedule 3.5

Prepared By EES Consulting, Inc.

Operation & Maintenance Expense	Allocation Date 2024 Total Expenses	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Distribution						
Op. Supervision & Engineering	$856,151	$0	$0	$0	$0	$856,151
Load Dispatching	$0	$0	$0	$0	$0	$0
Line and Station Expenses	$0	$0	$0	$0	$0	$0
Overhead Lines	$0	$0	$0	$0	$0	$0
Underground Lines	$0	$0	$0	$0	$0	$0
Street Lighting & Signal System	$0	$0	$0	$0	$0	$0
Meters	$0	$0	$0	$0	$0	$0
Customer Installations	$0	$0	$0	$0	$0	$0
Misc. Distribution	$0	$0	$0	$0	$0	$0
Rents	$0	$0	$0	$0	$0	$0
Maint. Supervision & Engineering	$0	$0	$0	$0	$0	$0
Maint. of Structures	$0	$0	$0	$0	$0	$0
Maint. of Station Equipment	$0	$0	$0	$0	$0	$0
Maint. of Structures and Equipment	$0	$0	$0	$0	$0	$0
Maint. of Overhead Lines	$0	$0	$0	$0	$0	$0
Maint. Of Underground Lines	$0	$0	$0	$0	$0	$0
Maint. of Lines	$0	$0	$0	$0	$0	$0
Maint. of Line Transformers	$0	$0	$0	$0	$0	$0
Maint. of Line Transformers - Underground	$0	$0	$0	$0	$0	$0
Maint. of Street Lighting & Signal System	$603,558	$0	$0	$0	$0	$603,558
Maint. of Meters	$0	$0	$0	$0	$0	$0
Maint. of Misc. Distribution Plant	-$279,534	$0	$0	$0	$0	-$279,534
Communications	$0	$0	$0	$0	$0	$0
Total Distribution	$1,180,175	$0	$0	$0	$0	$1,180,175
Total Operation & Maintenance	$1,180,175	$0	$0	$0	$0	$1,180,175

City of Palo Alto - 100% Demand
REVENUE REQUIREMENT COST ALLOCATION
DIRECT ASSIGNMENT BY CUSTOMER
Schedule 3.5

Prepared By EES Consulting, Inc.

Operation & Maintenance Expense	Allocation Date 2024 Total Expenses	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Customer Service, Accounts, & Sales						
Supervision	$0	$0	$0	$0	$0	$0
Meter Reading	$0	$0	$0	$0	$0	$0
Customer Records Collection	$0	$0	$0	$0	$0	$0
Uncollectable Accounts	$0	$0	$0	$0	$0	$0
Misc. Customer Accounts (Customer Deposits)	$0	$0	$0	$0	$0	$0
Customer Service & Information	$0	$0	$0	$0	$0	$0
Customer Communication & Education	$0	$0	$0	$0	$0	$0
Customer Assistance	$0	$0	$0	$0	$0	$0
Misc. Customer Service & Information	$0	$0	$0	$0	$0	$0
Demonstrating & Selling	$0	$0	$0	$0	$0	$0
Advertising	$0	$0	$0	$0	$0	$0
Misc. Sales Expenses	$0	$0	$0	$0	$0	$0
Sales Expenses	$0	$0	$0	$0	$0	$0
Key Accounts	$0	$0	$0	$0	$0	$0
Energy Efficiency, DSM& Low Income Program	$0	$0	$0	$0	$0	$0
Low Income Residential Energy Assistance Program	$0	$0	$0	$0	$0	$0
Total Customer Service, Accounts & Sales	$0	$0	$0	$0	$0	$0
Total O&M w/o Purchased Power Supply & A&G	$1,180,175	$0	$0	$0	$0	$1,180,175
Administrative & General						
Administrative & General Salaries	$82,525	$0	$0	$0	$0	$82,525
Office Supplies	$3,213	$0	$0	$0	$0	$3,213
Administrative Transfer - Credit	$0	$0	$0	$0	$0	$0
Outside Services & Pension Credit	$18,533	$0	$0	$0	$0	$18,533
Property Insurance	$7,858	$0	$0	$0	$0	$7,858
Injuries and Damages	$5,226	$0	$0	$0	$0	$5,226
Employee Pension & Benefits	$68,199	$0	$0	$0	$0	$68,199
Franchise Requirements	$674	$0	$0	$0	$0	$674
Regulatory Expense	$0	$0	$0	$0	$0	$0
Duplicate Charge - Credit	$0	$0	$0	$0	$0	$0
General Advertising	$0	$0	$0	$0	$0	$0
Misc. General Expense	$0	$0	$0	$0	$0	$0
General Advertising	$0	$0	$0	$0	$0	$0
Misc. General Expense	$3,228	$0	$0	$0	$0	$3,228
Environmental	$59	$0	$0	$0	$0	$59
COVID Expenses	$0	$0	$0	$0	$0	$0
Maint. of General Plant & Communication Equipment	$204	$0	$0	$0	$0	$204
Transportation	$0	$0	$0	$0	$0	$0
Cost Plan Charges	$35,143	$0	$0	$0	$0	$35,143
Total Administrative & General	$224,862	$0	$0	$0	$0	$224,862
Total O&M plus A&G	$1,405,037	$0	$0	$0	$0	$1,405,037

City of Palo Alto - 100% Demand
REVENUE REQUIREMENT COST ALLOCATION
DIRECT ASSIGNMENT BY CUSTOMER
Schedule 3.5

Prepared By EES Consulting, Inc.

Operation & Maintenance Expense	**Allocation Date 2024 Total Expenses**	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Depreciation						
Generation Plant	$0	$0	$0	$0	$0	$0
Transmission Plant	$0	$0	$0	$0	$0	$0
Distribution Plant	$0	$0	$0	$0	$0	$0
General Plant	$0	$0	$0	$0	$0	$0
Amortization of Plant	$0	$0	$0	$0	$0	$0
Amortization of Loss on Refunding	$0	$0	$0	$0	$0	$0
Miscellaneous Intangible Plant	$0	$0	$0	$0	$0	$0
Total Depreciation	$0	$0	$0	$0	$0	$0
Interest and Debt Service Expense						
Interest and Debt Service Electric	$162,593	$0	$0	$0	$0	$162,593
Amortization of Debt Discount	$0	$0	$0	$0	$0	$0
Other Interest Expense	$0	$0	$0	$0	$0	$0
Annual LT Debt Service	$0	$0	$0	$0	$0	$0
Annual ST Debt Service (AMI)	$0	$0	$0	$0	$0	$0
Accelerated Debt Reduction - LT Debt	$0	$0	$0	$0	$0	$0
Ind A Interest Expense	$0	$0	$0	$0	$0	$0
Total Interest / Debt Service Expense	$162,593	$0	$0	$0	$0	$162,593
Capital Projects Funded From Rates						
Production	$0	$0	$0	$0	$0	$0
Transmission	$0	$0	$0	$0	$0	$0
Distribution	$0	$0	$0	$0	$0	$0
General	$0	$0	$0	$0	$0	$0
Retirements	$0	$0	$0	$0	$0	$0
Open	$0	$0	$0	$0	$0	$0
Total Capital Projects Funded From Rates	$0	$0	$0	$0	$0	$0
Other Contributions						
General Fund Transfer to/(from)	$12,475	$0	$0	$0	$0	$12,475
Reserves	$0	$0	$0	$0	$0	$0
Debt Service Coverage Requirement	$0	$0	$0	$0	$0	$0
Other transfers out	$52,268	$0	$0	$0	$0	$52,268
Transfers In	$0	$0	$0	$0	$0	$0
Reserve Alloc Reapp	$0	$0	$0	$0	$0	$0
Margin Requirement	$0	$0	$0	$0	$0	$0
Total Other Contributions	$64,743	$0	$0	$0	$0	$64,743
Revenue Requirement Before Other Revenues	$1,632,374	$0	$0	$0	$0	$1,632,374
Revenue Req. Before Taxes and Other Revenues	$1,632,374	$0	$0	$0	$0	$1,6[illegible]

City of Palo Alto - 100% Demand
REVENUE REQUIREMENT COST ALLOCATION
DIRECT ASSIGNMENT BY CUSTOMER
Schedule 3.5

Prepared By EES Consulting, Inc.

Operation & Maintenance Expense	Allocation Date 2024 Total Expenses	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Other Revenues						
Late Charges	$0	$0	$0	$0	$0	$0
Connect / Re-Connect Fees	$42,064	$0	$0	$0	$0	$42,064
Misc Revenue	$0	$0	$0	$0	$0	$0
Joint Use Pole Attachment Income	$0	$0	$0	$0	$0	$0
Misc Revenue (Other)	$0	$0	$0	$0	$0	$0
Transfer Credits	$0	$0	$0	$0	$0	$0
Hydro Adjuster	$0	$0	$0	$0	$0	$0
Dividends from Affiliates, Interest	$0	$0	$0	$0	$0	$0
Interdepartmental Sales	$0	$0	$0	$0	$0	$0
Income (Loss) from Equity Investments	$0	$0	$0	$0	$0	$0
Open	$0	$0	$0	$0	$0	$0
Other Revenues	$0	$0	$0	$0	$0	$0
Investment Income	$0	$0	$0	$0	$0	$0
Misc Income (RA Sales & Surplus Sales)	$0	$0	$0	$0	$0	$0
Public Benefits Revenue	$0	$0	$0	$0	$0	$0
Total Other Revenues	$42,064	$0	$0	$0	$0	$42,064
REVENUE REQUIREMENT for COST ALLOCATION	$1,590,310	$0	$0	$0	$0	$1,590,310

Prepared By EES Consulting, Inc.

City of Palo Alto

INPUT RATE BASE
Schedule 4.1

INPUT RATE BASE
Schedule 4.1

FERC Account		Year 2021 Cost, $	Function	Classification & Allocation Factor	Classification & Allocation Method
	Distribution Plant				
360.00	Land & Rights		D	NCPP	Non-Coincident Peak - Primary
361.00	Structures & Improvements	$7,154,333	D	NCPP	Non-Coincident Peak - Primary
362.00	Station Equipment - Distribution	$59,404,780	D	NCPP	Non-Coincident Peak - Primary
363.00	Storage & Battery Equipment	$2,659,291	D	NCPP	Non-Coincident Peak - Primary
364.00	Poles, Towers, & Fixtures	$44,602,342	D	100%DP	Demand Only - Poles, Towers & Fixtures (100% Demand)
365.00	Overhead Conductors & Devices	$18,501,977	D	100%DC	Demand Only - Overhead and Underground Conduit (100% Demand)
366.00	Underground Conduit	$1,763,879	D	100%DC	Demand Only - Overhead and Underground Conduit (100% Demand)
367.00	Underground Conductors & Devices	$85,733,395	D	100%DC	Demand Only - Overhead and Underground Conduit (100% Demand)
368.00	Line Transformers	$31,475,442	D	100%DT	Demand Only- Transformers (100% Demand)
369.00	Services	$68,019,093	D	SERV	Services
370.00	Meters	$4,490,213	D	CUSTM	Customers Weighted for Meters and Services
371.00	Installation on Customer Premises	$1,258,542	D	CUSTM	Customers Weighted for Meters and Services
372.00	Leased Property on Cust. Premises		D	CUSTM	Customers Weighted for Meters and Services
373.00	Street Lights and Signal Systems	$25,222,037	D	DA1	Direct Assignment for Streetlights
	Total Distribution Plant	$350,285,324			
	Total Transmission & Distribution	$350,285,324			
	General Plant				
389.00	Land & Land Rights		SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
390.00	Structures & Improvements	$1,897,484	SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
391.00	Office Furniture & Equipment	$8,874,818	SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
392.00	Transportation Equipment	$415,330	SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
393.00	Stores Equipment		SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
394.00	Tools, Shop, & Garage Equipment	$2,685,629	SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
395.00	Laboratory Equipment		SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
396.00	Power Operated Equipment		SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
397.00	Communication Equipment	$22,487,683	SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
398.00	Misc. Equipment	$10,832,848	SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
399.00	Other Tangible Property - EV Charging	$29,836	SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
	Total General Plant	$47,223,629			
	Total Plant Before General Plant & Intangible	$350,285,324			
	Total Gross Plant in Service	$397,508,952			

City of Palo Alto

INPUT RATE BASE

Schedule 4.1

Prepared By EES Consulting, Inc.

INPUT RATE BASE

Schedule 4.1

FERC Account		Year 2021 Cost, $	Function	Classification & Allocation Factor	Classification & Allocation Method
	Less: Accumulated Depreciation				
	Intangible Plant		P	RBIG	On the Basis of Intangible Plant Rate Base
	Transmission Plant		T	RBT	On the Basis of Transmission Rate Base
	Distribution Plant	$139,992,346	D	RBD-NoDA	As Distribution Ratebase without DA Street Lighting
	General Plant	$29,441,360	SS	RBGP	On the Basis of General Plant Rate Base
	Street Lighting	$19,389,916	D	DA1	Direct Assignment for Streetlights
	Misc. Plant		SS	RBGP	On the Basis of General Plant Rate Base
	Total Accumulated Depreciation	$188,823,622			
	Total Net Plant	$208,685,330			
	Working Capital				
	90 Days of Non Power Supply O&M	$10,832,188	SS	OMWOP	On the Basis of O&M (w/o Purch. Power Supply)
	90 Days of Power Supply Cost	$28,459,651	P	OMP	On the Basis of Purchased Power O&M
	Total Working Capital	$39,291,839			
	Less: Net Customer Contributions				
	Production Plant	$0	P	RBG	On the Basis of Generation Rate Base
	Transmission Plant	$0	T	RBT	On the Basis of Transmission Rate Base
	Distribution Plant	$0	D	RBD	On the Basis of Distribution Rate Base
	Street Lights	$0	D	CUSTM	Customers Weighted for Meters and Services
	General Plant	$0	SS	RBGP	On the Basis of General Plant Rate Base
	Total Contributions	$0			
	TOTAL RATE BASE	$247,977,170			
	CWIP				
107.00	Production Plant	$0	P	RBG	On the Basis of Generation Rate Base
107.00	Transmission Plant	$0	T	RBT	On the Basis of Transmission Rate Base
107.00	Distribution Plant	$0	D	RBD	On the Basis of Distribution Rate Base
	Services	$0	D	RBD	On the Basis of Distribution Rate Base
107.00	General Plant	$0	SS	RBGP	On the Basis of General Plant Rate Base
	Other	$0	SS	GPLT	On the Basis of Gross Plant (w/o General Plant & Intangible)
	Total CWIP	$0			
	TOTAL RATE BASE plus CWIP	**$247,977,170**			

Prepared By EES Consulting, Inc.

City of Palo Alto - 100% Demand
RATE BASE FOR COST ALLOCATION
FUNCTIONALIZATION AND CLASSIFICATION
Schedule 4.2

		Power Supply			Transmission			Distribution			
Account Description	Total Rate Base	Demand PD	Energy PE	Direct Assignment PDA	Demand TD	Energy TE	Direct Assignment TDA	Demand DD	Energy DE	Customer DC	Direct Assignment DDA
Distribution Plant											
Land & Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Structures & Improvements	$7,154,333	$0	$0	$0	$0	$0	$0	$7,154,333	$0	$0	$0
Station Equipment - Distribution	$59,404,780	$0	$0	$0	$0	$0	$0	$59,404,780	$0	$0	$0
Storage & Battery Equipment	$2,659,291	$0	$0	$0	$0	$0	$0	$2,659,291	$0	$0	$0
Poles, Towers, & Fixtures	$44,602,342	$0	$0	$0	$0	$0	$0	$44,602,342	$0	$0	$0
Overhead Conductors & Devices	$18,501,977	$0	$0	$0	$0	$0	$0	$18,501,977	$0	$0	$0
Underground Conduit	$1,763,879	$0	$0	$0	$0	$0	$0	$1,763,879	$0	$0	$0
Underground Conductors & Devices	$85,733,395	$0	$0	$0	$0	$0	$0	$85,733,395	$0	$0	$0
Line Transformers	$31,475,442	$0	$0	$0	$0	$0	$0	$31,475,442	$0	$0	$0
Services	$68,019,093	$0	$0	$0	$0	$0	$0	$0	$0	$68,019,093	$0
Meters	$4,490,213	$0	$0	$0	$0	$0	$0	$0	$0	$4,490,213	$0
Installation on Customer Premises	$1,258,542	$0	$0	$0	$0	$0	$0	$0	$0	$1,258,542	$0
Leased Property on Cust. Premises	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Street Lights and Signal Systems	$25,222,037	$0	$0	$0	$0	$0	$0	$0	$0	$0	$25,222,037
Total Distribution Plant	$350,285,324	$0	$0	$0	$0	$0	$0	$251,295,438	$0	$73,767,848	$25,222,037
Total Transmission & Distribution	$350,285,324	$0	$0	$0	$0	$0	$0	$251,295,438	$0	$73,767,848	$25,222,037
General Plant											
Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Structures & Improvements	$1,897,484	$0	$0	$0	$0	$0	$0	$1,361,259	$0	$399,598	$136,627
Office Furniture & Equipment	$8,874,818	$0	$0	$0	$0	$0	$0	$6,366,814	$0	$1,868,980	$639,025
Transportation Equipment	$415,330	$0	$0	$0	$0	$0	$0	$297,958	$0	$87,466	$29,905
Stores Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Tools, Shop, & Garage Equipment	$2,685,629	$0	$0	$0	$0	$0	$0	$1,926,676	$0	$565,576	$193,377
Laboratory Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Power Operated Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Communication Equipment	$22,487,683	$0	$0	$0	$0	$0	$0	$16,132,712	$0	$4,735,762	$1,619,209
Misc. Equipment	$10,832,848	$0	$0	$0	$0	$0	$0	$7,771,508	$0	$2,281,328	$780,011
Other Tangible Property - EV Charging	$29,836	$0	$0	$0	$0	$0	$0	$21,404	$0	$6,283	$2,148
Total General Plant	$47,223,629	$0	$0	$0	$0	$0	$0	$33,878,332	$0	$9,944,994	$3,400,303
Total Plant Before General Plant & Intangible	$350,285,324	$0	$0	$0	$0	$0	$0	$251,295,438	$0	$73,767,848	$25,222,037
Total Gross Plant in Service	$397,508,952	$0	$0	$0	$0	$0	$0	$285,173,770	$0	$83,712,843	$28,622,340

RATE BASE FOR COST ALLOCATION
FUNCTIONALIZATION AND CLASSIFICATION
Schedule 4.2

Prepared By EES Consulting, Inc.

		Power Supply			Transmission			Distribution			
Account Description	Total Rate Base	Demand PD	Energy PE	Direct Assignment PDA	Demand TD	Energy TE	Direct Assignment TDA	Demand DD	Energy DE	Customer DC	Direct Assignment DDA
Less: Accumulated Depreciation											
Intangible Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transmission Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Distribution Plant	$139,992,346	$0	$0	$0	$0	$0	$0	$100,430,808	$0	$39,561,538	$0
General Plant	$29,441,360	$0	$0	$0	$0	$0	$0	$21,121,294	$0	$6,200,162	$2,119,903
Street Lighting	$19,389,916	$0	$0	$0	$0	$0	$0	$0	$0	$0	$19,389,916
Misc. Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Accumulated Depreciation	$188,823,622	$0	$0	$0	$0	$0	$0	$121,552,102	$0	$45,761,701	$21,509,819
Total Net Plant	$208,685,330	$0	$0	$0	$0	$0	$0	$163,621,668	$0	$37,951,142	$7,112,520
Working Capital											
90 Days of Non Power Supply O&M	$10,832,188	$0	$1,775,709	$0	$0	$0	$0	$6,099,572	$0	$2,641,883	$315,023
90 Days of Power Supply Cost	$28,459,651	$2,837,950	$25,621,702	$0	$0	$0	$0	$0	$0	$0	$0
Total Working Capital	$39,291,839	$2,837,950	$27,397,411	$0	$0	$0	$0	$6,099,572	$0	$2,641,883	$315,023
Less: Net Customer Contributions											
Production Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transmission Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Distribution Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Street Lights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Contributions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL RATE BASE	$247,977,170	$2,837,950	$27,397,411	$0	$0	$0	$0	$169,721,240	$0	$40,593,025	$7,427,544
CWIP											
Production Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transmission Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Distribution Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total CWIP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL RATE BASE plus CWIP	$247,977,170	$2,837,950	$27,397,411	$0	$0	$0	$0	$169,721,240	$0	$40,593,025	$7,427,544

City of Palo Alto - 100% Demand
RATE BASE COST ALLOCATION
CLASSIFICATION BY CUSTOMER
Schedule 4.3

Prepared By EES Consulting, Inc.

Account Description	Total Rate Base	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Distribution Plant						
Land & Rights	$0	$0	$0	$0	$0	$0
Structures & Improvements	$7,154,333	$1,051,419	$568,409	$3,136,220	$2,371,292	$26,993
Station Equipment - Distribution	$59,404,780	$8,730,274	$4,719,690	$26,041,063	$19,689,619	$224,134
Storage & Battery Equipment	$2,659,291	$390,816	$211,280	$1,165,744	$881,418	$10,033
Poles, Towers, & Fixtures	$44,602,342	$6,554,871	$3,543,641	$19,552,171	$14,783,375	$168,284
Overhead Conductors & Devices	$18,501,977	$2,719,096	$1,469,976	$8,110,646	$6,132,450	$69,808
Underground Conduit	$1,763,879	$259,224	$140,140	$773,225	$584,635	$6,655
Underground Conductors & Devices	$85,733,395	$12,599,593	$6,811,490	$37,582,645	$28,416,196	$323,471
Line Transformers	$31,475,442	$4,625,709	$2,500,713	$13,797,778	$10,432,485	$118,757
Services	$68,019,093	$13,711,891	$1,660,424	$43,161,532	$9,485,246	$0
Meters	$4,490,213	$3,777,333	$460,661	$203,761	$48,459	$0
Installation on Customer Premises	$1,258,542	$1,058,732	$129,117	$57,111	$13,582	$0
Leased Property on Cust. Premises	$0	$0	$0	$0	$0	$0
Street Lights and Signal Systems	$25,222,037	$0	$0	$0	$0	$25,222,037
Total Distribution Plant	$350,285,324	$55,478,957	$22,215,541	$153,581,897	$92,838,756	$26,170,173
Total Transmission & Distribution	$350,285,324	$55,478,957	$22,215,541	$153,581,897	$92,838,756	$26,170,173
General Plant						
Land & Land Rights	$0	$0	$0	$0	$0	$0
Structures & Improvements	$1,897,484	$300,528	$120,341	$831,948	$502,905	$141,763
Office Furniture & Equipment	$8,874,818	$1,405,613	$562,852	$3,891,146	$2,352,160	$663,047
Transportation Equipment	$415,330	$65,781	$26,341	$182,100	$110,078	$31,030
Stores Equipment	$0	$0	$0	$0	$0	$0
Tools, Shop, & Garage Equipment	$2,685,629	$425,356	$170,326	$1,177,509	$711,793	$200,646
Laboratory Equipment	$0	$0	$0	$0	$0	$0
Power Operated Equipment	$0	$0	$0	$0	$0	$0
Communication Equipment	$22,487,683	$3,561,649	$1,426,197	$9,859,680	$5,960,080	$1,680,078
Misc. Equipment	$10,832,848	$1,715,730	$687,033	$4,749,640	$2,871,111	$809,333
Other Tangible Property - EV Charging	$29,836	$4,725	$1,892	$13,082	$7,908	$2,229
Total General Plant	$47,223,629	$7,479,382	$2,994,983	$20,705,105	$12,516,034	$3,528,125
Total Plant Before General Plant & Intangible	$350,285,324	$55,478,957	$22,215,541	$153,581,897	$92,838,756	$26,170,173
Total Gross Plant in Service	$397,508,952	$62,958,339	$25,210,523	$174,287,002	$105,354,790	$29,698,298

City of Palo Alto - 100% Demand
RATE BASE COST ALLOCATION
CLASSIFICATION BY CUSTOMER
Schedule 4.3

Prepared By EES Consulting, Inc.

Account Description	Total Rate Base	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Less: Accumulated Depreciation						
Intangible Plant	$0	$0	$0	$0	$0	$0
Transmission Plant	$0	$0	$0	$0	$0	$0
Distribution Plant	$139,992,346	$24,706,790	$9,185,973	$67,312,840	$38,407,819	$378,925
General Plant	$29,441,360	$4,662,987	$1,867,208	$12,908,505	$7,803,065	$2,199,594
Street Lighting	$19,389,916	$0	$0	$0	$0	$19,389,916
Misc. Plant	$0	$0	$0	$0	$0	$0
Total Accumulated Depreciation	$188,823,622	$29,369,777	$11,053,181	$80,221,345	$46,210,884	$21,968,435
Total Net Plant	$208,685,330	$33,588,562	$14,157,342	$94,065,657	$59,143,905	$7,729,863
Working Capital		$0	$0	$0	$0	$0
90 Days of Non Power Supply O&M	$10,832,188	$2,056,374	$742,996	$4,610,246	$3,077,746	$344,826
90 Days of Power Supply Cost	$28,459,651	$4,455,996	$1,840,266	$10,311,631	$11,789,021	$62,737
Total Working Capital	$39,291,839	$6,512,371	$2,583,262	$14,921,877	$14,866,767	$407,563
Less: Net Customer Contributions		$0	$0	$0	$0	$0
Production Plant	$0	$0	$0	$0	$0	$0
Transmission Plant	$0	$0	$0	$0	$0	$0
Distribution Plant	$0	$0	$0	$0	$0	$0
Street Lights	$0	$0	$0	$0	$0	$0
General Plant	$0	$0	$0	$0	$0	$0
Total Contributions	$0	$0	$0	$0	$0	$0
TOTAL RATE BASE	$247,977,170	$40,100,933	$16,740,604	$108,987,533	$74,010,673	$8,137,426
CWIP		$0	$0	$0	$0	$0
Production Plant	$0	$0	$0	$0	$0	$0
Transmission Plant	$0	$0	$0	$0	$0	$0
Distribution Plant	$0	$0	$0	$0	$0	$0
Services	$0	$0	$0	$0	$0	$0
General Plant	$0	$0	$0	$0	$0	$0
Other	$0	$0	$0	$0	$0	$0
Total CWIP	$0	$0	$0	$0	$0	$0
TOTAL RATE BASE plus CWIP	$247,977,170	$40,100,933	$16,740,604	$108,987,533	$74,010,673	$8,137,426

City of Palo Alto - 100% Demand
RATE BASE COST ALLOCATION
DIRECT ASSIGNMENT BY CUSTOMER
Schedule 4.4

Prepared By EES Consulting, Inc.

Account Description	Total Rate Base	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Distribution Plant						
Land & Rights	$0	$0	$0	$0	$0	$0
Structures & Improvements	$0	$0	$0	$0	$0	$0
Station Equipment - Distribution	$0	$0	$0	$0	$0	$0
Storage & Battery Equipment	$0	$0	$0	$0	$0	$0
Poles, Towers, & Fixtures	$0	$0	$0	$0	$0	$0
Overhead Conductors & Devices	$0	$0	$0	$0	$0	$0
Underground Conduit	$0	$0	$0	$0	$0	$0
Underground Conductors & Devices	$0	$0	$0	$0	$0	$0
Line Transformers	$0	$0	$0	$0	$0	$0
Services	$0	$0	$0	$0	$0	$0
Meters	$0	$0	$0	$0	$0	$0
Installation on Customer Premises	$0	$0	$0	$0	$0	$0
Leased Property on Cust. Premises	$0	$0	$0	$0	$0	$0
Street Lights and Signal Systems	$25,222,037	$0	$0	$0	$0	$25,222,037
Total Distribution Plant	$25,222,037	$0	$0	$0	$0	$25,222,037
Total Transmission & Distribution	$25,222,037	$0	$0	$0	$0	$25,222,037
General Plant						
Land & Land Rights	$0	$0	$0	$0	$0	$0
Structures & Improvements	$136,627	$0	$0	$0	$0	$136,627
Office Furniture & Equipment	$639,025	$0	$0	$0	$0	$639,025
Transportation Equipment	$29,905	$0	$0	$0	$0	$29,905
Stores Equipment	$0	$0	$0	$0	$0	$0
Tools, Shop, & Garage Equipment	$193,377	$0	$0	$0	$0	$193,377
Laboratory Equipment	$0	$0	$0	$0	$0	$0
Power Operated Equipment	$0	$0	$0	$0	$0	$0
Communication Equipment	$1,619,209	$0	$0	$0	$0	$1,619,209
Misc. Equipment	$780,011	$0	$0	$0	$0	$780,011
Other Tangible Property - EV Charging	$2,148	$0	$0	$0	$0	$2,148
Total General Plant	$3,400,303	$0	$0	$0	$0	$3,400,303
Total Plant Before General Plant & Intangible	$25,222,037	$0	$0	$0	$0	$25,222,037
Total Gross Plant in Service	$28,622,340	$0	$0	$0	$0	$28,622,340

City of Palo Alto - 100% Demand
RATE BASE COST ALLOCATION
DIRECT ASSIGNMENT BY CUSTOMER
Schedule 4.4

Prepared By EES Consulting, Inc.

Account Description	Total Rate Base	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Less: Accumulated Depreciation						
Intangible Plant	$0	$0	$0	$0	$0	$0
Transmission Plant	$0	$0	$0	$0	$0	$0
Distribution Plant	$0	$0	$0	$0	$0	$0
General Plant	$2,119,903	$0	$0	$0	$0	$2,119,903
Street Lighting	$19,389,916	$0	$0	$0	$0	$19,389,916
Misc. Plant	$0	$0	$0	$0	$0	$0
Total Accumulated Depreciation	$21,509,819	$0	$0	$0	$0	$21,509,819
Total Net Plant	$7,112,520	$0	$0	$0	$0	$7,112,520
Working Capital	$0	$0	$0	$0	$0	$0
90 Days of Non Power Supply O&M	$315,023	$0	$0	$0	$0	$315,023
90 Days of Power Supply Cost						
Total Working Capital	$315,023	$0	$0	$0	$0	$315,023
Less: Net Customer Contributions	$0					
Production Plant	$0	$0	$0	$0	$0	$0
Transmission Plant	$0	$0	$0	$0	$0	$0
Distribution Plant	$0	$0	$0	$0	$0	$0
Street Lights	$0	$0	$0	$0	$0	$0
General Plant	$0	$0	$0	$0	$0	$0
Total Contributions	$0	$0	$0	$0	$0	$0
TOTAL RATE BASE	$7,427,544	$0	$0	$0	$0	$7,427,544
CWIP	$0	$0	$0	$0	$0	$0
Production Plant	$0	$0	$0	$0	$0	$0
Transmission Plant	$0	$0	$0	$0	$0	$0
Distribution Plant	$0	$0	$0	$0	$0	$0
Services	$0	$0	$0	$0	$0	$0
General Plant	$0	$0	$0	$0	$0	$0
Other	$0	$0	$0	$0	$0	$0
Total CWIP	$0	$0	$0	$0	$0	$0
TOTAL RATE BASE plus CWIP	$7,427,544	$0	$0	$0	$0	$7,427,544

Prepared By EES Consulting, Inc.

City of Palo Alto

CLASSIFICATION and ALLOCATION BY FUNCTION

Schedule 6.1

Classification Factors	Production			Transmission			Distribution				Total % Allocated
	Demand PD	Energy PE	Direct Assignment PDA	Demand TD	Energy TE	Direct Assignment TDA	Demand DD	Energy DE	Customer DC	Direct Assignment DDA	
CP1	100.00%			100.00%			100.00%				100.0%
CP2	100.00%			100.00%			100.00%				100.0%
CPS	100.00%			100.00%			100.00%				100.0%
CP12	100.00%			100.00%			100.00%				100.0%
LF	37.45%	62.55%									100.0%
TCP1				100.00%							100.0%
TCP2				100.00%							100.0%
TCPS				100.00%							100.0%
TCP12				100.00%							100.0%
TAE				100.00%							100.0%
CPG	100.00%			100.00%			100.00%				100.0%
CPT	100.00%			100.00%			100.00%				100.0%
AE	100.00%			100.00%			100.00%				100.0%
NCP	100.00%			100.00%			100.00%				100.0%
NCPP	100.00%			100.00%			100.00%				100.0%
NCPS	100.00%			100.00%			100.00%				100.0%
kWh		100.00%			100.00%			100.00%			100.0%
kWhP		100.00%			100.00%			100.00%			100.0%
kWhO		100.00%			100.00%			100.00%			100.0%
kWhPJAN		100.00%			100.00%			100.00%			100.0%
kWhPFEB		100.00%			100.00%			100.00%			100.0%
kWhPMAR		100.00%			100.00%			100.00%			100.0%
kWhPAPR		100.00%			100.00%			100.00%			100.0%
kWhPMAY		100.00%			100.00%			100.00%			100.0%
kWhPJUN		100.00%			100.00%			100.00%			100.0%
kWhPJUL		100.00%			100.00%			100.00%			100.0%
kWhPAUG		100.00%			100.00%			100.00%			100.0%
kWhPSEP		100.00%			100.00%			100.00%			100.0%
kWhPOCT		100.00%			100.00%			100.00%			100.0%
kWhPNOV		100.00%			100.00%			100.00%			100.0%
kWhPDEC		100.00%			100.00%			100.00%			100.0%
kWhOJAN		100.00%			100.00%			100.00%			100.0%
kWhOFEB		100.00%			100.00%			100.00%			100.0%
kWhOMAR		100.00%			100.00%			100.00%			100.0%
kWhOAPR		100.00%			100.00%			100.00%			100.0%
kWhOMAY		100.00%			100.00%			100.00%			100.0%

City of Palo Alto

Prepared By EES Consulting, Inc.

CLASSIFICATION and ALLOCATION BY FUNCTION

Schedule 6.1

Classification Factors	Production			Transmission			Distribution				Total % Allocated
	Demand PD	Energy PE	Direct Assignment PDA	Demand TD	Energy TE	Direct Assignment TDA	Demand DD	Energy DE	Customer DC	Direct Assignment DDA	
kWhOJUN		100.00%			100.00%			100.00%			100.0%
kWhOJUL		100.00%			100.00%			100.00%			100.0%
kWhOAUG		100.00%			100.00%			100.00%			100.0%
kWhOSEP		100.00%			100.00%			100.00%			100.0%
kWhOOCT		100.00%			100.00%			100.00%			100.0%
kWhONOV		100.00%			100.00%			100.00%			100.0%
kWhODEC		100.00%			100.00%			100.00%			100.0%
CUST									100.00%		100.0%
CUSTW									100.00%		100.0%
CUSTM									100.00%		100.0%
CUSTMR									100.00%		100.0%
MINSYSP							60.00%		40.00%		100.0%
MINSYSC							60.00%		40.00%		100.0%
MINSYST							50.00%		50.00%		100.0%
100%DP							100.00%		0.00%		100.0%
100%DC							100.00%		0.00%		100.0%
100%DT							100.00%		0.00%		100.0%
DA1										100.000%	100.0%
DA2			100.000%								100.0%
DA3		100.000%		0.000%						0.000%	100.0%
DA4		100.000%		0.000%						0.000%	100.0%
DA5		100.000%		0.000%						0.000%	100.0%
DA6							100.000%			0.000%	100.0%
DA7	100.000%									0.000%	100.0%
DA8		100.000%								0.000%	100.0%
DA9	0.000%	100.000%	0.000%	0.000%	0.000%	0.000%		0.000%		0.000%	100.0%
DA10	8.026%	72.463%	0.000%	0.000%	0.000%	0.000%	14.024%	0.000%	4.664%	0.822%	100.0%
REV	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%			100.0%
REV-P	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	100.0%
REV-T	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	100.0%
REV-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	100.0%
OTHER	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%		0.00%	100.0%
RB	1.14%	11.05%	0.00%	0.00%	0.00%	0.00%	68.44%	0.00%	16.37%	3.00%	100.0%
RB-P	1.14%	11.05%	0.00%	0.00%	0.00%	0.00%	68.44%	0.00%	16.37%	3.00%	100.0%
RB-T	1.14%	11.05%	0.00%	0.00%	0.00%	0.00%	68.44%	0.00%	16.37%	3.00%	100.0%
RB-D	1.14%	11.05%	0.00%	0.00%	0.00%	0.00%	68.44%	0.00%	16.37%	3.00%	100.0%
RBG	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.0%
RBIG	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.0[illegible]	[illegible]	0.0%

CLASSIFICATION and ALLOCATION BY FUNCTION

Schedule 6.1

Classification Factors	Production			Transmission			Distribution				Total % Allocated
	Demand PD	Energy PE	Direct Assignment PDA	Demand TD	Energy TE	Direct Assignment TDA	Demand DD	Energy DE	Customer DC	Direct Assignment DDA	
RBIG-P	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.0%
RBIG-T	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.0%
RBIG-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.0%
RBSG	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.0%
RBHG	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.0%
RBGG	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.0%
RBT	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.0%
RBD	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	71.74%	0.00%	21.06%	7.20%	100.0%
RBGP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	71.74%	0.00%	21.06%	7.20%	100.0%
RBGP-P	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	71.74%	0.00%	21.06%	7.20%	100.0%
RBGP-T	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	71.74%	0.00%	21.06%	7.20%	100.0%
RBGP-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	71.74%	0.00%	21.06%	7.20%	100.0%
RBSE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	100.0%
RBOH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	100.0%
RBUG	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	100.0%
RBTR	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	100.0%
OM	8.03%	72.46%	0.00%	0.00%	0.00%	0.00%	14.02%	0.00%	4.66%	0.82%	100.0%
OM-P	8.03%	72.46%	0.00%	0.00%	0.00%	0.00%	14.02%	0.00%	4.66%	0.82%	100.0%
OM-T	8.03%	72.46%	0.00%	0.00%	0.00%	0.00%	14.02%	0.00%	4.66%	0.82%	100.0%
OM-D	8.03%	72.46%	0.00%	0.00%	0.00%	0.00%	14.02%	0.00%	4.66%	0.82%	100.0%
OMAG	0.00%	16.47%	0.00%	0.00%	0.00%	0.00%	56.20%	0.00%	24.42%	2.91%	100.0%
OMAG-P	0.00%	16.47%	0.00%	0.00%	0.00%	0.00%	56.20%	0.00%	24.42%	2.91%	100.0%
OMAG-T	0.00%	16.47%	0.00%	0.00%	0.00%	0.00%	56.20%	0.00%	24.42%	2.91%	100.0%
OMAG-D	0.00%	16.47%	0.00%	0.00%	0.00%	0.00%	56.20%	0.00%	24.42%	2.91%	100.0%
OMG	9.97%	90.03%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.0%
OMT	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.0%
OMD	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	71.88%	0.00%	23.90%	4.21%	100.0%
OMDLUGT	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	71.88%	0.00%	23.90%	4.21%	100.0%
OMDS&E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	72.09%	0.00%	25.06%	2.86%	100.0%
MARKET		100.00%									100.0%
GPLT	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	71.74%	0.00%	21.06%	7.20%	100.0%
GPLT-P	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	71.74%	0.00%	21.06%	7.20%	100.0%
GPLT-T	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	71.74%	0.00%	21.06%	7.20%	100.0%
GPLT-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	71.74%	0.00%	21.06%	7.20%	100.0%
GRSPLT	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	71.74%	0.00%	21.06%	7.20%	100.0%
GRSPLT-P	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	71.74%	0.00%	21.06%	7.20%	100.0%
GRSPLT-T	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	71.74%	0.00%	21.0[illegible]	[illegible]	[illegible]00.0%

City of Palo Alto

Prepared By EES Consulting, Inc.

CLASSIFICATION and ALLOCATION BY FUNCTION

Schedule 6.1

Classification Factors	Production			Transmission			Distribution				Total % Allocated
	Demand PD	Energy PE	Direct Assignment PDA	Demand TD	Energy TE	Direct Assignment TDA	Demand DD	Energy DE	Customer DC	Direct Assignment DDA	
GRSPLT-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	71.74%	0.00%	21.06%	7.20%	100.0%
NETPLT	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	78.41%	0.00%	18.19%	3.41%	100.0%
NETPLT-P	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	78.41%	0.00%	18.19%	3.41%	100.0%
NETPLT-T	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	78.41%	0.00%	18.19%	3.41%	100.0%
NETPLT-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	78.41%	0.00%	18.19%	3.41%	100.0%
TOTCST	6.11%	62.36%	0.00%	0.00%	0.00%	0.00%	22.96%	0.00%	7.81%	0.76%	100.0%
TOTCST-P	6.11%	62.36%	0.00%	0.00%	0.00%	0.00%	22.96%	0.00%	7.81%	0.76%	100.0%
TOTCST-T	6.11%	62.36%	0.00%	0.00%	0.00%	0.00%	22.96%	0.00%	7.81%	0.76%	100.0%
TOTCST-D	6.11%	62.36%	0.00%	0.00%	0.00%	0.00%	22.96%	0.00%	7.81%	0.76%	100.0%
OMP	9.97%	90.03%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.0%
OMWOP	0.00%	16.39%	0.00%	0.00%	0.00%	0.00%	56.31%	0.00%	24.39%	2.91%	100.0%
OMWOP-P	0.00%	16.39%	0.00%	0.00%	0.00%	0.00%	56.31%	0.00%	24.39%	2.91%	100.0%
OMWOP-T	0.00%	16.39%	0.00%	0.00%	0.00%	0.00%	56.31%	0.00%	24.39%	2.91%	100.0%
OMWOP-D	0.00%	16.39%	0.00%	0.00%	0.00%	0.00%	56.31%	0.00%	24.39%	2.91%	100.0%
PROD	9.97%	90.03%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.0%
OMPT	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.0%
NCPplcc							100.00%				100.0%
NCPPplcc							100.00%				100.0%
NCPSplcc							100.00%				100.0%
WEST	16.000%	84.000%									100.0%
REN	3.158%	96.842%									100.0%
CALA	7.000%	93.000%									100.0%
CREDIT									100.000%		100.0%
CUST SERV									100.000%		100.0%
SERV									100.000%		100.0%
RR	6.114%	62.360%	0.000%	0.000%	0.000%	0.000%	22.956%	0.000%	7.813%	0.757%	100.0%
RR-P											0.0%
RR-T											0.0%
RR-D											0.0%
RBD-ST							61.755%		24.326%	13.919%	100.0%
RBD-NoDA							71.740%		28.260%		100.0%
DSRE		100.000%									100.0%
DSMEE		100.000%									100.0%
GF	2.197%	95.432%	0.000%	0.000%	0.000%	0.000%	1.596%	0.000%	[illegible]	[illegible]	[illegible]00.0%

February 2024

City of Palo Alto

Prepared By EES Consulting, Inc.

CLASSIFICATION and ALLOCATION BY FUNCTION

Schedule 6.1

Classification Factors	Production			Transmission			Distribution				Total % Allocated
	Demand PD	Energy PE	Direct Assignment PDA	Demand TD	Energy TE	Direct Assignment TDA	Demand DD	Energy DE	Customer DC	Direct Assignment DDA	
GF-P											0.0%
GF-T											0.0%
GF-D											0.0%
RSR											0.0%
RBD-NoDA Services	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	97.764%	0.000%	2.236%	0.000%	100.0%
Rcontr	5.572%	33.899%	0.000%	0.000%	0.000%	0.000%	45.137%	0.000%	15.393%	0.000%	100.0%
Rcontr-P											0.0%
Rcontr-D											0.0%
Rcontr-T											0.0%

Prepared By EES Consulting, Inc.

City of Palo Alto

CLASSIFICATION AND ALLOCATION BY CUSTOMER - ENERGY
Schedule 6.2

Test Year: 2025

Classification Factors	Total Allocated	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
CP1	0%					
CP2	0%					
CPS	0%					
CP12	0%					
LF	100%	15.993%	6.399%	35.490%	41.891%	0.226%
TCP1	0%					
TCP2	0%					
TCPS	0%					
TCP12	0%					
TAE	0%					
CPG	0%					
CPT	0%					
AE	0%					
NCP	0%					
NCPP	0%					
NCPS	0%					
kWh	100%	15.993%	6.399%	35.490%	41.891%	0.226%
kWhP	100%	15.982%	6.400%	35.506%	41.887%	0.226%
kWhO	100%	16.010%	6.399%	35.468%	41.897%	0.226%
kWhPJAN	100%	14.410%	6.917%	36.363%	42.085%	0.225%
kWhPFEB	100%	14.545%	6.663%	37.241%	41.340%	0.211%
kWhPMAR	100%	12.525%	6.257%	37.045%	43.965%	0.207%
kWhPAPR	100%	14.629%	6.632%	37.416%	41.083%	0.240%
kWhPMAY	100%	15.374%	6.104%	35.671%	42.626%	0.225%
kWhPJUN	100%	16.525%	6.785%	36.380%	40.069%	0.240%
kWhPJUL	100%	20.858%	6.237%	30.909%	41.781%	0.215%
kWhPAUG	100%	18.454%	6.359%	35.102%	39.861%	0.225%
kWhPSEP	100%	19.895%	6.565%	33.558%	39.740%	0.242%
kWhPOCT	100%	15.624%	5.946%	34.732%	43.460%	0.238%
kWhPNOV	100%	14.925%	6.224%	36.034%	42.584%	0.234%
kWhPDEC	100%	14.497%	6.127%	35.423%	43.731%	0.222%
kWhOJAN	100%	14.410%	6.917%	36.363%	42.085%	0.225%
kWhOFEB	100%	14.545%	6.663%	37.241%	41.340%	0.211%

City of Palo Alto

Prepared By EES Consulting, Inc.

CLASSIFICATION AND ALLOCATION BY CUSTOMER - ENERGY
Schedule 6.2

Test Year: 2025

Classification Factors	Total Allocated	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
kWhOMAR	100%	12.525%	6.257%	37.045%	43.965%	0.207%
kWhOAPR	100%	14.629%	6.632%	37.416%	41.083%	0.240%
kWhOMAY	100%	15.374%	6.104%	35.671%	42.626%	0.225%
kWhOJUN	100%	16.525%	6.785%	36.380%	40.069%	0.240%
kWhOJUL	100%	20.858%	6.237%	30.909%	41.781%	0.215%
kWhOAUG	100%	18.454%	6.359%	35.102%	39.861%	0.225%
kWhOSEP	100%	19.895%	6.565%	33.558%	39.740%	0.242%
kWhOOCT	100%	15.624%	5.946%	34.732%	43.460%	0.238%
kWhONOV	100%	14.925%	6.224%	36.034%	42.584%	0.234%
kWhODEC	100%	14.497%	6.127%	35.423%	43.731%	0.222%
CUST	0%					
CUSTW	0%					
CUSTM	0%					
CUSTMR	0%					
MINSYSP	0%					
MINSYSC	0%					
MINSYST	0%					
100%DP	0%					
100%DC	0%					
100%DT	0%					
DA1	0%	0.000%	0.000%	0.000%	0.000%	0.000%
DA2	0%	0.000%	0.000%	0.000%	0.000%	0.000%
DA3	100%	0.000%	0.000%	0.000%	0.000%	0.000%
DA4	100%	0.000%	0.000%	0.000%	0.000%	0.000%
DA5	100%	0.000%	0.000%	0.000%	0.000%	0.000%
DA6	0%	0.000%	0.000%	0.000%	0.000%	0.000%
DA7	100%	15.993%	6.399%	35.490%	41.891%	0.226%
DA8	100%	15.993%	6.399%	35.490%	41.891%	0.226%
DA9	0%	0.000%	0.000%	0.000%	0.000%	0.000%
DA10	100%	100.000%	0.000%	0.000%	0.000%	0.000%
REV	100%	16.225%	7.001%	40.225%	35.228%	1.321%
REV-P	100%	16.225%	7.001%	40.225%	35.228%	1.321%
REV-T	100%	16.225%	7.001%	40.225%	35.228%	1.321%
REV-D	100%	16.225%	7.001%	40.225%	35.228%	1.321%
OTHER	0%					
RB	100%	15.953%	6.498%	35.337%	42.000%	0.212%
RB-P	100%	15.953%	6.498%	35.337%	42.000%	0.212%

City of Palo Alto

Prepared By EES Consulting, Inc.

CLASSIFICATION AND ALLOCATION BY CUSTOMER - ENERGY
Schedule 6.2

Test Year: 2025

Classification Factors	Total Allocated	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
RB-T	0%	0.000%	0.000%	0.000%	0.000%	0.000%
RB-D	0%	0.000%	0.000%	0.000%	0.000%	0.000%
RBG	0%	0.000%	0.000%	0.000%	0.000%	0.000%
RBIG	0%	0.000%	0.000%	0.000%	0.000%	0.000%
RBIG-P	0%	0.000%	0.000%	0.000%	0.000%	0.000%
RBIG-T	0%	0.000%	0.000%	0.000%	0.000%	0.000%
RBIG-D	0%	0.000%	0.000%	0.000%	0.000%	0.000%
RBSG	0%	0.000%	0.000%	0.000%	0.000%	0.000%
RBHG	0%	0.000%	0.000%	0.000%	0.000%	0.000%
RBGG	0%	0.000%	0.000%	0.000%	0.000%	0.000%
RBT	0%	0.000%	0.000%	0.000%	0.000%	0.000%
RBD	0%	0.000%	0.000%	0.000%	0.000%	0.000%
RBGP	0%	0.000%	0.000%	0.000%	0.000%	0.000%
RBGP-P	0%	0.000%	0.000%	0.000%	0.000%	0.000%
RBGP-T	0%	0.000%	0.000%	0.000%	0.000%	0.000%
RBGP-D	0%	0.000%	0.000%	0.000%	0.000%	0.000%
RBSE	0%	0.000%	0.000%	0.000%	0.000%	0.000%
RBOH	0%	0.000%	0.000%	0.000%	0.000%	0.000%
RBUG	0%	0.000%	0.000%	0.000%	0.000%	0.000%
RBTR	0%	0.000%	0.000%	0.000%	0.000%	0.000%
OM	100%	15.993%	6.399%	35.490%	41.891%	0.226%
OM-P	100%	15.993%	6.399%	35.490%	41.891%	0.226%
OM-T	0%	0.000%	0.000%	0.000%	0.000%	0.000%
OM-D	0%	0.000%	0.000%	0.000%	0.000%	0.000%
OMAG	100%	15.377%	7.924%	33.120%	43.578%	0.000%
OMAG-P	100%	15.377%	7.924%	33.120%	43.578%	0.000%
OMAG-T	0%	0.000%	0.000%	0.000%	0.000%	0.000%
OMAG-D	0%	0.000%	0.000%	0.000%	0.000%	0.000%
OMG	100%	15.993%	6.399%	35.490%	41.891%	0.226%
OMT	0%	0.000%	0.000%	0.000%	0.000%	0.000%
OMD	0%	0.000%	0.000%	0.000%	0.000%	0.000%
OMDLUGT	0%					
OMDS&E	0%	0.000%	0.000%	0.000%	0.000%	0.000%
MARKET	0%					
GPLT	0%	0.000%	0.000%	0.000%	0.000%	0.000%
GPLT-P	0%	0.000%	0.000%	0.000%	0.000%	0.000%

City of Palo Alto

Prepared By EES Consulting, Inc.

CLASSIFICATION AND ALLOCATION BY CUSTOMER - ENERGY
Schedule 6.2

Test Year: 2025

Classification Factors	Total Allocated	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
GPLT-T	0%	0.000%	0.000%	0.000%	0.000%	0.000%
GPLT-D	0%	0.000%	0.000%	0.000%	0.000%	0.000%
GRSPLT	0%					
GRSPLT-P	0%					
GRSPLT-T	0%					
GRSPLT-D	0%					
NETPLT	0%	0.000%	0.000%	0.000%	0.000%	0.000%
NETPLT-P	0%	0.000%	0.000%	0.000%	0.000%	0.000%
NETPLT-T	0%	0.000%	0.000%	0.000%	0.000%	0.000%
NETPLT-D	0%	0.000%	0.000%	0.000%	0.000%	0.000%
TOTCST	0%					
TOTCST-P	0%					
TOTCST-T	0%					
TOTCST-D	0%					
OMP	100%	15.993%	6.399%	35.490%	41.891%	0.226%
OMWOP	100%	15.377%	7.924%	33.120%	43.578%	0.000%
OMWOP-P	100%	15.377%	7.924%	33.120%	43.578%	0.000%
OMWOP-T	0%	0.000%	0.000%	0.000%	0.000%	0.000%
OMWOP-D	0%	0.000%	0.000%	0.000%	0.000%	0.000%
UNP	0%					
LABORRB	0%					
LABORRR	0%					
TRANSP	0%					
ST	0%					
DC	0%					
PI	0%					
PROD	0%					
OMPT	100%	15.99%	6.40%	35.49%	41.89%	0.23%
NCPplcc	0%					
NCPPplcc	0%					
NCPSplcc	0%					
WEST	100%	15.993%	6.399%	35.490%	41.891%	0.226%
REN	100%	15.993%	6.399%	35.490%	41.891%	0.226%
CALA	100%	15.993%	6.399%	35.490%	41.891%	0.226%
CREDIT	0%					
CUST SERV	0%					
SERV	0%					
RR	0%					
RR-P	0%					
RR-T	0%					
RR-D	0%					
RBD-ST	0%					

City of Palo Alto

Prepared By EES Consulting, Inc.

CLASSIFICATION AND ALLOCATION BY CUSTOMER - ENERGY
Schedule 6.2

Test Year: 2025

Classification Factors	Total Allocated	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
RBD-NoDA	0%					
DSRE	100%	20.855%	8.271%	33.548%	37.325%	
DSMEE	100%	15.377%	7.924%	33.120%	43.578%	
GF	100%	15.990%	6.407%	35.479%	41.899%	0.225%
GF-P	100%	15.990%	6.407%	35.479%	41.899%	0.225%
GF-T	100%	15.990%	6.407%	35.479%	41.899%	0.225%
GF-D	100%	15.990%	6.407%	35.479%	41.899%	0.225%
RSR	0%					
RBD-NoDA Services	0%					
Rcontr	100%	15.918%	6.584%	35.203%	42.096%	0.199%
Rcontr-P	100%	15.918%	6.584%	35.203%	42.096%	0.199%
Rcontr-D	0%					
Rcontr-T	100%	15.918%	6.584%	35.203%	42.096%	0.199%

Prepared By EES Consulting, Inc.

City of Palo Alto

CLASSIFICATION AND ALLOCATION BY CUSTOMER - DEMAND
Schedule 6.2

Test Year: 2025

Classification Factors	Total Allocated	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
CP1	100%	12.009%	6.793%	44.857%	36.073%	0.268%
CP2	100%	12.171%	6.872%	44.850%	35.967%	0.140%
CPS	100%	12.171%	6.872%	44.850%	35.967%	0.140%
CP12	100%	12.624%	7.071%	42.933%	37.205%	0.167%
LF	100%	15.695%	7.635%	41.687%	34.599%	0.384%
TCP1	100%	12.009%	6.793%	44.857%	36.073%	0.268%
TCP2	100%	12.171%	6.872%	44.850%	35.967%	0.140%
TCPS	100%	12.171%	6.872%	44.850%	35.967%	0.140%
TCP12	100%	12.624%	7.071%	42.933%	37.205%	0.167%
TAE	100%	15.695%	7.635%	41.687%	34.599%	0.384%
CPG	100%	12.624%	7.071%	42.933%	37.205%	0.167%
CPT	100%	12.624%	7.071%	42.933%	37.205%	0.167%
AE	100%	15.695%	7.635%	41.687%	34.599%	0.384%
NCP	100%	14.696%	7.945%	43.837%	33.145%	0.377%
NCPP	100%	14.696%	7.945%	43.837%	33.145%	0.377%
NCPS	100%	14.696%	7.945%	43.837%	33.145%	0.377%
kWh	0%	0.000%	0.000%	0.000%	0.000%	0.000%
kWhP	0%	0.000%	0.000%	0.000%	0.000%	0.000%
kWhO	0%	0.000%	0.000%	0.000%	0.000%	0.000%
kWhPJAN	0%	0.000%	0.000%	0.000%	0.000%	0.000%
kWhPFEB	0%	0.000%	0.000%	0.000%	0.000%	0.000%
kWhPMAR	0%	0.000%	0.000%	0.000%	0.000%	0.000%
kWhPAPR	0%	0.000%	0.000%	0.000%	0.000%	0.000%
kWhPMAY	0%	0.000%	0.000%	0.000%	0.000%	0.000%
kWhPJUN	0%	0.000%	0.000%	0.000%	0.000%	0.000%
kWhPJUL	0%	0.000%	0.000%	0.000%	0.000%	0.000%
kWhPAUG	0%	0.000%	0.000%	0.000%	0.000%	0.000%
kWhPSEP	0%	0.000%	0.000%	0.000%	0.000%	0.000%
kWhPOCT	0%	0.000%	0.000%	0.000%	0.000%	0.000%
kWhPNOV	0%	0.000%	0.000%	0.000%	0.000%	0.000%
kWhPDEC	0%	0.000%	0.000%	0.000%	0.000%	0.000%
kWhOJAN	0%	0.000%	0.000%	0.000%	0.000%	0.000%
kWhOFEB	0%	0.000%	0.000%	0.000%	0.000%	0.000%
kWhOMAR	0%	0.000%	0.000%	0.000%	0.000%	0.000%
kWhOAPR	0%	0.000%	0.000%	0.000%	0.000%	0.000%
kWhOMAY	0%	0.000%	0.000%	0.000%	0.000%	0.000%
kWhOJUN	0%	0.000%	0.000%	0.000%	0.000%	0.000%
kWhOJUL	0%	0.000%	0.000%	0.000%	0.000%	0.000%
kWhOAUG	0%	0.000%	0.000%	0.000%	0.000%	0.000%
kWhOSEP	0%	0.000%	0.000%	0.000%	0.000%	0.000%

City of Palo Alto

Prepared By EES Consulting, Inc.

CLASSIFICATION AND ALLOCATION BY CUSTOMER - DEMAND
Schedule 6.2

Test Year: 2025

Classification Factors	Total Allocated	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
kWhOOCT	0%	0.000%	0.000%	0.000%	0.000%	0.000%
kWhONOV	0%	0.000%	0.000%	0.000%	0.000%	0.000%
kWhODEC	0%	0.000%	0.000%	0.000%	0.000%	0.000%
CUST	0%					
CUSTW	0%					
CUSTM	0%					
CUSTMR	0%					
MINSYSP	100%	6.134%	7.635%	48.737%	37.072%	0.422%
MINSYSC	100%	6.134%	7.635%	48.737%	37.072%	0.422%
MINSYST	100%	5.910%	7.627%	48.866%	37.175%	0.423%
100%DP	100%	14.696%	7.945%	43.837%	33.145%	0.377%
100%DC	100%	14.696%	7.945%	43.837%	33.145%	0.377%
100%DT	100%	14.696%	7.945%	43.837%	33.145%	0.377%
DA1	0%	0.000%	0.000%	0.000%	0.000%	0.000%
DA2	100%	0.000%	40.000%	60.000%	0.000%	0.000%
DA3	100%	0.000%	0.000%	0.000%	0.000%	0.000%
DA4	100%	0.000%	0.000%	0.000%	0.000%	0.000%
DA5	100%	0.000%	0.000%	0.000%	0.000%	0.000%
DA6	0%	0.000%	0.000%	0.000%	0.000%	0.000%
DA7	0%	0.000%	0.000%	0.000%	0.000%	0.000%
DA8	0%	0.000%	0.000%	0.000%	0.000%	0.000%
DA9	0%	0.000%	0.000%	0.000%	0.000%	0.000%
DA10	100%	100.000%	0.000%	0.000%	0.000%	0.000%
REV	100%	16.225%	7.001%	40.225%	35.228%	1.321%
REV-P	100%	16.225%	7.001%	40.225%	35.228%	1.321%
REV-T	100%	16.225%	7.001%	40.225%	35.228%	1.321%
REV-D	100%	16.225%	7.001%	40.225%	35.228%	1.321%
OTHER	0%					
RB	100%	14.669%	7.927%	43.807%	33.220%	0.378%
RB-P	100%	12.624%	7.071%	42.933%	37.205%	0.167%
RB-T	0%	0.000%	0.000%	0.000%	0.000%	0.000%
RB-D	100%	14.703%	7.941%	43.821%	33.154%	0.381%
RBG	0%	0.000%	0.000%	0.000%	0.000%	0.000%
RBIG	0%	0.000%	0.000%	0.000%	0.000%	0.000%
RBIG-P	0%	0.000%	0.000%	0.000%	0.000%	0.000%
RBIG-T	0%	0.000%	0.000%	0.000%	0.000%	0.000%
RBIG-D	0%	0.000%	0.000%	0.000%	0.000%	0.000%
RBSG	0%	0.000%	0.000%	0.000%	0.000%	0.000%
RBHG	0%	0.000%	0.000%	0.000%	0.000%	0.000%
RBGG	0%	0.000%	0.000%	0.000%	0.000%	0.000%
RBT	0%	0.000%	0.000%	0.000%	0.000%	0.000%
RBD	100%	14.696%	7.945%	43.837%	33.145%	0.377%

City of Palo Alto

Prepared By EES Consulting, Inc.

CLASSIFICATION AND ALLOCATION BY CUSTOMER - DEMAND
Schedule 6.2

Test Year: 2025

Classification Factors	Total Allocated	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
RBGP	100%	14.696%	7.945%	43.837%	33.145%	0.377%
RBGP-P	0%	0.000%	0.000%	0.000%	0.000%	0.000%
RBGP-T	0%	0.000%	0.000%	0.000%	0.000%	0.000%
RBGP-D	100%	14.696%	7.945%	43.837%	33.145%	0.377%
RBSE	100%	14.696%	7.945%	43.837%	33.145%	0.377%
RBOH	100%	14.696%	7.945%	43.837%	33.145%	0.377%
RBUG	100%	14.696%	7.945%	43.837%	33.145%	0.377%
RBTR	100%	14.696%	7.945%	43.837%	33.145%	0.377%
OM	100%	13.942%	7.627%	43.508%	34.623%	0.301%
OM-P	100%	12.624%	7.071%	42.933%	37.205%	0.167%
OM-T	0%	0.000%	0.000%	0.000%	0.000%	0.000%
OM-D	100%	14.696%	7.945%	43.837%	33.145%	0.377%
OMAG	100%	14.877%	7.834%	43.410%	33.391%	0.489%
OMAG-P	0%	0.000%	0.000%	0.000%	0.000%	0.000%
OMAG-T	0%	0.000%	0.000%	0.000%	0.000%	0.000%
OMAG-D	100%	14.877%	7.834%	43.410%	33.391%	0.489%
OMG	100%	12.624%	7.071%	42.933%	37.205%	0.167%
OMT	0%	0.000%	0.000%	0.000%	0.000%	0.000%
OMD	100%	14.696%	7.945%	43.837%	33.145%	0.377%
OMDLUGT	0%					
OMDS&E	100%	14.696%	7.945%	43.837%	33.145%	0.377%
MARKET	0%					
GPLT	100%	14.696%	7.945%	43.837%	33.145%	0.377%
GPLT-P	0%	0.000%	0.000%	0.000%	0.000%	0.000%
GPLT-T	0%	0.000%	0.000%	0.000%	0.000%	0.000%
GPLT-D	100%	14.696%	7.945%	43.837%	33.145%	0.377%
GRSPLT	0%					
GRSPLT-P	0%					
GRSPLT-T	0%					
GRSPLT-D	0%					
NETPLT	100.0000%	14.696%	7.945%	43.837%	33.145%	0.377%
NETPLT-P	0%	0.000%	0.000%	0.000%	0.000%	0.000%
NETPLT-T	0%	0.000%	0.000%	0.000%	0.000%	0.000%
NETPLT-D	100%	14.696%	7.945%	43.837%	33.145%	0.377%
TOTCST	0%					
TOTCST-P	0%					
TOTCST-T	0%					
TOTCST-D	0%					
OMP	100%	12.624%	7.071%	42.933%	37.205%	0.167%

City of Palo Alto

Prepared By EES Consulting, Inc.

CLASSIFICATION AND ALLOCATION BY CUSTOMER - DEMAND
Schedule 6.2

Test Year: 2025

Classification Factors	Total Allocated	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
OMWOP	100%	14.876%	7.834%	43.413%	33.389%	0.488%
OMWOP-P	0%	0.000%	0.000%	0.000%	0.000%	0.000%
OMWOP-T	0%	0.000%	0.000%	0.000%	0.000%	0.000%
OMWOP-D	100%	14.876%	7.834%	43.413%	33.389%	0.488%
UNP	0%					
LABORRB	0%					
LABORRR	0%					
TRANSP	0%					
ST	0%					
DC	0%					
PI	0%					
PROD	0%					
OMPT	0%	0.00%	0.00%	0.00%	0.000%	0.00%
NCPplcc	100%	6.285%	7.640%	48.651%	37.003%	0.421%
NCPPplcc	100%	6.190%	7.637%	48.705%	37.047%	0.421%
NCPSplcc	100%	5.910%	7.627%	48.866%	37.175%	0.423%
WEST	100%	12.624%	7.071%	42.933%	37.205%	0.167%
REN	100%	12.624%	7.071%	42.933%	37.205%	0.167%
CALA	100%	12.624%	7.071%	42.933%	37.205%	0.167%
CREDIT	0%					
CUST SERV	0%					
SERV	0%					
RR	0%					
RR-P	0%					
RR-T	0%					
RR-D	0%					
RBD-ST	100%	14.696%	7.945%	43.837%	33.145%	0.377%
RBD-NoDA	100.0000000%	14.696%	7.945%	43.837%	33.145%	0.377%
DSRE	0%					
DSMEE	0%					
GF	100%	13.572%	7.392%	43.134%	35.600%	0.302%
GF-P	100%	13.572%	7.392%	43.134%	35.600%	0.302%
GF-T	100%	13.572%	7.392%	43.134%	35.600%	0.302%
GF-D	100%	13.572%	7.392%	43.134%	35.600%	0.302%
RSR	0%					
RBD-NoDA Services	100%	14.696%	7.945%	43.837%	33.145%	0.377%
Rcontr	0%					
Rcontr-P	100%	12.624%	7.071%	42.933%	37.205%	0.167%
Rcontr-D	100%	14.826%	7.865%	43.530%	33.322%	0.457%
Rcontr-T	0%					

Prepared By EES Consulting, Inc.

City of Palo Alto

CLASSIFICATION AND ALLOCATION BY CUSTOMER - CUSTOMER

Schedule 6.2

Test Year: 2025

Classification Factors	Total Allocated	Residential E-1	Commercial E-2	Commercial E-	Commercial E-	Lights
CP1	0%			0.000%	0.000%	0.000%
CP2	0%			0.000%	0.000%	0.000%
CPS	0%			0.000%	0.000%	0.000%
CP12	0%			0.000%	0.000%	0.000%
LF	0%					
TCP1	0%					
TCP2	0%					
TCPS	0%					
TCP12	0%					
TAE	0%					
CPG	0%					
CPT	0%					
AE	0%					
NCP	0%					
NCPP	0%					
NCPS	0%					
kWh	0%					
kWhP	0%					
kWhO	0%					
kWhPJAN	0%					
kWhPFEB	0%					
kWhPMAR	0%					
kWhPAPR	0%					
kWhPMAY	0%					
kWhPJUN	0%					
kWhPJUL	0%					
kWhPAUG	0%					
kWhPSEP	0%					
kWhPOCT	0%					
kWhPNOV	0%					
kWhPDEC	0%					
kWhOJAN	0%					
kWhOFEB	0%					
kWhOMAR	0%					
kWhOAPR	0%					

City of Palo Alto

Prepared By EES Consulting, Inc.

CLASSIFICATION AND ALLOCATION BY CUSTOMER - CUSTOMER

Schedule 6.2

Test Year: 2025

Classification Factors	Total Allocated	Residential E-1	Commercial E-2	Commercial E-	Commercial E-	Lights
kWhOMAY	0%					
kWhOJUN	0%					
kWhOJUL	0%					
kWhOAUG	0%					
kWhOSEP	0%					
kWhOOCT	0%					
kWhONOV	0%					
kWhODEC	0%					
CUST	100%	86.444%	10.542%	2.772%	0.235%	0.007%
CUSTW	100%	46.540%	7.095%	40.298%	6.064%	0.004%
CUSTM	100%	84.124%	10.259%	4.538%	1.079%	0.000%
CUSTMR	100%	46.542%	7.095%	40.299%	6.064%	0.000%
MINSYSP	100%	86.444%	10.542%	2.772%	0.235%	0.007%
MINSYSC	100%	86.444%	10.542%	2.772%	0.235%	0.007%
MINSYST	100%	86.444%	10.542%	2.772%	0.235%	0.007%
100%DP	0%					
100%DC	0%					
100%DT	0%					
DA1	0%	0.000%	0.000%	0.000%	0.000%	0.000%
DA2	0%	0.000%	0.000%	0.000%	0.000%	0.000%
DA3	0%	0.000%	0.000%	0.000%	0.000%	0.000%
DA4	0%	0.000%	0.000%	0.000%	0.000%	0.000%
DA5	0%	0.000%	0.000%	0.000%	0.000%	0.000%
DA6	0%	0.000%	0.000%	0.000%	0.000%	0.000%
DA7	100%	15.993%	6.399%	35.490%	41.891%	0.226%
DA8	100%	15.993%	6.399%	35.490%	41.891%	0.226%
DA9	0%	0.000%	0.000%	0.000%	0.000%	0.000%
DA10	100%	100.000%	0.000%	0.000%	0.000%	0.000%
REV	100%	16.225%	7.001%	40.225%	35.228%	1.321%
REV-P	100%	16.225%	7.001%	40.225%	35.228%	1.321%
REV-T	100%	16.225%	7.001%	40.225%	35.228%	1.321%
REV-D	100%	16.225%	7.001%	40.225%	35.228%	1.321%
OTHER	0%					

City of Palo Alto

Prepared By EES Consulting, Inc.

CLASSIFICATION AND ALLOCATION BY CUSTOMER - CUSTOMER

Schedule 6.2

Test Year: 2025

Classification Factors	Total Allocated	Residential E-1	Commercial E-2	Commercial E-	Commercial E-	Lights
RB	100%	25.665%	3.158%	58.418%	12.759%	0.000%
RB-P	0%					
RB-T	0%					
RB-D	0%					
RBG	0%	0.000%	0.000%	0.000%	0.000%	0.000%
RBIG	0%	0.000%	0.000%	0.000%	0.000%	0.000%
RBIG-P	0%					
RBIG-T	0%					
RBIG-D	0%					
RBSG	0%	0.000%	0.000%	0.000%	0.000%	0.000%
RBHG	0%	0.000%	0.000%	0.000%	0.000%	0.000%
RBGG	0%	0.000%	0.000%	0.000%	0.000%	0.000%
RBT	0%	0.000%	0.000%	0.000%	0.000%	0.000%
RBD	100%	25.144%	3.050%	58.864%	12.942%	0.000%
RBGP	100%	25.144%	3.050%	58.864%	12.942%	0.000%
RBGP-P	0%					
RBGP-T	0%					
RBGP-D	0%					
RBSE	0%	0.000%	0.000%	0.000%	0.000%	0.000%
RBOH	0%	0.000%	0.000%	0.000%	0.000%	0.000%
RBUG	0%	0.000%	0.000%	0.000%	0.000%	0.000%
RBTR	0%	0.000%	0.000%	0.000%	0.000%	0.000%
OM	100%	28.854%	3.752%	55.644%	11.749%	0.001%
OM-P	0%					
OM-T	0%					
OM-D	0%					
OMAG	100%	33.186%	4.716%	51.989%	10.109%	0.001%
OMAG-P	0%					
OMAG-T	0%					
OMAG-D	0%					
OMG	0%					
OMT	0%					
OMD	100%	28.854%	3.752%	55.644%	11.749%	0.001%
OMDLUGT	0%					
OMDS&E	100%	33.882%	4.702%	51.281%	10.133%	0.001%

City of Palo Alto

Prepared By EES Consulting, Inc.

CLASSIFICATION AND ALLOCATION BY CUSTOMER - CUSTOMER

Schedule 6.2

Test Year: 2025

Classification Factors	Total Allocated	Residential E-1	Commercial E-2	Commercial E-	Commercial E-	Lights
MARKET	0%					
GPLT	100%	25.144%	3.050%	58.864%	12.942%	0.000%
GPLT-P	0%					
GPLT-T	0%					
GPLT-D	0%					
GRSPLT	0%					
GRSPLT-P	0%					
GRSPLT-T	0%					
GRSPLT-D	0%					
NETPLT	100%	25.144%	3.050%	58.864%	12.942%	0.000%
NETPLT-P	0%					
NETPLT-T	0%					
NETPLT-D	0%					
TOTCST	0%					
TOTCST-P	0%					
TOTCST-T	0%					
TOTCST-D	0%					
OMP	0%					
OMWOP	100%	33.157%	4.710%	52.013%	10.119%	0.001%
OMWOP-P	0%					
OMWOP-T	0%					
OMWOP-D	0%					
UNP	0%					
LABORRB	0%					
LABORRR	0%					
TRANSP	0%					
ST	0%					
DC	0%					
PI	0%					
PROD	0%					
OMPT	0%					
NCPplcc	0%					
NCPPplcc	0%					
NCPSplcc	0%					
WEST	0%					

City of Palo Alto

Prepared By EES Consulting, Inc.

CLASSIFICATION AND ALLOCATION BY CUSTOMER - CUSTOMER

Schedule 6.2

Test Year: 2025

Classification Factors	Total Allocated	Residential E-1	Commercial E-2	Commercial E-	Commercial E-	Lights
REN	0%					
CALA	0%					
CREDIT	100.000000%	35.000%	50.000%	14.000%	1.000%	
CUST SERV	100.000000%	16.188%	7.502%	36.806%	39.149%	0.355%
SERV	100.000000%	20.159%	2.441%	63.455%	13.945%	
RR	100%	29.131%	9.306%	51.253%	10.308%	
RR-P	0%					
RR-T	0%					
RR-D	100%	29.131%	9.306%	51.253%	10.308%	
RBD-ST	100%	25.144%	3.050%	58.864%	12.942%	
RBD-NoDA	100.000000%	25.144%	3.050%	58.864%	12.942%	0.000%
DSRE	0%					
DSMEE	0%					
GF	100%	33.186%	4.716%	51.989%	10.109%	0.001%
GF-P	100%	33.186%	4.716%	51.989%	10.109%	0.001%
GF-T	100%	33.186%	4.716%	51.989%	10.109%	0.001%
GF-D	100%	33.186%	4.716%	51.989%	10.109%	0.001%
RSR	0%					
RBD-NoDA Services	100%	84.124%	10.259%	4.538%	1.079%	0.000%
Rcontr	100%	33.193%	4.659%	51.937%	10.210%	0.001%
Rcontr-P	0%					
Rcontr-D	0%					
Rcontr-T	0%					

Prepared By EES Consulting, Inc.

City of Palo Alto

CLASSIFICATION AND ALLOCATION BY CUSTOMER - DIRECT ASSIGNMENT
Schedule 6.2

Test Year: 2025

Classification Factors	Total Allocated	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
CP1	0%	0.000%	0.000%	0.000%	0.000%	0.000%
CP2	0%	0.000%	0.000%	0.000%	0.000%	0.000%
CPS	0%	0.000%	0.000%	0.000%	0.000%	0.000%
CP12	0%	0.000%	0.000%	0.000%	0.000%	0.000%
LF	0%					
TCP1	0%					
TCP2	0%					
TCPS	0%					
TCP12	0%					
TAE	0%					
CPG	0%					
CPT	0%					
AE	0%					
NCP	0%					
NCPP	0%					
NCPS	0%					
kWh	0%					
kWhP	0%					
kWhO	0%					
kWhPJAN	0%					
kWhPFEB	0%					
kWhPMAR	0%					
kWhPAPR	0%					
kWhPMAY	0%					
kWhPJUN	0%					
kWhPJUL	0%					
kWhPAUG	0%					
kWhPSEP	0%					
kWhPOCT	0%					
kWhPNOV	0%					
kWhPDEC	0%					
kWhOJAN	0%					
kWhOFEB	0%					
kWhOMAR	0%					
kWhOAPR	0%					
kWhOMAY	0%					
kWhOJUN	0%					
kWhOJUL	0%					
kWhOAUG	0%					
kWhOSEP	0%					

City of Palo Alto **Prepared By EES Consulting, Inc.**

CLASSIFICATION AND ALLOCATION BY CUSTOMER - DIRECT ASSIGNMENT
Schedule 6.2

Test Year: 2025

Classification Factors	Total Allocated	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
kWhOOCT	0%					
kWhONOV	0%					
kWhODEC	0%					
CUST	0%					
CUSTW	0%					
CUSTM	0%					
CUSTMR	0%					
MINSYSP	0%					
MINSYSC	0%					
MINSYST	0%					
100%DP	0%					
100%DC	0%					
100%DT	0%					
DA1	100%	0.000%	0.000%	0.000%	0.000%	100.000%
DA2	100%	0.000%	0.000%	40.000%	60.000%	0.000%
DA3	0%	0.000%	0.000%	0.000%	0.000%	0.000%
DA4	0%	0.000%	0.000%	0.000%	0.000%	0.000%
DA5	0%	0.000%	0.000%	0.000%	0.000%	0.000%
DA6	0%	0.000%	0.000%	0.000%	0.000%	0.000%
DA7	100%	15.993%	6.399%	35.490%	41.891%	0.226%
DA8	100%	15.993%	6.399%	35.490%	41.891%	0.226%
DA9	0%	0.000%	0.000%	0.000%	0.000%	0.000%
DA10	100%	100.000%	0.000%	0.000%	0.000%	0.000%
REV	100%	16.225%	7.001%	40.225%	35.228%	1.321%
REV-P	100%	16.225%	7.001%	40.225%	35.228%	1.321%
REV-T	100%	16.225%	7.001%	40.225%	35.228%	1.321%
REV-D	100%	16.225%	7.001%	40.225%	35.228%	1.321%
OTHER	0%					
RB	100%	0%	0%	0%	0%	100%
RB-P	0%	0%	0%	0%	0%	0%
RB-T	0%	0%	0%	0%	0%	0%
RB-D	100%	0%	0%	0%	0%	100%
RBG	0%	0%	0%	0%	0%	0%
RBIG	0%	0%	0%	0%	0%	0%
RBIG-P	0%	0%	0%	0%	0%	0%
RBIG-T	0%	0%	0%	0%	0%	0%
RBIG-D	0%	0%	0%	0%	0%	0%
RBSG	0%	0%	0%	0%	0%	0%
RBHG	0%	0%	0%	0%	0%	0%
RBGG	0%	0%	0%	0%	0%	0%
RBT	0%	0%	0%	0%	0%	0%
RBD	100%	0%	0%	0%	0%	100%

City of Palo Alto

Prepared By EES Consulting, Inc.

CLASSIFICATION AND ALLOCATION BY CUSTOMER - DIRECT ASSIGNMENT
Schedule 6.2

Test Year: 2025

Classification Factors	Total Allocated	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
RBGP	100%	0%	0%	0%	0%	100%
RBGP-P	0%	0%	0%	0%	0%	0%
RBGP-T	0%	0%	0%	0%	0%	0%
RBGP-D	100%	0%	0%	0%	0%	100%
RBSE	0%	0%	0%	0%	0%	0%
RBOH	0%	0%	0%	0%	0%	0%
RBUG	0%	0%	0%	0%	0%	0%
RBTR	0%	0%	0%	0%	0%	0%
OM	100%	0%	0%	0%	0%	100%
OM-P	0%	0%	0%	0%	0%	0%
OM-T	0%	0%	0%	0%	0%	0%
OM-D	100%	0%	0%	0%	0%	100%
OMAG	100%	0%	0%	0%	0%	100%
OMAG-P	0%	0%	0%	0%	0%	0%
OMAG-T	0%	0%	0%	0%	0%	0%
OMAG-D	100%	0%	0%	0%	0%	100%
OMG	0%	0%	0%	0%	0%	0%
OMT	0%	0%	0%	0%	0%	0%
OMD	100%	0%	0%	0%	0%	100%
OMDLUGT	0%					
OMDS&E	100%	0%	0%	0%	0%	100%
MARKET	0%					
GPLT	100%	0%	0%	0%	0%	100%
GPLT-P	0%	0%	0%	0%	0%	0%
GPLT-T	0%	0%	0%	0%	0%	0%
GPLT-D	100%	0%	0%	0%	0%	100%
GRSPLT	0%					
GRSPLT-P	0%					
GRSPLT-T	0%					
GRSPLT-D	0%					
NETPLT	100%	0%	0%	0%	0%	100%
NETPLT-P	0%	0%	0%	0%	0%	0%
NETPLT-T	0%	0%	0%	0%	0%	0%
NETPLT-D	100%	0%	0%	0%	0%	100%
TOTCST	0%					
TOTCST-P	0%					
TOTCST-T	0%					
TOTCST-D	0%					
OMP	0%	0%	0%	0%	0%	0%
OMWOP	100%	0%	0%	0%	0%	100%
OMWOP-P	0%	0%	0%	0%	0%	0%
OMWOP-T	0%	0%	0%	0%	0%	0%

City of Palo Alto

Prepared By EES Consulting, Inc.

CLASSIFICATION AND ALLOCATION BY CUSTOMER - DIRECT ASSIGNMENT
Schedule 6.2

Test Year: 2025

Classification Factors	Total Allocated	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
OMWOP-D	100%	0%	0%	0%	0%	100%
UNP	0%					
LABORRB	0%					
LABORRR	0%					
TRANSP	0%					
ST	0%					
DC	0%					
PI	0%					
PROD	0%					
OMPT	0%	0%	0%	0%	0%	0%
NCPplcc	0%					
NCPPplcc	0%					
NCPSplcc	0%					
WEST	0%					
REN	0%					
CALA	0%					
CREDIT	0%					
CUST SERV	0%					
SERV	0%					
RR	0%					
RR-P	0%					
RR-T	0%					
RR-D	0%					
RBD-ST	100%					100.000%
RBD-NoDA	0%					
DSRE	0%					
DSMEE	0%					
GF	100%	0.000%	0.000%	0.000%	0.000%	100.000%
GF-P	100%	0.000%	0.000%	0.000%	0.000%	100.000%
GF-T	100%	0.000%	0.000%	0.000%	0.000%	100.000%
GF-D	100%	0.000%	0.000%	0.000%	0.000%	100.000%
RSR	0%					
RBD-NoDA Services	0%					
Rcontr	100%					100.000%
Rcontr-P	100%					100.000%
Rcontr-D	100%					100.000%
Rcontr-T	100%					100.000%

City of Palo Alto
FORECAST OF REVENUES FROM CURRENT RATES
Schedule 7.1

	Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Number of Customers						
Jul-24	30,193	26,100	3,183	837	71	2
Aug-24	30,193	26,100	3,183	837	71	2
Sep-24	30,193	26,100	3,183	837	71	2
Oct-24	30,193	26,100	3,183	837	71	2
Nov-24	30,193	26,100	3,183	837	71	2
Dec-24	30,193	26,100	3,183	837	71	2
Jan-25	30,193	26,100	3,183	837	71	2
Feb-25	30,193	26,100	3,183	837	71	2
Mar-25	30,193	26,100	3,183	837	71	2
Apr-25	30,193	26,100	3,183	837	71	2
May-25	30,193	26,100	3,183	837	71	2
Jun-25	30,193	26,100	3,183	837	71	2
Total / Average	30,193	26,100	3,183	837	71	2
Forecast kWh						
Jul-24	69,728,396	10,047,691	4,823,364	25,354,847	29,344,725	157,769
Aug-24	74,503,529	10,836,529	4,964,387	27,745,735	30,799,109	157,769
Sep-24	75,658,405	9,476,043	4,734,220	28,027,226	33,263,147	157,769
Oct-24	65,340,638	9,558,379	4,333,383	24,447,795	26,843,312	157,769
Nov-24	69,856,019	10,739,687	4,263,783	24,918,097	29,776,683	157,769
Dec-24	65,331,624	10,795,783	4,432,799	23,767,626	26,177,647	157,769
Jan-25	73,125,979	15,252,399	4,560,746	22,602,289	30,552,776	157,769
Feb-25	69,834,775	12,886,886	4,440,722	24,513,210	27,836,188	157,769
Mar-25	64,774,498	12,886,886	4,252,277	21,736,433	25,741,133	157,769
Apr-25	65,881,345	10,293,013	3,917,332	22,881,308	28,631,923	157,769
May-25	67,111,575	10,016,184	4,176,855	24,182,374	28,578,394	157,769
Jun-25	70,797,053	10,263,351	4,337,854	25,078,476	30,959,603	157,769
Total / Average	831,943,836	133,052,833	53,237,722	295,255,415	348,504,639	1,893,227

FORECAST OF REVENUES FROM CURRENT RATES
Schedule 7.1

		Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Energy Rates				$0.1806	$0.1210		
Flat Rate:		Flat Rate $/kWh					
Seasonal Rate:		J-24		$0.25991	$0.15795	$0.13992	
		A-24		$0.25991	$0.15795	$0.13992	
		S-24		$0.25991	$0.15795	$0.13992	
		O-24		$0.25991	$0.15795	$0.13992	
		N-24		$0.18057	$0.13667	$0.09287	
		D-24		$0.18057	$0.13667	$0.09287	
		J-25		$0.18057	$0.13667	$0.09287	
		F-25		$0.18057	$0.13667	$0.09287	
		M-25		$0.18057	$0.13667	$0.09287	
		A-25		$0.18057	$0.13667	$0.09287	
		M-25		$0.25991	$0.15795	$0.13992	
		J-25		$0.25991	$0.15795	$0.13992	
Distribution Charge for $/kWh:							
Block Rate:	1st Block kWh		$0.1695				
	2nd Block kWh		$0.24098				
	% in first block						
	1st Block $/kWh		50%	100%	100%	100%	
	2nd Block $/kWh		50%				
Energy Revenues							
Jul-24		$11,426,691	$2,062,339	$1,253,640	$4,004,798	$4,105,914	$0
Aug-24		$12,206,396	$2,224,252	$1,290,294	$4,382,439	$4,309,411	$0
Sep-24		$12,256,556	$1,945,005	$1,230,471	$4,426,900	$4,654,179	$0
Oct-24		$10,705,640	$1,961,905	$1,126,290	$3,861,529	$3,755,916	$0
Nov-24		$9,145,203	$2,204,374	$769,911	$3,405,556	$2,765,361	$0
Dec-24		$8,695,758	$2,215,889	$800,431	$3,248,321	$2,431,118	$0
Jan-25		$9,880,656	$3,130,631	$823,534	$3,089,055	$2,837,436	$0
Feb-25		$9,382,326	$2,645,098	$801,861	$3,350,220	$2,585,147	$0
Mar-25		$8,774,229	$2,645,098	$767,834	$2,970,718	$2,390,579	$0
Apr-25		$8,606,280	$2,112,692	$707,353	$3,127,188	$2,659,047	$0
May-25		$10,959,773	$2,055,872	$1,085,606	$3,819,606	$3,998,689	$0
Jun-25		$11,527,069	$2,106,604	$1,127,452	$3,961,145	$4,331,868	$0
Subtotal		$123,566,578	$27,309,759	$11,784,676	$43,647,477	$40,824,665	$0
Surcharge/Discounts		$0					
Total		$123,566,578	$27,309,759	$11,784,676	$43,647,477	$40,824,665	$0

FORECAST OF REVENUES FROM CURRENT RATES
Schedule 7.1

	Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Demand kW						
Jul-24	148,032	20,223	11,639	65,431	50,134	606
Aug-24	151,008	21,377	13,191	65,627	50,284	530
Sep-24	151,269	19,118	12,406	67,977	51,280	487
Oct-24	148,549	18,106	13,961	65,108	50,950	424
Nov-24	157,405	20,712	14,292	70,111	51,892	398
Dec-24	163,545	20,262	11,056	75,010	56,863	353
Jan-25	150,616	28,211	9,431	63,847	48,801	326
Feb-25	146,886	26,483	12,015	58,871	49,127	391
Mar-25	137,130	24,101	11,059	56,143	45,442	386
Apr-25	143,248	22,692	11,104	57,987	51,028	438
May-25	140,778	20,712	11,228	58,321	50,046	471
Jun-25	146,854	22,626	12,552	59,586	51,543	548
Total / Average						
Total	1,785,322	264,621	143,933	764,019	607,389	5,359
Demand Revenues	**Rate: $/kVa**					**$0.00**
Demand Revenues	**Rate: $/kW**					
Jul-24				$38.82	$39.08	
Aug-24				$38.82	$39.08	
Sep-24				$38.82	$39.08	
Oct-24				$38.82	$39.08	
Nov-24				$24.16	$21.71	
Dec-24				$24.16	$21.71	
Jan-25				$24.16	$21.71	
Feb-25				$24.16	$21.71	
Mar-25				$24.16	$21.71	
Apr-25				$24.16	$21.71	
May-25				$38.82	$39.08	
Jun-25				$38.82	$39.08	

FORECAST OF REVENUES FROM CURRENT RATES
Schedule 7.1

	Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Jul-24	$4,499,246	$0	$0	$2,540,016	$1,959,231	$0
Aug-24	$4,512,744	$0	$0	$2,547,636	$1,965,108	$0
Sep-24	$4,642,921	$0	$0	$2,638,881	$2,004,041	$0
Oct-24	$4,518,626	$0	$0	$2,527,495	$1,991,130	$0
Nov-24	$2,820,451	$0	$0	$1,693,875	$1,126,576	$0
Dec-24	$3,046,746	$0	$0	$1,812,254	$1,234,492	$0
Jan-25	$2,602,019	$0	$0	$1,542,549	$1,059,470	$0
Feb-25	$2,488,859	$0	$0	$1,422,322	$1,066,538	$0
Mar-25	$2,342,942	$0	$0	$1,356,404	$986,539	$0
Apr-25	$2,508,780	$0	$0	$1,400,962	$1,107,818	$0
May-25	$4,219,820	$0	$0	$2,264,028	$1,955,793	$0
Jun-25	$4,327,409	$0	$0	$2,313,126	$2,014,283	$0
Total	$42,530,564	$0	$0	$24,059,546	$18,471,018	$0
				$31.49	$30.41	

Total Revenues		Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Jul-24	$15,925,938	$2,062,339	$1,253,640	$6,544,814	$6,065,144	$0
Aug-24	$16,719,140	$2,224,252	$1,290,294	$6,930,075	$6,274,520	$0
Sep-24	$16,899,478	$1,945,005	$1,230,471	$7,065,781	$6,658,220	$0
Oct-24	$15,224,266	$1,961,905	$1,126,290	$6,389,025	$5,747,047	$0
Nov-24	$11,965,654	$2,204,374	$769,911	$5,099,431	$3,891,937	$0
Dec-24	$11,742,504	$2,215,889	$800,431	$5,060,575	$3,665,610	$0
Jan-25	$12,482,675	$3,130,631	$823,534	$4,631,604	$3,896,907	$0
Feb-25	$11,871,186	$2,645,098	$801,861	$4,772,542	$3,651,684	$0
Mar-25	$11,117,171	$2,645,098	$767,834	$4,327,122	$3,377,118	$0
Apr-25	$11,115,060	$2,112,692	$707,353	$4,528,150	$3,766,865	$0
May-25	$15,179,593	$2,055,872	$1,085,606	$6,083,634	$5,954,481	$0
Jun-25	$15,854,477	$2,106,604	$1,127,452	$6,274,271	$6,346,150	$0
Subtotal	**$166,097,142**	$27,309,759	$11,784,676	$67,707,023	$59,295,683	$0
Surcharge/Discounts	**$2,224,184**					$2,224,184
Total	**$168,321,326**	$27,309,759	$11,784,676	$67,707,023	$59,295,683	$2,224,184
Actual Revenue 2020	**$121,767,882**	$25,990,767	$0	$78,969,022	$16,808,093	

Prepared By EES Consulting, Inc.

City of Palo Alto

RECORDED CUSTOMERS AND ENERGY SALES
Schedule 8.4

Number of Customers / Services		Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
	Jul-20	29,646	25,600	3,146	828	70	2
	Aug-20	29,646	25,600	3,146	828	70	2
	Sep-20	29,646	25,600	3,146	828	70	2
	Oct-20	29,646	25,600	3,146	828	70	2
	Nov-20	29,646	25,600	3,146	828	70	2
	Dec-20	29,646	25,600	3,146	828	70	2
	Jan-21	29,646	25,600	3,146	828	70	2
	Feb-21	29,646	25,600	3,146	828	70	2
	Mar-21	29,646	25,600	3,146	828	70	2
	Apr-21	29,646	25,600	3,146	828	70	2
	May-21	29,646	25,600	3,146	828	70	2
	Jun-21	29,657	25,600	3,155	830	70	2
Total Average		29,647	25,600	3,147	828	70	2

Historic Energy, Demand And Customer Count
Historic Year

	Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Input Recorded Data						
Energy Sales (kWh)	815,778,523	161,545,337	45,675,813	242,402,726	364,257,301	1,897,346
Total Billing Capacity (kW)	1,297,123	0	0	669,694	627,429	0
Avg. Monthly Billing Capacity (kW)	108,094	0	0	55,808	52,286	0
Number of Customers	29,647	25,600	3,147	828	70	2
Ratio of NCP to Avg. Billing Capacity	0	0	0	1	1	0
Rate Classes NCP Demand at Meter	143,946	26,353	9,983	56,601	50,402	607
Estimated Based on Recorded Data						
Annual NCP Load Factor	65%	70%	52%	49%	82%	36%
Rate Classes CP Demand at Input Voltage	129,587	21,580	6,696	48,905	52,406	0
Annual CP Load Factor	72%	85%	78%	57%	79%	0%
Average On-Peak kWh as a % of Total kWh	0	59%	59%	59%	59%	59%
Average Off-Peak kWh as a % of Total kWh	0	41%	41%	41%	41%	41%

Load Data And Customer Sales
By Rate Class
-- Recorded Year --

kWh Sales at the Meter		Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
	Jul-20	73,231,986	14,023,120	3,706,590	20,012,168	35,331,996	158,112
	Aug-20	73,849,149	12,251,918	3,952,369	23,388,764	34,097,986	158,112
	Sep-20	68,373,227	14,404,467	4,238,732	21,872,119	27,699,797	158,112
	Oct-20	70,549,047	11,747,936	3,748,368	20,983,888	33,910,743	158,112
	Nov-20	70,794,348	12,875,793	3,843,162	22,652,340	31,264,941	158,112
	Dec-20	65,980,397	14,943,618	3,802,946	18,419,856	28,655,865	158,112
	Jan-21	73,133,571	17,810,143	4,189,079	19,934,934	31,041,303	158,112
	Feb-21	61,492,368	13,177,401	3,776,468	18,167,050	26,213,337	158,112
	Mar-21	66,127,244	15,568,887	3,644,218	18,844,923	27,911,104	158,112
	Apr-21	64,491,682	12,519,998	3,635,974	18,951,818	29,225,780	158,112
	May-21	60,888,633	11,166,525	3,553,485	19,181,670	26,828,841	158,112
	Jun-21	66,866,869	11,055,531	3,584,422	19,993,196	32,075,608	158,112
Total Sales		815,778,523	161,545,337	45,675,813	242,402,726	364,257,301	1,897,346

Prepared By EES Consulting, Inc.

City of Palo Alto

RECORDED CUSTOMER DEMAND
Schedule 8.5

Metered Demand - kVA

	Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Jul-20	115,509	0	0	56,986	58,523	0
Aug-20	116,971	0	0	59,892	57,079	0
Sep-20	112,729	0	0	64,300	48,429	0
Oct-20	120,509	0	0	63,081	57,428	0
Nov-20	118,056	0	0	64,070	53,986	0
Dec-20	101,695	0	0	51,203	50,492	0
Jan-21	96,729	0	0	48,603	48,126	0
Feb-21	95,270	0	0	48,287	46,983	0
Mar-21	102,713	0	0	51,730	50,983	0
Apr-21	106,043	0	0	51,216	54,827	0
May-21	95,855	0	0	52,131	43,725	0
Jun-21	115,044	0	0	58,194	56,850	0
Total	1,297,123	0	0	669,694	627,429	0

Individual Load Factor

	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Jul-20	66.78%	55.70%	47.20%	81.15%	35.00%
Aug-20	68.14%	50.59%	52.49%	80.29%	40.00%
Sep-20	68.84%	53.00%	45.72%	76.88%	45.00%
Oct-20	70.96%	41.72%	44.71%	79.37%	50.00%
Nov-20	72.02%	41.43%	47.52%	77.84%	55.00%
Dec-20	71.61%	53.89%	48.35%	76.28%	60.00%
Jan-21	72.67%	65.00%	55.13%	86.69%	65.00%
Feb-21	72.41%	55.00%	50.57%	74.99%	60.00%
Mar-21	71.87%	51.68%	48.96%	73.58%	55.00%
Apr-21	63.00%	49.00%	49.74%	71.65%	50.00%
May-21	65.00%	50.00%	49.46%	82.47%	45.00%
Jun-21	63.00%	48.00%	46.18%	75.84%	40.00%

Individual NCP (kW)

	Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
	Power Factor:	100%	100%	100%	100%	100%
Jul-20	153,284	28,224	8,944	56,986	58,523	607
Aug-20	155,944	26,758	11,627	59,892	57,079	588
Sep-20	152,074	28,124	10,749	64,300	48,429	472
Oct-20	156,422	22,995	12,479	63,081	57,428	439
Nov-20	154,939	24,030	12,467	64,070	53,986	386
Dec-20	140,844	28,982	9,801	51,203	50,492	366
Jan-21	138,660	32,941	8,662	48,603	48,126	327
Feb-21	129,312	24,459	9,229	48,287	46,983	354
Mar-21	142,993	30,087	9,793	51,730	50,983	399
Apr-21	143,152	26,711	9,974	51,216	54,827	425
May-21	130,074	23,860	9,871	52,131	43,725	488
Jun-21	149,199	23,587	10,037	58,194	56,850	531
Maximum	156,422	32,941	12,479	64,300	58,523	607

Prepared By EES Consulting, Inc.

Group Coincidence Factor	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Jul-20	80.00%	80.00%	86.88%	86.12%	100.00%
Aug-20	80.00%	80.00%	86.88%	86.12%	100.00%
Sep-20	80.00%	80.00%	86.88%	86.12%	100.00%
Oct-20	70.00%	80.00%	86.88%	86.12%	100.00%
Nov-20	80.00%	80.00%	88.34%	85.06%	100.00%
Dec-20	90.00%	90.00%	82.99%	83.64%	100.00%
Jan-21	80.00%	80.00%	82.50%	85.08%	100.00%
Feb-21	80.00%	80.00%	82.50%	85.08%	100.00%
Mar-21	80.00%	80.00%	86.91%	80.23%	100.00%
Apr-21	80.00%	80.00%	85.76%	82.17%	100.00%
May-21	85.00%	85.00%	84.76%	83.77%	100.00%
Jun-21	80.00%	80.00%	86.04%	83.68%	100.00%

Rate Class NCP @ Meter (kW)		Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Jul-20	130,254	22,579	7,155	49,510	50,402	607
Aug-20	132,490	21,406	9,301	52,035	49,159	588
Sep-20	129,144	22,499	8,600	55,864	41,709	472
Oct-20	130,784	16,097	9,983	54,805	49,459	439
Nov-20	132,104	19,224	9,974	56,601	45,919	386
Dec-20	119,994	26,084	8,821	42,494	42,230	366
Jan-21	114,650	26,353	6,930	40,096	40,944	327
Feb-21	107,111	19,567	7,383	39,835	39,971	354
Mar-21	118,165	24,070	7,835	44,959	40,903	399
Apr-21	118,745	21,369	7,979	43,922	45,050	425
May-21	109,973	20,281	8,390	44,183	36,630	488
Jun-21	125,071	18,869	8,030	50,071	47,570	531
Maximum	132,490	26,353	9,983	56,601	50,402	607

Rate Class NCP @ Primary Voltage (kW)		Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
	Line Losses:	2.85%	2.85%	2.85%	2.85%	2.85%
Jul-20	134,079	23,242	7,365	50,964	51,882	625
Aug-20	136,380	22,035	9,575	53,563	50,602	605
Sep-20	132,936	23,159	8,852	57,505	42,934	486
Oct-20	134,624	16,570	10,276	56,415	50,912	452
Nov-20	135,984	19,789	10,266	58,263	47,268	398
Dec-20	123,518	26,850	9,080	43,742	43,470	377
Jan-21	118,016	27,127	7,133	41,273	42,146	337
Feb-21	110,256	20,142	7,600	41,005	41,145	365
Mar-21	121,635	24,777	8,065	46,279	42,104	411
Apr-21	122,232	21,996	8,213	45,212	46,373	438
May-21	113,202	20,877	8,637	45,481	37,705	502
Jun-21	128,744	19,423	8,265	51,541	48,967	547
Maximum	136,380	27,127	10,276	58,263	51,882	625

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Rate Class NCP @ Input Voltage (kW)

		Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
	Line Losses:	1.00%	1.00%	1.00%	1.00%	1.00%
Jul-20	135,433	23,477	7,440	51,478	52,406	631
Aug-20	137,758	22,258	9,671	54,104	51,114	612
Sep-20	134,279	23,393	8,942	58,086	43,368	491
Oct-20	135,984	16,737	10,380	56,985	51,426	457
Nov-20	137,357	19,989	10,370	58,852	47,745	402
Dec-20	124,766	27,121	9,172	44,183	43,909	381
Jan-21	119,208	27,401	7,205	41,690	42,572	340
Feb-21	111,370	20,345	7,677	41,419	41,561	368
Mar-21	122,864	25,027	8,146	46,746	42,529	415
Apr-21	123,466	22,219	8,296	45,668	46,842	442
May-21	114,345	21,088	8,724	45,940	38,086	507
Jun-21	130,044	19,620	8,349	52,062	49,462	552
Maximum	137,758	27,401	10,380	58,852	52,406	631

System Coincidence Factor

	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Jul-20	91.92%	90.00%	95.00%	100.00%	0.00%
Aug-20	66.42%	90.00%	95.00%	100.00%	0.00%
Sep-20	76.11%	85.00%	90.00%	100.00%	0.00%
Oct-20	60.19%	85.00%	90.00%	100.00%	100.00%
Nov-20	81.25%	60.00%	82.00%	100.00%	100.00%
Dec-20	86.82%	90.00%	95.00%	100.00%	100.00%
Jan-21	93.28%	60.00%	72.00%	90.00%	100.00%
Feb-21	88.98%	90.00%	95.00%	100.00%	100.00%
Mar-21	90.27%	80.00%	88.00%	100.00%	100.00%
Apr-21	67.71%	70.00%	80.00%	100.00%	0.00%
May-21	70.75%	95.00%	95.00%	100.00%	0.00%
Jun-21	87.30%	95.00%	100.00%	100.00%	0.00%

Coincident Peak (CP) @ Input (kW)

	Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Jul-20	129,587	21,580	6,696	48,905	52,406	0
Aug-20	126,000	14,784	8,704	51,398	51,114	0
Sep-20	121,049	17,804	7,600	52,277	43,368	0
Oct-20	122,065	10,073	8,823	51,286	51,426	457
Nov-20	118,868	16,241	6,222	48,258	47,745	402
Dec-20	118,065	23,547	8,255	41,974	43,909	381
Jan-21	98,555	25,561	4,323	30,017	38,315	340
Feb-21	106,290	18,104	6,909	39,348	41,561	368
Mar-21	113,189	22,591	6,517	41,137	42,529	415
Apr-21	104,227	15,044	5,807	36,535	46,842	0
May-21	104,938	14,920	8,288	43,643	38,086	0
Jun-21	126,583	17,128	7,931	52,062	49,462	0
Total	1,389,416	217,376	86,075	536,840	546,762	2,362
Peak Month	129,587	21,580	6,696	48,905	52,406	0

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City of Palo Alto

RECORDED kWh AT INPUT
Schedule 8.6

kWh @ Input Voltage		Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
	Jul-20	76,166,455	14,585,038	3,855,116	20,814,073	36,747,779	164,448
	Aug-20	76,808,348	12,742,863	4,110,744	24,325,972	35,464,322	164,448
	Sep-20	71,113,001	14,981,666	4,408,582	22,748,554	28,809,752	164,448
	Oct-20	73,376,008	12,218,686	3,898,568	21,824,730	35,269,576	164,448
	Nov-20	73,631,139	13,391,737	3,997,161	23,560,039	32,517,754	164,448
	Dec-20	68,624,288	15,542,422	3,955,333	19,157,955	29,804,130	164,448
	Jan-21	76,064,096	18,523,811	4,356,939	20,733,744	32,285,155	164,448
	Feb-21	63,956,420	13,705,431	3,927,794	18,895,019	27,263,728	164,448
	Mar-21	68,777,020	16,192,746	3,790,245	19,600,055	29,029,526	164,448
	Apr-21	67,075,919	13,021,685	3,781,671	19,711,234	30,396,882	164,448
	May-21	63,328,493	11,613,977	3,695,876	19,950,296	27,903,896	164,448
	Jun-21	69,546,282	11,498,536	3,728,053	20,794,341	33,360,905	164,448
Total Purchases - Bottom Up		848,467,469	168,018,597	47,506,082	252,116,011	378,853,404	1,973,374

Historic Load Reconciliation	Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Secondary Line Losses		2.85%	2.85%	2.85%	2.85%	2.85%
Primary Line Losses		1.00%	1.00%	1.00%	1.00%	1.00%

	Total	Jul-20	Aug-20	Sep-20	Oct-20	Dec-20
Recorded Energy Purchases kWh	825,333,010	70,830,000	75,565,000	71,045,000	70,942,000	70,740,000
Bottom-Up Energy Purchases kWh	848,467,469	76,166,455	76,808,348	71,113,001	73,376,008	68,624,288
% Difference	-2.73%	-7%	-2%	0%	-3%	3%
Measured System Demand kW	1,498,919	130,922	145,019	140,484	127,402	120,490
CP @ Input Demand kW	1,389,416	129,587	126,000	121,049	122,065	118,065
% Difference	7.9%	1.0%	15.1%	16.1%	4.4%	2.1%

On-Peak Energy Use by Percentage		Average	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
	Jul-20	57%	57%	57%	57%	57%	57%
	Aug-20	60%	60%	60%	60%	60%	60%
	Sep-20	61%	61%	61%	61%	61%	61%
	Oct-20	61%	61%	61%	61%	61%	61%
	Nov-20	57%	57%	57%	57%	57%	57%
	Dec-20	62%	62%	62%	62%	62%	62%
	Jan-21	57%	57%	57%	57%	57%	57%
	Feb-21	60%	60%	60%	60%	60%	60%
	Mar-21	61%	61%	61%	61%	61%	61%
	Apr-21	61%	61%	61%	61%	61%	61%
	May-21	57%	57%	57%	57%	57%	57%
	Jun-21	62%	62%	62%	62%	62%	62%
Total (Derived)		59%	*59%*	*59%*	*59%*	*59%*	*59%*

Prepared By EES Consulting, Inc.

On-Peak kWh @ Input Voltage		Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
	Jul-20	43,523,334	8,334,240	2,202,906	11,893,659	20,998,560	93,969
	Aug-20	45,943,446	7,622,232	2,458,870	14,550,749	21,213,230	98,366
	Sep-20	43,054,796	9,070,530	2,669,140	13,772,929	17,442,633	99,564
	Oct-20	44,473,644	7,405,820	2,362,946	13,228,102	21,377,104	99,673
	Nov-20	42,019,648	7,642,366	2,281,090	13,445,188	18,557,157	93,847
	Dec-20	42,373,311	9,596,950	2,442,292	11,829,427	18,403,100	101,541
	Jan-21	43,464,843	10,584,948	2,489,659	11,847,757	18,448,509	93,969
	Feb-21	38,255,976	8,197,998	2,349,437	11,302,187	16,307,988	98,366
	Mar-21	41,640,495	9,803,768	2,294,773	11,866,696	17,575,694	99,564
	Apr-21	40,655,122	7,892,522	2,292,094	11,947,098	18,423,735	99,673
	May-21	36,140,158	6,627,838	2,109,154	11,385,189	15,924,131	93,847
	Jun-21	42,942,613	7,099,979	2,301,954	12,839,843	20,599,296	101,541
Total On-Peak Energy - Bottom-Up		504,487,387	99,879,191	28,254,316	149,908,824	225,271,136	1,173,919

Off-Peak Energy Use by Percentage		Average	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
	Jul-20	43%	43%	43%	43%	43%	43%
	Aug-20	40%	40%	40%	40%	40%	40%
	Sep-20	39%	39%	39%	39%	39%	39%
	Oct-20	39%	39%	39%	39%	39%	39%
	Nov-20	43%	43%	43%	43%	43%	43%
	Dec-20	38%	38%	38%	38%	38%	38%
	Jan-21	43%	43%	43%	43%	43%	43%
	Feb-21	40%	40%	40%	40%	40%	40%
	Mar-21	39%	39%	39%	39%	39%	39%
	Apr-21	39%	39%	39%	39%	39%	39%
	May-21	43%	43%	43%	43%	43%	43%
	Jun-21	38%	38%	38%	38%	38%	38%
Total (Derived)		41%	*41%*	*41%*	*41%*	*41%*	*41%*

Off-Peak kWh @ Input Voltage		Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
	Jul-20	32,643,121	6,250,799	1,652,211	8,920,414	15,749,220	70,478
	Aug-20	30,864,902	5,120,631	1,651,874	9,775,223	14,251,092	66,082
	Sep-20	28,058,205	5,911,137	1,739,441	8,975,624	11,367,119	64,884
	Oct-20	28,902,364	4,812,866	1,535,622	8,596,629	13,892,472	64,775
	Nov-20	31,611,490	5,749,372	1,716,070	10,114,850	13,960,597	70,601
	Dec-20	26,250,977	5,945,472	1,513,041	7,328,529	11,401,030	62,907
	Jan-21	32,599,253	7,938,862	1,867,280	8,885,987	13,836,645	70,478
	Feb-21	25,700,444	5,507,432	1,578,357	7,592,832	10,955,740	66,082
	Mar-21	27,136,525	6,388,978	1,495,472	7,733,359	11,453,832	64,884
	Apr-21	26,420,797	5,129,163	1,489,577	7,764,135	11,973,147	64,775
	May-21	27,188,335	4,986,140	1,586,722	8,565,107	11,979,765	70,601
	Jun-21	26,603,669	4,398,556	1,426,099	7,954,498	12,761,609	62,907
Total Off-Peak Energy - Bottom-Up		343,980,083	68,139,407	19,251,766	102,207,187	153,582,267	799,455

Prepared By EES Consulting, Inc.

City of Palo Alto

SUMMARY OF
FORECAST ENERGY, DEMAND AND CUSTOMER COUNT

	Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
	0					
Energy Sales (kWh)	831,943,836	133,052,833	53,237,722	295,255,415	348,504,639	1,893,227
Total Billing Capacity (kVa)	1,371,408	0	0	764,019	607,389	0
Avg. Monthly Billing Capacity (kVa)	114,284	0	0	63,668	50,616	0
Number of Customers	30,193	26,100	3,183	837	71	2
Ratio of NCP to Avg. Billing	2	0%	0%	98%	94%	0%
Rate Classes NCP Demand at Meter	144,419	22,568	11,434	62,252	47,558	606
Annual NCP Load Factor	3	67%	53%	54%	84%	36%
Rate Classes CP Demand at Input Voltage	137,082	16,462	9,311	61,491	49,449	367
Annual CP Load Factor	4	92%	65%	55%	80%	59%
On-Peak kWh as a % of Total kWh	3	59%	59%	59%	59%	59%
Off-Peak kWh as a % of Total kWh	2	41%	41%	41%	41%	41%

FORECAST CUSTOMERS AND ENERGY SALES
Schedule 8.1

	Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Current kWh Forecast:						
2022	815,778,523	161,545,337	45,675,813	242,402,726	364,257,301	1,897,346
Forecast Year: 2022	814,734,383	150,839,180	46,559,059	258,128,836	357,314,081	1,893,227
Forecast Year: 2023	810,356,252	158,172,937	52,965,635	261,629,660	335,694,792	1,893,227
Forecast Year: 2024	831,943,836	133,052,833	53,237,722	295,255,415	348,504,639	1,893,227
Forecast Year: 2025	831,943,836	133,052,833	53,237,722	295,255,415	348,504,639	1,893,227
Forecast Year: 2026	836,224,351	133,738,977	53,512,265	296,778,028	350,301,854	1,893,227
Current Customer Forecast:						
2022	29,647	25,600	3,147	828	70	2
Forecast Year: 2022	29,683	25,626	3,155	830	70	2
Forecast Year: 2023	30,012	25,944	3,164	832	70	2
Forecast Year: 2024	30,102	26,022	3,173	834	71	2
Forecast Year: 2025	30,193	26,100	3,183	837	71	2
Forecast Year: 2026	30,284	26,178	3,193	840	71	2

Forecast Rate Class Customer Count	Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Jul-24	30,193	26,100	3,183	837	71	2
Aug-24	30,193	26,100	3,183	837	71	2
Sep-24	30,193	26,100	3,183	837	71	2
Oct-24	30,193	26,100	3,183	837	71	2
Nov-24	30,193	26,100	3,183	837	71	2
Dec-24	30,193	26,100	3,183	837	71	2
Jan-25	30,193	26,100	3,183	837	71	2
Feb-25	30,193	26,100	3,183	837	71	2
Mar-25	30,193	26,100	3,183	837	71	2
Apr-25	30,193	26,100	3,183	837	71	2
May-25	30,193	26,100	3,183	837	71	2
Jun-25	30,193	26,100	3,183	837	71	2
Total Average Forecast Customers	30,193	26,100	3,183	837	71	2

City of Palo Alto

Prepared By EES Consulting, Inc.

FORECAST CUSTOMERS AND ENERGY SALES

Schedule 8.1

Customer Information	Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Weighting Factors for:						
Customers Meters & Services		$ 994.00	$ 994.00	$ 1,672.00	$ 4,698.00	$ -
Customer Billing and Collection		1.00	1.25	27.00	48.00	1.00
Customer Meter Reading		1.00	1.25	27.00	48.00	0.00
Weighted Number of Customers						
Customers Meters & Services	30,839,588	25,943,400	3,163,902	1,399,464	332,822	-
Customer Billing and Collection	56,080	26,100	3,979	22,599	3,400	2
Customer Meter Reading	56,078	26,100	3,979	22,599	3,400	-
Provided Services						
Power Purchased from Utility*		1	1	1	1	1
Reg & Shaping from Utility*		1	1	1	1	1
Uses Utility Transmission*		1	1	1	1	1
Uses Primary Distribution*		1	1	1	1	1
Uses Secondary Distribution*		1	1	1	1	1

Test Date Forecast Rate Class Sales kWh		Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
	Jul-22	67,689,876	11,430,517	3,842,021	23,573,069	28,686,500	157,769
	Aug-22	68,217,175	11,336,143	3,739,407	23,520,212	29,463,644	157,769
	Sep-22	73,543,374	12,597,531	4,233,790	26,249,560	30,304,724	157,769
	Oct-22	70,184,004	11,053,402	3,972,027	25,015,742	29,985,064	157,769
	Nov-22	65,022,004	12,135,523	3,302,030	22,290,316	27,136,366	157,769
	Dec-22	69,444,669	15,288,678	3,622,175	21,912,700	28,463,347	157,769
	Jan-23	71,077,996	16,288,179	3,826,925	22,656,899	28,148,224	157,769
	Feb-23	66,135,441	15,360,803	3,506,239	20,702,276	26,408,354	157,769
	Mar-23	80,239,962	15,486,385	4,660,352	20,960,972	38,974,484	157,769
	Apr-23	70,916,234	13,739,325	3,847,262	22,331,572	30,840,306	157,769
	May-23	62,208,176	11,021,806	3,385,099	21,388,033	26,255,469	157,769
	Jun-23	45,677,342	12,434,645	11,028,308	11,028,309	11,028,310	157,769
Total Sales		810,356,252	158,172,937	52,965,635	261,629,660	335,694,792	1,893,227

Forecast Rate Class Sales kWh		Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
	Jul-24	69,728,396	10,047,691	4,823,364	25,354,847	29,344,725	157,769
	Aug-24	74,503,529	10,836,529	4,964,387	27,745,735	30,799,109	157,769
	Sep-24	75,658,405	9,476,043	4,734,220	28,027,226	33,263,147	157,769
	Oct-24	65,340,638	9,558,379	4,333,383	24,447,795	26,843,312	157,769
	Nov-24	69,856,019	10,739,687	4,263,783	24,918,097	29,776,683	157,769
	Dec-24	65,331,624	10,795,783	4,432,799	23,767,626	26,177,647	157,769
	Jan-25	73,125,979	15,252,399	4,560,746	22,602,289	30,552,776	157,769
	Feb-25	69,834,775	12,886,886	4,440,722	24,513,210	27,836,188	157,769
	Mar-25	64,774,498	12,886,886	4,252,277	21,736,433	25,741,133	157,769
	Apr-25	65,881,345	10,293,013	3,917,332	22,881,308	28,631,923	157,769
	May-25	67,111,575	10,016,184	4,176,855	24,182,374	28,578,394	157,769
	Jun-25	70,797,053	10,263,351	4,337,854	25,078,476	30,959,603	157,769
Total Sales		831,943,836	133,052,833	53,237,722	295,255,415	348,504,639	1,893,227

City of Palo Alto

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FORECAST CUSTOMERS AND ENERGY SALES
Schedule 8.1

City of Palo Alto

FORECAST CUSTOMER DEMAND
Schedule 8.2

Billing Demand - kW

	Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Jul-24	115,564	0	0	65,431	50,134	0
Aug-24	115,911	0	0	65,627	50,284	0
Sep-24	119,258	0	0	67,977	51,280	0
Oct-24	116,058	0	0	65,108	50,950	0
Nov-24	122,003	0	0	70,111	51,892	0
Dec-24	131,873	0	0	75,010	56,863	0
Jan-25	112,648	0	0	63,847	48,801	0
Feb-25	107,997	0	0	58,871	49,127	0
Mar-25	101,584	0	0	56,143	45,442	0
Apr-25	109,015	0	0	57,987	51,028	0
May-25	108,367	0	0	58,321	50,046	0
Jun-25	111,128	0	0	59,586	51,543	0
Total	1,371,408	0	0	764,019	607,389	0

Individual Load Factor

	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Jul-24	67%	56%	47%	81%	35%
Aug-24	68%	51%	52%	80%	40%
Sep-24	69%	53%	46%	77%	45%
Oct-24	71%	42%	45%	79%	50%
Nov-24	72%	41%	48%	78%	55%
Dec-24	72%	54%	48%	76%	60%
Jan-25	73%	65%	55%	87%	65%
Feb-25	72%	55%	51%	75%	60%
Mar-25	72%	52%	49%	74%	55%
Apr-25	63%	49%	50%	72%	50%
May-25	65%	50%	49%	82%	45%
Jun-25	63%	48%	46%	76%	40%

Individual NCP (kW)

	Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Jul-24	148,032	20,223	11,639	65,431	50,134	606
Aug-24	151,008	21,377	13,191	65,627	50,284	530
Sep-24	151,269	19,118	12,406	67,977	51,280	487
Oct-24	148,549	18,106	13,961	65,108	50,950	424
Nov-24	157,405	20,712	14,292	70,111	51,892	398
Dec-24	163,545	20,262	11,056	75,010	56,863	353
Jan-25	150,616	28,211	9,431	63,847	48,801	326
Feb-25	146,886	26,483	12,015	58,871	49,127	391
Mar-25	137,130	24,101	11,059	56,143	45,442	386
Apr-25	143,248	22,692	11,104	57,987	51,028	438
May-25	140,778	20,712	11,228	58,321	50,046	471
Jun-25	146,854	22,626	12,552	59,586	51,543	548
Maximum	163,545	28,211	14,292	75,010	56,863	606

City of Palo Alto

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FORECAST CUSTOMERS AND ENERGY SALES

Schedule 8.1

Group Coincidence Factor	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Jul-24	80%	80%	87%	86%	100%
Aug-24	80%	80%	87%	86%	100%
Sep-24	80%	80%	87%	86%	100%
Oct-24	70%	80%	87%	86%	100%
Nov-24	80%	80%	88%	85%	100%
Dec-24	90%	90%	83%	84%	100%
Jan-25	80%	80%	82%	85%	100%
Feb-25	80%	80%	82%	85%	100%
Mar-25	80%	80%	87%	80%	100%
Apr-25	80%	80%	86%	82%	100%
May-25	85%	85%	85%	84%	100%
Jun-25	80%	80%	86%	84%	100%

Rate Class NCP @ Meter (kW)	Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Jul-24	126,119	16,178	9,311	56,846	43,178	606
Aug-24	128,508	17,101	10,553	57,017	43,307	530
Sep-24	128,930	15,294	9,925	59,059	44,165	487
Oct-24	124,714	12,674	11,169	56,566	43,881	424
Nov-24	134,478	16,569	11,434	61,937	44,139	398
Dec-24	138,350	18,236	9,950	62,252	47,558	353
Jan-25	124,629	22,568	7,545	52,672	41,518	326
Feb-25	121,551	21,186	9,612	48,566	41,795	391
Mar-25	113,764	19,281	8,847	48,793	36,457	386
Apr-25	119,132	18,153	8,883	49,729	41,929	438
May-25	118,976	17,605	9,544	49,430	41,925	471
Jun-25	123,088	18,101	10,041	51,268	43,129	548
Maximum	138,350	22,568	11,434	62,252	47,558	606

Rate Class NCP @ Meter (kW) - Winter	Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Jul-24	0	0	0	0	0	0
Aug-24	0	0	0	0	0	0
Sep-24	0	0	0	0	0	0
Oct-24	124,714	12,674	11,169	56,566	43,881	424
Nov-24	134,478	16,569	11,434	61,937	44,139	398
Dec-24	138,350	18,236	9,950	62,252	47,558	353
Jan-25	124,629	22,568	7,545	52,672	41,518	326
Feb-25	121,551	21,186	9,612	48,566	41,795	391
Mar-25	113,764	19,281	8,847	48,793	36,457	386
Apr-25	119,132	18,153	8,883	49,729	41,929	438
May-25	0	0	0	0	0	0
Jun-25	0	0	0	0	0	0
Maximum	138,350	22,568	11,434	62,252	47,558	438

City of Palo Alto

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FORECAST CUSTOMERS AND ENERGY SALES

Schedule 8.1

Rate Class NCP @ Meter (kW) - Summer		Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
	Jul-24	126,119	16,178	9,311	56,846	43,178	606
	Aug-24	128,508	17,101	10,553	57,017	43,307	530
	Sep-24	128,930	15,294	9,925	59,059	44,165	487
	Oct-24	0	0	0	0	0	0
	Nov-24	0	0	0	0	0	0
	Dec-24	0	0	0	0	0	0
	Jan-25	0	0	0	0	0	0
	Feb-25	0	0	0	0	0	0
	Mar-25	0	0	0	0	0	0
	Apr-25	0	0	0	0	0	0
	May-25	118,976	17,605	9,544	49,430	41,925	471
	Jun-25	123,088	18,101	10,041	51,268	43,129	548
Maximum		128,930	18,101	10,553	59,059	44,165	606

Rate Class NCP @ Primary Voltage (kW)		Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
		Line Losses:	2.85%	2.85%	2.85%	2.85%	2.85%
	Jul-24	129,823	16,653	9,585	58,516	44,445	624
	Aug-24	132,281	17,603	10,862	58,691	44,579	546
	Sep-24	132,716	15,743	10,216	60,793	45,462	501
	Oct-24	128,376	13,046	11,497	58,227	45,169	437
	Nov-24	138,426	17,056	11,770	63,756	45,435	410
	Dec-24	142,413	18,771	10,243	64,080	48,955	364
	Jan-25	128,289	23,231	7,766	54,218	42,737	336
	Feb-25	125,120	21,808	9,894	49,993	43,022	403
	Mar-25	117,104	19,847	9,107	50,226	37,527	397
	Apr-25	122,630	18,687	9,144	51,189	43,160	451
	May-25	122,469	18,122	9,824	50,882	43,157	485
	Jun-25	126,702	18,633	10,336	52,774	44,396	564
Maximum		142,413	23,231	11,770	64,080	48,955	624

NCP @ Primary Voltage (kW) - Winter		Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
	Jul-24	0	0	0	0	0	0
	Aug-24	0	0	0	0	0	0
	Sep-24	0	0	0	0	0	0
	Oct-24	128,376	13,046	11,497	58,227	45,169	437
	Nov-24	138,426	17,056	11,770	63,756	45,435	410
	Dec-24	142,413	18,771	10,243	64,080	48,955	364
	Jan-25	128,289	23,231	7,766	54,218	42,737	336
	Feb-25	125,120	21,808	9,894	49,993	43,022	403
	Mar-25	117,104	19,847	9,107	50,226	37,527	397
	Apr-25	122,630	18,687	9,144	51,189	43,160	451
	May-25	0	0	0	0	0	0
	Jun-25	0	0	0	0	0	0
Maximum		142,413	23,231	11,770	64,080	48,955	451

City of Palo Alto

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FORECAST CUSTOMERS AND ENERGY SALES
Schedule 8.1

NCP @ Primary Voltage (kW) - Summer		Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
	Jul-24	129,823	16,653	9,585	58,516	44,445	624
	Aug-24	132,281	17,603	10,862	58,691	44,579	546
	Sep-24	132,716	15,743	10,216	60,793	45,462	501
	Oct-24	0	0	0	0	0	0
	Nov-24	0	0	0	0	0	0
	Dec-24	0	0	0	0	0	0
	Jan-25	0	0	0	0	0	0
	Feb-25	0	0	0	0	0	0
	Mar-25	0	0	0	0	0	0
	Apr-25	0	0	0	0	0	0
	May-25	122,469	18,122	9,824	50,882	43,157	485
	Jun-25	126,702	18,633	10,336	52,774	44,396	564
Maximum		132,716	18,633	10,862	60,793	45,462	624

Rate Class NCP @ Input Voltage (kW)		Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
		Line Losses:	1.00%	1.00%	1.00%	1.00%	1.00%
	Jul-24	131,134	16,822	9,681	59,107	44,894	630
	Aug-24	133,618	17,781	10,972	59,284	45,029	551
	Sep-24	134,057	15,902	10,320	61,407	45,921	506
	Oct-24	129,673	13,178	11,613	58,815	45,625	441
	Nov-24	139,825	17,228	11,889	64,400	45,894	414
	Dec-24	143,851	18,961	10,346	64,728	49,449	367
	Jan-25	129,585	23,466	7,845	54,766	43,169	339
	Feb-25	126,384	22,029	9,994	50,498	43,457	407
	Mar-25	118,287	20,047	9,199	50,734	37,906	401
	Apr-25	123,869	18,875	9,236	51,706	43,596	456
	May-25	123,706	18,305	9,923	51,396	43,592	490
	Jun-25	127,982	18,821	10,441	53,307	44,844	570
Maximum		143,851	23,466	11,889	64,728	49,449	630

NCP @ Input Voltage (kW) - Winter		Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
	Jul-24	0	0	0	0	0	0
	Aug-24	0	0	0	0	0	0
	Sep-24	0	0	0	0	0	0
	Oct-24	129,673	13,178	11,613	58,815	45,625	441
	Nov-24	139,825	17,228	11,889	64,400	45,894	414
	Dec-24	143,851	18,961	10,346	64,728	49,449	367
	Jan-25	129,585	23,466	7,845	54,766	43,169	339
	Feb-25	126,384	22,029	9,994	50,498	43,457	407
	Mar-25	118,287	20,047	9,199	50,734	37,906	401
	Apr-25	123,869	18,875	9,236	51,706	43,596	456
	May-25	0	0	0	0	0	0
	Jun-25	0	0	0	0	0	0
Maximum		143,851	23,466	11,889	64,728	49,449	456

City of Palo Alto

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FORECAST CUSTOMERS AND ENERGY SALES

Schedule 8.1

NCP @ Input Voltage (kW) - Summer		Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
	Jul-24	131,134	16,822	9,681	59,107	44,894	630
	Aug-24	133,618	17,781	10,972	59,284	45,029	551
	Sep-24	134,057	15,902	10,320	61,407	45,921	506
	Oct-24	0	0	0	0	0	0
	Nov-24	0	0	0	0	0	0
	Dec-24	0	0	0	0	0	0
	Jan-25	0	0	0	0	0	0
	Feb-25	0	0	0	0	0	0
	Mar-25	0	0	0	0	0	0
	Apr-25	0	0	0	0	0	0
	May-25	123,706	18,305	9,923	51,396	43,592	490
	Jun-25	127,982	18,821	10,441	53,307	44,844	570
Maximum		134,057	18,821	10,972	61,407	45,921	630

System Coincidence Factor			Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
	Jul-24		92%	90%	95%	100%	0%
	Aug-24		66%	90%	95%	100%	0%
	Sep-24		76%	85%	90%	100%	0%
	Oct-24		60%	85%	90%	100%	100%
	Nov-24		81%	60%	82%	100%	100%
	Dec-24		87%	90%	95%	100%	100%
	Jan-25		93%	60%	72%	90%	100%
	Feb-25		89%	90%	95%	100%	100%
	Mar-25		90%	80%	88%	100%	100%
	Apr-25		68%	70%	80%	100%	0%
	May-25		71%	95%	95%	100%	0%
	Jun-25		87%	95%	100%	100%	0%

Coincident Peak (CP) @ Input (kW)		Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
	Jul-24	125,221	15,462	8,713	56,151	44,894	0
	Aug-24	123,035	11,811	9,875	56,320	45,029	0
	Sep-24	122,062	12,103	8,772	55,267	45,921	0
	Oct-24	116,802	7,931	9,871	52,934	45,625	441
	Nov-24	120,247	13,998	7,133	52,808	45,894	414
	Dec-24	137,082	16,462	9,311	61,491	49,449	367
	Jan-25	105,219	21,890	4,707	39,432	38,852	339
	Feb-25	120,433	19,602	8,995	47,973	43,457	407
	Mar-25	108,408	18,096	7,359	44,646	37,906	401
	Apr-25	104,206	12,780	6,465	41,365	43,596	0
	May-25	114,797	12,952	9,427	48,826	43,592	0
	Jun-25	124,500	16,431	9,919	53,307	44,844	0
Total CP Demand - Bottom Up		1,422,013	179,517	100,547	610,518	529,061	2,370
Peak Month		137,082	16,462	9,311	61,491	49,449	367

City of Palo Alto

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FORECAST CUSTOMERS AND ENERGY SALES
Schedule 8.1

City of Palo Alto

FORECAST kWh AT INPUT
Schedule 8.3

kWh @ Input Voltage		Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
	Jul-24	72,895,620	10,504,203	5,042,511	26,506,830	30,677,986	164,091
	Aug-24	77,887,708	11,328,881	5,189,941	29,006,347	32,198,449	164,091
	Sep-24	79,095,056	9,906,582	4,949,317	29,300,627	34,774,439	164,091
	Oct-24	68,308,507	9,992,659	4,530,268	25,558,567	28,062,923	164,091
	Nov-24	73,029,041	11,227,639	4,457,506	26,050,236	31,129,570	164,091
	Dec-24	68,299,083	11,286,284	4,634,201	24,847,494	27,367,013	164,091
	Jan-25	76,447,570	15,945,383	4,767,961	23,629,212	31,940,925	164,091
	Feb-25	73,006,833	13,472,395	4,642,484	25,626,954	29,100,910	164,091
	Mar-25	67,716,644	13,472,395	4,445,476	22,724,016	26,910,666	164,091
	Apr-25	68,873,780	10,760,670	4,095,314	23,920,907	29,932,798	164,091
	May-25	70,159,906	10,471,264	4,366,628	25,281,086	29,876,837	164,091
	Jun-25	74,012,830	10,729,661	4,534,942	26,217,902	32,366,235	164,091
Total Purchases - bottom up		869,732,579	139,098,013	55,656,547	308,670,178	364,338,751	1,969,090
growth in Purchases against Recorded (bottom-up)			*-17%*	*17%*	*22%*	*-4%*	*0%*

On-Peak Energy Use by Percentage		Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
	Jul-24	*57%*	57%	57%	57%	57%	57%
	Aug-24	*60%*	60%	60%	60%	60%	60%
	Sep-24	*61%*	61%	61%	61%	61%	61%
	Oct-24	*61%*	61%	61%	61%	61%	61%
	Nov-24	*57%*	57%	57%	57%	57%	57%
	Dec-24	*62%*	62%	62%	62%	62%	62%
	Jan-25	*57%*	57%	57%	57%	57%	57%
	Feb-25	*60%*	60%	60%	60%	60%	60%
	Mar-25	*61%*	61%	61%	61%	61%	61%
	Apr-25	*61%*	61%	61%	61%	61%	61%
	May-25	*57%*	57%	57%	57%	57%	57%
	Jun-25	*62%*	62%	62%	62%	62%	62%
Total		*59%*	*59%*	*59%*	*59%*	*59%*	*59%*

On-Peak kWh @ Input Voltage		Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
	Jul-24	41,654,301	6,002,353	2,881,411	15,146,637	17,530,135	93,765
	Aug-24	46,589,073	6,776,449	3,104,399	17,350,347	19,259,726	98,152
	Sep-24	47,887,467	5,997,861	2,996,524	17,739,830	21,053,905	99,347
	Oct-24	41,402,201	6,056,611	2,745,823	15,491,202	17,009,108	99,456
	Nov-24	41,676,045	6,407,363	2,543,799	14,866,289	17,764,951	93,643
	Dec-24	42,172,507	6,968,920	2,861,471	15,342,536	16,898,258	101,321
	Jan-25	43,683,970	9,111,573	2,724,527	13,502,297	18,251,808	93,765
	Feb-25	43,669,543	8,058,606	2,776,934	15,328,940	17,406,911	98,152
	Mar-25	40,998,499	8,156,753	2,691,478	13,758,073	16,292,847	99,347
	Apr-25	41,744,817	6,522,107	2,482,195	14,498,607	18,142,451	99,456
	May-25	40,038,693	5,975,717	2,491,937	14,427,352	17,050,044	93,643
	Jun-25	45,700,564	6,625,224	2,800,182	16,188,719	19,985,119	101,321
Total		517,217,679	82,659,536	33,100,680	183,640,829	216,645,263	1,171,371

City of Palo Alto

Prepared By EES Consulting, Inc.

FORECAST CUSTOMERS AND ENERGY SALES
Schedule 8.1

Off-Peak Energy Use by Percentage

	Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Jul-24	*43%*	*43%*	*43%*	*43%*	*43%*	*43%*
Aug-24	*40%*	*40%*	*40%*	*40%*	*40%*	*40%*
Sep-24	*39%*	*39%*	*39%*	*39%*	*39%*	*39%*
Oct-24	*39%*	*39%*	*39%*	*39%*	*39%*	*39%*
Nov-24	*43%*	*43%*	*43%*	*43%*	*43%*	*43%*
Dec-24	*38%*	*38%*	*38%*	*38%*	*38%*	*38%*
Jan-25	*43%*	*43%*	*43%*	*43%*	*43%*	*43%*
Feb-25	*40%*	*40%*	*40%*	*40%*	*40%*	*40%*
Mar-25	*39%*	*39%*	*39%*	*39%*	*39%*	*39%*
Apr-25	*39%*	*39%*	*39%*	*39%*	*39%*	*39%*
May-25	*43%*	*43%*	*43%*	*43%*	*43%*	*43%*
Jun-25	*38%*	*38%*	*38%*	*38%*	*38%*	*38%*
Total	*41%*	*41%*	*41%*	*41%*	*41%*	*41%*

Off-Peak kWh @ Input Voltage

	Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Jul-24	31,241,320	4,501,850	2,161,099	11,360,194	13,147,851	70,325
Aug-24	31,298,635	4,552,432	2,085,542	11,655,999	12,938,724	65,939
Sep-24	31,207,589	3,908,721	1,952,793	11,560,798	13,720,534	64,743
Oct-24	26,906,306	3,936,048	1,784,445	10,067,364	11,053,815	64,634
Nov-24	31,352,997	4,820,276	1,913,707	11,183,948	13,364,619	70,448
Dec-24	26,126,576	4,317,363	1,772,729	9,504,959	10,468,755	62,770
Jan-25	32,763,601	6,833,810	2,043,434	10,126,915	13,689,116	70,325
Feb-25	29,337,289	5,413,788	1,865,550	10,298,014	11,693,999	65,939
Mar-25	26,718,145	5,315,641	1,753,998	8,965,943	10,617,819	64,743
Apr-25	27,128,964	4,238,562	1,613,119	9,422,300	11,790,347	64,634
May-25	30,121,213	4,495,547	1,874,691	10,853,734	12,826,793	70,448
Jun-25	28,312,267	4,104,437	1,734,760	10,029,183	12,381,116	62,770
Total Off-Peak Energy	352,514,901	56,438,477	22,555,867	125,029,350	147,693,488	797,720

Summary of Future Test Period Seasonal Load Data
Power Supply

- System kWh @ Input Voltage- Winter

	Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
Jul-24	0	0	0	0	0	0
Aug-24	0	0	0	0	0	0
Sep-24	0	0	0	0	0	0
Oct-24	68,308,507	9,992,659	4,530,268	25,558,567	28,062,923	164,091
Nov-24	73,029,041	11,227,639	4,457,506	26,050,236	31,129,570	164,091
Dec-24	68,299,083	11,286,284	4,634,201	24,847,494	27,367,013	164,091
Jan-25	76,447,570	15,945,383	4,767,961	23,629,212	31,940,925	164,091
Feb-25	73,006,833	13,472,395	4,642,484	25,626,954	29,100,910	164,091
Mar-25	67,716,644	13,472,395	4,445,476	22,724,016	26,910,666	164,091
Apr-25	68,873,780	10,760,670	4,095,314	23,920,907	29,932,798	164,091
May-25	0	0	0	0	0	0
Jun-25	0	0	0	0	0	0
Total Winter	495,681,459	86,157,423	31,573,209	172,357,386	204,444,804	1,148,636

City of Palo Alto

Prepared By EES Consulting, Inc.

FORECAST CUSTOMERS AND ENERGY SALES
Schedule 8.1

-System kWh @ Input Voltage- Summer		Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
	Jul-24	72,895,620	10,504,203	5,042,511	26,506,830	30,677,986	164,091
	Aug-24	77,887,708	11,328,881	5,189,941	29,006,347	32,198,449	164,091
	Sep-24	79,095,056	9,906,582	4,949,317	29,300,627	34,774,439	164,091
	Oct-24	0	0	0	0	0	0
	Nov-24	0	0	0	0	0	0
	Dec-24	0	0	0	0	0	0
	Jan-25	0	0	0	0	0	0
	Feb-25	0	0	0	0	0	0
	Mar-25	0	0	0	0	0	0
	Apr-25	0	0	0	0	0	0
	May-25	70,159,906	10,471,264	4,366,628	25,281,086	29,876,837	164,091
	Jun-25	74,012,830	10,729,661	4,534,942	26,217,902	32,366,235	164,091
Total Summer		374,051,121	52,940,590	24,083,338	136,312,792	159,893,946	820,454
			0	0	0	0	0

CP @ Input Voltage- Winter		Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
	Jul-24	0	0	0	0	0	0
	Aug-24	0	0	0	0	0	0
	Sep-24	0	0	0	0	0	0
	Oct-24	116,802	7,931	9,871	52,934	45,625	441
	Nov-24	120,247	13,998	7,133	52,808	45,894	414
	Dec-24	137,082	16,462	9,311	61,491	49,449	367
	Jan-25	105,219	21,890	4,707	39,432	38,852	339
	Feb-25	120,433	19,602	8,995	47,973	43,457	407
	Mar-25	108,408	18,096	7,359	44,646	37,906	401
	Apr-25	104,206	12,780	6,465	41,365	43,596	0
	May-25	0	0	0	0	0	0
	Jun-25	0	0	0	0	0	0
Total Winter		812,397	110,759	53,841	340,648	304,779	2,370

CP @ Input Voltage- Summer		Total	Residential E-1	Small Commercial E-2	Medium Commercial E-4	Large Commercial E-7	Street/Traffic Lights
	Jul-24	125,221	15,462	8,713	56,151	44,894	0
	Aug-24	123,035	11,811	9,875	56,320	45,029	0
	Sep-24	122,062	12,103	8,772	55,267	45,921	0
	Oct-24	0	0	0	0	0	0
	Nov-24	0	0	0	0	0	0
	Dec-24	0	0	0	0	0	0
	Jan-25	0	0	0	0	0	0
	Feb-25	0	0	0	0	0	0
	Mar-25	0	0	0	0	0	0
	Apr-25	0	0	0	0	0	0
	May-25	114,797	12,952	9,427	48,826	43,592	0
	Jun-25	124,500	16,431	9,919	53,307	44,844	0
Total Summer		609,616	68,758	46,706	269,870	224,281	0

FY 2025 ELECTRIC UTILITY FINANCIAL PLAN

FY 2025 TO FY 2029

FY 2025 ELECTRIC UTILITY FINANCIAL PLAN

FY 2025 TO FY 2029

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SECTION 1: DEFINITIONS AND ABBREVIATIONS

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

SECTION 2: EXECUTIVE SUMMARY AND RECOMMENDATIONS

This document presents a Financial Plan for the City of Palo Alto (City) Electric Utility for the next five-year forecast, FY 2025 - 2029. This Financial Plan describes how revenues will cover the costs of operating the utility safely over that time while adequately investing for the future. It also addresses the financial risks facing the utility over the short term and long term and includes measures to mitigate and manage those risks.

SECTION 2A: OVERVIEW OF FINANCIAL POSITION

From July 2019 through April 2022 the City did not increase rates, to mitigate the economic impact of the COVID-19 pandemic on residents and businesses. In that time supply and distribution expenses increased $50 million (30%). The expense increases combined with pandemic-related electricity sales revenue declines created a $43 million shortfall in FY 2022. Some of this was related to the impacts of extreme drought and rising electricity market prices, and in response, the City activated the hydroelectric rate adjuster (E-HRA) in April 2022. In 2023 the City began increasing base rates to begin recovering costs, starting with a 5% rate increase on July 1, 2022. The intent was to use loans from the Electric Special Projects Reserve and what Operations Reserves remained to phase in rate increases gradually. But in late 2022 electricity market prices increased at unprecedented levels, leading to the need to increase the hydroelectric rate adjuster on January 1, 2023 to match the cost of replacing hydroelectric power with market power. On July 1, 2023 the City removed the hydroelectric rate adjuster while increasing its base electric rate 21%, the net result of which was a 5% rate <u>decrease</u>. This was possible due to heavy rains in the winter of 2022 / 2023 and the receipt of a judgment in a lawsuit related to the City's contract with the Western Area Power Administration for hydroelectric power from the Federal Central Valley Project. These two factors, combined with decreases in energy prices from the extreme winter 2022 / 2023 levels, enabled the City to replenish its reserves and stabilize rates at a level that fully recovers costs.

This forecast assumes long-term power prices continue to remain elevated over FY 2022 and earlier levels based on forward market price curve projections from independent commodity brokers. To reduce hydroelectric-related volatility in the future, staff is now making its rate projections assuming that long-term "normal" production from the City's hydroelectric resources is about 80% of historical average levels.

In contrast to last year's projection, this year's forecast includes significant one-time electric supply net revenues in FY 2024 and FY 2025 due to two factors. First, the utility had higher than average surplus electric energy sales due to the high hydroelectric generation associated with the heavy rains for winter 2022 / 2023 (for FY 2024). Second, the utility had significant revenue due to sales of surplus resource adequacy (generating capacity) under favorable market conditions that are not expected to continue long term. These one-time revenues are allowing the City to add to its hydroelectric stabilization reserve, which can be used to minimize the rate impacts of the additional costs associated with future dry years where hydroelectric generation is low.

There are also significant one-time costs in this forecast that were not in last year's forecast. They include large one-time costs associated capital investment, including a major Hanover Substation upgrade and grid modernization. There is also a timing issue associated with the first budget for grid modernization. This project was budgeted in FY 2024, but the debt issuance is not expected to take place until FY 2025, so this $25 million project is impacting reserves. This will require a one-year $20 million additional loan from the Electric Special Projects Reserve in FY 2024 rather than the $10 million repayment of a previous loan that was planned. This Financial Plan includes repayment of the total $30 million in outstanding Electric Special Projects Reserve loans in FY 2025.

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

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

Because of these long-term cost increases rates are projected to increase the median residential bill 8% in FY 2025 and 5% per year for FY 2026 through FY 2029. For July 1, 2024 (FY 2025) staff has worked with a consultant to complete a cost of service analysis (COSA) that showed the need for rate decreases for non-residential customers ranging from 1% to 6% due to shifts in consumption patterns related to the COVID-19 pandemic. As a result, net sales revenue for FY 2025 is expected to remain about the same as in FY 2024. Because the regional economy is still recovering from that pandemic, leading to uncertainties in future consumption patterns, staff intends to continue to update the cost of service model in future years as the recovery proceeds. It is possible that a lower than average increase will be needed for residential customers in future years as the recovery continues and a higher one for non-residential customers.

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

Due to the cash flow issue related to the budgeting of the first grid modernization project (in FY 2024) and the timing of the first debt issuance (in FY 2025), the Electric Utility's costs are high in FY 2024 and low in FY 2025. On average, though, the utility's costs for these two years is lower than FY 2023 levels. Expenses are expected to rise in FY 2026 through FY 2029, in part due to increasing power supply purchase costs, and in part due to grid modernization expenses. The average increase in utility costs from FY 2025 to 2029 is 3% annually[1] as shown in Table 1. Electric supply purchases continue to increase mainly due to rising transmission costs over the span of the financial plan and tightening requirements for resource adequacy.[2] Overall supply costs are projected to increase at 3% per year on average from FY 2025 to FY 2029. Operations and maintenance costs are projected to increase by about 2% per year on average due to both inflation as well as salary and benefits increases. Capital improvement costs, including debt service for grid modernization, are projected to increase 3.6% per year from FY 2025 through FY 2029.

Table 1: Electric Utility Expenses for FY 2023 to FY 2029

Expenses ($000)	FY 2023 (act)	FY 2024 (est)	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Power Supply Purchases	128,512	114,427	121,079	127,167	128,726	131,243	132,597
Operations	62,472	63,971	65,897	67,180	68,041	70,407	73,666
Capital - Rate Funded	21,656	66,884	0	15,143	14,671	12,688	13,089
Capital Debt Service	21	0	0	4,030	9,300	14,880	14,880
TOTAL	212,661	245,282	186,975	213,521	220,738	229,218	234,233

Table 2 below shows the proposed rates for FY 2025 and projections for FY 2026 through FY 2029. As noted above staff has completed a COSA and is proposing different rate changes for different customer classes in FY 2025 to align with the COSA results. Rates for non-residential customers will slightly decrease while rates for residential customers will increase. This is due to changes in consumption patterns related to the pandemic. Staff intends to continue to update the COSA model as the pandemic recovery continues which may result in additional rate adjustments by customer class in future years if consumption returns to historical patterns.

Table 2: Projected Electric Rates, FY 2025 to FY 2029

Projection	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Current	-6% to +8%[3]	5%	5%	5%	5%
Last Year	5%	5%	5%	5%	N/A

Staff is proposing several significant transfers in FY 2024 due to some very significant one-time revenues and expenses that have affected reserves. One-time revenues include a $24 million refund from the successful litigation against the Bureau of Reclamation for overcharges related

[1] Using the average of FY 2024 and FY 2025 for capital expenses.

[2] Resource adequacy represents the cost of maintaining generating capacity to fulfill the California Independent System Operator's capacity requirements assigned to the City.

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

to power purchases from the Central Valley Project as well as large one-time revenues related to resource adequacy sales, and large capital expenses related to grid modernization. As noted above, the capital expenses related to grid modernization are affecting the reserves in FY 2024, but this represents a temporary cash flow issue until the debt issuance to cover those expenses in FY 2025, at which time the reserves will be restored. However, as noted above, an internal loan from the Electric Special Projects Reserve will be required along with some inter-fund transfers. This will be added to the following $10 million in outstanding loans from prior years:

- In FY 2018 Council approved (Staff Report 8186[4]), a $10 million transfer from the Electric Special Projects (ESP) Reserve to the Operations Reserve to mitigate higher supply costs due to the drought, the costs of new renewable energy projects coming online and increasing transmission charges. $5 million was repaid in FY 2020
- In FY 2022 Council approved (Staff Report 13361, June 13, 2022), a $5 million transfer from the ESP Reserve to the Operations Reserve to avoid rate increases exceeding 5%.

This Financial Plan includes the repayment of all $30 million in loans in FY 2025.

In addition to the above transfers staff proposes to transfer $17 million to the Hydroelectric Stabilization Reserve in FY 2024 rather than $8.4 million (as was anticipated in the FY 2024 Electric Utility Financial Plan), bringing the balance to its target level and eliminating the chance that the hydroelectric rate adjuster will be activated if the winter of 2023/2024 ends up being dry. Rainfall patterns in California usually involve occasional above average hydroelectric years followed by multiple below-average years, so it is important to use the one-time revenues from wet years like the winter of 2022/2023 to replenish reserves and bring them above the target level.

Lastly, this plan includes a $5 million transfer in FY 2025 from the Distribution Operations Reserve to the CIP Reserve to bring it above its minimum level.

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

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

Table 3: Reserves Starting and Ending Balances, Revenues, Expenses, Transfers To/(From) Reserves, Operations and Capital (CIP) Reserve Guideline Levels for FY 2023 to FY 2028 ($000)

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

SECTION 2B: SUMMARY OF PROPOSED ACTIONS

Staff recommends the City Council adopt a Resolution:

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

SECTION 3: DETAIL OF FY 2024 RATE AND RESERVES PROPOSALS

SECTION 3A: RATE DESIGN

The Electric Utility's rates are evaluated and implemented in compliance with cost of service requirements set forth in the California Constitution and applicable statutory law. This Financial Plan is based on staff's assessment of the financial position of the Electric Utility and updated using the methodology from the "City of Palo Alto Electric Cost of Service and Rate Study"[5] drafted by EES Consulting, Inc. in 2023/2024. The COSA is also based on design guidelines adopted by Council on November 11, 2021 (Staff Report 13546).

SECTION 3B: CURRENT AND PROPOSED RATES

The City adopted the current rates effective July 1, 2023, when the City increased the electric base rates by 21% while simultaneously removing the hydroelectric rate adjuster for a net decrease of 5% in the overall rate. This large rate change was needed because the City did not increase rates during the COVID-19 pandemic and instead drew down reserves. While using reserves mitigated larger increases during the pandemic, costs continued to rise and higher rates were needed to recover costs.

The City's consultant has completed a review and revision of the Electric Utility's Cost of Service study and rates. This study determined the rate changes needed for the residential and commercial classes to align them with the customer class cost of service identified in the study.. To ensure the median residential customer experiences no more than an 8% rate increase staff is recommending no revenue change for the electric utility this year, as discussed above. The current rates and proposed FY 2025 rates are reflected in Table 4 below:

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

Table 4: Current and Proposed Electric Rates

	Current Rates	Proposed Rates (7/1/2024)	Change	
			$	%
E-1 (Residential)				
Tier 1 Energy ($/kWh)	0.17522	0.19337	0.01815	10%
Tier 2 Energy ($/kWh)	0.24666	0.20335	-0.04331	-18%
Customer Charge ($/day)		0.15250	0.15250	
E-2 & E-2-G (Small Non-Residential)				
Summer Energy ($/kWh)	0.26560	0.25211	-0.01349	-5%
Winter Energy ($/kWh)	0.18626	0.16415	-0.02211	-12%
Customer Charge ($/day)		0.18410	0.18410	
E-4 & E-4-G (Medium Non-Residential)				
Summer Energy ($/kWh)	0.16363	0.15387	-0.00976	-6%
Winter Energy ($/kWh)	0.12667	0.11018	-0.01649	-13%
Summer Demand ($/kW)	36.82668	45.29000	8.46332	23%
Winter Demand ($/kW)	24.16296	23.73000	-0.43296	-2%
Customer Charge ($/day)		3.73900	3.73900	
E-7 & E-7-G (Large Non-Residential)				
Summer Energy ($/kWh)	0.14561	0.13570	-0.00991	-7%
Winter Energy ($/kWh)	0.09856	0.08797	-0.01059	-11%
Summer Demand ($/kW)	39.08286	40.36000	1.27714	3%
Winter Demand ($/kW)	21.71270	27.79000	6.07730	28%
Customer Charge ($/day)		17.12210	17.12210	

Net Energy Metering Compensation Rates

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

Customers on the NEM 1 program who have chosen to have the value of any annual net generation they produced over the past 12 months credited back to their account do so under the Net Metering Net Surplus Electricity Compensation (E-NSE) rate. The Net Surplus Electricity Compensation rate represents the value of the City’s avoided cost or value of customer-generated electricity in Palo Alto, including compensation for the energy, avoided capacity charges, avoided transmission and ancillary service charges, avoided transmission and distribution (T&D) losses, and renewable energy credits (RECs), or environmental attributes. Staff proposes decreasing the E-NSE-1 rate to $0.1427/kWh based on updated avoided cost calculations reflecting declines in long-term electricity market prices expected to continue into the future.

Under the City's NEM successor program, participating solar customers in Palo Alto are billed at the current retail rate for electricity drawn from the grid, and receive a credit for electricity they export to the grid at the Export Electricity Compensation (EEC-1) rate. This compensation rate also reflects the avoided cost or value of customer-generated electricity in Palo Alto, calculated on a forward-looking basis for the upcoming fiscal year. As shown in the table below, the current avoided cost for solar generation in Palo Alto is $0.1535/kWh, which is higher than the City's projected avoided cost, which requires the proposed NEM compensation rate (E-EEC) to decrease to $0.1420/kWh. This decrease in the overall avoided cost is driven by changes in electricity market prices.

Table 5: NEM Buyback Rates – Current vs. Proposed

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

<u>Palo Alto Green (PAG) Program</u>

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

The PAG charge is a pass-through charge; the revenue collected through the PAG rate premium is intended to fully recover the costs of administering the program. The PAG program has very low overhead costs (e.g., the cost of hiring an auditor to carry out an annual Green-e verification process for the program), so most of the program cost is the purchase cost of the RECs. In the past year the wholesale cost of Green-e certified RECs in the Western US market has remained relatively flat at around $7.00/REC. As such, the PAG rate premium should remain at $7.5 per 1,000 kWh block (.75 cents/kWh), enough to cover the cost of the RECs and overhead. The PAG rate premium is reflected on the Residential Master-Metered and Small Non-Residential Green Power Electric Service (E-2-G), the Medium Non-Residential Green Power Electric Service (E-4-G), and the Large Non-Residential Green Power Electric Service (E-7-G) rate schedules.

SECTION 3C: BILL IMPACT OF PROPOSED RATE CHANGES

Table 6 shows the impact of the proposed July 1, 2024 rate changes on the residential and non-residential bills for various consumption levels. The rate changes vary by customer class due to the completion of a cost of service analysis as noted in *Section 3B: Current and Proposed Rates*. Because of the addition of a customer charge and the changes in the design of the tiers for the E-1 customer class usage in this class varies widely depending on consumption, generally increasing for customers who use less electricity and decreasing for those who use more. The increase for the median residential customer is about 8%. This trend is expected to continue when the utility moves to time of use rates, which provides prices that vary by time of day rather than by how much electricity a customer uses in a month. It is worth noting, however, that increases among low users, while large in percentage terms, are small in absolute dollar terms (no more than $10.63 per month, and most low users will see less of an increase than that). For residents in need, staff is investigating whether it is possible to adjust the rate assistance program to offset these increases.

For more on comparisons of rates with surrounding agencies, see Section 4F: Competitiveness below.

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

Rate Schedule	Usage (kWh/mo)	Peak Demand (kW-mo)	Bill under Current Rates ($/mo)	Bill Under Rates Proposed 7/1/24 ($/mo)	Change	
					$/mo	%
E-1 (Residential)	300	N/A	$52.57	$62.65	$10.08	19%
	(Summer Median) 365	N/A	$66.46	$75.22	$8.76	13%
	(Winter Median) 453	N/A	$88.16	$92.24	$4.07	5%
	650	N/A	$136.75	$135.61	($1.14)	-1%
	1200	N/A	$272.42	$257.34	($15.07)	-6%
E-2 (Small Non-Residential)	1,000	N/A	$225.93	$213.73	($12.20)	-5%
E-4 (Medium Non-Residential)	160,000	274	$31,580	$30,693	($887)	-3%
	500,000	856	$98,680	$95,667	($3,014)	-3%
E-7 (Large Non-Residential	2,000,000	3,424	$348,247	$340,864	($7,383)	-2%

SECTION 3D: PROPOSED RESERVE TRANSFERS

Staff is proposing various reserve transfers to manage a one-year cash flow issue related to the grid modernization project. The first $25 million phase of the project was budgeted in the FY 2024 fiscal year, while the first debt issuance associated with the project is expected in FY 2025. This will have a negative impact on the distribution operation reserve in FY 2024. Without transfers from other reserves the distribution operations reserve would be significantly negative by the end of FY 2024. Fortunately, one-time revenues associated with a $24 million judgment from successful litigation against the Bureau of Reclamation (recognized in FY 2023 in the Supply Operations Reserve, leaving it close to the maximum reserve guideline) will help manage this cash flow issue, along with a one-year internal loan from the Electric Special Projects reserve. In the FY 2024 Electric Utility Financial Plan staff had intended to repay an earlier $10 million in internal loans from the Electric Special Projects Reserve in FY 2024. Instead, staff recommends postponing that loan repayment until FY 2025 and taking an additional $20 million in internal loans from the reserve for one year. The following transfers are proposed:

- In FY 2024, to keep the distribution operations reserve from going negative:
    - A transfer of $20 million from the Electric Special Projects Reserve to the Supply Operations Reserve
    - A transfer of $58 million from the Supply Operations Reserve to the Distribution Operations Reserve
- In FY 2025, to repay the internal loans from the Electric Special Projects Reserve and replenish the Supply Operations Reserve:
    - A transfer of $20 million from the Distribution Operations Reserve to the Supply Operations Reserve
    - A transfer of $30 million from the Supply Operations Reserve to the Electric Special Projects Reserve

The FY 2025 transfers are tentative and may need to be adjusted in the FY 2026 Financial Plan based on the results for the FY 2024 and FY 2025 fiscal years.

The electric utility is also experiencing one-time sales revenues and supply cost savings in FY 2024 related to high hydroelectric generation resulting from the rainy winter of 2022/2023. In addition, current market conditions are enabling the utility to realize higher than usual sales revenue related to surplus resource adequacy and REC sales in FY 2024, FY 2025, and FY 2026. Staff is recommending using these one-time revenues to replenish the hydroelectric stabilization reserve, bringing it to $17.4 million, a level which will allow the City to avoid having to activate the hydroelectric rate adjuster if upcoming winters are drier than average.

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

The City maintains a Cap and Trade Program Reserve within the Electric fund to hold any revenues from the sale of carbon allowances freely allocated by the California Air Resources Board to the City's electric utility that are not spent within the fiscal year. Cap and Trade Program revenues are provided to the electric utility to support a wide variety of carbon reducing activities. Until the establishment of the REC Exchange program, adopted by Council in August 2020 (Staff Report #11556),[6] all of this Cap and Trade Program revenue was spent on purchasing renewable energy and none was held in reserve.

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

Figure 8 (for Supply Fund Reserves) and Figure 9 (for Distribution Fund Reserves) in *Section 5E: FY 2025 – FY 2029 Projections* show the impact of these transfers on reserves levels. Table 7 shows the projected balance of each of the Electric Utility reserves for the period covered by this Financial Plan. See also: *Appendix A: Electric Utility Financial Forecast Detail*

[6] Staff Report 11556 https://www.cityofpaloalto.org/civicax/filebank/documents/78046

[7] https://cityofpaloalto.primegov.com/Public/CompiledDocument?meetingTemplateId=8715&compileOutputType=1 Staff Report 14735 Item 3, Agenda Item 3, *Utilities Advisory Commission Recommend the City Council Affirm the Continuation of the REC Exchange Program*, Staff Report #14375

Table 7: End of Fiscal Year Electric Utility Reserve Balances for FY 2023 to FY 2029

Ending Reserve Balance ($000)	FY 2023 (Act)	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Re-appropriations	253	253	253	253	253	253	253
Commitments	9,400	9,400	9,400	9,400	9,400	9,400	9,400
Low Carbon Fuel Standard (LCFS)	6,713	4,053	1,486	-	-	-	-
Cap and Trade	2,231	3,231	4,941	6,151	7,231	8,141	8,871
Underground Loan	727	727	727	727	727	727	727
Public Benefits	5,673	7,431	9,033	10,569	12,032	13,422	14,733
Special Projects	20,149	149	30,149	32,149	34,149	36,149	38,149
Hydro Stabilization	400	17,400	17,400	17,400	17,400	17,400	17,400
Capital	880	880	5,880	5,880	5,880	5,880	5,880
Rate Stabilization	-	-	-	-	-	-	-
Distribution and Supply Operations	38,882	22,522	39,672	41,074	40,766	41,216	43,037
Unassigned	-	-	-	-	-	-	-
TOTAL	85,306	66,046	118,941	123,602	127,837	132,588	138,449

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 Utilities Control Center was built to house the terminals for a new System Control and Data Acquisition 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[8] 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.

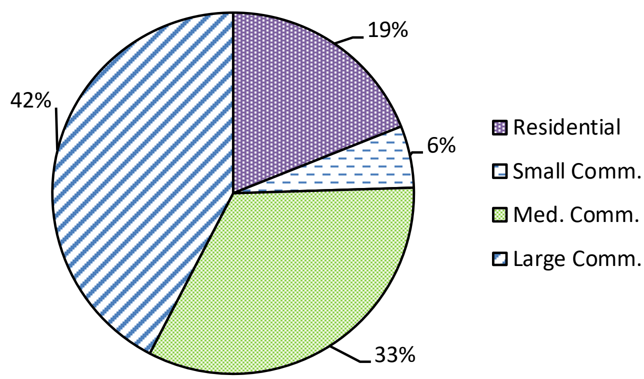
[8] *Implementation of Direct Access for Electric Utility Customers*, CMR:460:97, December 1, 1997

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

SECTION 4B: CUSTOMER BASE

The City of Palo Alto's Electric Utility provides electric service to the residents, businesses, and other electric customers in Palo Alto. There are about 29,700 customers connected to the electric system, 25,600 (86%) of which are residential and 4,100 (14%) of which are non-residential. Residential customers consumed 157 gigawatt-hours (GWh) in FY 2022, approximately 19% of the electricity sold, while non-residential customers consumed 81% or 669 GWh. Residential customers use electricity primarily for lighting, refrigeration, electronics, and air conditioning.[9] Non-residential customers use most of their electricity for cooling, ventilation, lighting, office equipment (offices), cooking (restaurants), and refrigeration (grocery stores).[10]

Figure 1: Customer Consumption By Class (FY 2023)



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 about 42% 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 about 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.

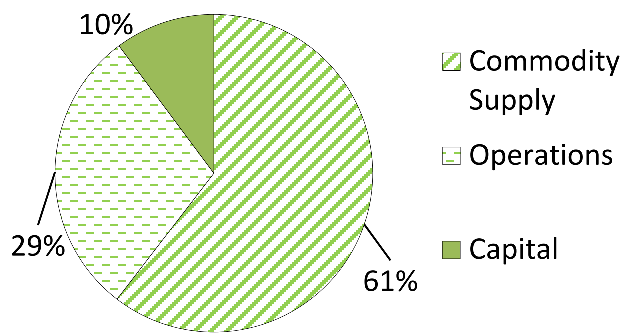
[9] Source: Residential Appliance Saturation Survey, California Energy Commission, 2010

[10] 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 about 60% of the Electric Utility's costs in FY 2022. Operational costs represented about 30%, 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 55% of total costs in FY 2028.

Figure 2: Cost Structure (FY 2023)



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

Figure 3: Hydroelectric Variability as a % of Load (FY 2023)

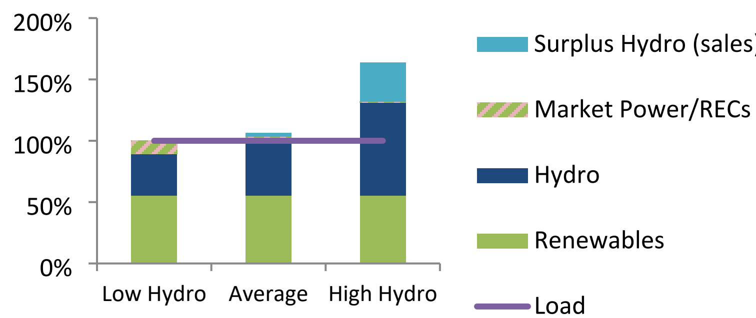
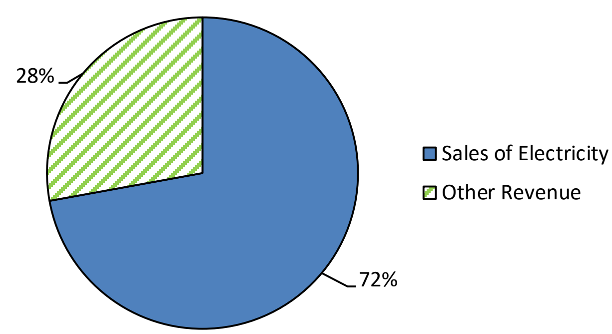


Figure 4: Revenue Structure (FY 2023)



As shown in Figure 4 the Electric Utility received about 72% 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 prefunding program associated with its contract with WAPA, revenues from sales of surplus hydroelectric energy during wet years, as well as LCFS and Cap and Trade revenues. *Appendix A: Electric Utility Financial Forecast Detail* shows more detail on the utility's cost and revenue structures.

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

SECTION 4E: RESERVES STRUCTURE

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

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

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

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

SECTION 4F: COMPETITIVENESS

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

Table 8 presents sample median residential bills for Palo Alto, PG&E, and the City of Santa Clara (Silicon Valley Power) for several usage levels. Rates used to calculate the monthly bills shown below were in effect as of January 1, 2024.

Table 8: Residential Monthly Electric Bill Comparison (Effective 1/1/2024, $/mo.)

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

SECTION 5: UTILITY FINANCIAL PROJECTIONS

SECTION 5A: LOAD FORECAST

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

Figure 5: Historical Electricity Consumption

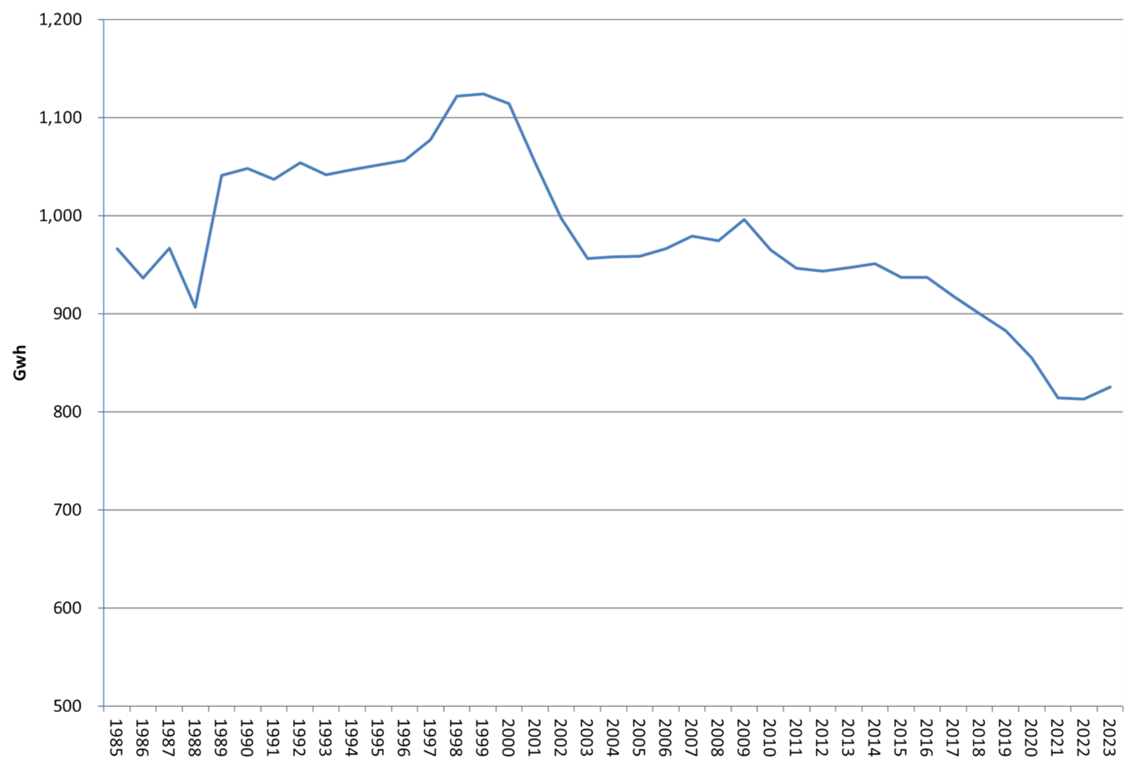
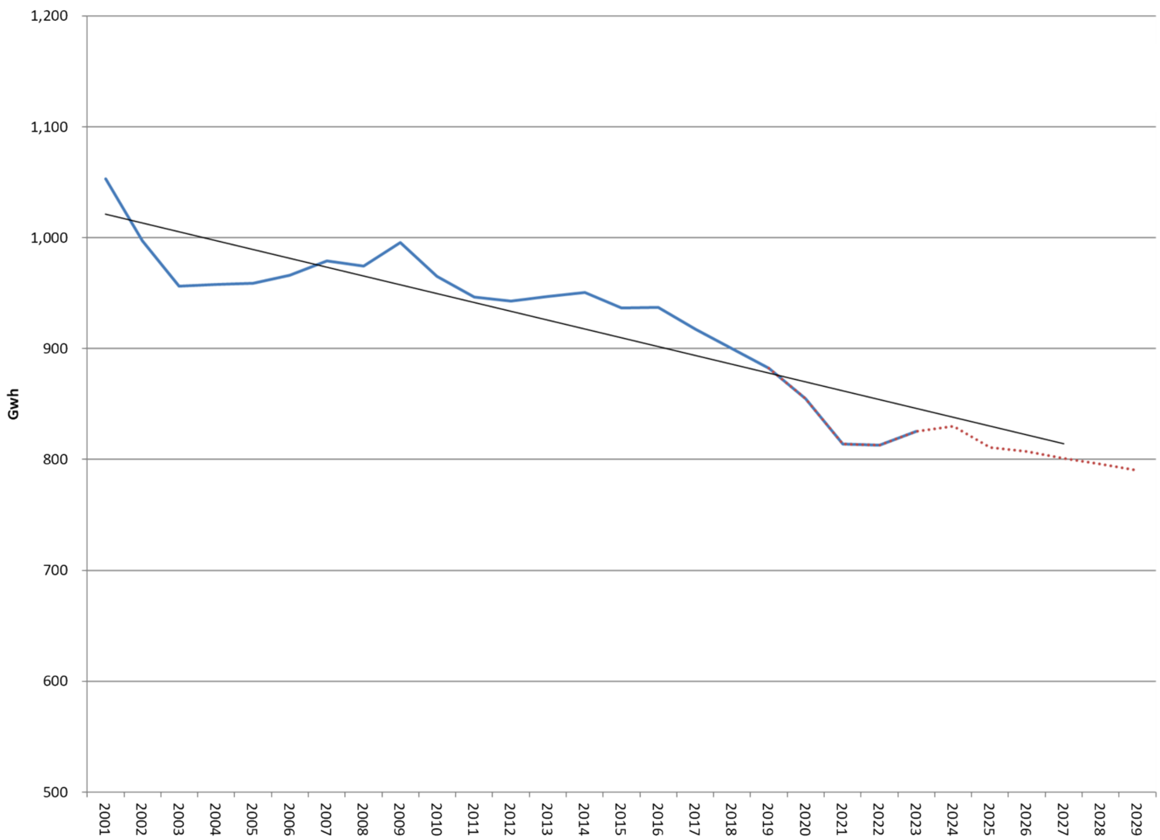


Figure 6 shows the forecast of electricity consumption through FY 2029. The solid black straight line is the long-term average trend of usage.

The small-dash red line represents the projected retail sales used in the financial forecast. Sales, which are depressed due to the economic effects of the pandemic, are assumed to recover to a level slightly above the long-term trend line. These projections are uncertain and will be revised if continuing sales change. Potential factors that may offset declining sales include a potential data center project. Building and vehicle electrification at a business as usual level is included in this forecast but large increases in the rate of building and vehicle electrification could increase sales further as well.

Figure 6: Forecasted Electricity Consumption



SECTION 5B: FY 2019 TO FY 2023 COST AND REVENUE TRENDS

As shown in *Appendix A: Electric Utility Financial Forecast Detail*, annual expenses for the Electric Utility increased significantly from FY 2019 to FY 2023. Electric supply costs increased as new renewable projects came online, and transmission costs rose and have continued to rise as improvements are made to the California grid. Capital investment and operational costs have increased due to construction inflation, increased investment in the electric system, and the cost of contract field crews to cover operational work due to challenges with vacancies.

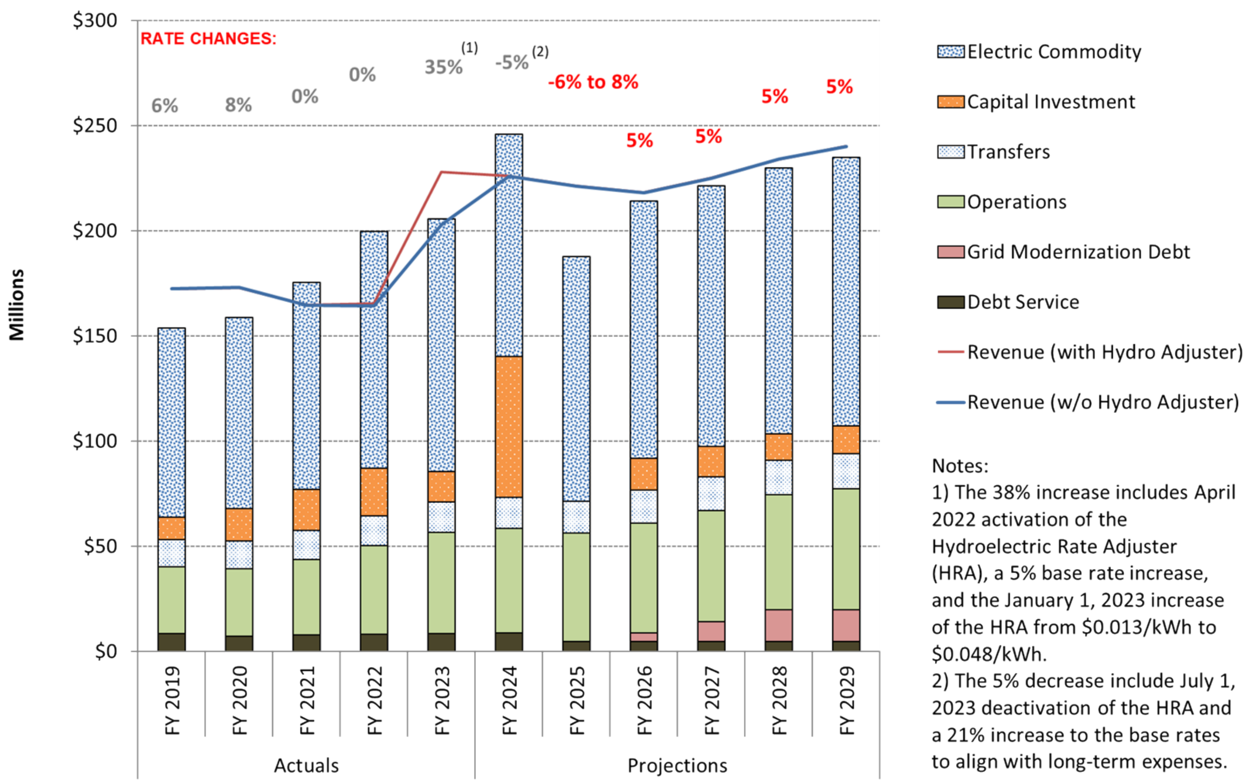
Section 6A: Electricity Purchases discusses the factors influencing electric supply expenses. During the drought in FY 2021 and FY 2022 costs increased due to a lack of hydroelectric generation. Better than average hydro conditions in FY 2019 led to lower than expected generation expenses as well as better than expected surplus energy revenues, but extreme drought followed. In FY 2023 the drought broke with record rainfall over the winter, but this was also accompanied by record high gas prices that drove electricity market prices high as well, offsetting the benefits of the rainfall.

The commodity and distribution costs for FY 2025 in Figure 7 are unusual due to one-time commodity revenues and savings and due to the timing of various capital investments and related debt issuances in FY 2024 and FY 2025. If using a more representative year (such as FY 2026), commodity costs can be seen to have increased 4% to 5% per year since FY 2020 and operational and capital investment costs can be seen to have increased 5% to 6% per year. The forecasted increases in distribution cost relate primarily to debt service for the grid modernization project as well as continuing construction inflation and other inflation. Combined, the utility's costs 4% to 5% per year on average for the last few years (after adjusting for the unusually low FY 2025 expenses)

Figure 7 shows the electric utility revenues, expenses, and proposed rate changes for the previous five years, the current year, and the projections for the next five years. The rate change percentages listed include the hydroelectric rate adjuster, which was activated in April 2022, increased in January 2023, and removed in July 2023. The removal of the hydroelectric rate adjuster was combined with a 21% base rate increase, leading to a 5% overall rate decrease**.**

The cost bars in FY 2024 reflect a one-time timing issue with the startup of the grid modernization project. The first year of spending was budgeted in FY 2024, but the first debt issuance will not take place until FY 2025 (this was to allow time for the City to apply for a grant, which it did not receive). It also reflects a one-time transfer in FY 2024 related to new customer investments.

Figure 7: Electric Utility Revenues, Expenses, and Rate Changes: Actual Costs through FY 2023 and Projections through FY 2029



Notes:
1) The 38% increase includes April 2022 activation of the Hydroelectric Rate Adjuster (HRA), a 5% base rate increase, and the January 1, 2023 increase of the HRA from \$0.013/kWh to \$0.048/kWh.
2) The 5% decrease include July 1, 2023 deactivation of the HRA and a 21% increase to the base rates to align with long-term expenses.

SECTION 5C: FY 2023 RESULTS

FY 2023 revenues were $50 million higher than projections due to the activation of the hydroelectric rate adjuster ($26 million) and the receipt of the $24 million judgment related to a lawsuit against the Federal government related to the City's contract with the Western Area Power Administration. This was partially offset by net supply purchase costs that came in $28 million higher than projected due to extraordinarily high electric market prices. Operational costs came in about $8.7 million lower than projected due to savings in administration and demand side management (DSM) costs. Capital projects costs were lower than projections by $7.5 million.

Table 9 FY 2023, Actual Results vs. FY 2023 Financial Plan Forecast ($000)

	Net Cost/(Benefit)	Type of change
Higher revenues from Hydroelectric Rate Adjuster and judgment	($49,846)	Revenue increase
Higher electric supply costs	$28,099	Cost increase
Lower operational costs	($8,772)	Cost decrease
Lower than forecasted capital investment	($7,463)	Cost decrease
Net Cost / (Benefit) of Variances	**($37,982)**	

SECTION 5D: FY 2024 PROJECTIONS

Net revenues are expected to be $6.3 million lower than projected, but this includes wholesale revenues that are $20 million higher than forecasted due to better hydroelectric conditions than were anticipated in the FY 2024 Financial Plan forecast and higher prices for resource adequacy and REC sales. This is offset by a $26.6 million decrease in other revenues because the judgment for the lawsuit mentioned above was received in FY 2023 rather than FY 2024 as anticipated. Purchase costs are currently projected to be $3.6 million lower due to market prices moderating and hydroelectric conditions improving. Operations costs are projected to be $5.4 million lower than forecasted, but due to grid modernization and a rebuild of the Hanover Substation capital investment costs are projected to be $41 million more than previously forecasted. The net effect of these forecasted changes is $38 million in net impact to reserves, which offsets the $38 million in net benefit to reserves from FY 2023 results compared to forecasts.

Table 10 Change in Projected FY 2024 Results:
FY 2025 Financial Plan Forecast vs. FY 2024 Financial Plan Forecast ($000)

	Net Cost/(Benefit)	Type of change
Higher wholesale revenues	($20,234)	Revenue increase
Other revenues lower than forecasted	$26,605	Revenue decrease
Lower than forecasted supply costs	($3,592)	Cost decrease
Lower than forecasted operational costs	($5,473)	Cost decrease
Additional capital investment costs	$41,376	Cost increase
Net Cost / (Benefit) of Variances to Ops Reserve	**$38,681**	

SECTION 5E: FY 2025 – FY 2029 PROJECTIONS

As shown in Figure 7 above, From FY 2025 through FY 2029 increasing power supply costs combined with rising capital investment and debt service costs due to the grid modernization project are projected to lead to 5% per year projected rate increases in FY 2026 through FY 2029. A one-time transfer in FY 2026 related to the electric utility's share of the dark fiber system rebuild is also expected.

With California reservoirs filled and prices declining, power supply costs are expected to be lower in FY 2024 than previously forecasted, but hydroelectric revenue continues to vary annually and will be negatively affected by climate change over time. To reduce hydroelectric-related volatility in the future, staff is now making its rate projections assuming that long-term "normal" production from the City's hydroelectric resources is about 80% of historical average levels. Over the longer term, increasing transmission costs and tightening resource adequacy requirements are also expected to steadily increase electric supply costs.

The projected rate increases of 5% per year for FY 2026 through FY 2029 are expected to keep revenues in line with expenses. Staff recommends against raising rates significantly in FY 2025 to allow for changes in rates among customer classes to align with the recently completed cost of service analysis. This will allow the City to limit the rate changes for any customer class to 8% or less in FY 2025.

Reserves trends based on these revenue projections are shown in Figure 9 (for Supply Fund Reserves) and Figure 10 (for Distribution Fund Reserves), below. The Supply and Distribution Operations Reserves are projected to be slightly below the minimum level in FY 2024 but are expected to return to within guideline levels by the end of FY 2025.

This Financial Plan includes the restoration of the hydroelectric stabilization reserve from nearly empty to $17.4 million by the end of FY 2025, close to the reserve maximum and enough to allow the utility to absorb the increased costs associated with lower hydroelectric generation across multiple dry years. It also includes repayment of all internal loans from the Electric Special Projects Reserve by the end of FY 2025. And lastly, it includes significant interfund transfers in FY 2024 and FY 2025 to manage the impact of the cash flow issue associated with the startup of the grid modernization project (see *Section 3D: Proposed Reserve Transfers* for more detail).

The reserves charts below show significant increases in the Public Benefits and Cap and Trade reserves over the forecast period. This reflects that those funding sources are currently not fully utilized, but staff expects that to change as the City launches more electrification programs funded by those sources.

Figure 9: Electric Utility Reserves (Supply Fund): Actual Reserve Levels through FY 2023 and Projections through FY 2029

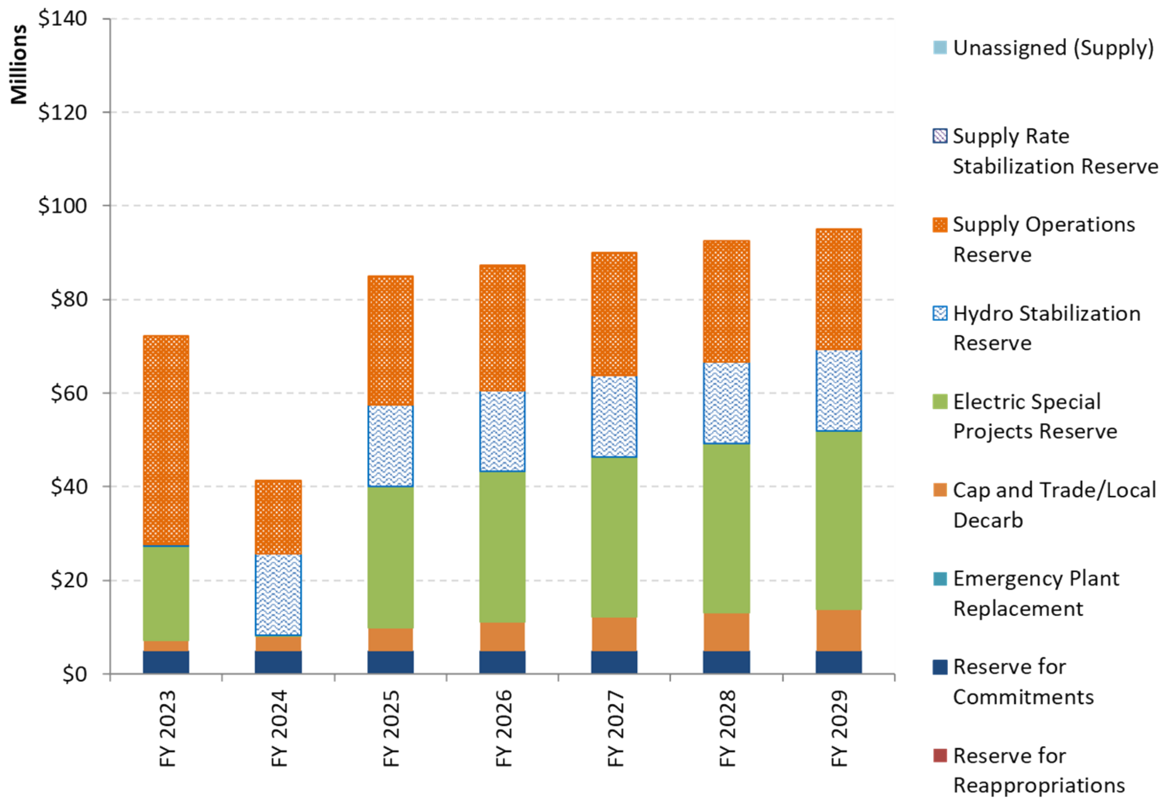
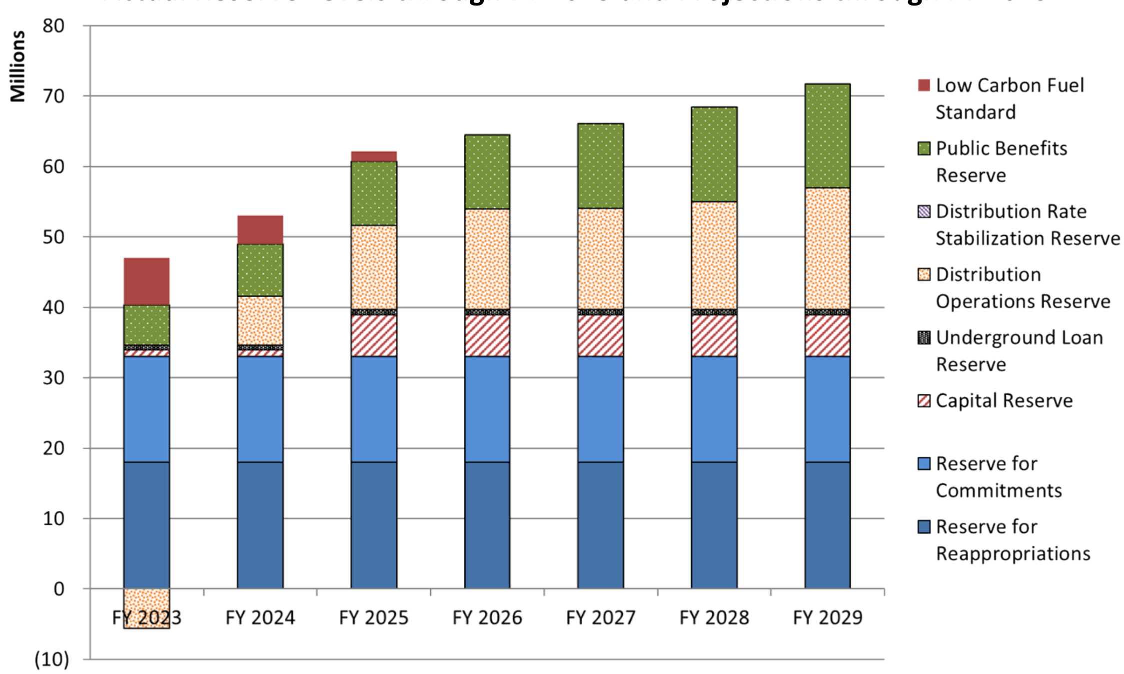


Figure 10: Electric Utility Reserves (Distribution Fund): Actual Reserve Levels through FY 2023 and Projections through FY 2029



SECTION 5F: RISK ASSESSMENT AND RESERVES ADEQUACY

The Electric Utility currently has two primary contingency reserves, the Supply Operations Reserve and the Distribution Operations Reserve. In addition, the Electric Utility has a Hydro Stabilization Reserve, an ESP Reserve, and a Capital Reserve, which can be utilized with Council approval.

There are a variety of risks associated with the Supply Fund related to resource generation variability, market price volatility, transmission cost increases, regulatory changes to market rules. Because of the high range of uncertainty in energy price predictions more than three years in the future, this risk assessment is only performed for the first two fiscal years of the forecast period. It is important to note that the likelihood of all these adverse scenarios occurring simultaneously and to the degree described in Table 12 is very low.

Table 12: Electric Supply Fund Risk Assessment

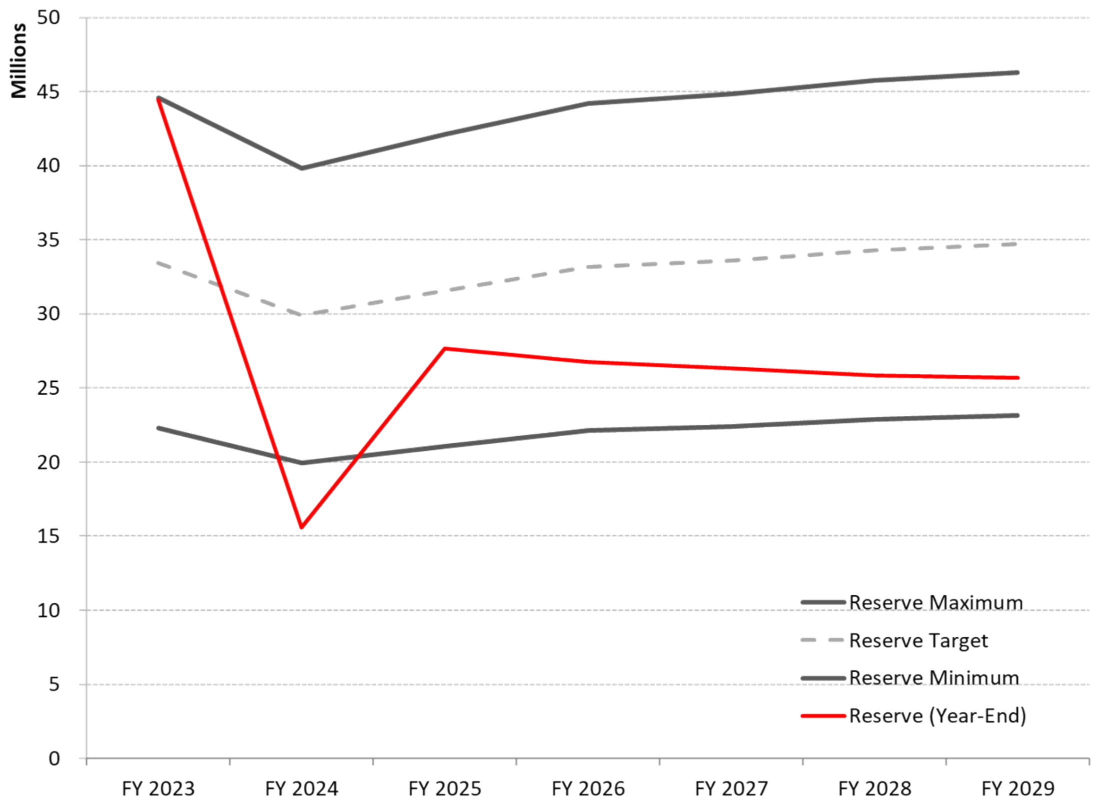
Categories of Electric Supply Cost Uncertainties	Estimates of Adverse Outcomes (M$)	Estimates of Adverse Outcomes (M$)
	FY 2025	FY 2026
1. Load Net Revenue	4.8	3.8
2. Hydro Production: Western & Calaveras	8.4	3.8
3. Renewable Production: Landfill, Wind, Solar, Geothermal	1.1	1.9
4. REC Purchases	0.5	0.5
5. REC Sales	3.8	2.8
6. Market Price	2.4	2.1
7. Resource Adequacy	3.2	1.1
8. Transmission/CAISO	4.8	5.0
9. Plant Outage	1.0	1.0
10. Western Cost	1.3	1.7
11. Legislative & Regulatory	0.0	0.0
12. Supplier Default+	0.2	0.2
Electric Supply Fund Risks	**31.6**	**23.9**

Of the risks faced by the Electric Utility's Supply Fund, the risk of a dry year with very low hydroelectric output is normally the largest, accounting for more than one-third ($8.4 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 2025, $4.8 million is related to potential transmission cost increases (above staff's current forecast). $4.8 million is related to the potential that total load (and the associated retail sales revenue) may be lower than projected. Other risks related to production from the City's renewable contracts and market prices for purchases and sales of energy and resource adequacy (Items 3, 4, 5, 6, and 7 above) total $11 million due to the unusually high market prices and surplus sales contract volumes in FY 2025.

As shown in Figure 11, staff projects the Supply Operations Reserve to drop below the minimum guideline levels in FY 2024 but return to within guideline levels by the end of FY 2025. Note that the high reserve level in FY 2023 is related to the timing of a $24M judgment from a lawsuit related to the allocation of costs of the Central Valley Project. These funds are being redistributed to other purposes in FY 2024, with the transfers resulting in a reduction in the Supply Operations Reserve. Figure 12 shows that the combined Hydro Stabilization and Supply Operations Reserves are projected to be above the risk assessment level through the forecast period.

Figure 11: Electric Supply Operations Reserve Adequacy



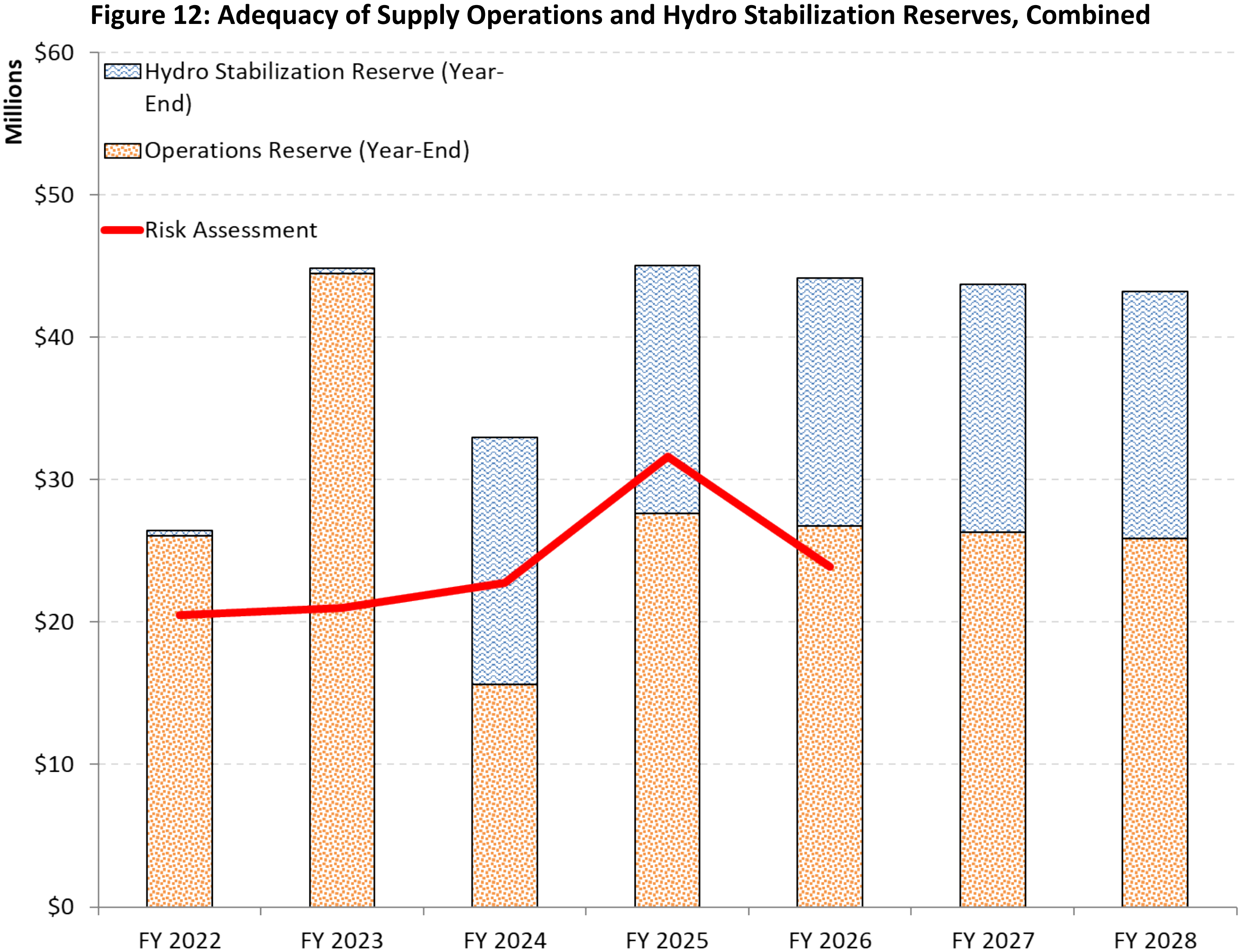


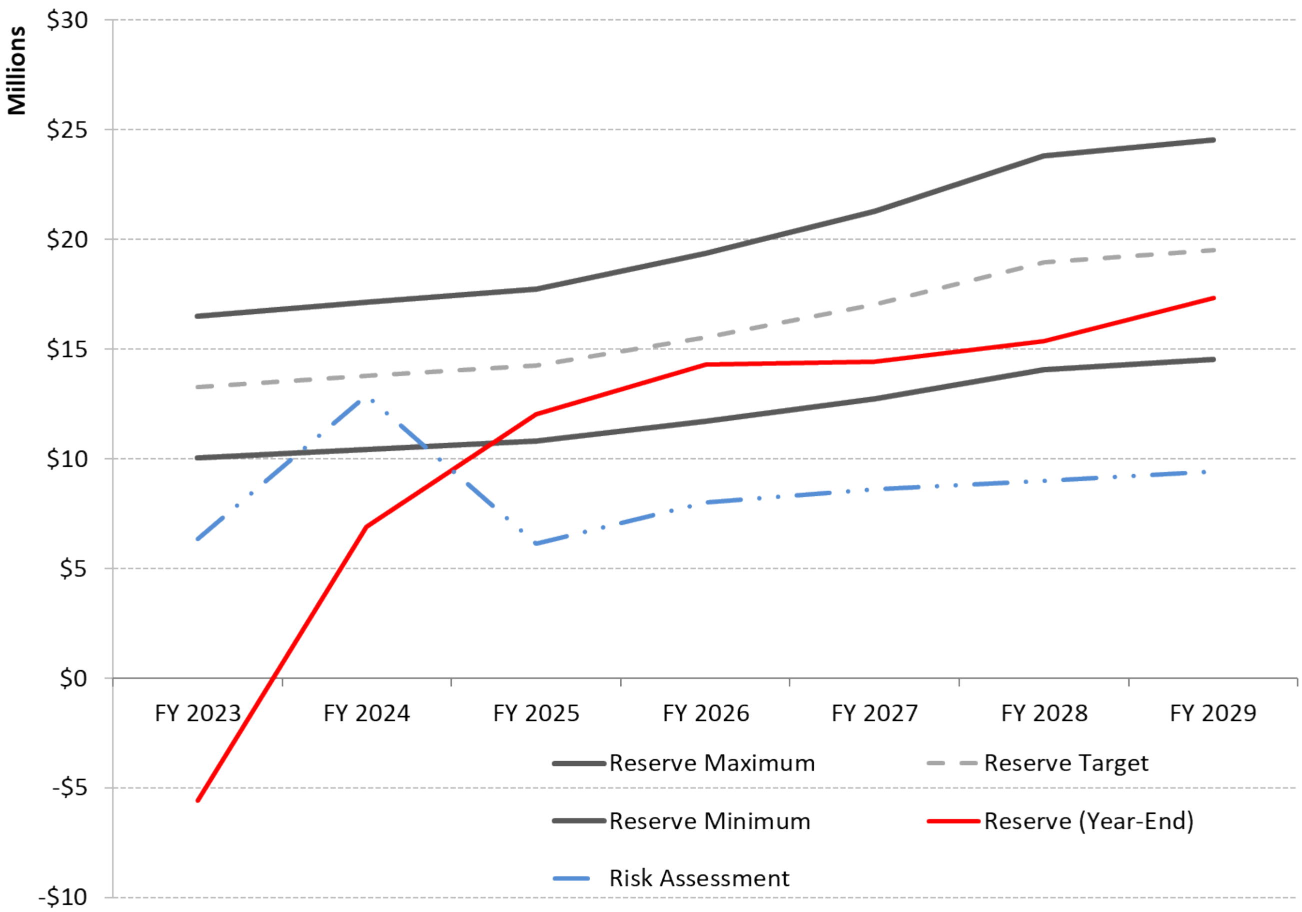
Table 13 summarizes the risk assessment calculation for the Distribution Operations Reserve through FY 2029. As shown in Figure 13, the Distribution Operations Reserve is also projected to drop near to the minimum reserve guidelines in FY 2025, but is projected to recover to target levels over the course of the forecast period. The risk assessment includes the revenue shortfall that could accrue due to:

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

Table 13: Electric Distribution Fund Risk Assessment ($000)

	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Total non-commodity revenue	$77,592	$82,369	$90,316	$98,135	$102,722
Max. revenue variance, previous ten years	8%	8%	8%	8%	8%
Risk of revenue loss	$6,124	$6,501	$7,128	$7,745	$8,107
CIP Budget	$0	$15,143	$14,671	$12,688	$13,089
CIP Contingency @10%	$0	$1,514	$1,467	$1,269	$1,309
Total Risk Assessment value	$6,124	$8,015	$8,595	$9,014	$9,416

Figure 13: Electric Distribution Operations Reserve Adequacy

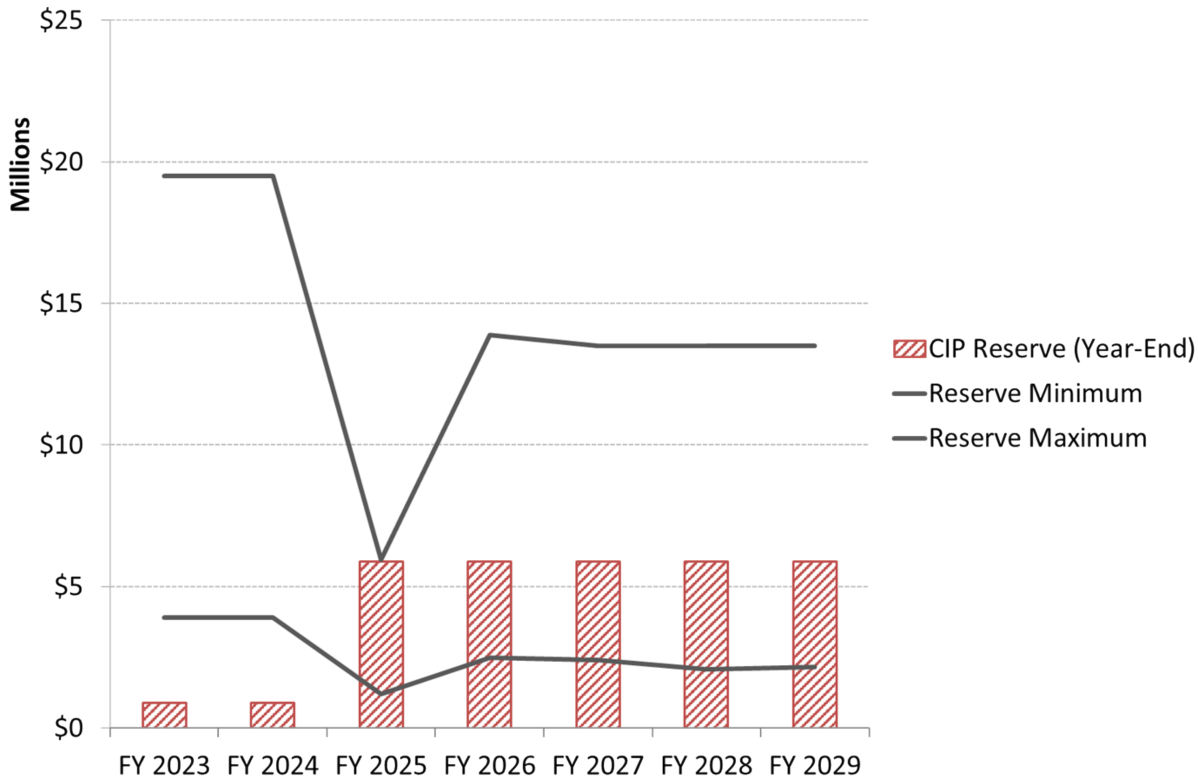


The Electric Utility also has a CIP Reserve that acts as a reserve for short term capital contingencies or as a place to set aside funds for large, one-time projects that the Utilities would otherwise need to debt-fund. Figure 14 below reflects the maximum and minimum CIP Reserve guideline levels, starting in FY 2023. Because of the fluctuating annual dollar amounts and timing of CIP projects budgeted to occur during the forecast period, as well as the potential for new ongoing projects to be included in the CIP plan in later years, four years of budgeted CIP are used to calculate the reserve maximum levels. The minimum CIP Reserve level is 20% of the maximum CIP Reserve guideline level.

This Financial Plan plans to fund the CIP Reserve to its minimum level by the end of FY 2025 and includes additional contributions to the reserve in later years. In addition, staff recommends amending the reserve guidelines to direct staff to transfer any unspent CIP budget that is not reappropriated or encumbered at the end of each fiscal year to the CIP Reserve. These represent ratepayer funds already collected for the purpose of CIP investment, and retaining them in the CIP Reserve would allow the City to use them to fund future unanticipated CIP expenses (such as mid-year budget adjustments due to increased costs for specific projects) that were not included in a financial plan.

Figure 14 shows the projected CIP Reserve balances and guideline levels for FY 2023 through FY 2029. The CIP reserve is projected to be above the minimum guideline by the end of FY 2025. Per the Reserves Management Practices (Appendix B), Section 10, any rate plan that does not return CIP reserves to minimum levels within one year requires Council approval. Council approved the FY 2024 Electric Utility Financial Plan, which included keeping the CIP Reserve below minimum until FY 2026. This plan achieves minimum CIP Reserve levels by the end of FY 2025.

Figure 14: Electric CIP Reserve Adequacy



SECTION 5G: LONG-TERM OUTLOOK

This forecast covers the period from FY 2025 through FY 2029, 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 are seeing a number of notable events. The contract with the Western Area Power Administration (Western) for power from the Central Valley Project (CVP) is expiring in 2024, with an option in 2024 to reduce the City's share. 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.

Over the next decade six of the utility's renewable contracts will begin expiring with the first contract expired in 2026 and the last in 2034. It is difficult to know whether renewable energy prices will be more or less favorable than the contract prices when those contracts expire.

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

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

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

Over the next several years the Electric Utility will continue to execute its usual monitoring, repair, and replacement routine for the distribution system, but is also beginning the rollout of various smart grid technologies and a major grid modernization effort that will result in rebuilding of the electric system and capacity increases. This rebuild will involve debt service that will be repaid over 30 years and will have an uncertain effect on electric system capital investment needs in the 2030s and beyond.

The utility is actively promoting electric vehicle ownership and gas-to-electric fuel switching in Palo Alto. In the coming years these factors are expected to create notable increases in electric consumption and have a variety of impacts on the distribution system. Other technologies such as battery storage and rooftop solar installations are also becoming even more common. The utility has already started to take some of these factors into account in its long-term planning processes but will need to continue to incorporate them into its planning methodologies.

Over the long term, electricity may replace natural gas and petroleum almost entirely as part of the City's efforts to combat climate change. Many, if not most, vehicles would use electricity, though hydrogen is another potential fuel source under development and other technologies might be developed. Staff is undertaking initial analysis of these types of scenarios in the context of the Sustainability and Climate Action Plan (S/CAP) development process. Utility analyses in progress or completed that take into account potential load growth benefits and impacts include a grid modernization study, the Electric Integrated Resource Plan, and an upcoming S/CAP funding needs and sources study that may help assess the impact of these trends on rates. Staff will integrate results from these studies in Financial Plans as they become available.

SECTION 5H: ALTERNATIVE RATE PROJECTIONS

Staff is not presenting any alternative rate projections in this Financial Plan.

SECTION 6: DETAILS AND ASSUMPTIONS

SECTION 6A: ELECTRICITY PURCHASES

As shown in Figure 16 the utility is projected to get roughly 45% of its energy from hydroelectric projects in a normal year, but is getting over 50% during FY 2024 and FY 2025 due to the favorable hydroelectric generation conditions resulting from the rains of the 2022/2023 winter. In the longer term contracts with renewable sources make up approximately 50% to 55% of the portfolio. If hydroelectric conditions end up being lower than forecasted (as they were in FY 2023) or if loads increase, some power may come from unspecified market sources. Under the City's Carbon Neutral Plan, CPAU purchases RECs corresponding to the amount of market energy it purchases.

Figure 16: Electricity Supply by Source

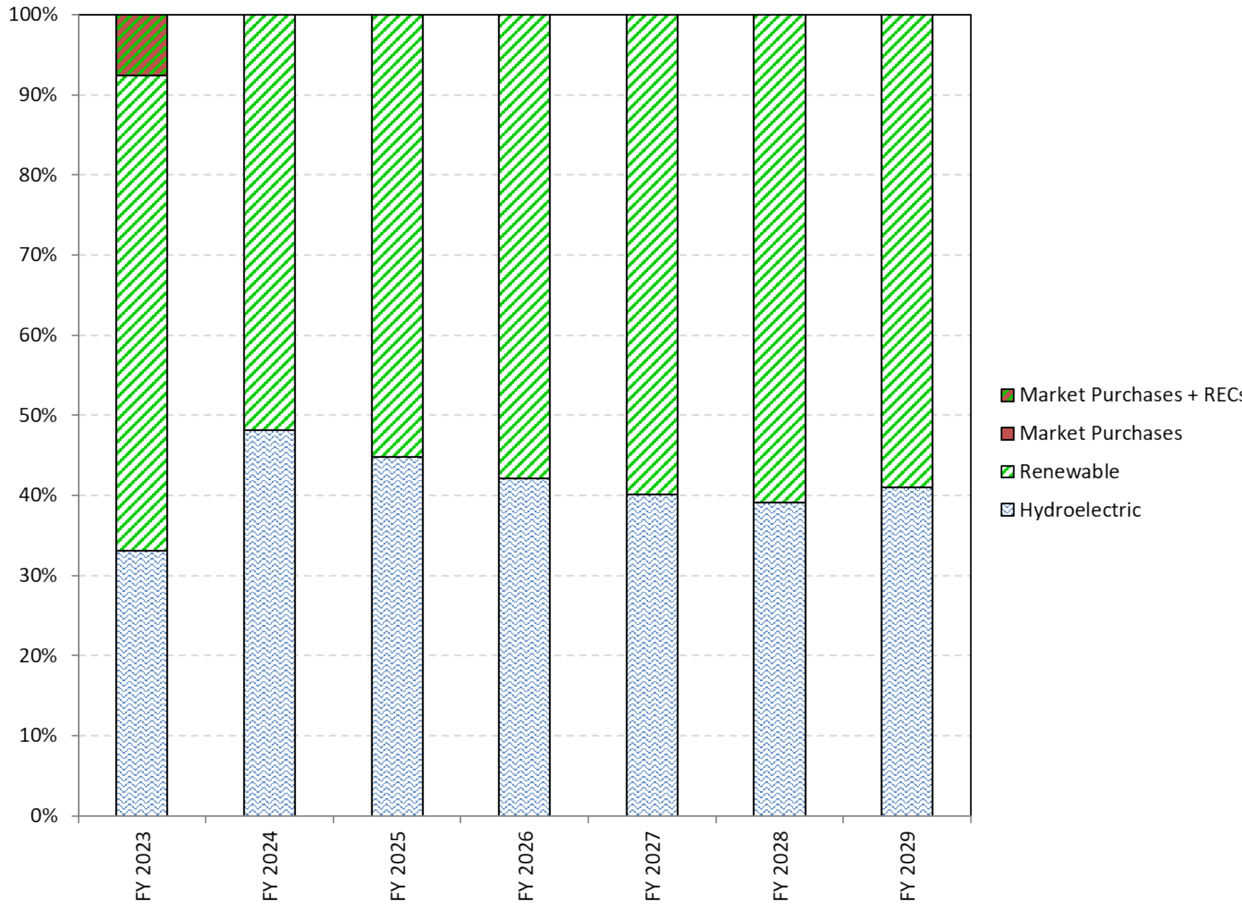
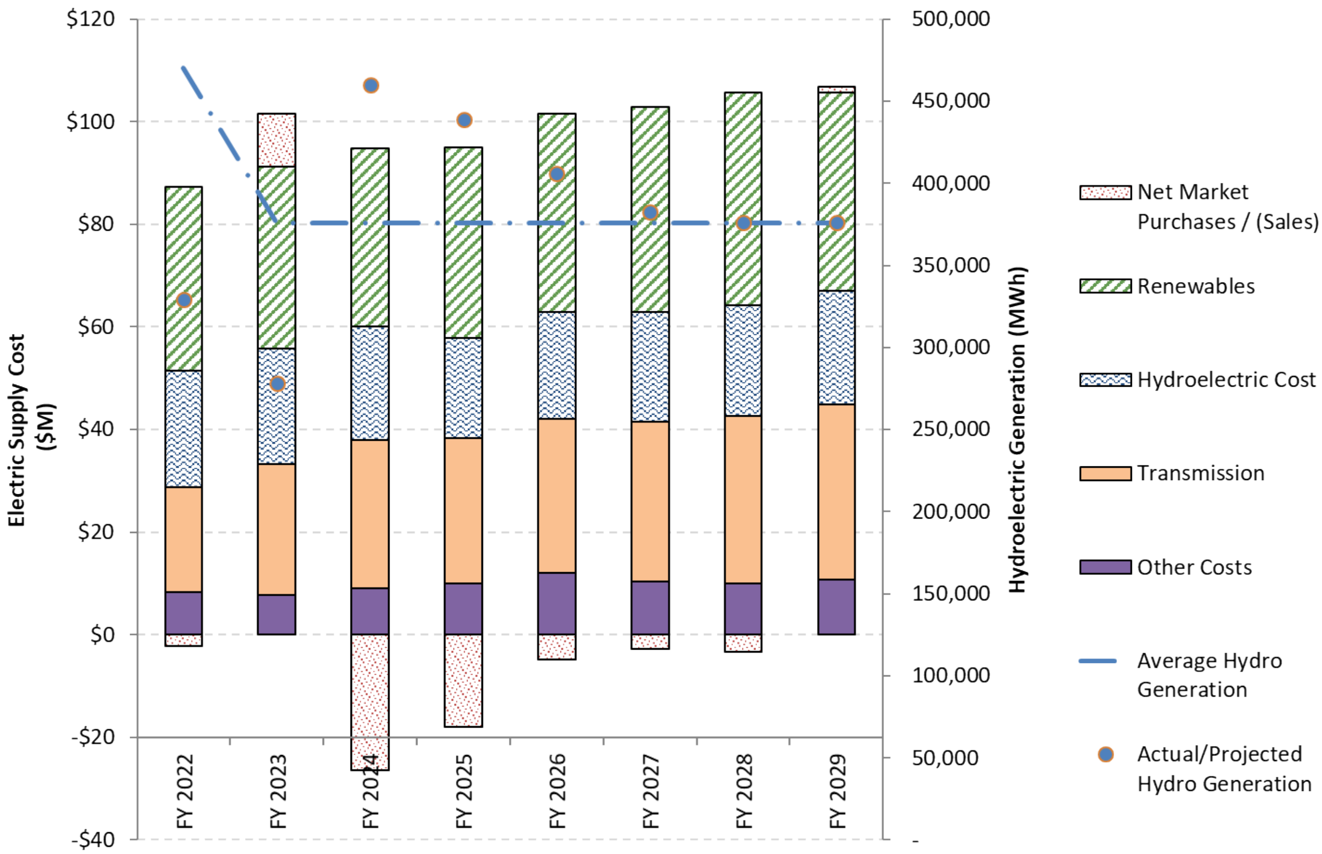


Figure 16 shows the historical and projected costs for the electric supply portfolio,[11] as well as average and actual hydroelectric generation.[12] FY 2022 and FY 2023 had lower than average hydroelectric generation, while FY2024 and FY 2025 had higher than forecasted generation. Starting in FY 2023 (in the FY 2024 Electric Utility Financial Plan) staff lowered its projection of an average hydroelectric year to more closely align with the past 10 years of historical averages. But with the current favorable reservoir conditions staff is projecting hydroelectric generation to be better than average through FY 2026.

Renewable energy costs have stayed relatively flat as one renewable energy contract ended while another renewable project came online to fulfill the City's carbon neutral and RPS goals. The current market outlook is uncertain for newer renewables projects because of headwinds from supply chain issues and tailwinds from federal subsidies. Transmission charges are projected to increase as new transmission lines are built throughout California to accommodate new renewable projects. In total, net electric supply costs are projected to increase from about average of $83 million from FY 2022 through FY 2025 to about $106 million by FY 2029.

[11] 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.
[12] Average hydroelectric generation based on the current E-HRA rate schedule.

Figure 17: Electric Supply Portfolio Costs, Historical and Projected



SECTION 6B: OPERATIONS

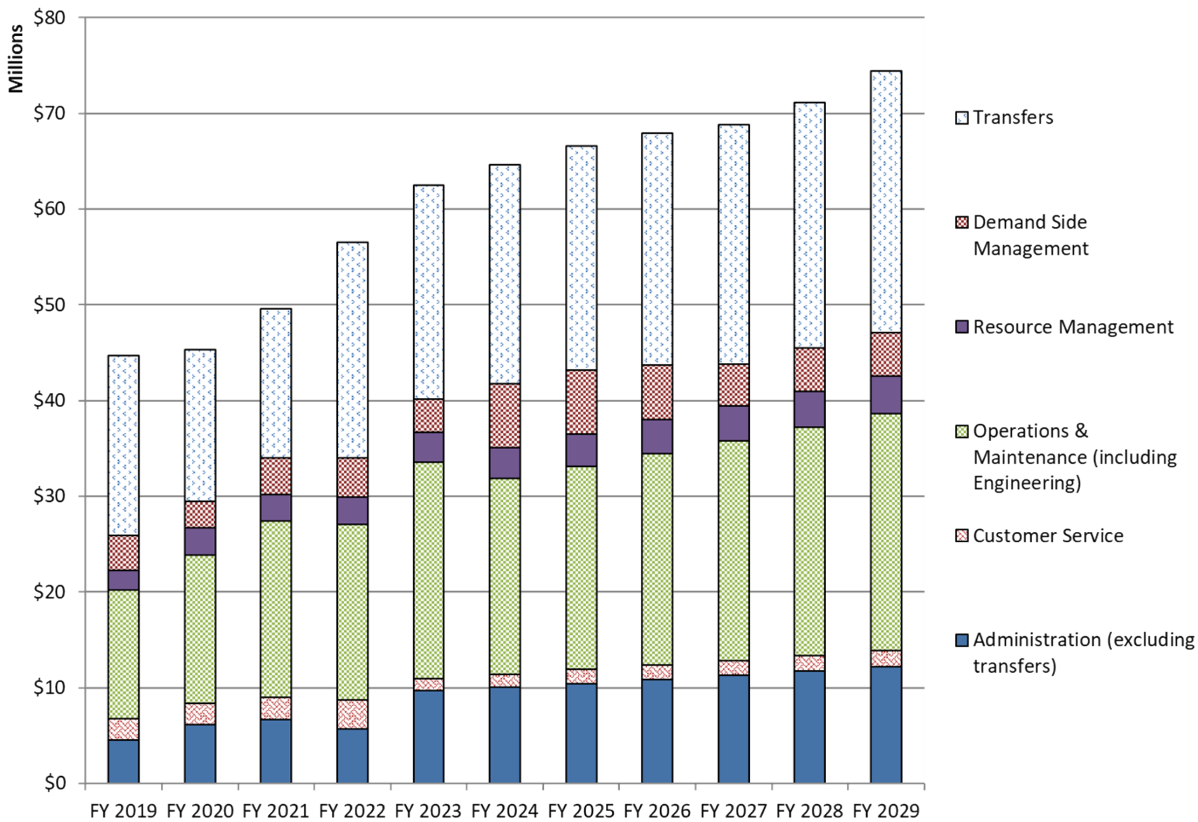
CPAU's Electric Utility operations include the following activities:

- Administration, including financial management of charges allocated to the Electric Utility for administrative services provided by the General Fund and for Utilities Department administration, as well as debt service and other transfers. Additional detail on Electric Utility debt service is provided in Section 6D (Debt Service)
- Customer Service
- Engineering work for maintenance activities (as opposed to capital activities)
- Operations and Maintenance of the distribution system; and
- Resource Management

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

From FY 2019 to FY 2023, overall operations costs have risen annually by about 7% on average. This is primarily driven by increased operations and maintenance and administrative overhead allocations. Operations and maintenance costs are increasing primarily due to inflation driven by the tight labor market and the cost of using contract field crews to backfill for vacant positions. These costs may be reduced depending on how much work is needed and may be phased out as longer-term employees are gained.

Figure 18: Historical and Projected Electric Utility Operational Costs



SECTION 6C: CAPITAL IMPROVEMENT PROGRAM (CIP)

Staff projects CIP spending for FY 2025 through FY 2029 to focus primarily on grid modernization. Other significant one-time projects include a rebuild of Hanover Substation (budgeted in FY 2024, mid-year), a major project at the Colorado Substation, undergrounding of power lines in the Foothills, and completion of the Smart Grid (Advanced Metering Infrastructure) project. Ongoing projects include replacement of deteriorated wood poles, substation physical security upgrades, and ongoing capital investment in smaller projects on the electric distribution system to maintain/improve reliability. Total spending over the forecast period, including the FY 2024 budget, is over $450 million, far higher than past CIP spending plans. Of this, about $330 million is planned to be financed through debt, as explained in *Section 6D: Debt Service* below.

The remainder of the CIP plan for 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 (such as funds from the Electric Special Projects Reserve for smart grid). The details of the CIP budget will be available in the Proposed FY 2025 Utilities Capital Budget. Table 14 shows the FY 2025 projected budget and the five year CIP spending plan, although these figures are preliminary pending budget discussions starting in May.

Table 14: Electric Utility CIP Spending ($000)

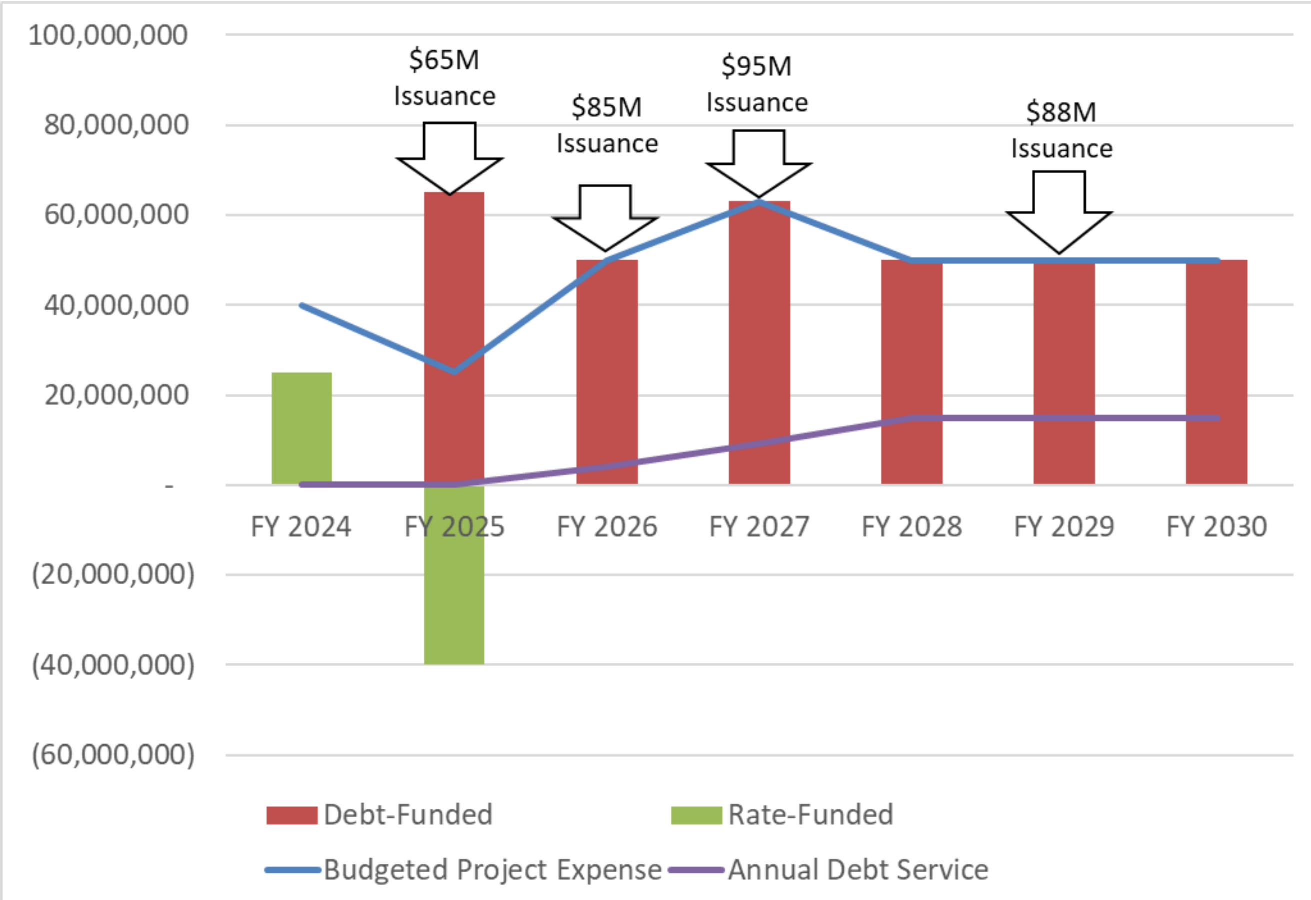
Project Category	Current Budget *	FY 2025 (New Budget, Excluding Reappropriations)	FY 2026	FY 2027	FY 2028	FY 2029
One Time Projects	26,363,974	10,100,000	3,750,000	2,850,000	750,000	750,000
Reliability	4,516,765	765,000	798,300	900,000	529,000	544,870
Undergrounding	1,368	-	-	-	-	-
4/12 kV Conversion	2,487,541	-	-	-	-	-
Underground Rebuild	1,112,000	-	-	-	-	-
Ongoing	8,093,369	3,915,000	3,875,000	4,040,500	4,361,000	4,491,830
Customer Connections	5,865,828	2,700,000	2,700,000	2,700,000	2,700,000	2,781,000
Smart Grid	12,710,117	-	-	-	-	-
Grid Modernization	25,000,000	25,000,000	50,000,000	50,000,000	50,000,000	50,000,000
Total	**86,150,963**	**42,480,000**	**61,123,300**	**60,490,500**	**58,340,000**	**58,567,700**

** Includes unspent funds from previous years carried forward or reappropriated to the current fiscal year*

SECTION 6D: DEBT SERVICE

The Electric Utility made its last payment on the 2007 Electric Utility Clean Renewable Energy Tax Credit Bonds, Series A in FY 2021. This $1.5 million bond issuance was to fund a portion of the construction costs of solar demonstration projects at the Municipal Services Center, Baylands Interpretive Center, and Cubberley Community Center. It currently has no debt service expenses related to its own distribution system (though it does have debt service expenses related to the Calaveras Dam, a power supply expense). However, staff expects to issue substantial amounts of debt to fund up to $300 million in grid modernization expenses through FY 2030. A tentative projection of how much of the cost of that project will be debt funded vs. rate funded is shown in Figure 19 below. This plan is reflected in the financial projections in this Financial Plan. The timing and amount of the debt issuances will likely change as the grid modernization project progresses. Note that the debt issuance in FY 2025 will be used for FY 2024 expenses, resulting in the use of rate/reserve funding in FY 2024 and a refund to the reserves in FY 2025 as the bond proceeds are applied to those FY 2024 expenses.

Figure 19: Projected Funding Plan for Grid Modernization Project



The Electric Utility pledges reserves and net revenue as security for the bond issuances listed in Table 15 even though the Electric Utility is not responsible for the debt service payments. The Electric Utility's reserves or net revenues would only be called upon if the responsible utilities are unable to make their debt service payments. Staff does not currently foresee this occurring. Staff projects that the Electric Utility's net revenues in each future year will exceed 125% of debt service (see Appendix B, line 70).

Table 15: Other Issuances Secured by Electric Utility's Revenues or Reserves

Bond Issuance	Responsible Utilities	Annual Debt Service ($000)	Secured by Electric Utility's:	
			Net Revenues	Reserves
1999 Utility Revenue Bonds, Series A	Storm Drain Wastewater Collection Wastewater Treatment	$1,207	No	Yes
2009 Water Revenue Bonds (Build America Bonds)	Water	$1,977*	No	Yes
2011 Utility Revenue Refunding Bonds, Series A	Gas Water	$1,457	No	Yes
**Net of Federal interest subsidy*				

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.[13] 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 20 to 25% comes from other sources. Of these other sources, about 50% to 75% represents wholesale revenues of surplus energy sales. These revenues may offset electric supply purchase costs, smooth rate increases, or fund reserves or other costs. Of the remaining revenues, the largest revenue sources are interest on reserves, connection fees for new or replacement electric services, and carbon allowance revenues associated with the State's cap-and-trade program

Revenues from connection fees have increased since FY 2009 but vary from year to year. Connection fee revenues are collected to offset costs incurred in setting up new connections and are pass-through in nature. Staff forecasts $1.4 million in FY 2025.

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

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

SECTION 6G: SALES REVENUES

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

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

SECTION 7: COMMUNICATIONS PLAN

The fiscal year (FY) 2025 electric utility communications strategy covers these primary areas: cost drivers, cost containment measures, efficiency services and utility bill savings, capital improvement projects for infrastructure safety and reliability, carbon neutral portfolio, and beneficial electrification. City of Palo Alto Utilities (CPAU) communication methods include utilities webpages, utility bill inserts, messaging on utility bills, email newsletters, print and digital ads, social media, and business and neighborhood customer presentations.

In advance of the rate-setting process, staff working on rates and communications are focusing on informing customers of the need to recover funds to bring financial reserves above the minimum guideline following the 2020 through 2022 reserve drawdowns. It is also important to educate customers about the cost to buy and transport electricity to Palo Alto, as well as the cost to distribute it within Palo Alto, including maintaining and replacing infrastructure, customer service, billing, and administration. Long-term cost trends show supply and distribution costs increasing over time. CPAU implements cost containment as a priority and is improving efficiencies with metering and billing through Advanced Metering Infrastructure (AMI), and a new power Outage Management System (OMS) that automates customer notifications, allowing staff to devote time to restoring service. Despite raising rates, electric costs to customers still remain lower than the comparator regional investor-owned utility, PG&E.

CPAU promotes energy efficiency programs to help customers keep utility bill costs low even as market prices increase or CPAU raises utility rates. Programs such as the Home Efficiency Genie and commercial energy efficiency audits help residents and businesses better understand energy usage, and activities they can implement to improve efficiency and keep utility costs low. The Home Efficiency Genie program now provides a home electrification readiness assessment so customers who want to switch out gas for electric appliances or install an electric vehicle (EV) charger can understand what may be necessary for electric panel upgrades. The City offers attractive financing and assistance with installation to eliminate barriers to adoption.

The Business Energy Advisor (BEA) provides a “concierge” service for businesses to evaluate areas of their facility for efficiency improvements such as in the areas of building envelope, lighting, and heating. BEA acts as the flagship program for businesses to then learn about available rebates for appliance or facility upgrades and opportunities for building electrification. CPAU also offers programs to help non-residential facilities install EV charging infrastructure to assist employees and tenants with goals to switch from fossil fueled transportation to clean, electric driving.

CPAU customers 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. CPAU will highlight these environmental attributes and value in our communications.

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 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 202[illegible]	[illegible]	[illegible]	FY 2029
2												
3	**STARTING RESERVES**											
4	Reappropriations (Non-CIP)	-	-	-	56,811	120,000	253,000	253,000	253,000	253,000	253,000	253,000
5	Commitments (Non-CIP)	3,725,000	3,910,695	3,518,525	3,512,355	(2,321,000)	9,400,307	9,400,307	9,400,307	9,400,307	9,400,307	9,400,307
6	Low Carbon Fuel Standard (LCFS) Reser	-	-	6,340,000	6,943,525	7,235,894	6,712,544	4,053,126	1,485,979	-	-	-
7	Cap and Trade Program				1,189,000	1,189,000	2,230,759	3,230,759	4,940,759	6,150,759	7,230,759	8,140,759
8	Underground Loan Reserve	730,147	726,659	726,659	726,659	726,659	726,659	726,659	726,659	726,659	726,659	726,659
9	Public Benefits Reserves	681,330	809,700	1,904,547	3,027,599	3,890,872	5,672,542	7,431,387	9,033,068	10,568,541	12,031,587	13,421,659
10	Electric Special Projects Reserve	41,837,855	41,664,855	46,664,855	46,664,855	24,649,000	20,148,855	148,855	30,148,855	32,148,855	34,148,855	36,148,855
11	Hydro Stabilization Reserve	11,400,000	11,400,000	15,400,000	15,400,000	400,000	400,000	17,400,000	17,400,000	17,400,000	17,400,000	17,400,000
12	Capital Reserves	879,964	879,964	5,879,964	879,964	879,964	879,964	879,964	5,879,964	5,879,964	5,879,964	5,879,964
13	Rate Stabilization Reserves	9,010,840	-	-	-	-	-	-	-	-	-	-
14	Electrification Reserve						4,500,000	4,500,000	4,500,000	4,500,000	4,500,000	4,500,000
14	Operations Reserves (Supply & Dist)	18,600,000	45,244,167	38,538,459	29,902,850	28,559,158	38,881,723	22,522,316	39,671,926	41,073,721	40,765,805	41,216,341
15	Unassigned	244,354	-	0	(0)	-	-	-	-	-	-	-
16	TOTAL STARTING RESERVES	87,109,490	104,636,040	118,973,010	108,303,618	65,329,547	89,806,353	70,546,373	123,440,517	128,101,807	132,336,936	137,087,544
17												
18	**REVENUES**											
19	Net Sales	131,471,245	137,026,504	129,389,001	130,557,545	164,554,954	172,499,236	169,251,184	177,609,240	185,889,795	194,655,810	203,790,614
20	Wholesale Revenues	21,060,071	20,686,925	25,959,207	25,529,188	30,745,937	46,036,151	44,045,073	30,470,737	28,761,527	28,880,651	25,773,090
21	Other Revenues and Transfers In	19,914,635	15,260,937	9,324,996	9,348,837	32,788,973	7,487,037	7,918,630	10,102,079	10,322,293	10,432,345	10,530,882
22	TOTAL REVENUES	172,445,951	172,974,366	164,673,204	165,435,570	228,089,864	226,022,424	221,214,887	218,182,056	224,973,615	233,968,806	240,094,586
23												
24	**EXPENSES**											
25	Electric Supply Purchases	97,989,910	97,716,399	106,202,833	120,493,205	128,512,096	114,427,008	121,078,734	127,167,371	128,726,357	131,243,066	132,597,189
26	Operating Expenses											
27	Administration											
28	*Allocated Charges*	*4,568,027*	*6,146,498*	*6,674,515*	*5,732,098*	*9,664,335*	*10,050,709*	*10,452,918*	*10,871,097*	*11,305,551*	*11,757,503*	*12,227,733*
29	*Rent*	*5,454,097*	*5,666,805*	*5,949,976*	*6,069,000*	*6,324,000*	*6,474,174*	*6,733,141*	*7,002,466*	*7,282,565*	*7,573,867*	*7,876,822*
30	*Equity Transfer*	*12,973,000*	*13,134,000*	*13,638,000*	*14,138,000*	*14,534,000*	*14,905,000*	*15,121,000*	*15,550,000*	*15,989,000*	*16,421,000*	*16,892,000*
31	*Transfers and Other Adjustments*	*369,321*	*(3,000,057)*	*(4,027,621)*	*2,311,226*	*1,495,296*	*1,474,594*	*1,533,578*	*1,594,921*	*1,658,718*	*1,725,067*	*2,571,441*
32	Subtotal, Administration	23,364,445	21,947,247	22,234,870	28,250,324	32,017,631	32,904,477	33,840,636	35,018,484	36,235,834	37,477,437	39,567,996
33	Resource Management	2,082,405	2,870,524	2,781,010	2,824,303	3,086,893	3,199,728	3,337,316	3,474,146	3,592,267	3,726,330	3,872,887
34	Demand Side Management	3,655,547	2,733,047	3,819,646	4,086,083	3,477,495	6,715,260	6,689,764	5,766,493	4,442,832	4,530,005	4,577,027
35	Operations and Mtc	11,606,585	13,450,568	15,988,315	16,576,083	20,538,544	18,323,978	19,084,973	19,858,105	20,591,664	21,373,323	22,217,356
36	Engineering (Operating)	1,838,799	2,051,303	2,408,524	1,806,550	2,022,434	2,102,495	2,187,351	2,275,108	2,364,474	2,457,918	2,555,940
37	Customer Service	2,180,400	2,228,469	2,320,338	2,974,968	1,328,808	1,378,296	1,436,736	1,495,354	1,547,991	1,604,957	1,667,871
38	Allowance for Unspent Budget	-	-	-	-	-	(653,147)	(680,138)	(707,644)	(734,072)	(762,568)	(792,845)
39	Subtotal, Operating Expenses	44,728,180	45,281,157	49,552,702	56,518,311	62,471,805	63,971,087	65,896,638	67,180,047	68,040,990	70,407,403	73,666,233
40	Capital Expenses											
41	Capital Program Contribution	10,770,456	15,539,840	21,487,061	34,524,744	21,656,368	66,884,310	-	15,143,324	14,671,084	12,687,640	13,089,202
42	Capital-Related Debt Service	100,000	100,000	100,000	100,000	20,789	-	-	4,030,024	9,300,055	14,880,088	14,880,088
43	Subtotal, Capital Expenses	10,870,456	15,639,840	21,587,061	34,624,744	21,677,157	66,884,310	-	19,173,348	23,971,139	27,567,728	27,969,291
44	TOTAL EXPENSES	153,588,546	158,637,396	177,342,596	211,636,260	212,661,058	245,282,404	186,975,372	213,520,766	220,738,486	229,218,198	234,232,712
45												
46	**ENDING RESERVES**											
47	Reappropriations (Non-CIP)	-	-	56,811	120,000	253,000	253,000	253,000	253,000	253,000	253,000	253,000
48	Commitments (Non-CIP)	3,910,695	3,518,525	3,512,355	(2,321,000)	9,400,307	9,400,307	9,400,307	9,400,307	9,400,307	9,400,307	9,400,307
51	Low Carbon Fuel Standard (LCFS) Reser	-	6,340,000	6,943,525	7,235,894	6,712,544	4,053,126	1,485,979	-	-	-	-
52	Cap and Trade Program			1,189,000	1,189,000	2,230,759	3,230,759	4,940,759	6,150,759	7,230,759	8,140,759	8,870,759
53	Underground Loan Reserve	726,659	726,659	726,659	726,659	726,659	726,659	726,659	726,659	726,659	726,659	726,659
54	Public Benefits Reserves	809,700	1,904,547	3,027,599	3,890,872	5,672,542	7,431,387	9,033,068	10,568,541	12,031,587	13,421,659	14,733,094
55	Electric Special Projects Reserve	41,664,855	46,664,855	46,664,855	24,649,000	20,148,855	148,855	30,148,855	32,148,855	34,148,855	36,148,855	38,148,855
56	Hydro Stabilization Reserve	11,400,000	15,400,000	15,400,000	400,000	400,000	17,400,000	17,400,000	17,400,000	17,400,000	17,400,000	17,400,000
57	Capital Reserve	879,964	5,879,964	879,964	879,964	879,964	879,964	5,879,964	5,879,964	5,879,964	5,879,964	5,879,964
58	Rate Stabilization Reserve	-	-	-	-	-	-	-	[illegible]	[illegible]	[illegible]	-
59	Electrification Reserve					4,500,000	4,500,000	4,500,000	4,5[illegible]	[illegible]	[illegible]00	4,500,000
60	Operations Reserve (Supply & Dist)	45,244,167	38,538,459	29,902,850	28,559,158	38,881,723	22,522,316	39,671,926	41,073,721	40,765,805	41,216,341	43,036,780
61	Unassigned	-	0	(0)	-	-	-	-	-	-	-	-
62	TOTAL ENDING RESERVES	104,636,040	118,973,010	108,303,618	65,329,547	89,806,353	70,546,373	123,440,517	128,101,807	132,336,936	137,087,544	142,949,418

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FISCAL YEAR	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
ELECTRIC LOAD		0	0								
Purchases (MWh)	905,071	879,913	827,106	836,828	849,043	869,163	835,686	832,000	825,954	820,400	814,662
Sales (MWh)	884,322	854,761	813,881	812,841	825,297	830,051	810,616	807,040	801,176	795,788	790,222
BILL AND RATE CHANGES											
System Average Rate ($/kWh)	$ 0.1487	$ 0.1603	$ 0.1590	$ 0.1606	$ 0.1994	$ 0.2078	$ 0.2088	$ 0.2201	$ 0.2320	$ 0.2446	$ 0.2579
Change in System Average Rate	5%	8%	-1%	1%	24%	4%	0%	5%	5%	5%	5%
Change in Average Residential Bill	6%	8%	-1%	-1%	5%	21%	0%	5%	5%	5%	5%
REVENUES											
Net Sales	76%	79%	79%	78%	61%	76%	77%	81%	83%	83%	85%
Other Revenues and Transfers In	24%	21%	21%	21%	28%	24%	23%	19%	17%	17%	15%
TOTAL REVENUES	100%	100%	100%	99%	89%	100%	100%	100%	100%	100%	100%
EXPENSES											
Commodity Purchases	53%	53%	53%	55%	58%	39%	55%	51%	51%	50%	50%
Operating Expenses											
Administration											
Allocated Charges	*3%*	*4%*	*4%*	*3%*	*5%*	*4%*	*6%*	*5%*	*5%*	*5%*	*5%*
Rent	*4%*	*4%*	*3%*	*3%*	*3%*	*3%*	*4%*	*3%*	*3%*	*3%*	*3%*
Debt Service	*6%*	*5%*	*4%*	*4%*	*4%*	*4%*	*3%*	*4%*	*6%*	*9%*	*8%*
Equity Transfer	*8%*	*8%*	*8%*	*7%*	*7%*	*6%*	*8%*	*7%*	*7%*	*7%*	*7%*
Transfers and Other Adjustments	*0%*	*-2%*	*-2%*	*1%*	*1%*	*1%*	*1%*	*1%*	*1%*	*1%*	*1%*
Subtotal, Administration	21%	18%	17%	18%	20%	17%	21%	21%	23%	25%	25%
Resource Management	1%	2%	2%	1%	2%	1%	2%	2%	2%	2%	2%
Operations and Mtc	8%	8%	9%	8%	10%	7%	10%	9%	9%	9%	9%
Engineering (Operating)	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
Customer Service	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
Allowance for Unspent Budget	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Subtotal, Operating Expenses	32%	31%	31%	30%	33%	27%	34%	33%	35%	37%	38%
Capital Program Contribution	7%	10%	11%	11%	7%	27%	0%	7%	7%	6%	6%
TOTAL EXPENSES	92%	95%	94%	97%	98%	93%	89%	91%	92%	93%	93%
SUPPLY OPERATIONS RESERVE											
Min (60 days of non-capital expenses)	16,831,022	16,957,154	18,345,636	20,817,535	22,301,354	19,923,460	21,062,871	22,110,623	22,412,033	22,874,360	23,148,588
Target (90 days of non-capital expenses	25,246,533	25,435,732	27,518,453	31,226,303	33,452,031	29,885,189	31,594,307	33,165,935	33,618,049	34,311,540	34,722,882
Max (120 days of non-capital expenses)	33,662,044	33,914,309	36,691,271	41,635,071	44,602,708	39,846,919	42,125,743	44,221,246	44,824,065	45,748,720	46,297,176
DISTRIBUTION OPERATIONS RESERVE											
Min (60 days of non-capital expenses)	7,869,900	8,621,917	8,051,581	7,811,860	10,035,492	10,426,314	10,800,438	11,701,048	12,741,650	14,084,430	14,525,802
Target (90 days of non-capital expenses	10,096,233	11,071,856	10,898,913	10,608,212	13,266,354	13,781,173	14,267,972	15,541,561	17,022,183	18,952,824	19,527,952
Max (120 days of non-capital expenses)	12,322,566	13,521,795	13,746,245	13,404,564	16,497,217	17,136,033	17,735,506	19,382,073	21,302,716	23,821,219	24,530,102
Risk Assessment Value	4,992,321	6,001,771	6,381,125	6,668,204	6,330,333	12,894,566	6,123,942	8,015,246	8,595,304	9,014,046	9,416,218
DEBT SERVICE COVERAGE RATIO											
Net Revenues (125% of Debt Service)	451%	518%	214%	-43%	535%	649%	818%	371%	300%	264%	272%
Available Reserves (5x Debt Service)*	11.9	16.1	13.4	8.4	9.4	7.0	23.9	13.5	8.7	6.5	6.8

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

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 11 (Rate Stabilization Reserves)
f) For operating contingencies, as described in Section 12 (Operations Reserves)
g) For tracking 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, as described in Section 16 (Cap and Trade Program Reserve)
h) For tracking funding of City buildings, appliance and vehicle electrification projects and programs, as described in Section 17 (Electrification Reserve)
i) 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 (Rate Stabilization Reserves)
g) For operating contingencies, as described in Section 12 (Operations Reserves)
h) For tracking 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, as described in Section 15 (Low Carbon Fuel Standard Reserve)
i) 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 4. Reserves for Commitments

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

Section 5. Reserves for Reappropriations

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

Section 6. Electric Special Projects Reserve

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

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

Section 7. Hydroelectric Stabilization Reserve

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

a) Projected Hydro Output: Near the end of each fiscal year, staff will determine the actual and expected hydro output for that fiscal year, compare that to the long-term average annual output level (495,957 MWh as of March 2018), and multiply the difference by the average of the monthly round-the-clock forward market prices for each month of the current fiscal year.
b) Changes in Reserves. Staff is authorized to transfer the amount described in Sec. 7(a) from the Operations Reserve to the Hydroelectric Stabilization Reserve for hydro output deviations above long-term average levels, or transfer this amount from the Hydroelectric Stabilization Reserve to the Operations Reserve for hydro output deviations below long-term average levels.
c) Implementation of HRA. The level of the Hydroelectric Stabilization Reserve *after* the transfers described above shall be the basis for staff's determination, with Council approval, of whether to implement the Hydro Rate Adjuster (Electric Rate E-HRA) for the following fiscal year.
d) Reserve Guidelines. Staff will manage the Hydroelectric Stabilization Reserve according to the following guideline levels:

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

Section 8. Underground Loan Reserve

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

Section 9. Public Benefits Reserve

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

Section 10. CIP Reserve

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

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

Minimum Level	20% of the maximum CIP Reserve guideline level

Maximum Level	Average annual (12 month)[14] CIP budget, for 48 months of budgeted CIP expenses[15]

b) Changes in Reserves: At the end of each fiscal year staff will transfer from the Distribution Operations Reserve to the CIP Reserve an amount equal to the amount of electric utility unspent CIP budget at the end of the fiscal year reduced by the amount of any contractual commitments and reappropriations. 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.

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. At the end of each fiscal year, the Cap and Trade Program Reserve will be adjusted by the net of revenues and expenses associated with the Cap and Trade program.

Section 17. Electrification Reserve

This reserve is used to track funding of City buildings, appliance and vehicle electrification projects and programs, including development and implementation costs and associated financial incentives, loans and rebates for participating customers. The reserve may be funded by any lawful source of funds available for such programs, including new or ongoing utility revenues derived from customer participation. The reserve balance shall be annually adjusted based on the net of revenues and expenses associated with the City's building appliance and vehicle electrification projects and programs using this reserve.

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:

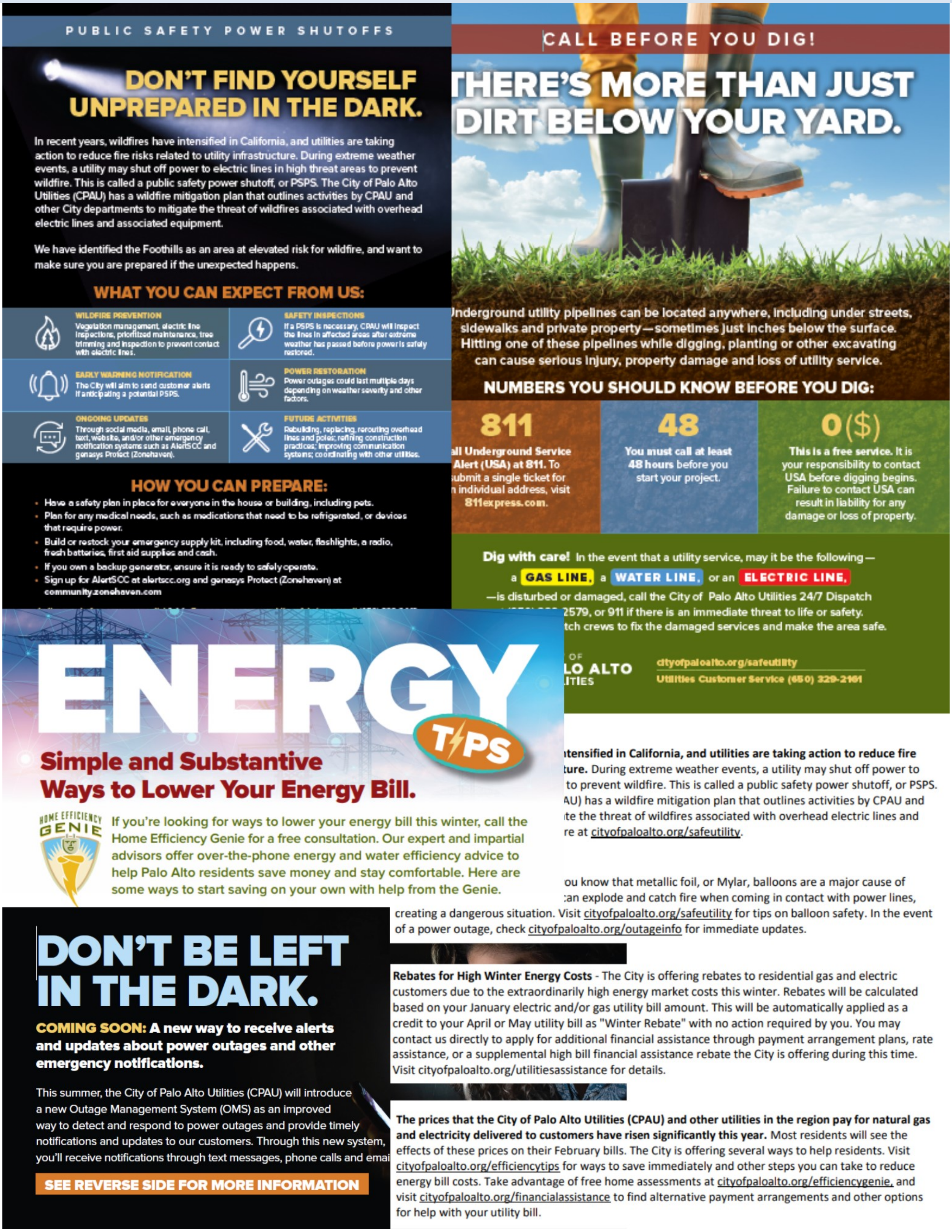
- monitoring the substations and performing routine maintenance;
- performing preventative maintenance on the system;
- monitoring the system's status from the UCC using SCADA;
- maintaining the SCADA system;
- investigating outages and other customer complaints and performing emergency repairs;
- clearing 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



RESIDENTIAL ELECTRIC SERVICE

UTILITY RATE SCHEDULE E-1

A. APPLICABILITY:

This Rate Schedule applies to separately metered single-family residential dwellings receiving Electric Service from the City of Palo Alto Utilities.

B. TERRITORY:

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

C. UNBUNDLED RATES:

Per kilowatt-hour (kWh)	Commodity	Distribution	Public Benefits	Total
Tier 1 usage	$ 0.10270~~09999~~	$ 0.085186~~954~~	$ 0.00549~~68~~	$ 0.193377~~521~~
Tier 2 usage Any usage over Tier 1	0.13311~~873~~	0.08272~~10225~~	0.00549~~68~~	0.221324~~666~~
Customer Charge~~Minimum Bill~~ ($/day)				0.15254~~181~~

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. The Customer Charge is based on the number of days in your particular billing cycle. On a Customer's bill statement, the bill amount may be broken down into appropriate components as calculated under Section C.

2. Calculation of Usage Tiers

Tier 1 Electricity usage shall be calculated and billed based upon a level of 15.37~~11~~ kWh per day, prorated by Meter reading days of Service. As an example, for a 30-day bill, the Tier 1 level would be 461 ~~330~~ kWh. For further discussion of bill calculation and proration, refer to Rule and Regulation 11.

RESIDENTIAL ELECTRIC SERVICE

UTILITY RATE SCHEDULE E-1

{End}

RESIDENTIAL MASTER-METERED AND SMALL NON-RESIDENTIAL ELECTRIC SERVICE

UTILITY RATE SCHEDULE E-2

A. APPLICABILITY:

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

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

B. TERRITORY:

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

C. UNBUNDLED RATES:

Per kilowatt-hour (kWh)	Commodity	Distribution	Public Benefits	Total
Summer Period	$ 0.14926~~216~~	$ 0.09735~~0.11775~~	$ 0.00549~~0.00568~~	$ 0.25210~~0.26559~~
Winter Period	0.09242~~0.10196~~	0.06623~~0.07861~~	0.00549~~0.00568~~	0.16414~~0.18625~~
~~Minimum Bill~~Customer Charge ($/day)				0.18411~~1.0646~~

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 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 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}

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

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	$ 0.14926~~0.14216~~	$ 0.09735~~0.11775~~	$ 0.00549~~0.00568~~	$ 0.0075	$ 0.25960~~0.27309~~
Winter Period	0.09242~~0.10196~~	0.06623~~0.07861~~	0.00549~~0.00568~~	0.0075	$ 0.17164~~0.19375~~
~~Minimum Bill~~Customer Charge ($/day)					0.1841~~1.0646~~

2. 1000 kWh Block Purchase Option:

Per kilowatt-hour (kWh)	Commodity	Distribution	Public Benefits	Total
Summer Period	$ 0.14926~~0.14216~~	$ 0.09735~~0.11775~~	$ 0.00549~~0.00568~~	$ 0.25210~~0.26559~~
Winter Period	0.09242~~0.10~~	0.06623~~0.07~~	0.00549~~0.~~	0.16414~~0.~~

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

UTILITY RATE SCHEDULE E-2-G

~~196~~	~~861~~	~~00568~~	~~18625~~

~~Minimum Bill~~Customer Charge ($/day)	0.1841~~1.0646~~
Palo Alto Green Charge (per 1000 kWh block)	$7.50

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 either 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 ELECTRIC SERVICE

UTILITY RATE SCHEDULE E-4

A. APPLICABILITY:

This Rate Schedule applies to Demand metered Secondary Electric Service for Customers with a maximum Demand below 1,000 kilowatts. 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:

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

C. UNBUNDLED RATES:

Rates per kilowatt (kW) and kilowatt-hour (kWh):

	Commodity	Distribution	Public Benefits	Total
Summer Period				
Demand Charge (per kW)	$ 10.98~~5.28~~	$ 34.31~~31.54~~		$ 45.29~~36.82~~
Energy Charge (per kWh)	0.12318~~0.13157~~	0.02520~~0.02638~~	0.00549~~0.00568~~	0.15387~~0.16363~~
Winter Period				
Demand Charge (per kW)	$ 2.57~~3.29~~	$ 21.16~~20.87~~		$ 23.73~~24.16~~
Energy Charge (per kWh)	0.07949~~0.09461~~	0.02520~~0.02638~~	0.00549~~0.00568~~	0.11018~~0.12667~~
~~Minimum Bill~~Customer Charge ($/day)				3.7390~~22.0012~~

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 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.

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 been 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 (0.25%) 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 City of Palo Alto full-service rate schedule as is applicable to their kilowatt-Demand and kilowatt-hour usage profile.

6. 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 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 his 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.

7. Standby Charge

a. Applicability: The standby charge, subject to the exemptions in subsection D(7)(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}

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)	$ 10.98~~5.28~~	$ 34.31~~31.54~~			$ 45.29~~36.82~~
Energy Charge (per kWh)	0.12318~~0.13157~~	0.02520~~0.02638~~	0.00549~~0.00568~~	0.0075	0.16137~~0.17113~~
Winter Period					
Demand Charge (per kW)	$ 2.57~~3.29~~	$ 21.16~~20.87~~			$ 23.73~~24.16~~
Energy Charge (per kWh)	0.07949~~0.09461~~	0.02520~~0.02638~~	0.00549~~0.00568~~	0.0075	0.11768~~0.13417~~
~~Minimum Bill~~Customer Charge ($/day)					3.7390~~22.0012~~

MEDIUM NON-RESIDENTIAL GREEN POWER ELECTRIC SERVICE

UTILITY RATE SCHEDULE E-4-G

2. 1000 kWh Block Purchase Option:

	Commodity	Distribution	Public Benefits	Total
Summer Period				
Demand Charge (per kW)	$ 10.98~~5.28~~	$ 34.31~~31.54~~		$ 45.29~~36.82~~
Energy Charge (per kWh)	0.12318~~0.13157~~	0.02520~~0.02638~~	0.00549~~0.00568~~	0.15387~~0.16363~~
Palo Alto Green Charge (per 1000 kWh block)				$7.50
Winter Period				
Demand Charge (per kW)	$ 2.57~~3.29~~	$ 21.16~~20.87~~		$ 23.73~~24.16~~
Energy Charge (per kWh)	0.07949~~0.09461~~	0.02520~~0.02638~~	0.00549~~0.00568~~	0.11018~~0.12667~~
Palo Alto Green Charge (per 1000 kWh block)				$7.50
~~Minimum Bill~~Customer Charge ($/day)				3.7390~~22.0012~~

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 either 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}

MEDIUM NON-RESIDENTIAL ELECTRIC TIME OF USE SERVICE

UTILITY RATE SCHEDULE E-4 TOU

A. APPLICABILITY:

This voluntary Rate Schedule applies to Demand metered Secondary Electric Service for Customers with Demand between 500 and 1,000 kilowatts per month and who have sustained this level of usage for at least three consecutive months during the most recent 12 month period. 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. In addition, this Rate Schedule is applicable for Customers who did not pay power factor adjustments during the last 12 months.

B. TERRITORY:

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

C. UNBUNDLED RATES:

Rates per kilowatt (kW) and kilowatt-hour (kWh):

	Commodity	Distribution	Public Benefits	Total
Summer Period				
Demand Charge (per kW)				
Peak	$ 9.72~~3.22~~	$ 17.18~~10.85~~		$ 26.90~~14.07~~
~~Mid-Peak~~Max Demand	1.29~~1.11~~	17.18~~10.85~~		18.47~~11.96~~
~~Off-Peak~~	~~1.11~~	~~10.85~~		~~11.96~~
Energy Charge (per kWh)				
Peak	$ 0.17038~~0.12020~~	$ 0.02538~~0.02636~~	$ 0.00549~~0.00568~~	$ 0.20125~~0.15224~~
Mid-Peak	0.14041~~0.15204~~	0.02538~~0.02636~~	0.00549~~0.00568~~	0.17128~~0.18408~~
Off-Peak	0.10556~~0.09229~~	0.02538~~0.02636~~	0.00549~~0.00568~~	0.13643~~0.12433~~
Winter Period				
Demand Charge (per kW)				
Peak	$ 1.30~~1.83~~	$ 10.73~~11.63~~		$ 12.03~~13.46~~
Max Demand~~Off-Peak~~	1.30~~1.83~~	10.73~~11.63~~		12.03~~13.46~~

MEDIUM NON-RESIDENTIAL ELECTRIC TIME OF USE SERVICE

UTILITY RATE SCHEDULE E-4 TOU

	Commodity	Distribution	Public Benefits	Total
Energy Charge (per kWh)				
Peak	$ 0.11976~~0.14744~~	$ 0.02500~~0.02636~~	$ 0.00549~~0.00568~~	$ 0.15025~~0.17948~~
Mid-Peak	0.09452	0.02500	0.00549	0.12501
Off-Peak	0.06525 ~~0.12619~~	0.02500~~0.02636~~	~~$~~ 0.00549~~68~~	0.09574 ~~0.15823~~
~~Minimum Bill~~Customer Charge ($/day)				3.7390~~22.0012~~

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. Definition of Time Periods

SUMMER PERIOD (Service from May 1 to October 31):

Energy

Peak: ~~12~~4:00 ~~noon~~p.m. to 9~~6~~:00 p.m. Monday through Friday (except holidays)

Mid Peak: 2~~8~~:00 p~~a~~.m. to 4~~12~~:00 ~~noon~~p.m. Monday through Friday (except holidays)
9~~6~~:00 p.m. to 11~~9~~:00 p.m.

Off-Peak: ~~9:00 p.m. to 8:00 a.m.~~All other hours Monday through Friday (except holidays)
All day Saturday, Sunday, and holidays

Demand

Peak: 4:00 p.m. to 9:00 p.m. Monday through Friday (except holidays)

Max Demand: All ~~other~~ hours ~~Monday through Friday (except~~

~~holidays)~~Every day
~~All day Saturday, Sunday, and holidays~~

WINTER PERIOD (Service from November 1 to April 30):

Energy

Peak:	4~~8~~:00 p~~a~~.m. to 9:00 p.m.	Monday through Friday (except holidays)
Mid Peak:	9:00 a.m. to 2:00 p.m.	Monday through Friday (except holidays)
Off-Peak:	~~9:00 p.m. to 8:00 a.m.~~All other hours	Monday through Friday (except holidays)
	All day	Saturday, Sunday, and holidays

Demand

Peak:	4:00 p.m. to 9:00 p.m.	Monday through Friday (except holidays)
Max Demand:	All ~~other~~ hours	~~Monday through Friday (except holidays)~~Every day
	~~All day~~	~~Saturday, Sunday, and holidays~~

TYPES OF DEMAND CHARGES: The Peak Demand Charge per kilowatt applies to the maximum peak-period demand during the time periods noted above. The Maximum (Max) Demand charge per kilowatt applies to the maximum demand at any time during the month. Both demand charges apply in each billing period, and the maximum peak-period demand and maximum demand may occur at different times in the billing period depending on customer usage patterns.

SEASONAL RATE CHANGES: When the billing period includes use in both 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. Demand Meter

Whenever the monthly use of energy has exceeded 8,000 kilowatt-hours for three consecutive months, a 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 kilowatt-hours for twelve consecutive months, whereupon, at the option of the City, it may be removed.

The Billing Demand to be used in computing charges under this schedule will be the actual Maximum Demand in kilowatts taken during any 15-minute interval in each of the designated time periods as defined under Section D.2.

4. Power Factor Adjustment

Time of Use Customers must not have had a power factor adjustment assessed on their Service for at least 12 months. Power factor is calculated based on the ratio of kilowatt hours to kilovolt-ampere hours consumed during the month, and must not have fallen below 95% to avoid the power factor adjustment.

Should the City of Palo Alto Utilities Department find that the Customer's Service should be subject to power factor adjustments, the Customer will be removed from the E-4-TOU rate schedule and placed on another applicable rate schedule as is suitable to their kilowatt Demand and kilowatt-hour usage.

5. Changing Rate Schedules

Customers electing to be served under E-4 TOU must remain on said Rate Schedule for a minimum of 12 months. Should the Customer so wish, at the end of 12 months, the Customer may request a Rate Schedule change to any applicable City of Palo Alto full-service Rate Schedule as is suitable to their kilowatt Demand and kilowatt-hour usage.

6. 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 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 his 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.

7. Standby Charge

a. Applicability: The standby charge, subject to the exemptions in subsection D(7)(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 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.

MEDIUM NON-RESIDENTIAL ELECTRIC TIME OF USE SERVICE

UTILITY RATE SCHEDULE E-4 TOU

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

{End}

LARGE NON-RESIDENTIAL ELECTRIC TIME OF USE SERVICE

UTILITY RATE SCHEDULE E-7 TOU

A. APPLICABILITY:

This voluntary Rate Schedule applies to Demand Metered Service for non-residential Customers with a Maximum Demand of at least 1,000KW per month per site, who have sustained this Demand level at least 3 consecutive months during the last twelve months. In addition, this Rate Schedule is applicable for Customers who did not pay power factor adjustments during the last 12 months.

B. TERRITORY:

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

C. UNBUNDLED RATES:

Rates per kilowatt (kW) and kilowatt-hour (kWh):

	Commodity	Distribution	Public Benefits	Total
Summer Period				
Demand Charge (per kW)				
Peak	$ 11.28~~3.86~~	$ 14.71~~11.08~~		$ 25.99~~14.94~~
~~Mid-Peak~~	~~1.13~~	~~11.08~~		~~12.21~~
~~Off-Peak~~Max Demand	1.45~~1.13~~	14.71~~11.08~~		16.16~~12.21~~
Energy Charge (per kWh)				
Peak	$ 0.18019~~0.14457~~	$ 0.00362~~0.00075~~	$ 0.00549~~0.00568~~	$ 0.18930~~0.15100~~
Mid-Peak	0.14850~~0.18205~~	0.00362~~0.00075~~	0.00549~~0.00568~~	0.15761~~0.18848~~
Off-Peak	0.11164~~0.11171~~	0.00362~~0.00075~~	0.00549~~0.00568~~	0.12075~~0.11814~~
Winter Period				
Demand Charge (per kW)				
Peak	$ 1.45~~1.78~~	$ 12.99~~9.22~~		$ 14.44~~11.00~~
Max Demand~~Off-Peak~~	1.45~~1.78~~	12.99~~9.22~~		14.44~~11.00~~
Energy Charge (per kWh)				
Peak	$ 0.12104~~0.09~~	$ 0.00354~~0.00075~~	$ 0.00549~~0.00568~~	$ 0.13007~~0.10340~~

	~~697~~			
Mid-Peak	0.09552	0.00354	0.00549	0.10455
Off-Peak	0.06594~~0.08323~~	0.00354~~0.00075~~	0.00549~~0.00568~~	0.07497~~0.08966~~
~~Minimum Bill~~Customer Charge ($/day)				17.1221~~62.5539~~

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. Definition of Time Periods

SUMMER PERIOD (Service from May 1 to October 31):

Energy

Peak: 4~~12~~:00 pm~~noon~~ to 9~~6~~:00 p.m. Monday through Friday (except holidays)

Mid Peak: 2:00 p.m. to 4:00 p.m.~~8:00 a.m. to 12:00 noon~~ Monday through Friday (except holidays)
9:00 p.m. to 11:00 p.m.~~6:00 p.m. to 9:00 p.m.~~

Off-Peak: ~~9:00 p.m. to 8:00 a.m.~~All other hours Monday through Friday (except holidays)
All day Saturday, Sunday, and holidays

Demand

Peak: 4:00 p.m. to 9:00 p.m. Monday through Friday (except holidays)

Max Demand: ~~All other hours~~ ~~Monday through Friday (except holidays)~~
~~All day~~All hours ~~Saturday, Sunday, and holidays~~Every day

WINTER PERIOD (Service from November 1 to April 30):

Energy

LARGE NON-RESIDENTIAL ELECTRIC TIME OF USE SERVICE

UTILITY RATE SCHEDULE E-7 TOU

Peak:	4~~8~~:00 p~~a~~.m. to 9:00 p.m.	Monday through Friday (except holidays)
Mid Peak:	9:00 a.m. to 2:00 p.m.	Monday through Friday (except holidays)
Off-Peak:	~~9:00 p.m. to 8:00 a.m.~~All other hours	Monday through Friday (except holidays)
	All day	Saturday, Sunday, and holidays

Demand

Peak:	4:00 p.m. to 9:00 p.m.	Monday through Friday (except holidays)
Max Demand:	~~All other hours~~	~~Monday through Friday (except holidays)~~
	~~All day~~	~~Saturday, Sunday, and holidays~~All hours
	Every day	

TYPES OF DEMAND CHARGES: The Peak Demand Charge per kilowatt applies to the maximum peak-period demand during the time periods noted above. The Maximum (Max) Demand charge per kilowatt applies to the maximum demand at any time during the month. Both demand charges apply in each billing period, and the maximum peak-period demand and maximum demand may occur at different times in the billing period depending on customer usage patterns.

SEASONAL RATE CHANGES: When the billing period includes use in both 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. Request for Service

Qualifying Customers may request Service under this schedule for more than one Account or one Meter if the Accounts are on 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.

4. Demand Meter

Whenever the monthly use of energy has exceeded 8,000 kilowatt-hours for three consecutive months, a 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 kilowatt-hours for twelve consecutive months, whereupon, at the option of the City, it may be removed.

The Billing Demand to be used in computing charges under this schedule will be the actual Maximum Demand in kilowatts taken during any 15-minute interval in each of the designated time periods as defined under Section D.2.

5. Power Factor Adjustment

Time of Use Customers must not have had a power factor adjustment assessed on their Service for at least 12 months. Power factor is calculated based on the ratio of kilowatt hours to kilovolt-ampere hours consumed during the month, and must not have fallen below 95% to avoid the power factor adjustment.

Should the City of Palo Alto Utilities Department find that the Customer's Service should be subject to power factor adjustments, the Customer will be removed from the E-7-TOU rate schedule and placed on another applicable rate schedule as is suitable to their kilowatt Demand and kilowatt-hour usage.

6. Changing Rate Schedules

Customers electing to be served under E-7 TOU must remain on said Rate Schedule for a minimum of 12 months. Should the Customer so wish, at the end of 12 months, the Customer may request a Rate Schedule change to any applicable City of Palo Alto full-service Rate Schedule as is suitable to their kilowatt Demand and kilowatt-hour usage.

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 1/2 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 his 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	$0.84	$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 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}

LARGE NON-RESIDENTIAL GREEN POWER ELECTRIC SERVICE

UTILITY RATE SCHEDULE E-7-G

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)	$ 11.95~~6.03~~	$ 28.41~~33.05~~			$ 40.36~~39.08~~
Energy Charge (per kWh)	0.12659~~0.13917~~	0.00362~~0.00075~~	0.00549~~0.00568~~	0.0075	0.14320 ~~0.15310~~
Winter Period					
Demand Charge (per kW)	$ 2.79~~3.46~~	$ 25.00~~18.25~~			$ 27.79~~21.71~~
Energy Charge (per kWh)	0.07894~~0.09212~~	0.00354~~0.00075~~	0.00549~~0.00568~~	0.0075	0.09547 ~~0.10605~~
~~Minimum Bill~~Customer Charge ($/day)					17.1221~~62.5539~~

2. 1000 kWh Block Purchase Option:

	Commodity	Distribution	Public Benefits	Total
Summer Period				
Demand Charge (per kW)	$ 11.95~~6.03~~	$ 28.41~~33.05~~		$ 40.36~~39.08~~
Energy Charge (per kWh)	0.12659~~0.13917~~	0.00362~~0.00075~~	0.00549~~0.00568~~	0.13570 ~~0.14560~~
Palo Alto Green Charge (per 1000 kWh block)				$ 7.50
Winter Period				
Demand Charge (per kW)	$ 2.79~~3.46~~	$ 25.00~~18.25~~		$ 27.79~~21.71~~
Energy Charge (per kWh)	0.07894~~0.09212~~	0.00354~~0.00075~~	0.00549~~0.00568~~	0.08797 ~~0.09855~~
Palo Alto Green Charge (per 1000 kWh block)				$7.50
~~Minimum Bill~~Customer Charge ($/day)				17.1221~~62.5539~~

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 either 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.

LARGE NON-RESIDENTIAL GREEN POWER ELECTRIC SERVICE

UTILITY RATE SCHEDULE E-7-G

{End}

LARGE NON-RESIDENTIAL ELECTRIC TIME OF USE SERVICE

UTILITY RATE SCHEDULE E-7 TOU

A. APPLICABILITY:

This voluntary Rate Schedule applies to Demand Metered Service for non-residential Customers with a Maximum Demand of at least 1,000KW per month per site, who have sustained this Demand level at least 3 consecutive months during the last twelve months. In addition, this Rate Schedule is applicable for Customers who did not pay power factor adjustments during the last 12 months.

B. TERRITORY:

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

C. UNBUNDLED RATES:

Rates per kilowatt (kW) and kilowatt-hour (kWh):

	Commodity	Distribution	Public Benefits	Total
Summer Period				
Demand Charge (per kW)				
Peak	$ 11.28~~3.86~~	$ 14.71~~11.08~~		$ 25.99~~14.94~~
~~Mid-Peak~~	~~1.13~~	~~11.08~~		~~12.21~~
~~Off-Peak~~Max Demand	1.45~~1.13~~	14.71~~11.08~~		16.16~~12.21~~
Energy Charge (per kWh)				
Peak	$ 0.18019~~0.14457~~	$ 0.00362~~0.00075~~	$ 0.00549~~0.00568~~	$ 0.18930~~0.15100~~
Mid-Peak	0.14850~~0.18205~~	0.00362~~0.00075~~	0.00549~~0.00568~~	0.15761~~0.18848~~
Off-Peak	0.11164~~0.11171~~	0.00362~~0.00075~~	0.00549~~0.00568~~	0.12075~~0.11814~~
Winter Period				
Demand Charge (per kW)				
Peak	$ 1.45~~1.78~~	$ 12.99~~9.22~~		$ 14.44~~11.00~~
Max Demand~~Off-Peak~~	1.45~~1.78~~	12.99~~9.22~~		14.44~~11.00~~
Energy Charge (per kWh)				
Peak	$ 0.12104~~0.09~~	$ 0.00354~~0.00075~~	$ 0.00549~~0.00568~~	$ 0.13007~~0.10340~~

	~~697~~			
Mid-Peak	0.09552	0.00354	0.00549	0.10455
Off-Peak	0.06594~~0.08323~~	0.00354~~0.00075~~	0.00549~~0.00568~~	0.07497~~0.08966~~
~~Minimum Bill~~Customer Charge ($/day)				17.1221~~62.5539~~

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. Definition of Time Periods

SUMMER PERIOD (Service from May 1 to October 31):

Energy

Peak: 4~~12~~:00 pm~~noon~~ to 9~~6~~:00 p.m. Monday through Friday (except holidays)

Mid Peak: 2:00 p.m. to 4:00 p.m.~~8:00 a.m. to 12:00 noon~~ Monday through Friday (except holidays)
9:00 p.m. to 11:00 p.m.~~6:00 p.m. to 9:00 p.m.~~

Off-Peak: ~~9:00 p.m. to 8:00 a.m.~~All other hours Monday through Friday (except holidays)
All day Saturday, Sunday, and holidays

Demand

Peak: 4:00 p.m. to 9:00 p.m. Monday through Friday (except holidays)

Max Demand: ~~All other hours~~ ~~Monday through Friday (except holidays)~~
~~All day~~All hours ~~Saturday, Sunday, and holidays~~Every day

WINTER PERIOD (Service from November 1 to April 30):

Energy

Peak:	4~~8~~:00 p~~a~~.m. to 9:00 p.m.	Monday through Friday (except holidays)
Mid Peak:	9:00 a.m. to 2:00 p.m.	Monday through Friday (except holidays)
Off-Peak:	~~9:00 p.m. to 8:00 a.m.~~All other hours	Monday through Friday (except holidays)
	All day	Saturday, Sunday, and holidays

Demand

Peak:	4:00 p.m. to 9:00 p.m.	Monday through Friday (except holidays)
Max Demand:	~~All other hours~~	~~Monday through Friday (except holidays)~~
	~~All day~~	~~Saturday, Sunday, and holidays~~All hours
	Every day	

TYPES OF DEMAND CHARGES: The Peak Demand Charge per kilowatt applies to the maximum peak-period demand during the time periods noted above. The Maximum (Max) Demand charge per kilowatt applies to the maximum demand at any time during the month. Both demand charges apply in each billing period, and the maximum peak-period demand and maximum demand may occur at different times in the billing period depending on customer usage patterns.

SEASONAL RATE CHANGES: When the billing period includes use in both 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. Request for Service

Qualifying Customers may request Service under this schedule for more than one Account or one Meter if the Accounts are on 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.

4. Demand Meter

Whenever the monthly use of energy has exceeded 8,000 kilowatt-hours for three consecutive months, a 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 kilowatt-hours for twelve consecutive months, whereupon, at the option of the City, it may be removed.

The Billing Demand to be used in computing charges under this schedule will be the actual Maximum Demand in kilowatts taken during any 15-minute interval in each of the designated time periods as defined under Section D.2.

5. Power Factor Adjustment

Time of Use Customers must not have had a power factor adjustment assessed on their Service for at least 12 months. Power factor is calculated based on the ratio of kilowatt hours to kilovolt-ampere hours consumed during the month, and must not have fallen below 95% to avoid the power factor adjustment.

Should the City of Palo Alto Utilities Department find that the Customer's Service should be subject to power factor adjustments, the Customer will be removed from the E-7-TOU rate schedule and placed on another applicable rate schedule as is suitable to their kilowatt Demand and kilowatt-hour usage.

6. Changing Rate Schedules

Customers electing to be served under E-7 TOU must remain on said Rate Schedule for a minimum of 12 months. Should the Customer so wish, at the end of 12 months, the Customer may request a Rate Schedule change to any applicable City of Palo Alto full-service Rate Schedule as is suitable to their kilowatt Demand and kilowatt-hour usage.

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 1/2 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 his 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

LARGE NON-RESIDENTIAL ELECTRIC TIME OF USE SERVICE

<u>UTILITY RATE SCHEDULE E-7 TOU</u>

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	$0.84	$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 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.

LARGE NON-RESIDENTIAL ELECTRIC TIME OF USE SERVICE

UTILITY RATE SCHEDULE E-7 TOU

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

{End}

STREET LIGHTS

UTILITY RATE SCHEDULE E-14

A. APPLICABILITY:

This Rate Schedule applies to all street and highway lighting installations, which CPAU elects to operate and maintain.

B. TERRITORY:

Within the incorporated limits of the City of Palo Alto and on land owned or leased by the City.

C. RATES:

Lamp Rating:	**Per Lamp Per Month** Class A: CPAU supplies electricity and switching service only.
High Pressure Sodium Vapor Lamps	
100 watts	5.60 ~~6.21~~
200 watts	10.34 ~~11.46~~
250 watts	12.70 ~~14.08~~
310 watts	15.72 ~~17.42~~
400 watts	20.24 ~~22.43~~

STREET LIGHTS

UTILITY RATE SCHEDULE E-14

	Per Lamp Per Month – Class C: CPAU supplies electricity and switching and maintains lighting system, including lamps and glassware.
Lamp Rating:	
Mercury-Vapor Lamps	
400 watts	32.33 ~~35.83~~
High Pressure Sodium Vapor Lamps	
70 watts	29.75 ~~32.97~~
100 watts	31.17 ~~34.55~~
150 watts	33.54 ~~37.17~~
250 watts	38.27 ~~42.42~~
Light Emitting Diode (LED) Lamps	
70 watts-equivalent	26.60 ~~29.48~~
100 watts-equivalent	27.68 ~~30.68~~
150 watts-equivalent	28.66 ~~31.77~~
250 watts	31.38 ~~34.78~~

D. SPECIAL CONDITIONS:

1. Type of Service: This Rate Schedule applies to series, multiple, and single lamp street lighting systems to which CPAU delivers Service at secondary voltage. Unless a variation is approved by CPAU in its sole discretion, Service to street lighting systems will be delivered at 120/240 volts, three-wire, single-phase or 120/208 volt three-wire, single phase from star-connected poly-phase lines. Single phase service from 480-volt sources will be available in certain areas at CPAU's discretion. All voltages stated herein are nominal, and reasonable variations may occur. New lights will normally be installed as multiple lamp systems with a single Service point or single lamp with and individual Service point.

2. Point of Delivery: Delivery will be made to the Customer's system at a Service point or at points designated by CPAU. CPAU will furnish the Service connection to one point for each lamp or group

of lamps, provided the Customer has designed the system to include the minimum number of delivery points. CPAU will make all underground connections to CPAU's system at the Customer's expense.

3. Switching: CPAU will perform switching (on CPAU's side of the points of delivery) at no Charge, provided there are at least 10 kilowatts of lamp load on each circuit separately switched, including all lamps on the circuit whether served under this Rate Schedule or not. An extra charge of $2.50 per month will be made for each circuit separately switched unless such switching installation is made for CPAU's convenience.

4. Annual Burning Schedule: The rates in this Rate Schedule apply to lamps which will be turned on and off once each night in accordance with a regular burning schedule approved by CPAU and not exceeding 4,100 hours per year.

5. Maintenance: The Class C rates in this Rate Schedule include all labor necessary for replacement of glassware, including inspection and cleaning. Maintenance of glassware by CPAU is limited to standard glassware that is commonly used and manufactured in reasonably large quantities, as determined by CPAU in its sole discretion. The Class C rates include maintenance of circuits between lamp posts and of circuits and equipment in and on the posts, provided these are all of good standard construction as determined by CPAU. CPAU in its sole discretion may decline to grant Class C rates for maintenance of systems with non-standard glassware, or inadequate circuitry and equipment. Class C rates applied to any agency other than the City of Palo Alto also include painting of posts with one coat of good ordinary paint, as determined by CPAU to be needed to maintain good appearance. Maintenance does not include replacement of posts damaged by third parties or acts of nature.

6. System Owned In-Part by CPAU: If CPAU agrees to a Customer's request for CPAU to install, own, or maintain any portion of the lighting fixtures, supports, and/or interconnecting circuits, the Customer shall be responsible for an extra monthly Charge of one and one-fourth percent of CPAU's contribution to the cost of the street lighting system.

7. Rates For Lamps Not on this Rate Schedule: In the event a Customer installs a lamp which is not represented on this Rate Schedule, CPAU will prepare an interim rate reflecting CPAU's estimated costs associated with the specific lamp. This interim rate will serve as the effective rate for billing purposes until the new lamp rating is added to Rate Schedule E-14.

{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 everywhere the City of Palo Alto provides Electric Service.

C. RATES:

	Per kWh
Net Surplus Electricity Compensation rate	$ 0.1427 ~~0.1535~~

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}

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:

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

C. RATE:

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

	Per kWh
Export electricity compensation rate	$ 0.1420 ~~0.1685~~

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}

APPENDIX A: 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)~~1 (Rate Stabilization Reserves)
f) For operating contingencies, as described in Section 12 (Operations Reserves)
g) For tracking 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, as described in Section 16 (Cap and Trade Program Reserve)
~~f)~~h) For tracking funding of City buildings, appliance and vehicle electrification projects and programs, as described in Section 17 (Electrification Reserve)
i) 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)
~~g)~~h) For tracking 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, as described in Section 15 (Low Carbon Fuel Standard Reserve)
i) 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~~ 13 (Unassigned Reserves).

Section 4. Reserves for Commitments

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

Section 5. Reserves for Reappropriations

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

Section 6. Electric Special Projects Reserve

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

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

Section 7. Hydroelectric Stabilization Reserve

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

a) Projected Hydro Output: Near the end of each fiscal year, staff will determine the actual and expected hydro output for that fiscal year, compare that to the long-term average annual output level (495,957 MWh as of March 2018), and multiply the difference by the average of the monthly round-the-clock forward market prices for each month of the current fiscal year.
b) Changes in Reserves. Staff is authorized to transfer the amount described in Sec. 7(a) from the Operations Reserve to the Hydroelectric Stabilization Reserve for hydro output deviations above long-term average levels, or transfer this amount from the Hydroelectric Stabilization Reserve to the Operations Reserve for hydro output deviations below long-term average levels.
c) Implementation of HRA. The level of the Hydroelectric Stabilization Reserve *after* the transfers described above shall be the basis for staff's determination, with Council approval, of whether to implement the Hydro Rate Adjuster (Electric Rate E-HRA) for the following fiscal year.
d) Reserve Guidelines. Staff will manage the Hydroelectric Stabilization Reserve according to the following guideline levels:

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

Section 8. Underground Loan Reserve

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

Section 9. Public Benefits Reserve

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

Section 10. CIP Reserve

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

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

Minimum Level	20% of the maximum CIP Reserve guideline level

Maximum Level	Average annual (12 month)[1] CIP budget, for 48 months of budgeted CIP expenses[2]

b) Changes in Reserves: At the end of each fiscal year staff will transfer from the Distribution Operations Reserve to the CIP Reserve an amount equal to the amount of electric utility unspent CIP budget at the end of the fiscal year reduced by the amount of any contractual commitments and reappropriations. Any other additions to or withdrawals from the CIP reserve require Council action.~~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.

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.

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

~~[2] 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.~~

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. At the end of each fiscal year, the Cap and Trade Program Reserve will be adjusted by the net of revenues and expenses associated with the Cap and Trade program.

Section 17. Electrification Reserve

This reserve is used to track funding of City buildings, appliance and vehicle electrification projects and programs, including development and implementation costs and associated financial incentives, loans and rebates for participating customers. The reserve may be funded by any lawful source of funds available for such programs, including new or ongoing utility revenues derived from customer participation. The reserve balance shall be annually adjusted based on the net of revenues and expenses associated with the City's building appliance and vehicle electrification projects and programs using this reserve.

CITY OF
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PROPOSED FY 2025 ELECTRIC FINANCIAL PLAN AND RATE CHANGES

Utilities Advisory Commission

March 6, 2024

www.cityofpaloalto.org

Electric Rate Proposal

FY 2025 proposal

- Cost of Service Analysis completed February 2024 – requires rate changes varying by customer class and consumption pattern to match the cost to serve
- 8% ($6.20/month) increase for the median residential customer
- 0.5% increase in revenue – lower than last year's 5% forecasted revenue increase
  - This is manageable due to large one-time electric supply revenues in FY 2024 – FY 2026
  - Will mitigate the bill impacts of incorporating COSA changes

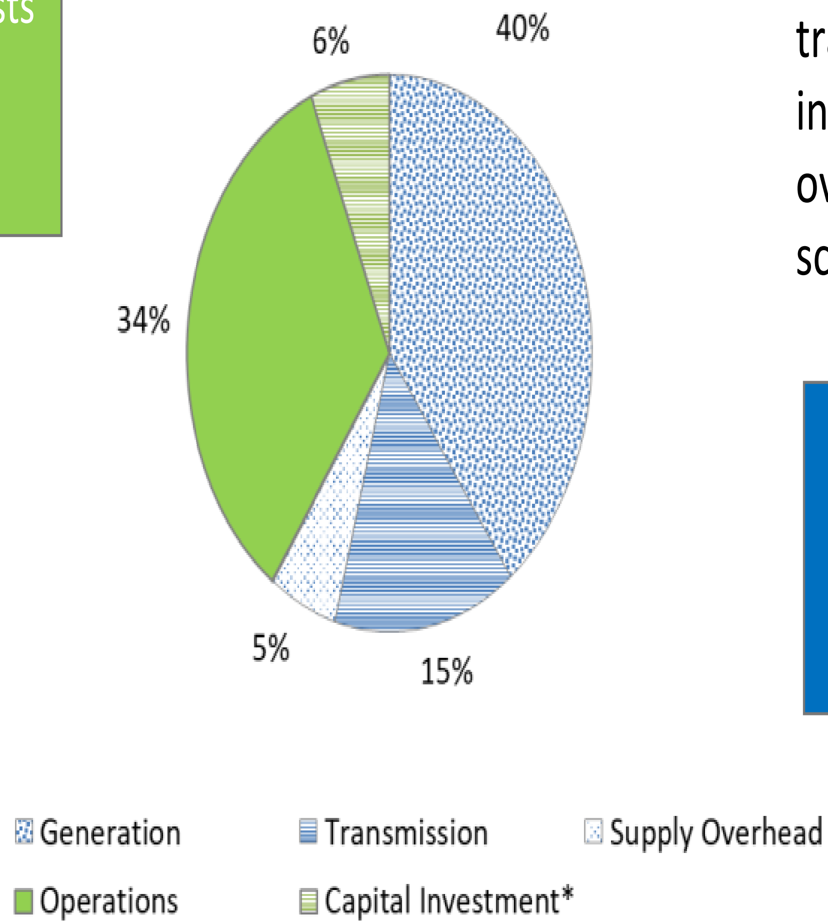
Future years

- 5% rate increase per year projected for FY 2026-FY 2029
- Issue debt for Grid Modernization by end of FY25
- Reflects continuing transmission cost increases, other rising supply costs, grid modernization

Electric Utility Cost Structure (FY 2023)

Electric Distribution costs (in green): $70 million 40%

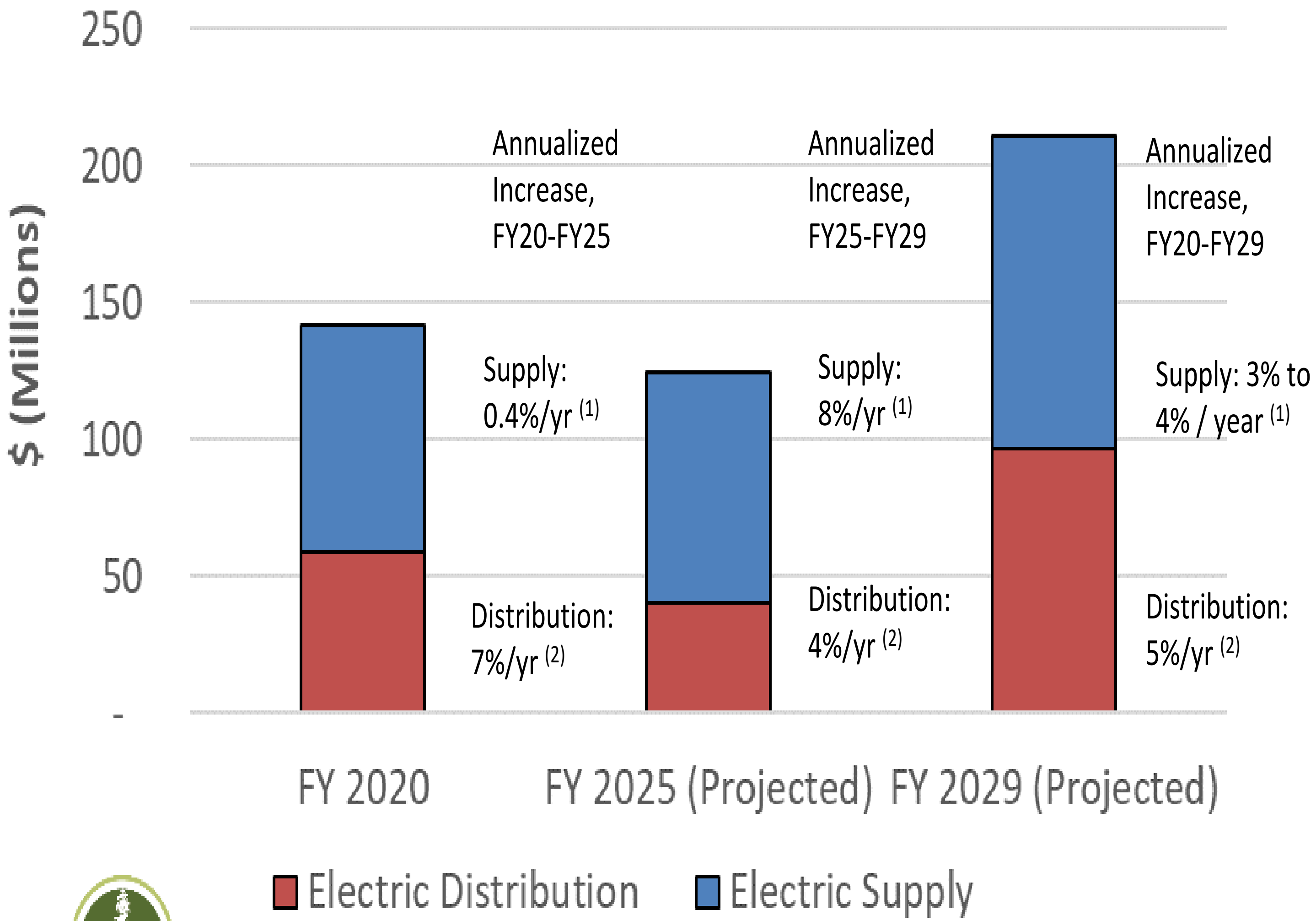
Electric Distribution: The cost to distribute electricity within Palo Alto, including: maintaining and replacing electric infrastructure, customer service, billing, administration, etc.



Electric Supply: The cost to buy electricity and transport it to Palo Alto, including operational overhead (e.g. energy scheduling)

Electric Supply costs (in blue): $104 million 60%

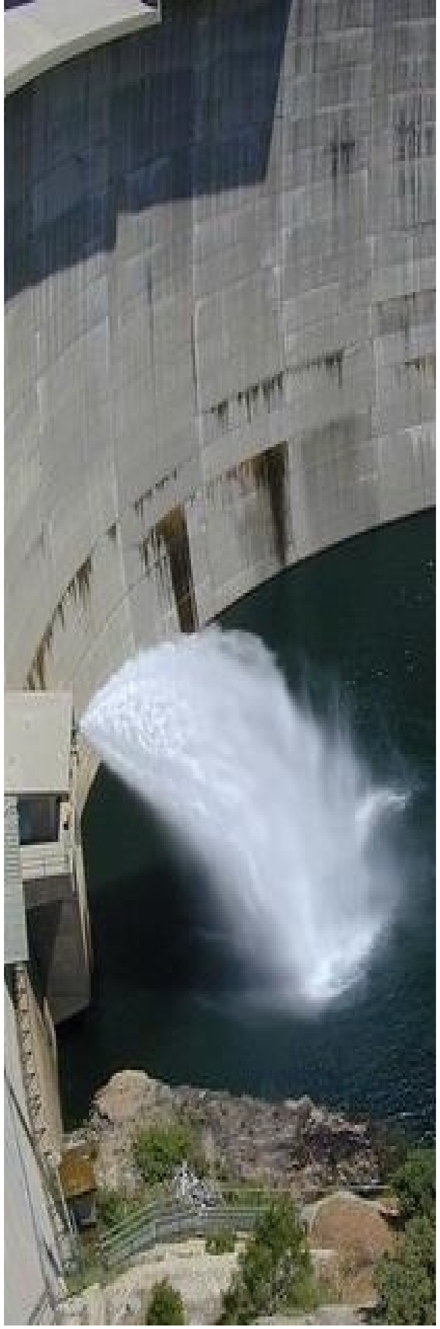
LONG TERM COST TRENDS



(1) The annualized increase in supply costs is skewed by one-time supply revenues in FY 2025. The annualized change from FY 2020 to FY 2029 is projected to be 3% to 4% per year.

(2) The annualized increase in distribution costs is heavily skewed by timing issues associated with major capital investments in FY 2024 and debt financing for those investments beginning in FY 2025. 7% per year represents the change from FY 2020 to the average of FY 2024 and FY 2025 distribution costs. 4% per year represents the change from that average to FY 2029. The annualized change from FY 2020 to FY 2029 is projected to be 5% per yr

CITY OF PALO ALTO

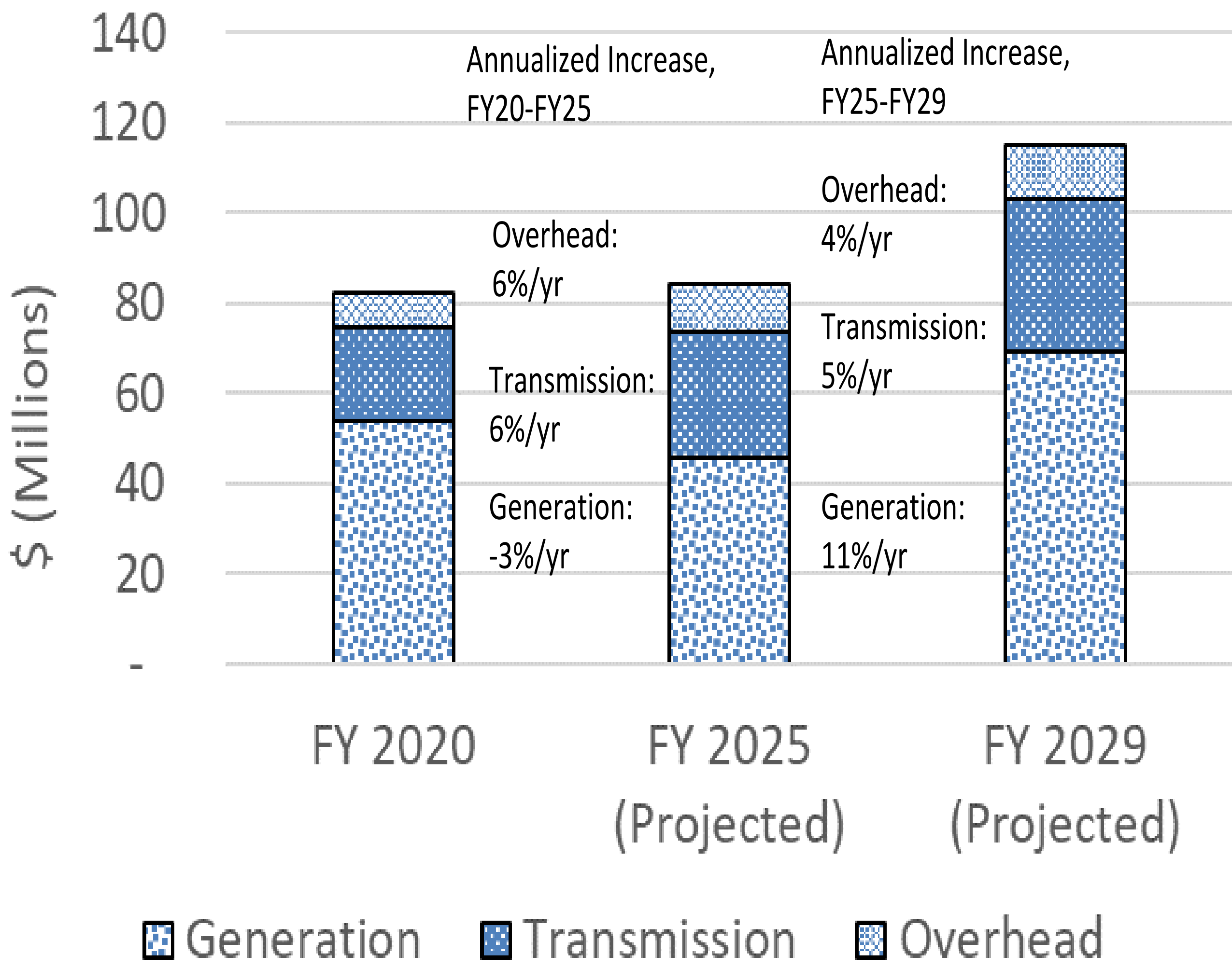


Supply Cost Drivers

- FY 2024 / FY 2025 electric supply costs are very low due to one-time surplus energy, REC, and resource adequacy[1] sales
- Transmission costs have been steadily increasing and this increase is projected to continue
- Resource adequacy[1] costs are projected to increase through FY 2029
- Hydropower costs forecasted to decline through FY 2029 due to debt service retirement for the Calaveras project
  - But additional debt may be issued for dam improvements

(1) Resource adequacy represents the cost of maintaining generating capacity to fulfill the California Independent System Operator's capacity requirements assigned to the City.

LONG TERM COST TRENDS: SUPPLY



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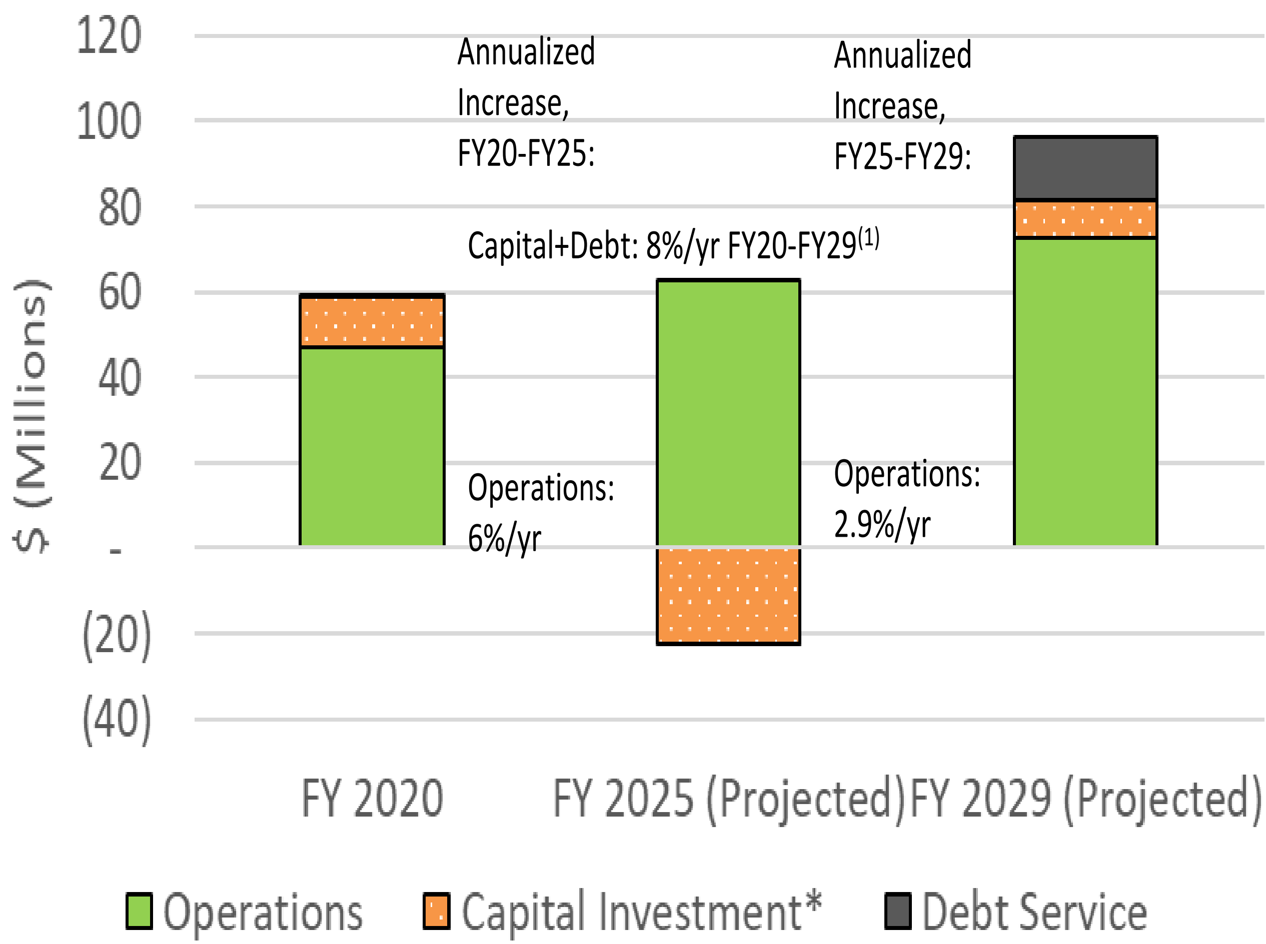
Distribution Cost Drivers

- Construction inflation, other inflation, benefit costs
- Overhead returning to historic levels as vacancies filled
- Contract line crew cost for backfilling vacancies
- Increased capital investment in the electric distribution system needed due to system age
- Debt service for Grid Modernization Project to:
  - replace aging infrastructure,
  - modernize the grid to enhance reliability
  - increase capacity for electrification
- Substantial one-time investments for Hanover Substation rebuild, Electric Utility share of Fiber Rebuild

LONG TERM COST TRENDS: DISTRIBUTION



(1) FY 2024 and FY 2025 capital and debt service numbers skewed by the timing of major capital investments and the timing of debt service to be issued to fund them, so only FY 20 to FY 29 combined annualized increases are shown.

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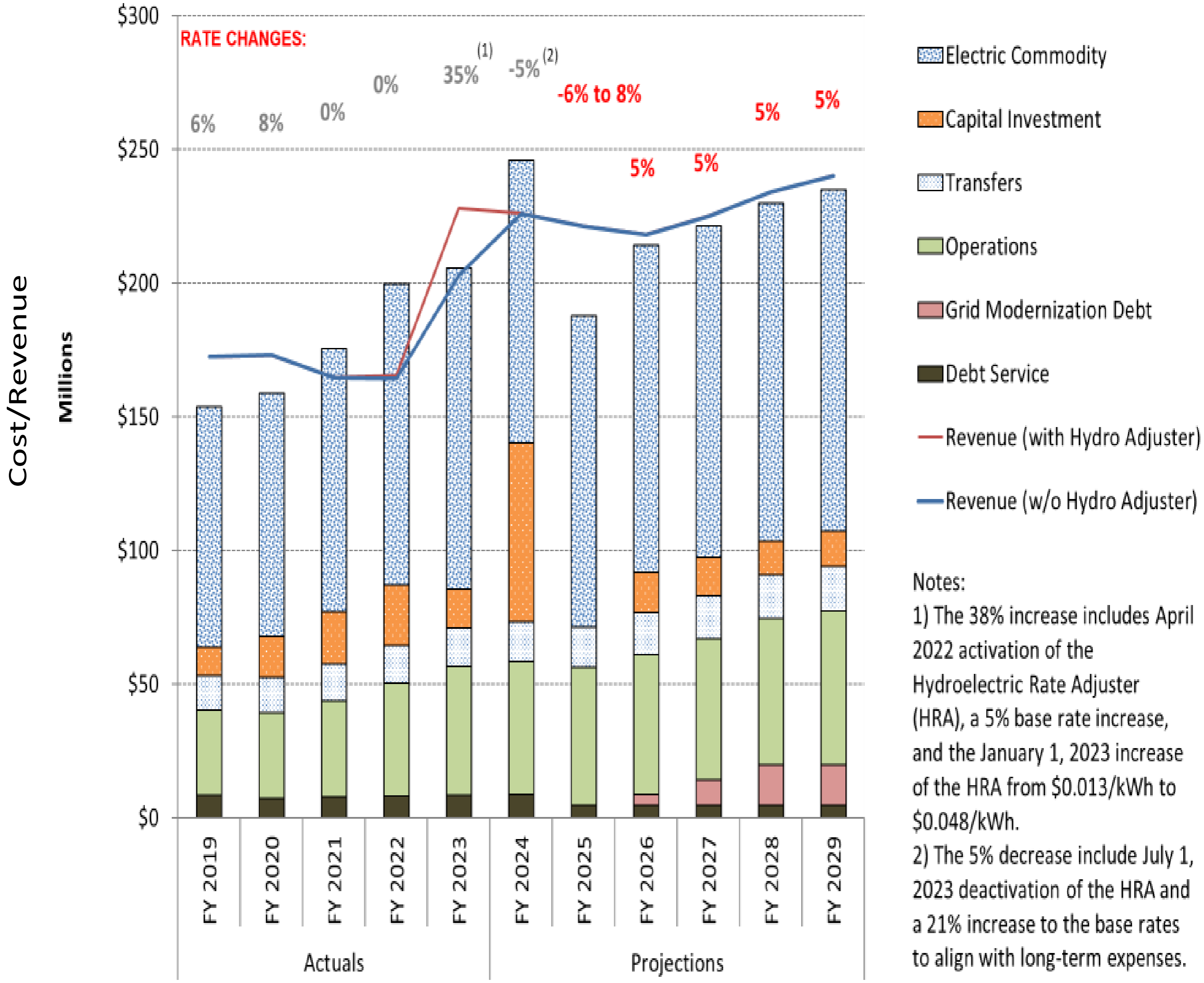
FY 2025 Preliminary: Electric Cost and Revenue Projections



Notes:
1) The 38% increase includes April 2022 activation of the Hydroelectric Rate Adjuster (HRA), a 5% base rate increase, and the January 1, 2023 increase of the HRA from $0.013/kWh to $0.048/kWh.
2) The 5% decrease include July 1, 2023 deactivation of the HRA and a 21% increase to the base rates to align with long-term expenses.

Basic Cost of Service Methodology

- First establish how much revenue you need
- Then use consumption patterns to allocate costs among customer classes according to how they incur utility costs
  - CPA classes: E-1 (residential), E-2 (small non-residential), E-4 (medium non-residential), E-7 (large non-res)
  - Costs allocators include things like kWh used, peak kW demand, number of customers in class
- Then design rates that provide prices that allocate costs to customers who consume in different ways.
  - Examples include tiered rates, seasonal rates, time of use rates, fixed charges, etc.

Prop 26 Considerations

- Prop 26 (2010): State ballot initiative that amended the State Constitution
- Gas and electric rates must represent the cost of service absent voter/ratepayer approval
- Cost of service analysis is the record demonstrating that the rates are cost-based
- Only applies to fees/charges imposed by local agencies (including gas/electric utility rates) – investor-owned utilities have all the latitude the CPUC will give them

Adopted Policy Guidelines (Nov 1, 2021)

1. Rates must be based on the cost of providing service. This is the overriding principle for the cost of service analysis (COSA); all other rate design considerations are subsidiary to this basic premise.

2. The effect of proposed rate design changes on low income customers should be considered, to the extent permissible within a cost-based rate structure.

3. Rates should ensure all value provided by building and vehicle electrification, including public vehicle charging, is reflected in the rates while remaining cost-based.

4. Rates should ensure all value provided by on-site generation and storage is reflected in the rates while simultaneously avoiding subsidies between customer classes and remaining cost based.

5. The COSA and rate design should support a transition to more time variant rates (such as TOU, seasonal, etc.) as AMI infrastructure is deployed.

6. The COSA should provide support for transition to fixed/minimum monthly charges.

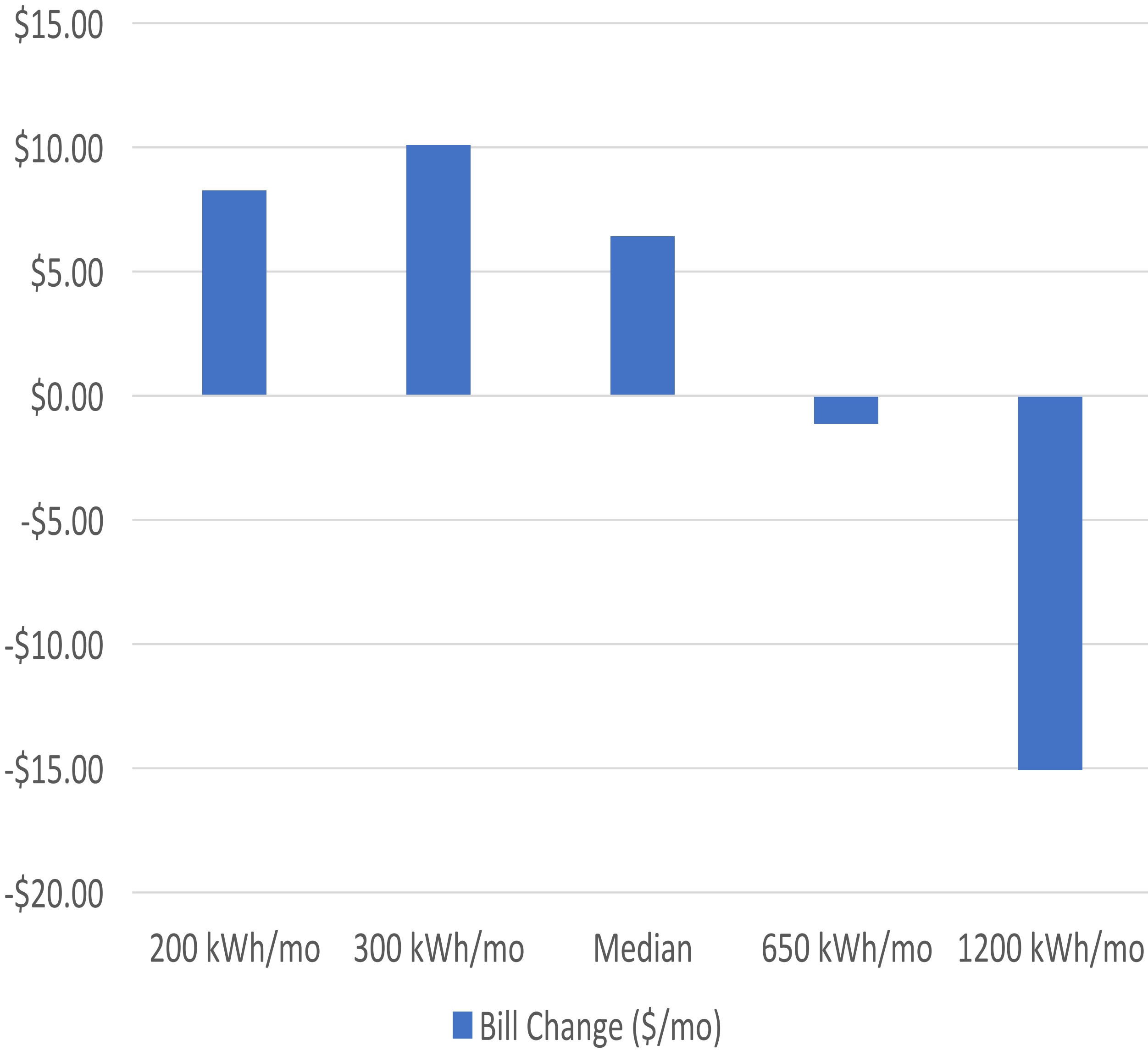
Key Results from this COSA

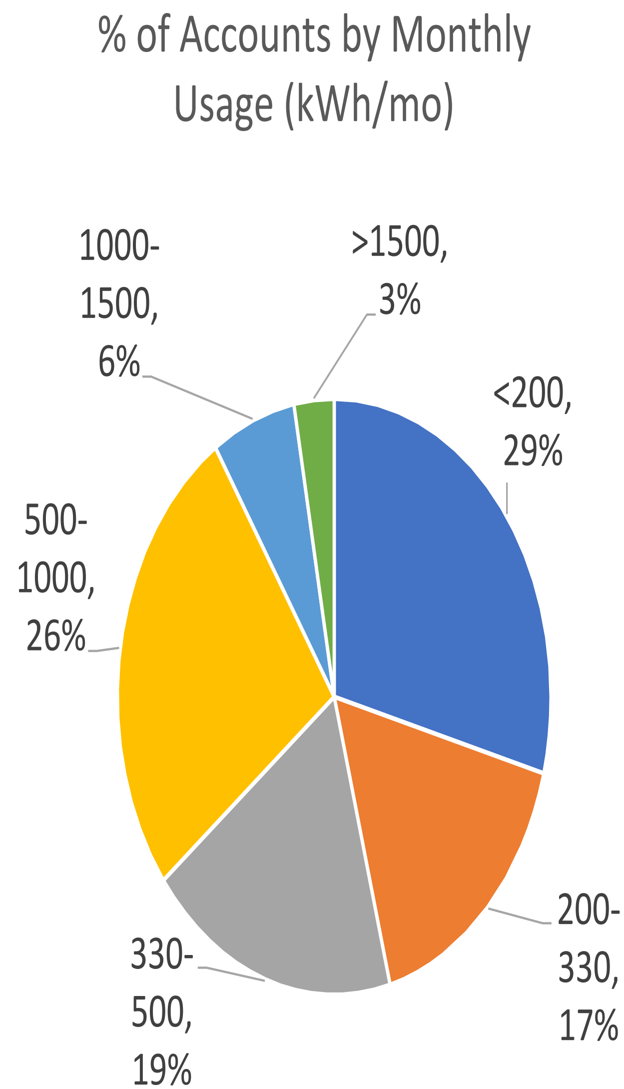
- No time of use (TOU) rates for E-1 (residential) and E-2 (small commercial) yet – likely July 1, 2026, will explore earlier options
- Changing the time periods for existing medium commercial (E-4 TOU) and large commercial (E-7 TOU) time of use rates
- Median residential bill increasing 8% due to three factors:
  - Residential class needs increase in revenue to meet cost of service while commercial classes need decreases
  - Addition of fixed charge
  - Flattening of tiers due to change in residential consumption
- All three factors impact lower users most
- Not increasing revenue this year to avoid larger impacts

Estimated Bill Changes

Rate Schedule	Usage (kWh/mo)	Peak Demand (kW-mo)	Bill under Current Rates ($/mo)	Bill Under Rates Proposed 7/1/24 ($/mo)	Change	
					$/mo	%
E-1 (Residential)	300	N/A	$52.57	$62.65	$10.08	19%
	(Summer Median) 365	N/A	$66.46	$75.22	$8.76	13%
	(Winter Median) 453	N/A	$88.16	$92.24	$4.07	5%
	650	N/A	$136.75	$135.61	($1.14)	-1%
	1200	N/A	$272.42	$257.34	($15.07)	-6%
E-2 (Small Non-Residential)	1,000	N/A	$225.93	$213.73	($12.20)	-5%
E-4 (Medium Non-Residential)	160,000	274	$31,580	$30,693	($887)	-3%
	500,000	856	$98,680	$95,667	($3,014)	-3%
E-7 (Large Non-Residential	2,000,000	3,424	$348,247	$340,864	($7,383)	-2%

Residential Bill Changes by Usage Level ($/month)





Current Gas Bill Comparisons *($/Mo. or Yr.)*

Residential

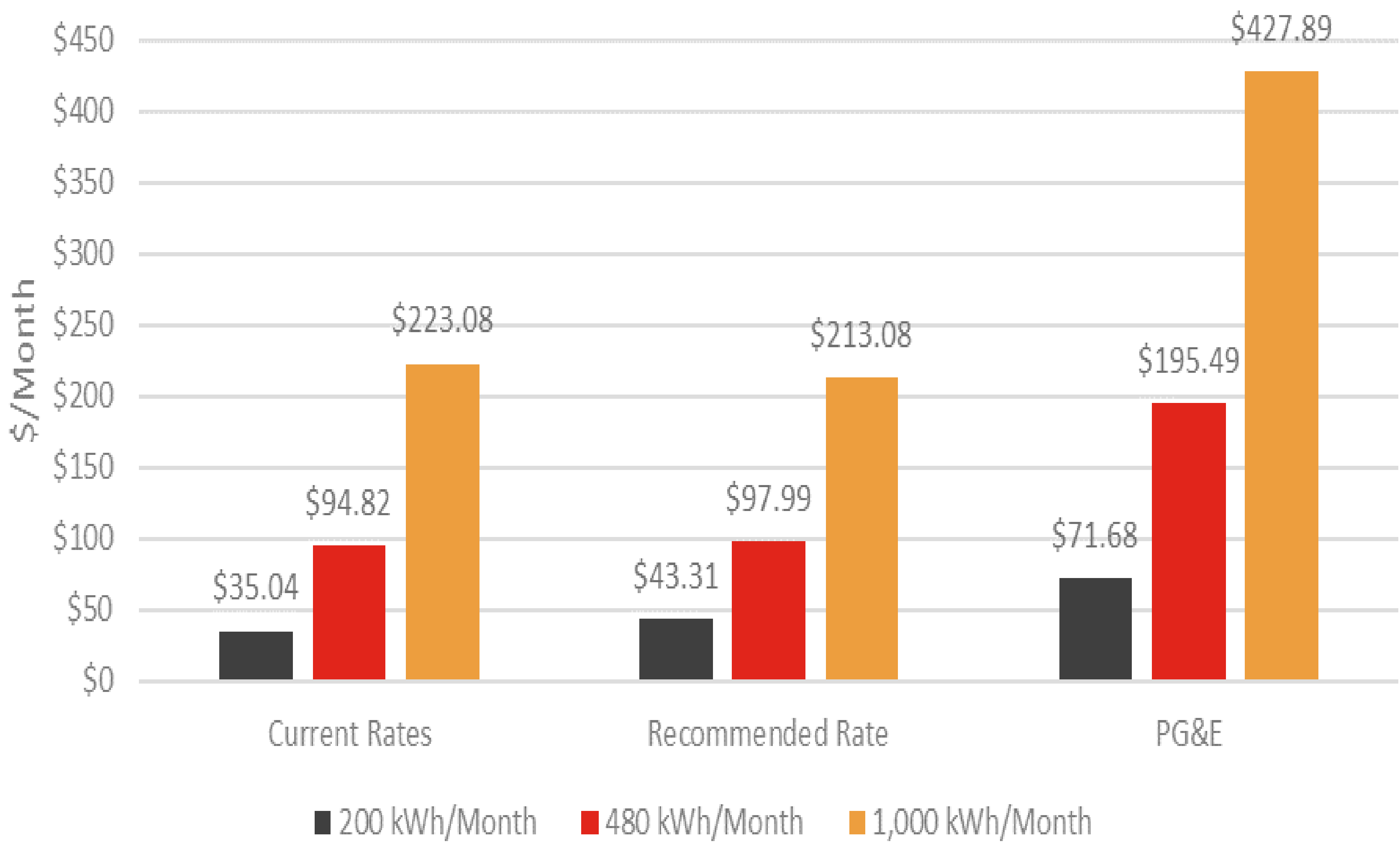
Season	Usage (kwh)	Palo Alto	PG&E	Santa Clara
Winter	300	52.56	126.03	49.02
	453 (Median)	88.16	191.88	74.93
	650	136.75	295.44	108.29
	1200	274.41	584.55	201.42
Summer	300	52.56	130.78	49.02
	(Median) 365	66.45	153.33	60.03
	650	136.75	314.76	108.29
	1200	282.18	603.87	161.54

Palo Alto median residential bill was about 40% below PG&E's for CY 2023, before the large PG&E January 1, 2024 rate increases. Now 50% to 60% below

Commercial

Staff is in the process of doing a more extensive review of commercial competitiveness and will provide updates in the future

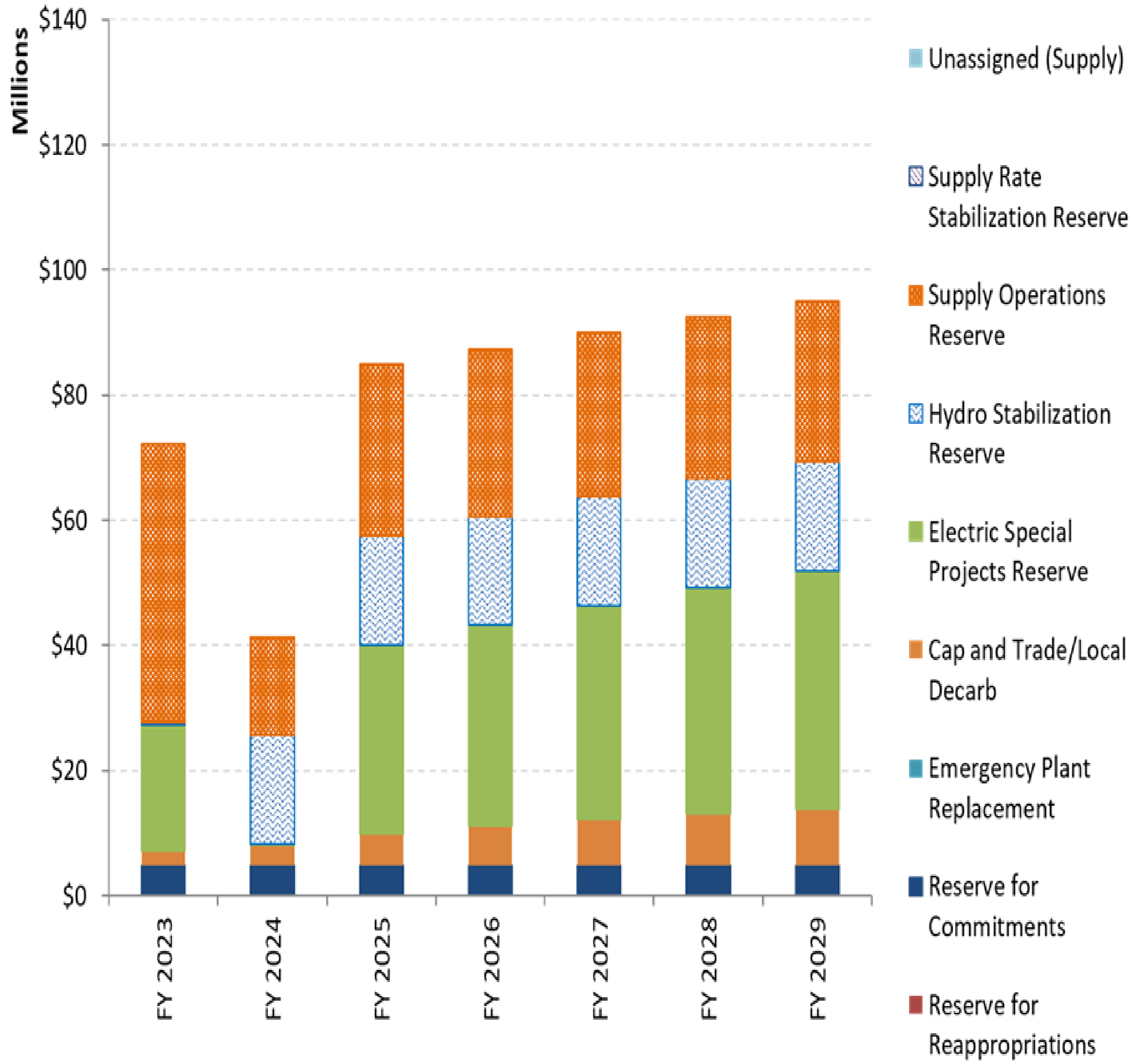
Residential Bill Comparison by Usage Level



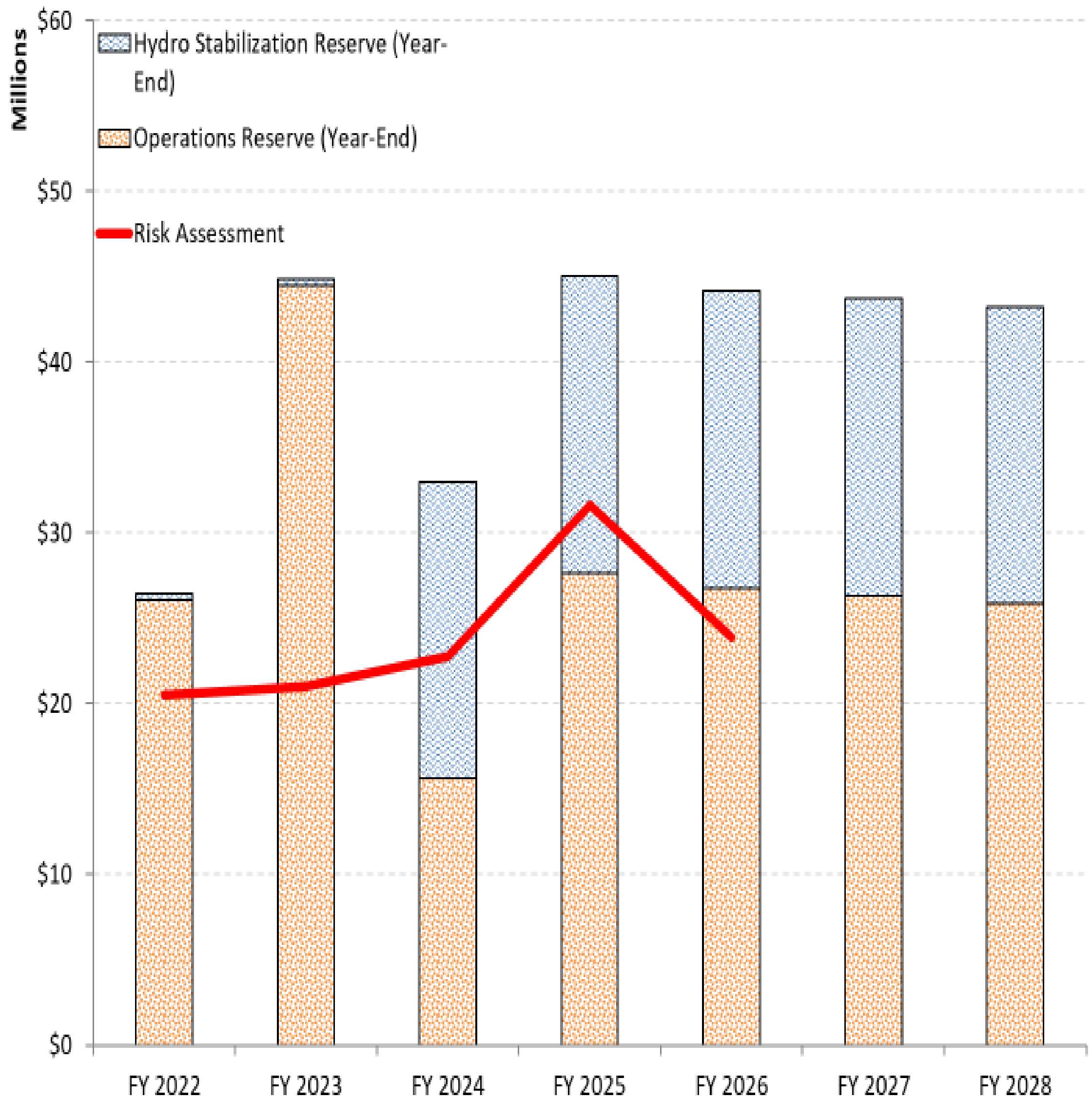
CITY OF PALO ALTO

Electric Supply Operating Reserve Projections

Electric Supply Reserve Projections



Electric Supply Reserve Adequacy



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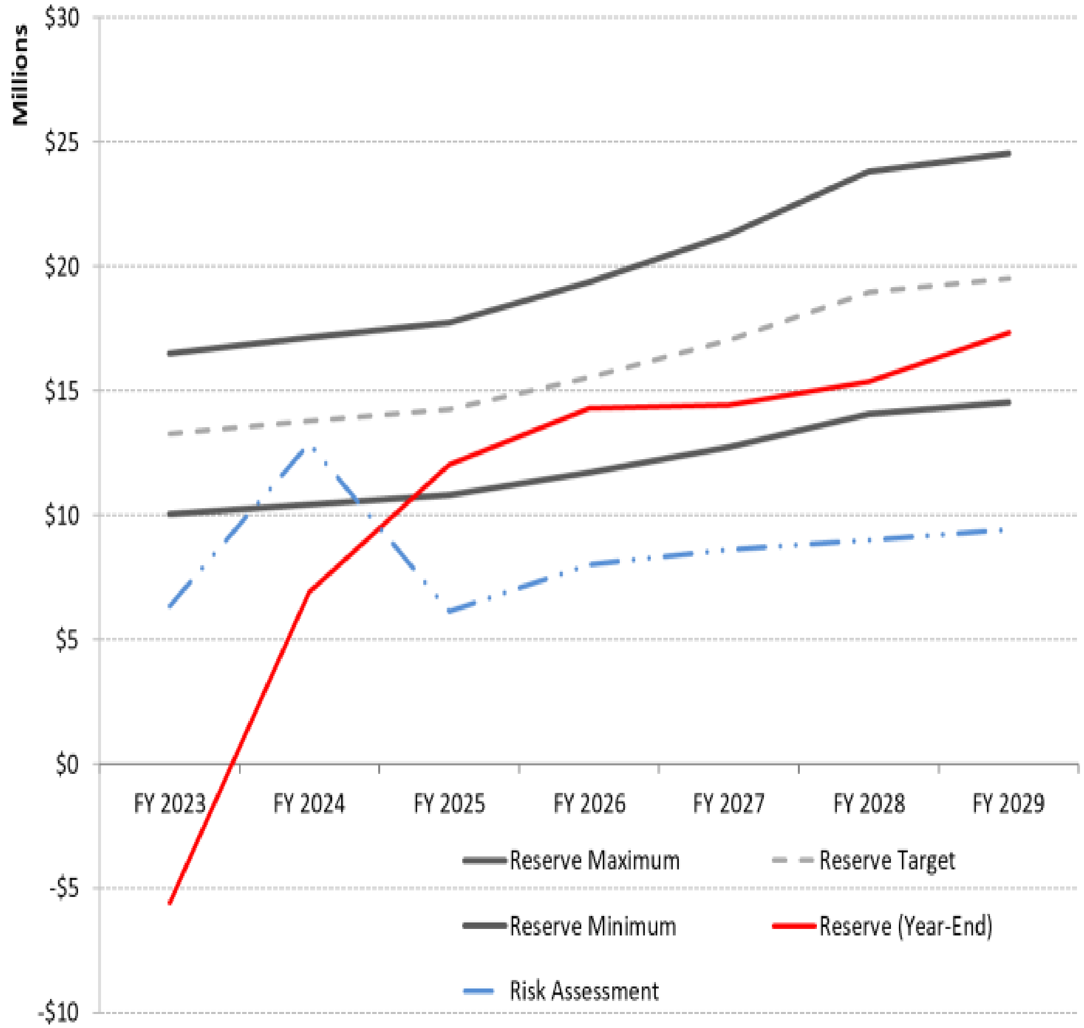
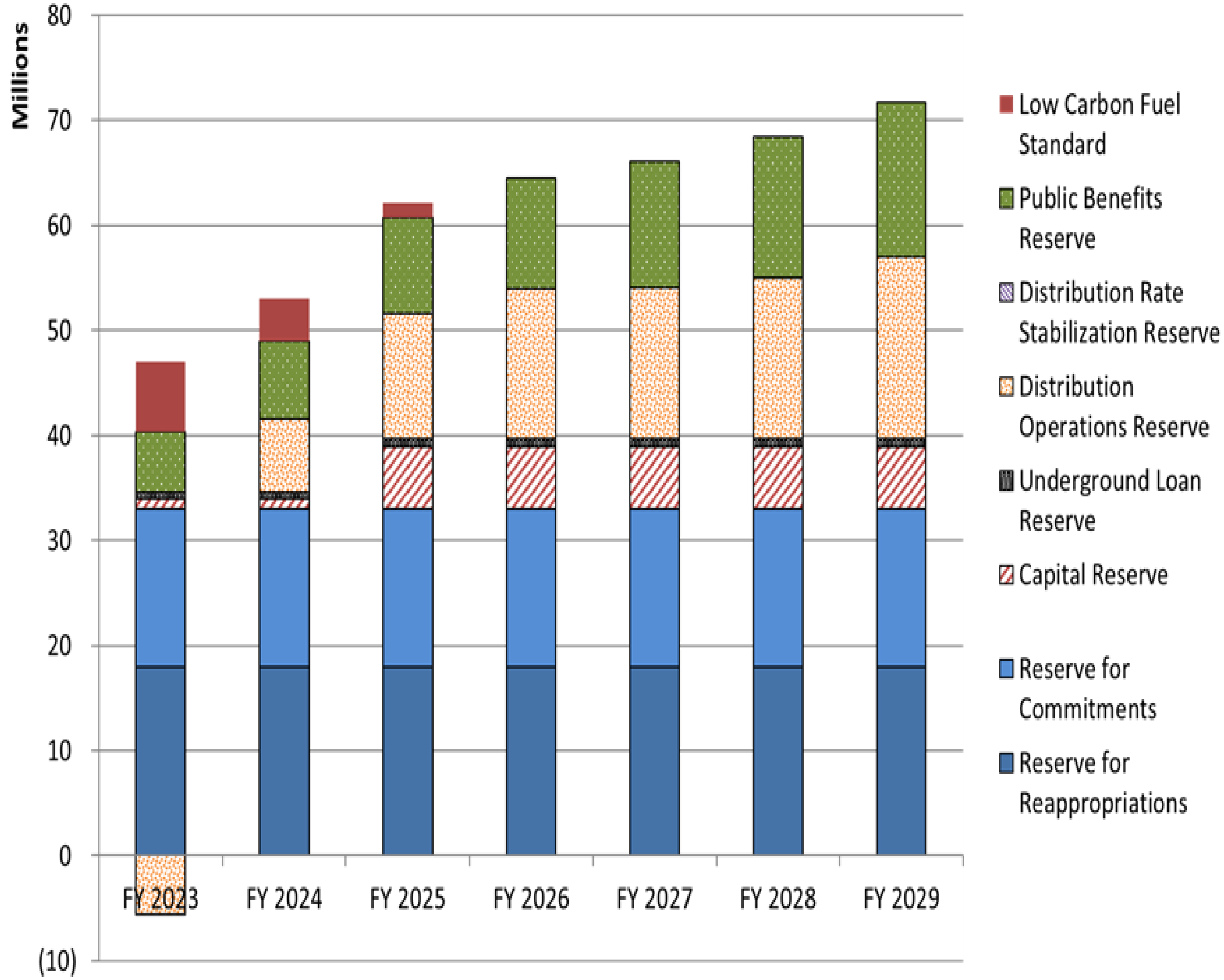
Electric Distribution Operating Reserve Projections



Electric Distribution Reserve Projections



ELECTRIC RECOMMENDATION

Staff recommends the UAC recommend that the City Council adopt a resolution:

1. Accepting the 2024 City of Palo Alto Electric Cost of Service and Rate Study (Exhibit 1)
2. Approving the FY 2025 Electric Financial Plan (Exhibit 2), which includes the following actions:
   a. Amending the Electric Utility Reserves Management Practices (Attachment B), to direct staff to transfer to the CIP reserve, at the end of each fiscal year, any budgeted capital investment that remains unspent, uncommitted, and which is not proposed for reappropriation to the following fiscal year and to clarify how the Cap and Trade Program Reserve is adjusted each year.
   b. Approving the following transfers at the end of FY 2024:
      i. Up to $20 million from the Electric Special Projects Reserve to the Supply Operations Reserve;
      ii. Up to $17 million from the Supply Operations Reserve to the Hydroelectric Stabilization Reserve;
      iii. Up to $58 million from the Supply Operations Reserve to the Distribution Operations Reserve; and
   c. Approving the following transfers in FY 2025:
      i. Up to $26 million from the Distribution Operations Reserve to the Supply Operations Reserve;
      ii. Up to $30 million from the Supply Operations Reserve to the Electric Special Projects Reserve; and
      iii. Up to $5 million from the Distribution Operations Reserve to the CIP Reserve;

ELECTRIC RECOMMENDATION (CONTINUED)

Staff recommends the UAC recommend that the City Council adopt a resolution:

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

CITY OF PALO ALTO

Utilities Advisory Commission Staff Report

From: Dean Batchelor, Director Utilities
Report Type: ACTION ITEMS
Lead Department: Utilities

Meeting Date: March 6, 2024
Staff Report: 2401-2475

TITLE

Staff Recommend the Utilities Advisory Commission Recommend that the City Council Adopt a Resolution Approving the Fiscal Year 2025 Gas Utility Financial Plan, Including the General Fund Transfer, and Increasing Gas Rates by Amending Rate Schedules G-1 (Residential Gas Service), G-2 (Residential Master-Metered and Commercial Gas Service), G-3 (Large Commercial Gas Service), and G-10 (Compressed Natural Gas Service)

RECOMMENDATION

Staff recommend the Utilities Advisory Commission recommend that the City Council adopt a resolution (Attachment A):

1. Approving the fiscal year (FY) 2025 Gas Utility Financial Plan (Attachment A, Exhibit 1), which includes amending the Gas Utility Reserve Management Practices (Attachment A, Exhibit 2); and
2. Increasing gas rates by amending Rate Schedules G-1 (Residential Gas Service), G-2 (Residential Master-Metered and Commercial Gas Service), G-3 (Large Commercial Gas Service), and G-10 (Compressed Natural Gas Service) (Attachment A, Exhibit 3); and
3. Transferring up to 11.9% of gas utility gross revenues received during FY 2023 to the General Fund in FY 2025.

EXECUTIVE SUMMARY

The FY 2025 Gas Utility Financial Plan (Exhibit 1 to the Resolution) includes projections of the utility's costs and revenues for FY 2024 through FY 2029. Gas commodity prices have substantially decreased from the unprecedented high prices in FY 2023 and returned to normal levels in FY 2024. The uncertain nature of gas market prices and gas sales means these forecasts could change.

Staff proposes to increase the distribution component of the gas rates by 15% in FY 2025 to bring revenue up to a level closer to recovering the costs of operations and prevent further depletion of reserves. This distribution rate increase is projected to increase overall customer bills by about 9% in FY 2025 if gas supply-related costs remain unchanged. In FY 2021 and FY 2022, the Gas

Utility maintained minimal rate increases, leading to revenues that fell short of covering costs. In FY 2023, although revenues exceeded costs, there were additional costs associated with FY 2023 that are reflected in FY 2024. Specifically, FY 2023 carbon offset purchases were paid in FY 2024 and the transfer of FY 2023 Cap and Trade auction revenue from the Operations Reserve to the Cap and Trade reserve, which is a cost item, occurred in FY 2024. By the end of FY 2024, staff projects the Operations Reserve to drop below the minimum guideline range. Staff projects overall distribution costs to increase by 4% from FY 2024 to FY 2025 and by 5% on average annually from FY 2025 through FY 2029. This distribution cost increase is due to projected increases in operations costs as well as capital costs related to the safety and maintenance of gas pipelines in Palo Alto as well as preparation for electrification-related costs. In addition, increased costs from prior years reduced reserve levels and rates need to be increased to bring reserves gradually back to within guideline ranges.

Staff plans to request that Council determine the amount of the General Fund transfer for the Gas Utility in FY 2025. Each year the City Council may transfer from the gas utility to the General Fund an amount up to 18% of the gross revenues of the gas utility, though Council may choose to transfer a lesser amount. Staff proposes an 11.9%, or $8,959,629 transfer for FY 2025, which aligns with the voter-approved changes codified in PAMC 2.28.185. Staff anticipates recommending the continuation of a gradual annual transfer increase to up to 18% of gross revenues by FY 2027. Alternatively, in alignment with Measure L, Council may choose to transfer up to 18% of gas utility gross revenues, or $13,552,380 for FY 2025. The two alternatives and their associated rate increases are shown in the section below titled “Alternative Gas Increase Plans.”

Background

Every year staff presents the UAC with Financial Plans for its Electric, Water, Gas, and Wastewater Collection Utilities and recommends any rate adjustments required to maintain their financial health. These Financial Plans include a comprehensive overview of the utility’s operations, both retrospective and prospective, and are intended to be a reference for UAC and Council members as they review the budget and 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 City’s gas is purchased from a variety of marketers who source gas from throughout the Western United States and Canada. The City pays Pacific Gas and Electric (PG&E) to transport the gas across its gas transmission system to Palo Alto, which is then delivered to customers through Palo Alto’s gas distribution system.

The Gas Utility's costs are divided into two main categories: gas supply costs (which includes the cost of the gas itself, the cost of transmitting the gas to Palo Alto, and environmental costs[1]) and the costs of running the business and operating the distribution system. As noted above, gas supply costs vary with the market, and the costs are passed through to customers through a gas supply rate component that varies monthly.

Discussion

Staff's annual assessment of the financial position of the City's Gas Utility is completed to ensure adequate revenue to fund operations, including reserves, and to ensure that the City's rates comply 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:

The FY 2025 Gas Utility Financial Plan includes the following proposed actions:

1. Approve the FY 2025 Gas Utility Financial Plan (Attachment A, Exhibit 1), which includes amending the Gas Utility Reserve Management Practices (Attachment A, Exhibit 2); and
2. Increase distribution rates by 15% (for an estimated 9% increase to total rates in FY 2025); and
3. Transfer up to 11.9% of gas utility gross revenues received during FY 2023 to the General Fund in FY 2025.

These proposed actions are described in more detail below and in the FY 2025 Gas Financial Plan (Attachment A, Exhibit 1).

Overview of Cost and Rate Projections and Drivers

Gas Utility costs include supply-related costs, collected through a supply (or commodity) rate that varies monthly based upon market prices, and distribution-related costs, collected through a distribution rate adjusted annually.

Supply costs include the commodity cost of the natural gas itself, gas transmission, and gas environmental charges. Although it is not possible to accurately forecast commodity rates, staff monitors market prices monthly and automatically incorporates market prices into monthly supply rate adjustments, which are passed directly to customers as a line item on their utility bills. Staff projects commodity prices to decline in FY 2025 compared with FY 2024 and projects overall supply costs to increase on average about 2% per year from FY 2025 through FY 2029.

[1] These are the costs of complying with the State's Cap and Trade system and procuring offsets under the City's Carbon Neutral Gas program.

Supply costs in FY 2024 reflect FY 2023 carbon offset purchases that were paid in FY 2024, the cost for the capped-price winter natural gas purchasing strategy, and zero costs reflected for the transfer of Cap and Trade allowance revenues received in FY 2023 from the Operations Reserve to the Cap and Trade Reserve; this transfer is reflected in FY 2024 expenses.

Table 1 shows actual supply costs in FY 2023 and projections in FY 2024 through FY 2029. Weather, transmission, storage, and/or economic forces can shift this course rapidly.

Table 1: Gas Sales, Supply Costs, and Transfers from Operations Reserve to Cap and Trade Reserve

	Actual	Projected					
	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Sales (K Therms)	**28,582**	**24,230**	**27,351**	**27,189**	**27,129**	**27,030**	**26,857**
Market-Based Commodity	$ 38,713	$ 16,449	$ 15,557	$ 15,309	$ 14,891	$ 14,407	$ 13,934
Transportation	$ 4,144	$ 4,483	$ 4,112	$ 4,331	$ 4,514	$ 4,632	$ 4,741
Carbon Offset	$ 871	$ 1,222	$ 2,175	$ 2,270	$ 2,481	$ 2,723	$ 3,133
Cap-and-Trade Compliance Costs	$ 2,198	$ 3,759	$ 4,422	$ 4,985	$ 5,559	$ 6,148	$ 6,740
Sub-Total Supply Costs Without Deferred Items	**$ 45,926**	**$ 25,911**	**$ 26,265**	**$ 26,896**	**$ 27,445**	**$ 27,911**	**$ 28,547**
Transfer from Operations Reserve to Cap and Trade Reserve	**$ -**	**$ 3,074**	**$ 3,327**	**$ 3,612**	**$ 3,866**	**$ 4,109**	**$ 4,340**
Deferred Items from FY 2023 to FY 2024							
Carbon Offset	$ -	$ 1,483	$ -	$ -	$ -	$ -	$ -
Transfer from Operations Reserve to Cap and Trade Reserve	$ -	$ 2,285	$ -	$ -	$ -	$ -	$ -
Sub-total FY 2023 costs reflected in FY 2024	**$ -**	**$ 3,768**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total	**$ 45,926**	**$ 32,754**	**$ 29,592**	**$ 30,508**	**$ 31,311**	**$ 32,020**	**$ 32,887**

Gas commodity prices are anticipated to decrease by around 2% on average from FY 2024 to FY 2025. The mild weather experienced in FY 2024 is contributing to lower gas usage, with expectations of a return to higher levels in FY 2025, aligning with long-term projections. Gas usage is expected to resume a downward trend of 0.5% annually from FY 2025 to FY 2029. Staff forecasts FY 2025 total gas supply costs to be about 1% higher than FY 2024 total supply costs without deferred items ("Sub-Total Supply Costs Without Deferred Items" row in Table 1). Including deferred items, and transfers from the Operations Reserve to the Cap and Trade Reserve, total supply costs are projected to decrease 10% from FY 2024 to FY 2025 and then increase annually by 2% on average from FY 2025 through FY 2029 ("Total" row in Table 1).

Table 2 shows total gas utility costs. The operations and capital costs are considered distribution costs. Distribution costs include the costs of running the business and operating the distribution system. The attached Financial Plan projects distribution costs to increase 6.1% on average from FY 2025 through FY 2029.

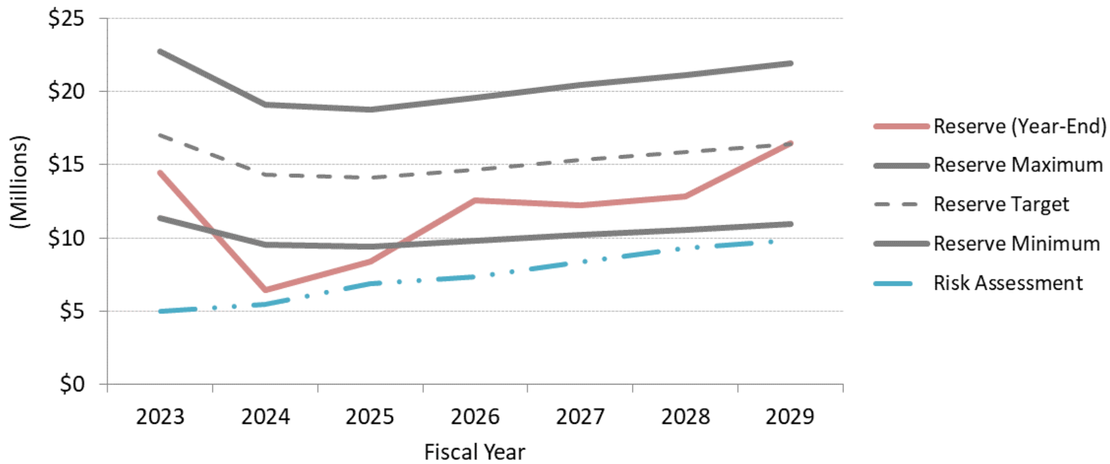
Table 2 Gas Utility Costs for FY 2023 to FY 2029 ($,000)

Expenses ($000)	Actual	Projected					
	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Supply Costs	**45,926**	**27,395**	**26,265**	**26,896**	**27,445**	**27,911**	**28,547**
Commodity	38,713	16,449	15,557	15,309	14,891	14,407	13,934
Transportation	4,144	4,483	4,112	4,331	4,514	4,632	4,741
Carbon Offset	871	2,705	2,175	2,270	2,481	2,723	3,133
Cap-and-Trade	2,198	3,759	4,422	4,985	5,559	6,148	6,740
Distribution Costs	**28,008**	**38,527**	**40,238**	**39,433**	**47,125**	**50,684**	**51,184**
Operations	25,176	30,629	30,867	32,598	34,816	36,331	38,083
Capital	2,832	7,897	9,371	6,836	12,310	14,353	13,100
TOTAL	**73,934**	**65,921**	**66,503**	**66,329**	**74,571**	**78,595**	**79,731**

The Gas Utility last increased distribution rates on July 1, 2023, which resulted in an estimated 8% increase in the total system average gas rate (the supply rate plus the distribution rate). The attached Financial Plan includes an increase in distribution rates effective July 1, 2024 that will result in about a 9% increase to the total system average gas rate and includes additional 7% increase in FY 2026 and in FY 2027 and 6% annually from FY 2028 through FY 2029.

The unprecedented and extreme gas prices experienced in FY 2023 had a significant impact on the Gas Utility's reserves. To bring the reserves back within guideline levels in FY 2025, double-digit increases in the gas distribution rate would be necessary. The rate increases in the attached Financial Plan partially replenish the gas utility’s reserves over the next several years. The FY 2025 Financial Plan proposes to allow the Operations Reserve to be below the risk assessment levels for FY 2024 and FY 2025 and return to within the guideline range by the end of FY 2026, one year earlier than last year's forecast. The Gas Utility Reserves Management Practices require returning reserves to within minimum guidelines (60 days of O&M and commodity expense) within one year unless an alternative plan is approved by Council. Figure 1 shows the actual year-end balance in the Operations Reserve for FY 2023 and projected year-end balances for FY 2024 through FY 2029.

Figure 1: Operations Reserve Projection



In addition to replenishing Gas Utility reserves, distribution rate increases are needed to pay for increasing operations costs and Capital Improvement Project (CIP) expenditures in the distribution system. Distribution system operations costs are increasing primarily due to inflationary increases across all cost categories including salary and benefit, administrative costs, and capital costs. This Financial Plan projects increases in capital and operational costs that align similarly with the City's Budget and Long-Range Financial Forecast and average approximately 6% per year over the next five years. The priority for the City's Gas Utility is operating the system safely, which requires the replacement of higher risk PVC and steel mains on a reasonable timeline. The cost of gas main replacement continues to rise. For this reason, failing to increase the gas main replacement program budget steady would result in a reduction of the rate of main replacement over time. This Financial Plan addresses these challenges in a way that will allow CPAU to meet its main replacement needs by increasing the main replacement budget beginning in FY 2025 and including a 5.4% annual construction inflationary increase thereafter. Staff is also controlling costs by applying for grant funding for the upcoming main replacement project 25 through the Natural Gas Distribution Infrastructure Safety and Modernization grant opportunity. Staff plan to apply each year for the grant opportunity. In addition, the attached Financial Plan includes transfers of between $4 million to $7 million each year from FY 2026 to FY 2029 in order to bring the currently zero dollar CIP Reserve to within the guideline range gradually by the end of the forecast period.

In addition, with the ongoing discussions and direction from City Council related to electrification of homes and neighborhoods throughout the City and transitioning away from natural gas, the City may be able to retire some PVC and steel mains through aggressive electrification in neighborhoods with these types of mains. Staff is planning to budget funds and is working to develop an efficient phasing plan for electrification and the scaling back of the gas infrastructure. Decommissioning and electrification costs, if needed, are included in CIP budgets. The CIP budgets include $4 million in gas decommissioning costs and an additional $3 million annually from FY 2027 through FY 2029 for electrification-related costs.

The City's natural gas rates are based on the 2019 Natural Gas Cost of Service and Rates Study, updated with current and proposed operating costs. In order to move towards full cost recovery and replenish gas reserves, while minimizing rate impacts, staff recommends a distribution rate increase to all customer classes of 15%, which staff estimates will result in an approximate 9% system average rate increase, if commodity rates remain unchanged from FY 2024.

Proposed Gas Rates

Staff proposes to adjust gas rates as shown in Table 1 and Table 2 below, effective July 1, 2024. These changes are projected to increase distribution rates by 15% resulting in a total system average gas rate (total of supply and distribution) increasing by roughly 9% for all classes. These rate changes are included in the proposed amended rate schedules in (Exhibit 3 to the Resolution).

Table 1: Current and Proposed Monthly Service Charges

Rate Schedule	Current Rates (as of 7/1/23)	Proposed Rates (effective 7/1/24)	Change ($)	Change (%)
G-1 *(Residential)*	$ 14.01	$ 16.11	$ 2.10	15%
G-2 *(Small Commercial)*	129.78	149.24	19.46	15%
G-3 *(Large Commercial)*	593.79	682.85	89.06	15%
G-10 *(CNG)*	87.77	100.93	13.16	15%

Table 2: Current and Proposed Gas Distribution Charges

	Current Rates (as of 7/1/23)	Proposed Rates (effective 7/1/24)	Change ($)	Change (%)
G-1 *(Residential)*				
Tier 1 Rates	$ 0.6807	$ 0.7828	$ 0.1021	15%
Tier 2 Rates	1.7406	2.0016	0.2610	15%
G-2 *(Residential Master-Metered and Small Commercial)*				
Uniform Rate	0.8941	1.0282	0.1341	15%
G-3 *(Large Commercial)*				
Uniform Rate	0.8852	1.0179	0.1327	15%
G-10 *(CNG)*				
Uniform Rate	0.0145	0.0166	0.0021	14%*

*Adjusted downward due to rounding

Bill Impact of Proposed Rate Changes

Table 3 shows the impact of the proposed July 1, 2024 rate changes on the median residential bill. The average annual gas bill for the median residential customer is projected to be 9% higher in FY 2025 than FY 2024, excluding supply-related cost changes. However, since customer gas usage varies and the price of commodities changes monthly, the actual change may be different. Table 3 shows a representative winter period (November thru March) and summer period (April through October) bill comparison.

Table 3: Impact of Proposed Gas Rate Changes on Residential Bills

Usage (Therms/month)	Bill Amount (Current Rates)	Bill Amount (Proposed Rates)	Change	
			$/mo.	%
Summer*				
10	$ 29	$ 32	$ 3	11%
18 (median)	42	45	4	9%
30	69	75	7	10%
45	106	116	10	10%
Winter*				
30	$ 65	$ 70	$ 5	8%
54 (median)	105	113	8	7%
80	170	184	14	8%
150	362	396	34	9%

Table 4 shows the impact of the proposed July 1, 2024 rate changes on various representative commercial customer bills. The overall increases for the G-2 and G-3 classes are projected to be about 8-14% on an annual basis, excluding supply-related cost changes.

Table 4: Impact of Proposed Gas Rate Changes on Commercial Bills

Usage (Therms/month)	Bill under (Current Rates)	Bill under (Proposed Rates)	Change	
			$/mo	%
250	$ 168	$ 190	$ 22	13%
1,000	281	312	31	11%
3,200	614	669	55	9%
35,000	5,429	5,839	441	8%
250,000	38,146	41,001	2,855	7%

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

Table 5 shows the projected rate adjustments over the next five years and the impact of distribution rate increases on the median monthly residential gas bill (54 therms/month in winter, 18 therms/month in summer) of $70.05 in FY 2024, assuming commodity rates are static.

Table 5: Projected Distribution Rate Adjustments, FY 2025 to FY 2029

	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Gas Utility	9%	7%	7%	6%	6%
Estimated Bill Impact ($/mo)*	$6.30	$5.40	$5.70	$5.20	$5.60

Reserve Balances

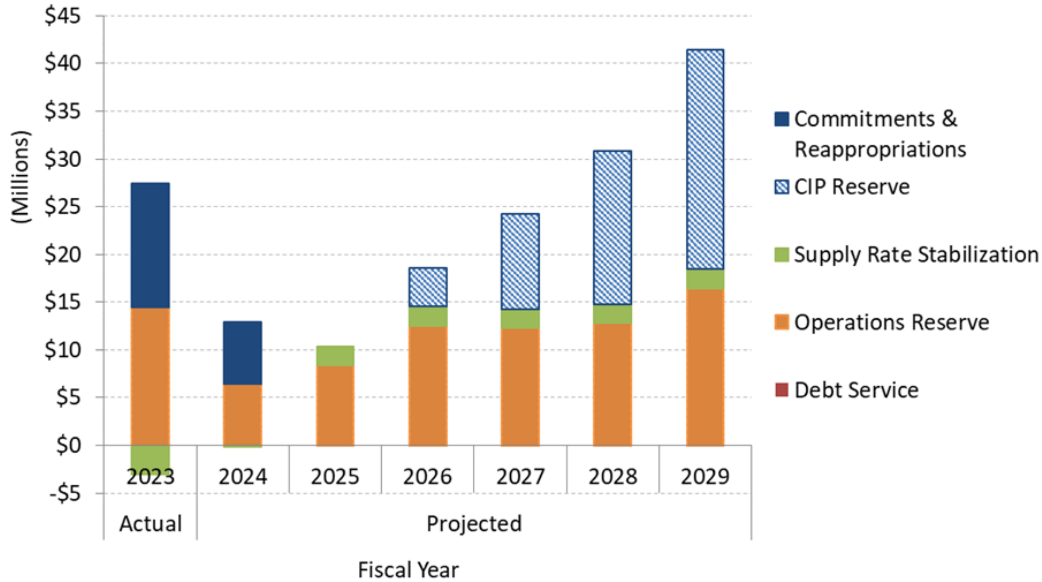
Error! Reference source not found. and Figure 2 below shows the reserve balances from FY 2024 and projected through FY 2029.

Table 6: Operations, Rate Stabilization and CIP Reserve Starting and Ending Balances, Revenues, Transfers To/(From) Reserves, Capital Program Contribution To/(From) Reserves, and Reserve Guideline Levels for FY 2024 to FY 2029 ($000)

	Fiscal Year	2024	2025	2026	2027	2028	2029
	Starting Reserve Balances						
1	Operations Reserve*	11,360	6,471	10,382	14,555	14,258	14,808
2	CIP Reserve	-	-	-	4,000	10,000	16,000
3	Cap and Trade	6,731	12,090	15,417	19,029	22,895	27,004
4	Debt Service Reserve	378	378	378	378	-	-
	Revenues						
5	Total Revenues	57,958	67,087	70,889	76,030	81,035	86,055
6	Cap and Trade	3,074	3,327	3,612	3,866	4,109	4,340
	Expenses						
7	Non-CIP Expenses	(52,665)	(53,806)	(55,881)	(58,396)	(60,133)	(62,290)
8	Planned CIP	(7,897)	(9,371)	(6,836)	(12,310)	(14,353)	(13,100)
	Transfers						
9	Operations Reserve*	(5,359)	(3,327)	(7,612)	(9,487)	(10,109)	(11,340)
10	CIP Reserve	-	-	4,000	6,000	6,000	7,000
11	Cap and Trade	5,359	3,327	3,612	3,866	4,109	4,340
12	Debt Service Reserve	-	-	-	(378)	-	-
	Ending Reserve Balances						
1+5+6+7+8+9	Operations Reserve*	6,471	10,382	14,555	14,258	14,808	18,472
2+10	CIP Reserve	-	-	4,000	10,000	16,000	23,000
3+11	Cap and Trade	12,090	15,417	19,029	22,895	27,004	31,344
4+12	Debt Service Reserve	378	378	378	-	-	-
	Operations Reserve Guidelines						
13	Minimum	9,538	9,392	9,780	10,235	10,560	10,953
14	Maximum	19,076	18,783	19,559	20,469	21,121	21,906
	CIP Reserve Guidelines						
15	Minimum	6,365	8,634	8,103	9,573	13,331	13,727
16	Maximum	12,729	17,268	16,206	19,145	26,663	27,453

**Operations Reserve represents the Gas Supply Fund Rate Stabilization Reserve and the Gas Distribution Fund Operations Reserve combined.*

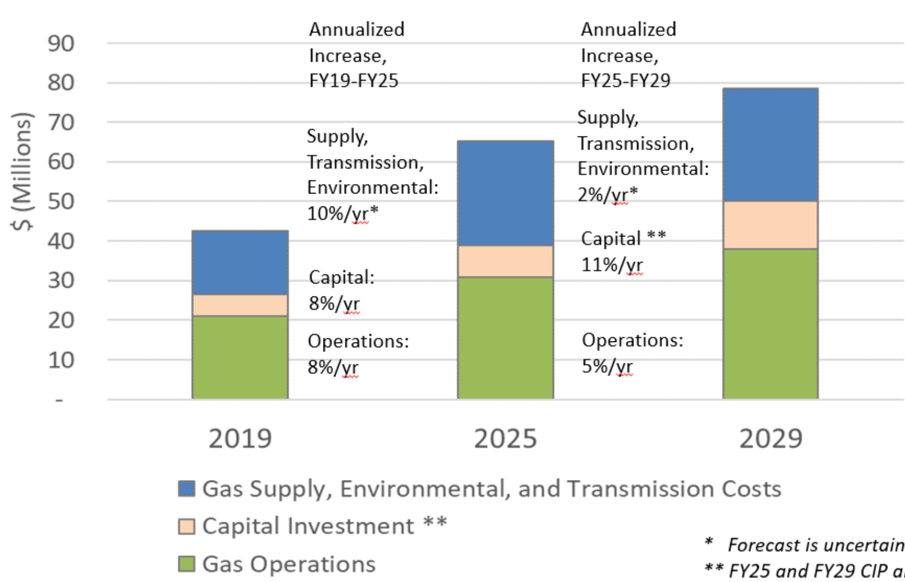
Figure 2: Actual Reserve Levels for FY 2023 and Projections through FY 2029



Cost Trends

Figure 3 below illustrates the projected long run changes in the Gas Utility's costs. Cost increases over the FY 2019 to FY 2029 time period are mainly from supply costs, followed by operations and capital expenses, including the electrification placeholders. Gas supply costs are projected to increase by 10% annually on average from FY 2019 through FY 2025 and 2% annually on average from FY 2025 through FY 2029. This includes projected declines in gas usage in Palo Alto of 0.5% annually from FY 2025 through FY 2029 and projected declines in commodity prices of 2.8% annually on average from FY 2025 through FY 2029.

Figure 3: Long Term Cost Trends



** Forecast is uncertain and will vary with market prices*
*** FY25 and FY29 CIP are an average of two years due to staggered main replacement schedule.*

Despite the low increase from FY 2025 to FY 2029 in gas commodity cost estimates, there are several components of supply costs that are increasing more rapidly during that time period. Cap and Trade allowance costs are projected to increase by 11% annually on average. Transmission costs are projected to increase by 4% annually. Carbon offset costs are projected to increase by 10% annually.

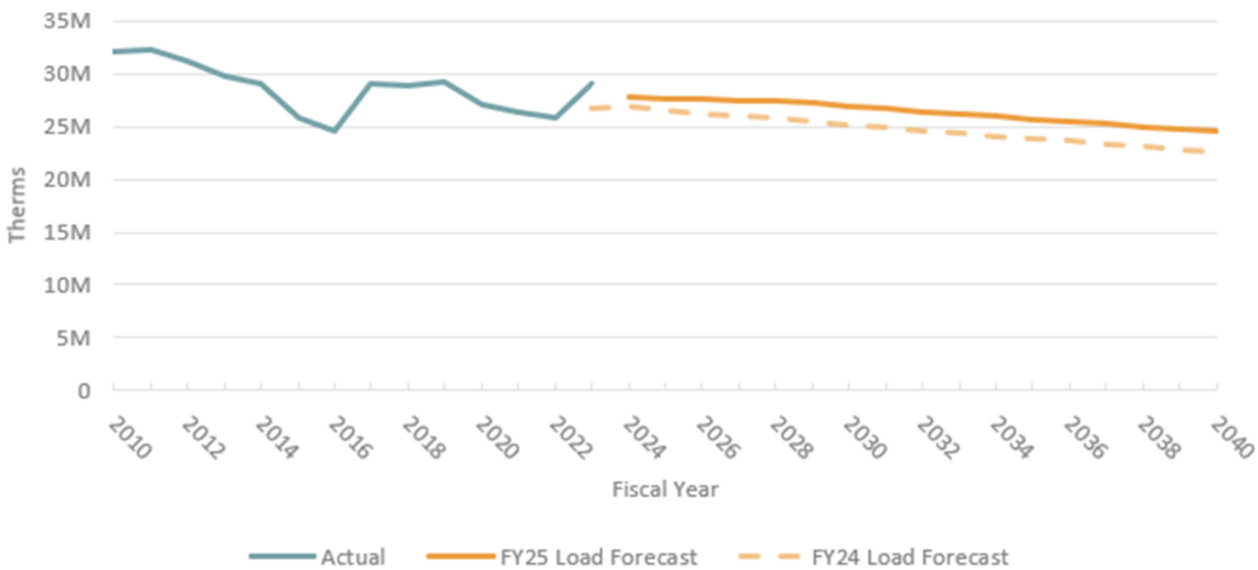
Staff also projects operations costs to increase by about 5% annually on average from FY 2025 to FY 2029, primarily due to inflation and salary and benefit increases. Operations costs assumes staff's proposal for the cross-bore funding program is approved. However, if the Council approves a lower level of funding for the program, staff would recommend the same rate trajectory and the operations reserve would recover more quickly to within the minimum guideline range. The cross-bore safety program ensures that gas pipelines have not crossed through sewer laterals, which is rare but possible during trenchless installation. This is referred to as a "cross-bore," and while they are very rare, if they exist, they pose a risk of gas leaks if a plumber uses a cutting tool to clear a sewer line and accidentally cuts the gas line. While a majority of sewer laterals have been inspected, staff has come across several services which are not able to be scoped, either due to infiltration by roots or broken/collapsed pipe segments. The estimated expense is $0.9 million in FY 2025 and $0.4 million in FY 2026.

Gas Purchases Forecast

Gas usage in Palo Alto declined from FY 2020 to FY 2022, mainly due to the Covid pandemic and drought in California. The increase in gas usage in FY 2023 was likely due to modest usage recovery from Covid and lower than normal average temperature during the winter. However, as seen with prior economic and drought-related gas usage declines in the past, it is likely that consumption will not come back to pre-conservation/pandemic levels but will likely become a long-run usage decline. Further changes, such as the voluntary replacement of gas appliances with electric appliances, building electrification of new construction as mandated by the 2019 Reach Code, and customer behavior are also expected to lower long run usage. In addition, separate strategic planning and financial analysis will be performed separate from this Financial Plan to address a financial and infrastructure strategy for the gas utility during a transition to an electrified community. Any insights from separate analyses will be integrated into future Financial plans.

The latest forecast in Figure 2 below anticipates gas supply purchases for FY 2025 at 27,711,370 therms, about 4% higher than forecasted in the FY 2024 Financial Plan. This upward projection may have been influenced by increased consumption in FY 2023, which has slightly altered the long-term trend. Long term declining gas consumption will put upward pressure on rates, as generally increasing and fixed costs to operate and distribute gas will be spread across fewer units of sale.

Figure 1: Gas Supply Purchases Forecast



<u>Gas Bill Comparison with Surrounding Cities</u>

Table 7 presents the median residential bills for Palo Alto and PG&E customers from FY 2022 to FY 2024. In FY 2023, the annual gas bill for the median Palo Alto residential customer was $940, about 4% higher compared to a PG&E customer with equivalent consumption. This is attributed to the gas price spike during the winter of 2022/2023, which impacted all California utilities except PG&E, which avoided exceptionally high gas prices.

Looking ahead to FY 2024, the anticipated annual gas bill for the median Palo Alto residential customer is expected to be about 11% lower than that of a PG&E customer with equivalent consumption. PG&E's gas transportation rates continue to rise to fund system improvements for pipeline safety and maintenance.

The bill calculations below for PG&E customers are based on PG&E Climate Zone X, an area which includes the surrounding communities.

Table 7: Residential Monthly Natural Gas Bill Comparison ($/month)

Time Period	Median Usage (therms)	Palo Alto	PG&E Zone X	% Difference
FY 2022	Annual (400 Thms)	$ 689	$ 776	(13%)
FY 2023		940	904	4%
FY 2024*		753	837	(11%)
FY 2024 Summer*	Monthly (18 Thms)	42	39	7%
FY 2024 Winter*	Monthly (54 Thms)	105	132	(25%)

**Calculated based on actual and projected supply-related costs*

Staff is in the process of doing a more extensive review of commercial competitiveness and will provide updates in the future.

Alternative Gas Increase Plans

The Gas Utility's transfer to the City's General Fund is a component of the City's gas rates. City voters first authorized the transfer in 1950, and in November 2022 voters approved Measure L affirming the continuation of this practice by amending the Municipal Code. The attached Financial Plan includes two alternatives for this transfer for FY 2025 as follows:

1. **Transfer 11.9%:** The primary proposal in the attached Financial Plan recommends this lower percentage due to the substantial commodity revenues generated in FY 2023. This alternative suggests transferring 16.5% of the FY 2024 gas utility gross revenue for FY 2026, followed by 18% of gross revenue for FY 2027 and subsequent years. This approach allows for a gradual increase in the transfer up to 18% by FY 2027.
2. **Transfer 18%:** This is the maximum transfer allowed in accordance with Measure L. However, this results in a high transfer amount in FY 2025 that would significantly negatively impact the Gas Utility's reserves and require a higher rate increase in FY 2025.

Table 10 summarizes the overall rate changes without supply-related changes, and Table 11 summarizes the gross revenue transfer percentages and dollar amounts associated with the two alternatives.

Table 10: Summary of Rate Changes for Alternatives (Excludes Supply Rate Changes)

	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Transfer 11.9%	9%	7%	7%	6%	6%
Transfer 18%	15%	5%	5%	5%	6%

Table 11: Proposed / Projected and Alternate Transfers as % of Gross Revenues Two FY Prior[2]

	Approved (Council Resolution 10101)	Proposed / Alternate	Projected	
	FY 2024	FY 2025	FY 2026	FY 2027
Gas Utility Gross Revenue Two Fiscal Years Prior ($000)				
	$49,721	$75,291[3]	$61,032	$70,414[4]
				$73,618
Percent of gas utility gross revenue to transfer				
	15.5%	**11.9%**	16.5%	18%
		18%	18%	
Transfer amount ($000)				
Transfer 11.9%	$7,707	$8,960	$10,070	$12,674
Transfer 18%		$13,552	$10,986	$13,251
Change in Transfer from Prior Fiscal Year (%)				
	7%	16%	12%	26%
		76%	-19%	21%

Timeline

The Finance Committee is scheduled to review the FY 2025 Gas Financial Plan in April 2024. The City Council will consider adopting the Financial Plan and rate adjustments as part of the FY 2025 budget review and adoption process in June 2024. If Council approves the proposed rate changes, the rates will become effective July 1, 2024.

Resource Impact

The resource impact of the recommendations summarized in this report is the continued financial solvency of the Gas Utility and, as the City is a ratepayer, an increase to General Fund expenses (due to the rate increases) and revenues (due to the General Fund transfer). Normal year sales revenues for the Gas Utility in FY 2024 are projected to increase by roughly 9% or $5 million as a result of the proposed rate increases, not including fluctuations in commodity revenue/cost. The change in General Fund revenues from FY 2024 to FY 2025 would depend on the General Fund transfer alternative chosen by Council, as shown above in Table 10. Under the 11.9% transfer in FY 2025 alternative, which was supported by UAC members during their discussion of preliminary rates in January 2024, General Fund revenues would increase from

[2] Measure L authorizes a transfer based on 18% (or a lesser percentage if approved by Council) of the revenue for two fiscal years prior, so the FY 2024 transfer is based on FY 2022 revenue.
[3] Represents actual gas utility gross revenues for FY 2023.
[4] There are two values for gross revenue in FY 2027 because there are two possible rate trajectories shown in Table 3 that would impact the forecasted revenue for FY 2025 (two fiscal years prior to FY 2027); the first would increase rates by 9% in FY 2025 leading to forecasted revenues of $70.414 million and the second would increase rates by 15% in FY 2025 leading to forecasted revenues of $73.618 million.

$7,707,000 million in FY 2024 to $8,959,629 million in FY 2025, an increase of about $1,252,629 million.

Policy Implications

The proposed gas rate adjustments are consistent with Council-adopted Reserve Management Practices that are part of the Financial Plan and were developed using a cost-of-service study and methodology consistent with the California constitution and industry-accepted cost of service principles. As noted in the Reserves Management Practices (Exhibit 2 to the Resolution), if reserves fall below the minimum guidelines, Council approval is required for a rate plan that requires more than one year to return reserves to within guideline levels.

Stakeholder Engagement

Staff and the UAC's recommendation on the FY 2025 gas rate increases will go to the Finance Committee in April 2024 and be presented to City Council in June 2024 during the budget adoption process.

Environmental Review

The UAC's review and recommendation to the Finance Committee on the FY 2024 Gas 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: Gas Resolution FY25
- Attachment B: Gas Presentation FY25

AUTHOR/TITLE:
Dean Batchelor, Director of Utilities
Staff: Lisa Bilir, Senior Resource Planner

Attachment A

* NOT YET APPROVED *
Resolution No. __________

Resolution of the Council of the City of Palo Alto Approving the Fiscal Year 2025 Gas Utility Financial Plan and General Fund Transfer, and Increasing Gas Rates by Amending Rate Schedules G-1 (Residential Gas Service), G-2 (Residential Master-Metered and Commercial Gas Service), G-3 (Large Commercial Gas Service), and G- 10 (Compressed Natural Gas 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, including reserves. 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 June 17, 2024, 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 adopts the fiscal year ("FY") 2025 Gas Utility Financial Plan (Exhibit 1), including the amendments to the Gas Utility Reserves Management Practices (Exhibit 2);

SECTION 2. The Council hereby approves the transfer of up to 11.9% of gas utility gross revenues received during FY 2023 to the general fund in FY 2025;

SECTION 3. Pursuant to Section 12.20.010 of the Palo Alto Municipal Code, Utility Rate Schedule G-1 (Residential Gas Service) is hereby amended to read as attached and incorporated. Utility Rate Schedule G-1, as amended, shall become effective July 1, 2024 (Exhibit 3);

* NOT YET APPROVED *

SECTION 4. Pursuant to Section 12.20.010 of the Palo Alto Municipal Code, Utility Rate Schedule G-2 (Residential Master-Metered and Commercial Gas Service) is hereby amended to read as attached and incorporated. Utility Rate Schedule G-2, as amended, shall become effective July 1, 2024 (Exhibit 3);

SECTION 5. Pursuant to Section 12.20.010 of the Palo Alto Municipal Code, Utility Rate Schedule G-3 (Large Commercial Gas Service) is hereby amended to read as attached and incorporated. Utility Rate Schedule G-3, as amended, shall become effective July 1, 2024 (Exhibit 3);

SECTION 6. Pursuant to Section 12.20.010 of the Palo Alto Municipal Code, Utility Rate Schedule G-10 (Compressed Natural Gas Service Service) is hereby amended to read as attached and incorporated. Utility Rate Schedule G-10, as amended, shall become effective July 1, 2024 (Exhibit 3);

SECTION 7. The City Council finds as follows:

a. Revenues derived from the gas rates approved by this resolution do not exceed the funds required to provide gas service.

b. Revenues derived from the gas rates approved by this resolution shall not be used for any purpose other than providing gas service, and the purposes set forth in Article VII, Section 2, of the Charter of the City of Palo Alto.

SECTION 8. The Council finds that 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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Attachment A

* NOT YET APPROVED *

<u>SECTION 9.</u> The Council finds that approving the FY 2025 Gas Utility 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 gas 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

FY 2025 GAS UTILITY FINANCIAL PLAN

FY 2025 TO FY 2029

GAS UTILITY FINANCIAL PLAN

FY 2025 TO FY 2029

TABLE OF CONTENTS

SECTION 1: DEFINITIONS AND ABBREVIATIONS

ABS: Acrylonitirile butydene styrene, a plastic gas main material

AMI: Advanced Metering Infrastructure

CARB: California Air Resources Board

CIP: Capital Improvement Program

CNG: Compressed Natural Gas

CPAU: City of Palo Alto Utilities Department

CPUC: California Public Utilities Commission

Cross-bore: A cross-bore exists when one utility line has been drilled or "bored" through a portion of another line. Gas cross-bores can occur in sewer lines as a result of "horizontal boring" construction practices.

Distribution: transportation of gas to customers.

GMR Program: Gas Main Replacement Program

Local Transportation: transportation of gas to Palo Alto across PG&E's distribution system from PG&E City Gate.

Malin: a delivery hub referred to in gas purchase contracts and located in Malin, Oregon, where the northern end of PG&E's Redwood Transmission Pipeline is located.

MMBtu: Millions of British thermal units, a unit of gas measurement equal to ten therms. Commonly used for high volume gas measurement. Wholesale purchases of gas from suppliers are typically measured in MMBtu.

O&M: Operations and Maintenance

PE or **HDPE:** Polyethylene, a gas main material (more specifically, High-Density Polyethylene)

PG&E: Pacific Gas and Electric

PG&E Citygate, or **Citygate:** a delivery hub referred to in gas purchase contracts. Any gas delivered to PG&E's distribution system (such as gas delivered at the southern end of PG&E's Redwood Transmission Pipeline) is said to have been delivered at PG&E Citygate.

PVC: Polyvinyl chloride, a plastic gas main material

Summer: April 1 to October 31

Therms: The standard unit of measurement for natural gas sales to customers, equal to 100,000 British thermal units. Therms measure the heating value of the gas, rather than its volume.

Transmission: transportation of gas between major gas delivery hubs via a gas transmission pipeline, such as PG&E's Redwood pipeline.

UAC: Utilities Advisory Commission, an appointed body that advises the City Council on CPAU issues.

Winter: November 1 to March 31

SECTION 2: EXECUTIVE SUMMARY AND RECOMMENDATIONS

This document presents a Financial Plan for the City's Gas Utility for the next five years. This Financial Plan provides revenues to 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

Gas commodity prices have substantially decreased from the unprecedented high prices in FY 2023 and returned to normal levels in FY 2024. In FY 2021 and FY 2022, the Gas Utility maintained minimal rate increases, leading to revenues that fell short of covering costs. In FY 2023, although revenues exceeded costs, there were additional costs associated with FY 2023 that are reflected in FY 2024. Specifically, FY 2023 carbon offset purchases were paid in FY 2024 and the transfer of FY 2023 Cap and Trade auction revenue from the Operations Reserve to the Cap and Trade reserve, which is a cost item, occurred in FY 2024. By the end of FY 2024, staff projects the Operations Reserve to drop below the minimum guideline range. Staff projects overall distribution costs to increase by 4% from FY 2024 to FY 2025 and by 5% on average annually from FY 2025 through FY 2029. Additionally, the operations reserves is projected to be below the guideline range by the end of FY 2024 and the CIP Reserve is empty. Rates need to be increased to gradually bring reserves back to within guideline ranges. Staff is proposing an increase in the distribution component of gas rates in FY 2025 of 15% that will be used to pay for the utility's costs and to rebuild reserves gradually. The projected distribution rate increase is expected to raise overall customer bills by about 9% in FY 2025 if gas supply-related costs remain unchanged.

While gas commodity prices are projected to decline approximately 2% on average from FY 2024 to FY 2025, mild weather so far in FY 2024 reduced gas usage, which staff expects will return to a higher level consistent with the long-term trend in FY 2025. From FY 2025 to FY 2029, staff forecasts gas usage to gradually decline by 0.5% annually on average. The uncertain nature of gas market prices and gas sales means these forecasts could change. Gas commodity costs are passed directly to customers through a rate adjuster, currently capped at $4/therm.

CIP costs fluctuate from year to year, while staff has historically planned for a new gas main replacement project every year, higher-than-expected bid proposals have necessitated resizing and redesign of some projects. Since FY 2020, staff has budgeted for a new, larger main replacement project every other year, allowing CPAU to effectively address construction market challenges and optimize staffing resources. However, replacement costs continue to rise, and maintaining the gas main replacement program budget at the same level results in a reduction in the rate of main replacement over time. This Financial Plan addresses these challenges by increasing the main replacement budget starting in FY 2025 and including a 5.4% annual construction inflationary increase thereafter. Staff is also controlling costs by applying for grant funding for the upcoming main replacement Project 25 through the Natural Gas Distribution Infrastructure Safety and Modernization grant opportunity. Staff plan to apply each year for the grant. In addition, the attached Financial Plan includes transfers of between $4 million to $7 million each year from FY 2026 to FY 2029 in order to bring the currently empty CIP Reserve to within the guideline range gradually by the end of the forecast period. Decommissioning and electrification costs, if needed, are included in CIP budgets. The CIP budgets include $4 million in gas decommissioning costs and an additional $3 million annually from FY 2027 through FY 2029 for electrification-related costs.

Gas total supply costs are projected to increase on average about 2% per year (though this forecast is uncertain)[1] over the forecasting period from FY 2025 to FY 2029, while distribution operational costs are expected to increase on average about 5% per year, primarily due to salary and benefit increases, and CIP costs are projected to increase on average about 9% per year, due to increasing construction costs, gas decommissioning expenses. This leads to an average increase of about 5% per year in the overall costs for the Gas Utility through the forecasting period. However, total gas bills, including both commodity and distribution components, are forecasted to rise at a slightly higher average rate of 7% per year. This is because distribution rates are currently below costs, necessitating higher rate increases than distribution cost increases for full cost recovery and reserve replenishment.

Table 1 provides an overview of Gas Utility expenses over the period covered by this Financial Plan.

Table 1: Gas Utility Expenses for FY 2023 to FY 2029 ($,000)

Expenses ($000)	Actual	Projected					
	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Supply Costs	**45,926**	**27,395**	**26,265**	**26,896**	**27,445**	**27,911**	**28,547**
Commodity	38,713	16,449	15,557	15,309	14,891	14,407	13,934
Transportation	4,144	4,483	4,112	4,331	4,514	4,632	4,741
Carbon Offset	871	2,705	2,175	2,270	2,481	2,723	3,133
Cap-and-Trade	2,198	3,759	4,422	4,985	5,559	6,148	6,740
Distribution Costs	**28,008**	**38,527**	**40,238**	**39,433**	**47,125**	**50,684**	**51,184**
Operations	25,176	30,629	30,867	32,598	34,816	36,331	38,083
Capital	2,832	7,897	9,371	6,836	12,310	14,353	13,100
TOTAL	**73,934**	**65,921**	**66,503**	**66,329**	**74,571**	**78,595**	**79,731**

As shown in Table 1, total Gas Utility costs are projected to be similar in FY 2025 as in FY 2024; there is an increase of 4% in the distribution costs (operations and capital costs combined) and a decrease in the supply costs. Supply costs were higher in FY 2024 because lack of staffing resulted in carbon offset purchases being deferred from FY 2023 to FY 2024. Additionally, FY 2024 costs reflect the Council's adopted revised natural gas purchasing strategy for the 2023 – 2024 winter months to include insurance against very high prices. A longer-term strategy for mitigating

[1] This results from a projected gradual decline in the main component of gas supply costs, the cost of gas purchased in the market (the "commodity" charge), combined with significant increases in smaller components of commodity costs: gas transportation and environmental charges. The net result is a gradual increase in costs. However, forecasting commodity costs if very uncertain. For more detail gas supply rate design and the sources for these forecasts, see Section 4G: Gas Supply Pass-Through Rates and Section 6A: Gas Purchase Costs

against potential future gas price spikes will be presented to Council for consideration prior to next winter. However, costs of that longer-term strategy are not yet known and are not included in this cost projection. Staff expects overall costs to increase by about 5% per year from FY 2025 through FY 2029 and expects distribution costs to increase 6% per year on average from FY 2025 through FY 2029. Additional rate increases are needed to pay for increasing supply, operations and capital costs as well as gradually bringing the utility's reserves back up within guideline ranges by the end of the forecast period.

In order to move towards full cost recovery while minimizing rate impacts, the Financial Plan includes the rate trajectory shown in Table 2, which shows the overall annual rate increases, excluding supply-related cost changes.

Table 2: Projected Gas Rate Trajectory for FY 2025 to FY 2029

Projection	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
FY 2025 Financial Plan (Current)	9%	7%	7%	6%	6%
FY 2024 Financial Plan	7%	5%	5%	5%	N/A
FY 2023 Financial Plan	4%	4%	3%	N/A	N/A

The unprecedented and extreme gas prices experienced in FY 2023 had a significant impact on the Gas Utility's reserves. To bring the reserves back within guideline levels, double-digit increases in distribution rates would be necessary. In last year's financial plan, Staff anticipated that the Gas Operations Reserve would fall below the risk assessment levels in FY 2024 and FY 2025 and remain below the minimum guideline in FY 2026. However, the current projection suggests that the Operations Reserve will return above the minimum guideline by FY 2026, one year earlier than last year's forecast. For more detailed information, please refer to Section 5E: Risk Assessment and Reserves Adequacy.

The Gas Utility's transfer to the City's General Fund is another component of the City's gas rates. City voters first authorized the transfer in 1950, and in November 2022 voters approved Measure L, affirming the continuation of this practice by amending the Municipal Code. According to Measure L, the City Council has the authority to transfer an amount of up to 18% of the Gas Utility gross revenues to the general fund each year[2], although City Council may opt to transfer a lesser amount.

This Financial Plan proposes to transfer 11.9% of the Gas Utility's gross revenues from FY 2023, $8,959,629, to the general fund for FY 2025, which aligns with the voter-approved changes codified in PAMC 2.28.185. Additionally, staff anticipates recommending the continuation of a gradual annual transfer increase to up to 18% of gross revenues by FY 2027. Alternatively, the "Transfer 18%" alternative proposes transferring 18% of the Gas Utility's gross revenue each year starting from FY 2025, in line with the voters' approval in Measure L. However, this increase in the transfer amount would significantly impact the gas reserves and require a larger rate increase. Additional details are shown in Section 5G: Alternative Gas Increase Plans.

[2] 18% of the gross revenues of the Gas Utility received "during the fiscal year two fiscal years before the fiscal year of the transfer." (Section 2.28.185, Palo Alto Municipal Code).

Table 3 shows the projected reserve balances and transfers over the forecast period. As noted above, staff is seeking approval for the Gas Operations Reserve to be at the risk assessment levels for FY 2024 and FY 2025. The Gas Utility Reserves Management Practices (Attachment B, Section 8) require returning Operations reserves to within minimum guidelines (60 days of O&M and commodity expense) within one year unless an alternative plan is approved by Council.

Each year, the Cap and Trade allowance sales revenues are recorded in revenue accounts in the Gas Supply Fund and staff then transfers the revenues to the Cap and Trade Reserve. In FY 2024 staff moved the Cap and Trade Reserve from the Gas Distribution Fund to the Gas Supply Fund for ease of administration. The $5.359 million FY 2024 Cap and Trade transfer shown in Table 3 is the sum of the $2.285 million from Cap and Trade auction revenue in FY 2023 and the forecasted Cap and Trade auction revenue for FY 2024 of $3.074 million. Staff transferred the $2.285 million FY 2023 Cap and Trade auction revenue from the Supply Rate Stabilization Reserve to the Cap and Trade Reserve in mid-year of FY 2024.

Table 3: Operations, Rate Stabilization and CIP Reserve Starting and Ending Balances, Revenues, Transfers To/(From) Reserves, Capital Program (CIP) Contribution To/(From) Reserves, and Reserve Guideline Levels for FY 2024 to FY 2029 ($,000)

	Fiscal Year	2024	2025	2026	2027	2028	2029
	Starting Reserve Balances						
1	Operations Reserve*	11,360	6,471	10,382	14,555	14,258	14,808
2	CIP Reserve	-	-	-	4,000	10,000	16,000
3	Cap and Trade	6,731	12,090	15,417	19,029	22,895	27,004
4	Debt Service Reserve	378	378	378	378	-	-
	Revenues						
5	Total Revenues	57,958	67,087	70,889	76,030	81,035	86,055
6	Cap and Trade	3,074	3,327	3,612	3,866	4,109	4,340
	Expenses						
7	Non-CIP Expenses	(52,665)	(53,806)	(55,881)	(58,396)	(60,133)	(62,290)
8	Planned CIP	(7,897)	(9,371)	(6,836)	(12,310)	(14,353)	(13,100)
	Transfers						
9	Operations Reserve*	(5,359)	(3,327)	(7,612)	(9,487)	(10,109)	(11,340)
10	CIP Reserve	-	-	4,000	6,000	6,000	7,000
11	Cap and Trade	5,359	3,327	3,612	3,866	4,109	4,340
12	Debt Service Reserve	-	-	-	(378)	-	-
	Ending Reserve Balances						
1+5+6+7+8+9	Operations Reserve*	6,471	10,382	14,555	14,258	14,808	18,472
2+10	CIP Reserve	-	-	4,000	10,000	16,000	23,000
3+11	Cap and Trade	12,090	15,417	19,029	22,895	27,004	31,344
4+12	Debt Service Reserve	378	378	378	-	-	-
	Operations Reserve Guidelines						
13	Minimum	9,538	9,392	9,780	10,235	10,560	10,953
14	Maximum	19,076	18,783	19,559	20,469	21,121	21,906
	CIP Reserve Guidelines						
15	Minimum	6,365	8,634	8,103	9,573	13,331	13,727
16	Maximum	12,729	17,268	16,206	19,145	26,663	27,453

**Operations Reserve represents the Gas Supply Fund Rate Stabilization Reserve and the Gas Distribution Fund Operations Reserve combined.*

SECTION 2B: SUMMARY OF PROPOSED ACTIONS

Staff proposes the following actions for the Gas Utility:

1. Approve the FY 2025 Gas Utility Financial Plan, which includes amending the Gas Utility Reserve Management Practices, reflected in Appendix C: Gas Utility Reserves Management Practices, sections 2, 10, and 11; and
2. Increase distribution rates by 15% (for an estimated 9% increase to total rates) for FY 2025; and
3. Transfer up to 11.9% of gas utility gross revenues received during FY 2023 to the general fund in FY 2025.

SECTION 3: DETAIL OF FY 2025 RATE AND RESERVE PROPOSALS

SECTION 3A: RATE DESIGN

The Gas Utility's rates are evaluated and implemented in compliance with cost of service requirements set forth in the California Constitution and applicable statutory law. The Gas Utility's proposed rates are based on the methodology from the March *2019 Natural Gas Cost of Service and Rates Study*.

The City's natural gas rates are based on the 2019 Natural Gas Cost of Service and Rates Study, updated with current and proposed operating costs. As mentioned in last year's financial plan, there has been a notable decrease in gas consumption among various customer classes due to the shift towards remote work and businesses operating with reduced staff during the COVID-19 pandemic. Concurrently, there has been an increase in expenses related to salaries and benefits, and administrative functions provided by the City's General Fund staff, as well as rising supply costs. These factors have contributed to expenses surpassing revenues for several years, leading to a depletion of the gas reserves. In order to move towards full cost recovery and replenish gas reserves, while minimizing rate impacts, Staff recommends increasing the distribution component of the rates by 15%, which equates to around a 9% increase to total rates, if commodity rates remained unchanged from FY 2024. Rate impacts of these changes are outlined in Section 3B: Current and Proposed Rates.

Distribution rates typically comprise approximately 70% of the overall rate, which consists of both gas supply and distribution components (though in FY 2023 it accounted for about 40% due to unprecedented supply cost increases). Supply-related costs include the cost of the natural gas itself (the "commodity" rate), gas transmission, and gas environmental charges, and these are a fluctuating component of the Gas Utility's expenses. Commodity rates, which typically make up approximately 30% of overall retail gas rates, vary significantly due to changes in market conditions. Staff monitors market prices monthly and automatically incorporates market prices into monthly supply rate adjustments, which are passed directly to customers as a line item on their utility bills.

The overall rate changes (commodity plus distribution) referenced in this report are based on current gas market forecasts that indicate that the commodity portion of the overall rate will decline from the level observed in FY 2023 to a more normal range. Current gas market forward prices indicate that average annual commodity prices are projected to decline about 2% in FY 2025 from FY 2024. This is consistent with current gas market forecasts from various sources, including forward gas contracts on exchanges and forecasts from suppliers, but staff cautions that these forecasts can change rapidly due to changing weather, economic factors, or gas supply constraints.

SECTION 3B: CURRENT AND PROPOSED RATES

Gas rates have two drivers: 1) Supply costs – these are costs related to the purchase of gas supply, transmission costs to bring the gas to Palo Alto's meters, and environmental costs, such as the purchase of cap and trade allowances for gas burned and carbon neutral offsets; and 2) Distribution costs.

Supply costs are charged to customers via four pass-through rate components related to supplying gas to customers:

1. Gas commodity: This represents the cost of buying gas in the markets.
2. Gas transportation: This reflects the cost of transporting purchased gas to Palo Alto. This charge continues to increase as PG&E collects costs related to improving storage facilities, decommissioning older facilities, increased costs resulting from wildfire mitigation, accounting for and greenhouse gas mitigation costs. Based on PG&E's estimates, prices are going to continue to escalate about 4% annually between FY 2026 to FY 2029.
3. Cap and Trade compliance: This covers the cost of mandated participation in the State's cap and trade program and changes depending on the cost of allowances and gas demand.
4. Carbon offset charge: This accounts for the cost of buying offsets for the City's Carbon Neutral Gas Portfolio. The costs associated with the carbon neutral gas plan are passed directly to customers, with the maximum rate impact is $0.10 per therm.

All gas supply, transportation, and environmental costs are passed through to customers as monthly prices change. Two years' worth of history of these supply rate components can be found on Palo Alto's website.[3]

CPAU has four rate schedules: one for separately metered residential customers (G-1), one for small commercial and master-metered multi-family residential customers (G-2), one for customers using over 250,000 therms per year (G-3), and a specific schedule for the City's Compressed Natural Gas (CNG) station (G-10). To recover distribution costs, all customers pay a monthly service charge, which funds meter reading, billing, and other customer service costs, as well as a portion of Operations and Maintenance (O&M) costs. All customers are also assessed a distribution charge based on each therm of gas used. Separately metered residential customers are charged on a tiered basis, differentiated by season. During the winter months, the first 2 therms per day (60 therms for a 30 day billing period) are charged a base price per therm, and all additional units charged a higher price per therm. During the summer months, the first tier

[3] Monthly Gas Commodity & Volumetric Rates https://www.cityofpaloalto.org/files/assets/public/utilities/rates-schedules-for-utilities/residential-utility-rates/monthly-gas-volumetric-and-service-charges-residential.pdf

level is 0.667 therms per day, or 20 therms for a 30 day billing period. Commercial customers pay a uniform price for each therm used.

Table 5 shows the current monthly service charges for all rate schedules. Table 6 shows the consumption charges related to distribution. As mentioned earlier, commodity charges change monthly, and transportation charges are tied to the PG&E G-WSL rate schedule. Some recent commodity price history is discussed in *Section 6A: Gas Purchase Costs.*

Table 4: Current and Proposed Monthly Service Charges

Rate Schedule	Current Rates (as of 7/1/23)	Proposed Rates (effective 7/1/24)	Change ($)	Change (%)
G-1 *(Residential)*	$ 14.01	$ 16.11	$ 2.10	15%
G-2 *(Small Commercial)*	129.78	149.24	19.46	15%
G-3 *(Large Commercial)*	593.79	682.85	89.06	15%
G-10 *(CNG)*	87.77	100.93	13.16	15%

Table 5: Current and Proposed Gas Distribution Charges

	Current Rates (as of 7/1/23)	Proposed Rates (effective 7/1/24)	Change ($)	Change (%)
G-1 *(Residential)*				
Tier 1 Rates	$ 0.6807	$ 0.7828	$ 0.1021	15%
Tier 2 Rates	1.7406	2.0016	0.2610	15%
G-2 *(Residential Master-Metered and Small Commercial)*				
Uniform Rate	0.8941	1.0282	0.1341	15%
G-3 *(Large Commercial)*				
Uniform Rate	0.8852	1.0179	0.1327	15%
G-10 *(CNG)*				
Uniform Rate	0.0145	0.0166	0.0021	14%*

*Adjusted downward due to rounding

SECTION 3C: BILL IMPACT OF PROPOSED RATE CHANGES

Table 7 shows the impact of the proposed July 1, 2024 rate changes on the median monthly residential bill for representative average winter and summer bills. The average annual gas bill for the median residential customer is projected to be 9% higher in FY 2025 than FY 2024, excluding supply-related cost changes. However, since customer gas usage varies and the price of commodities changes monthly, the actual change may vary. Table 7 shows a representative winter period (November thru March) and summer period (April through October) bill comparison.

Table 6: Monthly Impact of Proposed Gas Rate Changes on Residential Bills[4]

Usage (Therms/month)	Bill Amount (Current Rates)	Bill Amount (Proposed Rates)	Change	
			$/mo.	%
Summer				
10	$ 29	$ 32	$ 3	11%
18 (median)	42	45	4	9%
30	69	75	7	10%
45	106	116	10	10%
Winter				
30	$ 65	$ 70	$ 5	8%
54 (median)	105	113	8	7%
80	170	184	14	8%
150	362	396	34	9%

Table 8 shows the impact of the proposed July 1, 2024 rate changes on various representative commercial customer bills. The overall increases for the G-2 and G-3 classes are projected to be about 7-13% on an annual basis, excluding supply-related cost changes.

Table 7: Monthly Impact of Proposed Gas Rate Changes on Commercial Bills[8]

Usage (Therms/month)	Bill under (Current Rates)	Bill under (Proposed Rates)	Change	
			$/mo	%
250	$ 168	$ 190	$ 22	13%
1,000	281	312	31	11%
3,200	614	669	55	9%
35,000	5,429	5,839	441	8%
250,000	38,146	41,001	2,855	7%

SECTION 3D: PROPOSED AMENDED RESERVES MANAGEMENT PRACTICES

Staff requests Council authorization to amend the Gas Utility Reserves Management Practices. The Gas Utility Reserve Management Practices, Section 10, currently authorize staff to transfer the difference between Gas Supply Fund costs and revenues from the Gas Distribution Fund to the Gas Supply Fund, or vice versa. This amendment, if approved by Council, would modify Section 10 to authorize staff to transfer funds between the Gas Supply Fund and the Gas Distribution Fund if consistent with the purposes of the two reserves involved in the transfer and in order to balance gas utility reserves to avoid negative balances.

This amendment is needed to provide a mechanism to transfer distribution revenues from the Gas Distribution Fund to the Gas Supply Fund to cover expenses that are funded by distribution revenues, such as administration of the Gas Supply Fund. Additionally, the amendment would

[4] Current rates are derived from actual commodity prices up to January 2024 and forecasted prices until June 2024. Proposed rates, while based on the same commodity prices as current rates, incorporate adjustments solely in the increase of distribution rates.

help avoid negative balances, such as the FY 2023 year-end balance of -$3.077 million in the Supply Rate Stabilization Reserve, when funds are otherwise available in the Gas Utility. This was the case at year-end FY 2023. The proposed change would allow staff to complete the transfer once actual costs and revenues are known (rather than estimated) at year end.

In FY 2026, the final debt service payment is expected on the 2011 Utility Revenue Refunding Bonds, Series A. At that time, the $0.378 million in the debt service reserve will partially offset the final year's debt service payment.

Table 3 and *Appendix A: Gas Utility Financial Forecast Detail* show the impact of transfers on reserve levels.

SECTION 4: UTILITY OVERVIEW

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

SECTION 4A: GAS UTILITY HISTORY

On September 22, 1917, the City of Palo Alto issued a bond to purchase the property of Palo Alto Gas Company and continue it as a municipal enterprise. At the time, the system was comprised of 21 miles of mains, 1,900 meters, and was valued at $65,500. PG&E supplied the gas, which was synthesized from coal at its Potrero gasification facility. Almost immediately the City faced challenges. Losses were at nearly 25% according to PG&E's master meter, and PG&E had filed with the Railroad Commission (the forerunner to today's CPUC) to increase rates by nearly 72.5%. Despite these initial hurdles, Palo Alto's system grew tremendously, and by 1924 revenues had exceeded those of the electric utility. Sales were such that the annual reports of the time noted gas usage "appears to be greater than that of any other city in the state, showing that gas is a very popular form of fuel in Palo Alto." Just prior to the acquisition of the neighboring town of Mayfield's gas system (centered around today's California Avenue) in 1929, the miles of main in service and customer connections had doubled.

Notable changes to the gas supply itself came in 1930, when PG&E ceased supplying purely manufactured (or coal) gas from its Potrero Hill facility in San Francisco and instead switched to natural gas. In 1935, a supplementary butane injection system (later retired) was purchased from Standard Oil to mitigate large wintertime peaks. Gas sales were at 248,658 million cubic feet (MCF) with 4,849 active services.

Early gas mains in Palo Alto were made of steel, but in the 1950s, like many other utilities, CPAU switched to ABS plastic. CPAU switched to PVC plastic in the early 1970s, but around 100 miles of ABS mains had already been installed. A 1990 evaluation of the system found a steadily increasing rate of gas leaks associated with those mains, something that other gas utilities had also been experiencing. To reduce leaks, CPAU accelerated its main replacement program from 7,000 feet (1.3 miles) of replacements per year to 20,000 feet (3.8 miles) per year. This would enable the utility to replace all of its ABS and its most vulnerable steel and PVC mains with polyethylene (PE) mains over the course of the following 36 years.[5] The Gas Utility has replaced all but .11 miles of ABS gas mains, which consists of mainly short sections of pipelines in various locations throughout the City. These sections will be replaced as the distribution mains around them are replaced. The majority of ABS, Taenite, and K40 gas services were replaced in 2020. The only ABS, Tenite and K40 gas services remaining are on moratorium streets; these services will be replaced as the street moratorium expires. The Gas Utility completed the replacement of approximately 22,000 linear feet of PVC gas main and over 250 natural gas services in FY22 under the Gas Main Replacement Project 23. This is an example of how local control of its Gas Utility has provided Palo Alto residents with substantial benefits. During the 1990s and 2000s, while CPAU was increasing its main replacement rate to ensure a robust gas distribution system, PG&E was underspending on safety-related infrastructure, according to a past audit.[6]

In the 1990s, while grappling with the issues surrounding its distribution system, CPAU was also participating in major changes to the structure of the gas industry in California. Until 1988 CPAU had a formal policy of setting its rates equal to PG&E's rates and successfully did so with the exception of one year in the mid-1970s. At times this led to inadequate revenue (1974 to 1981) as PG&E, the City's only gas supplier, regularly filed requests with the CPUC to increase the wholesale gas supply rates charged to the Gas Utility. In the 1990s, as the CPUC began deregulating the natural gas industry in California, the Gas Utility began purchasing gas from suppliers other than PG&E. In 1997 the CPUC adopted the "Gas Accord,"[7] which enabled the Gas Utility (along with other local transportation-only customers) to obtain transmission rights on PG&E's Redwood transmission pipeline running from Malin, Oregon into California.

In 2000/2001 the California energy crisis occurred, causing major disruptions to the Gas Utility's supply costs. Wholesale gas prices rose over 500% between January 2000 and January 2001. The Council approved drawing down reserves to provide ratepayer relief and, for two years following the crisis, CPAU rates were above PG&E's as reserves were replenished. In April 2001 the Council approved a hedging practice of buying fixed price gas one to three years into the future. After reaching a low point in October 2001, prices continued to rise, and the CPAU hedging strategy frequently resulted in a wholesale supply cost advantage compared to PG&E until prices began to decline steeply in mid-2008. At that point the Gas Utility's wholesale supply costs became higher than market gas prices due to fixed price contracts entered into prior to 2008. As a result the Gas Utility's wholesale supply costs were higher than PG&E's for several years. In 2012 Council approved a plan to formally cease the hedging strategy and purchase all gas on the short-term ("spot") markets. As of July 1, 2012, the commodity portion of the gas rates changes every month based on the spot market gas price. In January 2015, the Council adopted a new rate component to collect the costs of purchasing allowances for the purpose of compliance with the State's cap-and-trade program.[8] As of November 1, 2016, the Council adopted a resolution changing the Local Transportation rate (which had been collapsed into the Distribution rate in 2015 to streamline bill presentation), to be a pass-through of PG&E's Gas Transportation Rate to

[5] Staff Report CMR:183:90. *Infrastructure Review and Update,* March 1, 1990

[6] *Focused Financial Audit of The Pacific Gas & Electric Company's Gas Distribution Operations*, Overland Consulting, made available through a CPUC Administrative Law Judge's ruling on A12-11-009/I13-03-007 on 5/31/2013

[7] CPUC decision 97-08-055. Since then, the Gas Accord has been amended four times, with the most recent being Gas Accord V, application A.09-09-013

[8] Staff Report 5397, 1/26/2015: https://www.cityofpaloalto.org/civicax/filebank/documents/45537

Wholesale/Resale Customers (G-WSL) charge to Palo Alto.[9] In December 2016, Council approved a carbon neutral gas plan, with a goal of achieving a carbon neutral gas portfolio by FY 2018.[10] The City's gas utility has been carbon neutral since FY 2018 through the purchase of offsets.

SECTION 4B: CUSTOMER BASE

CPAU's Gas Utility provides natural gas service to the residents, businesses, and other gas customers in Palo Alto. Close to 23,800 customers are connected to the natural gas system, approximately 21,500 (90%) of which are residential and 2,300 (10%) of which are non-residential. In a normal year, residential customers consume about 10 to 11 million therms of gas per year, roughly 40% of the gas sold, while non-residential customers consume 60% (about 15 to 18 million therms). Residential customers use gas primarily for space heating (46% of gas consumed) and water heating (42%), with the remainder consumed for other purposes such as cooking, clothes drying, and heating pools and spas. Non-residential customers use gas for space and water heating (73% of gas consumed), cooking (20%), and industrial processes (6%).[11]

The Gas Utility receives gas at the four receiving stations within Palo Alto where CPAU's distribution system connects with Pacific Gas and Electric's (PG&E's) system. These receiving stations are jointly operated by CPAU and PG&E. CPAU purchases gas from various natural gas marketers, with PG&E providing only local transportation service (transportation from the PG&E City Gate gas delivery hub to Palo Alto). CPAU also has transmission rights on PG&E's transmission pipeline from Malin, Oregon to PG&E City Gate, allowing it to purchase lower priced gas at that location. CPAU does not produce or store any natural gas, and purchases gas in the monthly and daily spot markets. The cost of the purchased gas is passed through directly to customers through a rate adjuster that varies monthly with market (Bidweek) prices. In a similar fashion, the costs for local transportation is tied to PG&E's G-WSL rate schedule, and it varies when and if PG&E changes its rate schedule. The cost of purchased gas and PG&E local transportation service usually account for roughly one third of the utility's expenditures.

SECTION 4C: DISTRIBUTION SYSTEM

To deliver gas from the receiving stations to its customers, the utility owns 210 miles of gas mains (which transport the gas to various parts of the city) and close to 23,800 gas services (which connect the gas mains to the customers' gas lines). These mains and services, along with their associated valves, regulators, and meters, represent the vast majority of the infrastructure used to deliver gas in Palo Alto. CPAU has an ongoing CIP to repair and replace its infrastructure over time, the expense of which normally accounts for around 15 to 20% on average of the utility's expenditures. Costs for main replacements have been going up in recent years.

In addition to the CIP, the Gas Utility performs a variety of maintenance activities related to the system, such as monitoring the system for leaks, testing and replacing meters, monitoring the condition of steel pipe, and building and replacing gas services for buildings being built or

[9] Staff Report 7260 10/17/2016 http://www.cityofpaloalto.org/civicax/filebank/documents/54165

[10] Staff Report 7533 12/05/2016 http://www.cityofpaloalto.org/civicax/filebank/documents/54882

[11] Source: Statewide Commercial End Use Study, California Energy Commission report, 2006. Statistics shown are for end users in PG&E Climate Zone 4 (the Peninsula) where Palo Alto is located.

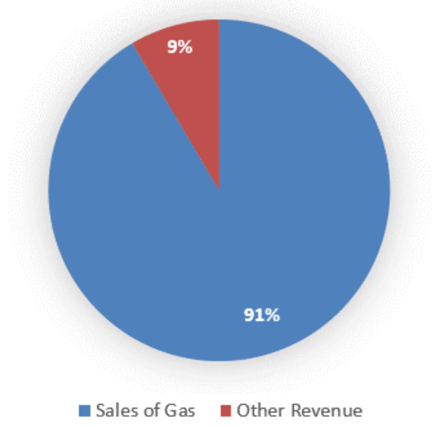
redeveloped throughout the city. The utility also shares the costs of other system-wide operational activities (such as customer service, billing, meter reading, supply planning, energy efficiency, equipment maintenance, and street restoration) with the City's other utilities. These maintenance and operations expenses, as well as associated administration, debt service, rent, and other costs, make up roughly half of the utility's expenses.

In addition to these ongoing activities, CPAU launched a cross-bore safety inspection program to identify and replace cross-bores over the last several years. The estimated expense will be around $0.9 million in FY 2025 and $0.4 million in FY 2026 for the cross-bore program. Operations cost projections assume staff's proposal for the cross-bore funding program is approved. However, if the Council approves a lower level of funding for the program, staff would recommend the same rate trajectory and the operations reserve would recover more quickly to within the minimum guideline range.

SECTION 4D: COST STRUCTURE AND REVENUE SOURCES

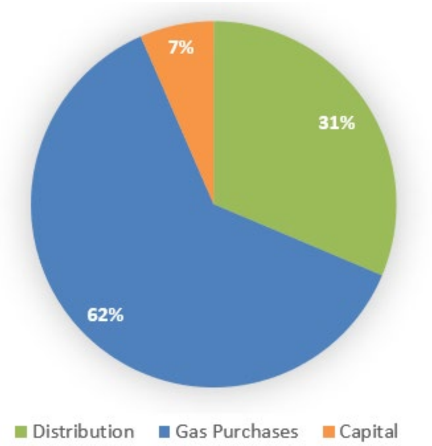
As shown in Figure 1, the Gas Utility receives about 91% of its revenue from sales of gas and the remainder from capacity and connection fees, interest on reserves, and other sources. *Appendix A: Gas Utility Financial Forecast Detail* shows more detail on the utility's cost and revenue structures.

Figure 1: Revenue Structure (FY 2023)



As shown in Figure 2, in FY 2023, gas purchase costs accounted for about 62% of the Gas Utility's costs, about 15% higher than a typical year due to the winter price spike during the 2022/23 winter. This percentage can vary widely from year to year, as this cost is based upon market purchases, and includes costs related to cap and trade. Distribution costs in FY 2023 represented 31% of expenses and capital costs were responsible for the remaining 7%. CIP is on average about 10 to 15% of expenses, but as main replacement projects occur every other year, the percentage swings more.

Figure 2: Cost Structure (FY 2023)



SECTION 4E: RESERVES STRUCTURE

CPAU maintains six reserves for its Gas Utility to manage various types of contingencies and track program spending. The summary below describes each of these briefly. See *Appendix C: Gas Utility Reserves Management Practices* for more detailed definitions and guidelines for reserve management:

- **Reserve for Commitments:** A reserve equal to the utility's outstanding contract liabilities for the current fiscal year. Most City funds, including the General Fund, have a Commitments Reserve.
- **Reserve for Re-appropriations:** A reserve 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.
- **Capital Improvement Program (CIP) Reserve:** The CIP reserve can be used to accumulate funds for future expenditure on CIP projects. This CIP can also act as a contingency reserve for the CIP. This type of reserve is used in other utility funds (Electric, Water, and Wastewater Collection) as well.
- **Rate Stabilization Reserve:** This reserve is 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 (Electric, Water, and Wastewater Collection) as well.
- **Operations Reserve:** This is the primary contingency reserve for the Gas Utility and is used to manage yearly variances from budget for operational gas costs. This type of reserve is used in other utility funds (Electric, Water, and Wastewater Collection) as well.
- **Unassigned Reserve:** This reserve is for any funds not assigned to the other reserves and is normally empty.
- **Cap and Trade Reserve:** This reserve tracks unspent or unallocated revenues from the sale of carbon allowances freely allocated by the California Air Resources Board to the gas utility, under the State's Cap and Trade Program.

SECTION 4F: COMPETITIVENESS

Table 9 presents the median residential bills for Palo Alto and PG&E customers from FY 2022 to FY 2024. In FY 2023, the annual gas bill for the median Palo Alto residential customer was $940, about 4% higher compared to a PG&E customer with equivalent consumption. This is attributed to the gas price spike during the winter of 2022/2023, affecting all California utilities except PG&E, which managed to evade the exceptionally high gas prices.

Looking ahead to FY 2024, the anticipated annual gas bill for the median Palo Alto residential customer is expected to be about 11% lower than that of a PG&E customer with equivalent consumption. PG&E's gas transportation rates continue to rise to fund system improvements for pipeline safety and maintenance.

The bill calculations below for PG&E customers are based on PG&E Climate Zone X, an area which includes the surrounding communities.

Table 8: Residential Natural Gas Bill Comparison ($/month or year)

Time Period	Median Usage (therms)	Palo Alto	PG&E Zone X	% Difference
FY 2022	Annual (400 Thms)	$ 689	$ 776	(13%)
FY 2023		940	904	4%
FY 2024*		753	837	(11%)
FY 2024 Summer*	Monthly (18 Thms)	42	39	7%
FY 2024 Winter*	Monthly (54 Thms)	105	132	(25%)

**Calculated based on actual and projected supply-related costs*

Staff is actively conducting a comprehensive review of commercial customer competitiveness and will provide updates in the future.

SECTION 4G: GAS SUPPLY PASS-THROUGH RATES

The City has four pass-through rates related to supplying gas to customers: 1) gas commodity, which represents the cost of buying gas in the markets, 2) gas transportation, which represents the cost of transporting purchased gas to Palo Alto, 3) Cap and Trade compliance, which represents the cost of mandated participation in the State's cap and trade program, and 4) carbon offset charge, which represents the cost of buying offsets for the City's Carbon Neutral Gas Portfolio. Gas commodity rates are forecasted to decline slightly over the forecast period, but increases in other rate components are forecasted to lead to a net gradual increase in total gas supply costs over the forecast period.

For the gas commodity charge, starting in July 2012, CPAU replaced a "laddering" hedging strategy for purchasing gas supplies with a strategy to buy gas on the short-term, or "spot" markets and pass the commodity cost to customers on a monthly basis. Prior to December 2018, commodity prices had generally fluctuated in a fairly narrow band, averaging around $0.32/therm. Over the last few years, a variety of factors combined that led to more variability in prices: Regional temperatures were cooler than normal, but in addition, gas supplies stored in underground facilities have been lower than normal, as well as constrained due to problems with the Aliso Canyon facility in southern California. There have been periodic pipeline constraints at both the northern and southern California borders. While there was not an actual constriction on supply, the confluence of all these factors drove up the bidweek prices for all California delivery points during FY 2023.

Gas Capped-Price Winter 2023-2024 Gas Purchasing Strategy

On September 18, 2023, Palo Alto City Council adopted a resolution which modified the City's gas purchasing strategy for the winter of FY 2024 in response to the high energy prices that occurred in the winter of FY 2023 which resulted in dramatically high bills for Palo Alto customers. This purchasing strategy is an insurance policy to mitigate the potential for a repeat of high winter gas prices to a maximum $0.15 per therm. It involves purchasing price caps, limiting the price of gas cost $2 per therm for a portion of City's anticipated gas needs.

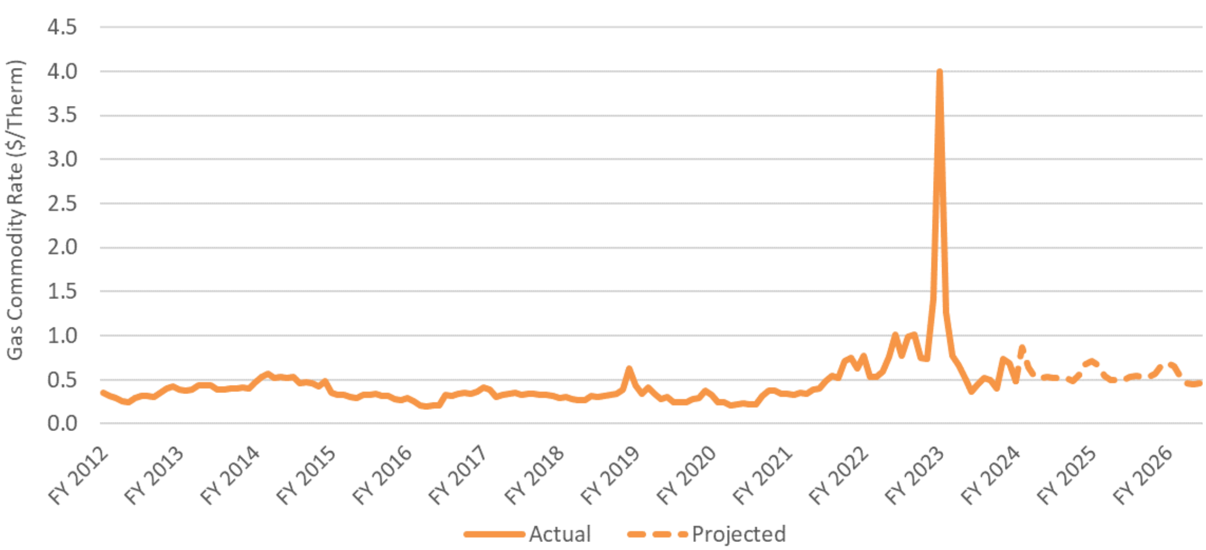
Per Council's decision, staff implemented the capped-price winter natural gas purchasing strategy in October 2023 for the gas year November 2023-October 2024. Within the constraints set by Council, staff was able to purchase $2 per therm price caps for about half of Palo Alto's expected load for the months of December 2023, January 2024 and February 2024. The cost of the price caps was $0.275 per therm and a total cost of $1.5 million. Spread out over the entire year, an adder of $0.055 per therm is applied to the gas commodity charge passed through to customers. This represents approximately $1.81 on a typical residential customer's monthly bill or an approximate 2.8% increase, not taking into account changes in the underlying commodity price which is still based on a market index. The amended rate schedules associated with this implementation were effective November 1, 2023. The City's website and rate schedules were updated to reflect the change in purchasing strategy.

Current Gas Price Projection

After experiencing a notable price spike last winter, natural gas prices have seen a significant decline, returning to more typical ranges. This shift can be attributed to several factors, including milder temperatures nationwide that diminished demand for heating and an above-average level of gas storage. The combination of these factors has put downward pressure on natural gas prices. Looking ahead, it is anticipated that gas prices will maintain a stable level in the long term. This is attributed to diminished demand resulting from electrification efforts and a consistent gas production that exerts a downward pressure on prices. Conversely, the increase in liquefied natural gas (LNG) exports is expected to contribute to pushing prices higher.

Figure 3 shows the City's actual commodity rates through January 2024, and projected rates through FY 2026. Note that while gas commodity costs might be forecasted to decline slightly, increases in other gas supply components (transportation, environmental charges) are expected to offset that, leading to a gradual increase in overall gas supply costs.

Figure 3: Palo Alto Gas Commodity Rates, Actual and Projected, FY 2012 - FY 2026



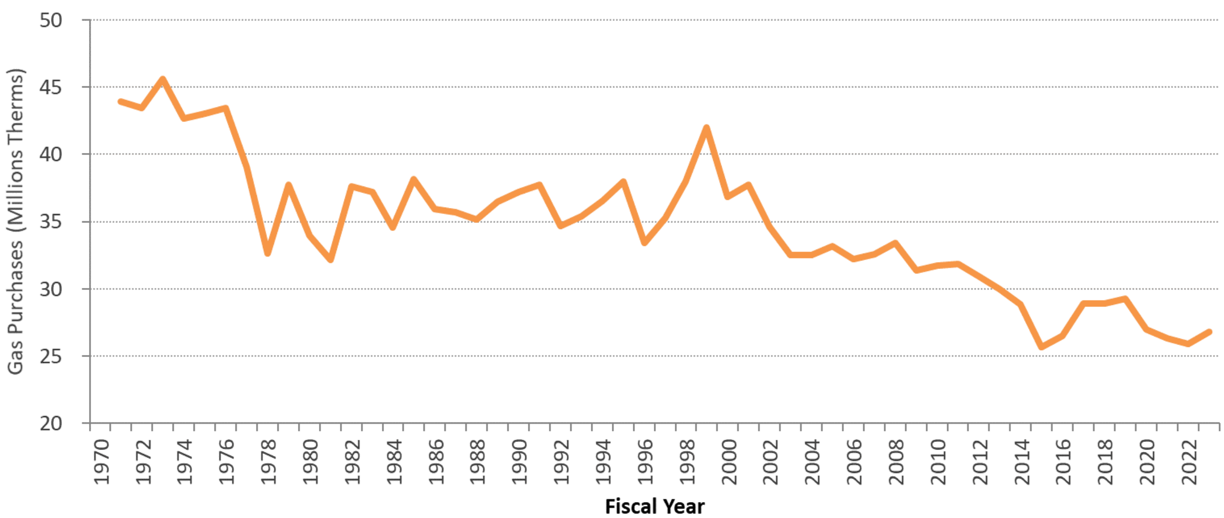
SECTION 5: UTILITY FINANCIAL PROJECTIONS

SECTION 5A: LOAD FORECAST

Gas usage in Palo Alto is volatile, varying with both economic and weather conditions. As shown in Figure 5, in the early 1970s, gas purchases reached over 45 million therms per year. Usage dropped dramatically in the 1976/1977 drought when customers saved significant amounts of (hot) water by upgrading to efficient showerheads. During the 1980s and 1990s average gas usage was around 36 million therms per year. Usage dropped again in the early 2000s. In FY 2001, gas prices escalated during the California energy crisis and Palo Alto's rates increased by nearly 200%. From 2003 to 2011, usage decreased by 2.3% mainly as a result of continued customer investments in energy efficiency.

In 2014 and 2015, unusually warm winters, as well as ongoing drought, caused gas usage to tumble to historic lows. In 2017 and 2018, as the drought eased, gas usage increased again, but appeared to have stabilized. The Covid pandemic resulted in gas usage decreasing again, mainly in the commercial sectors as a result of many businesses operating staff remotely. Gas usage decreased by about 12% in 2020 and 2021, compared with 2019.

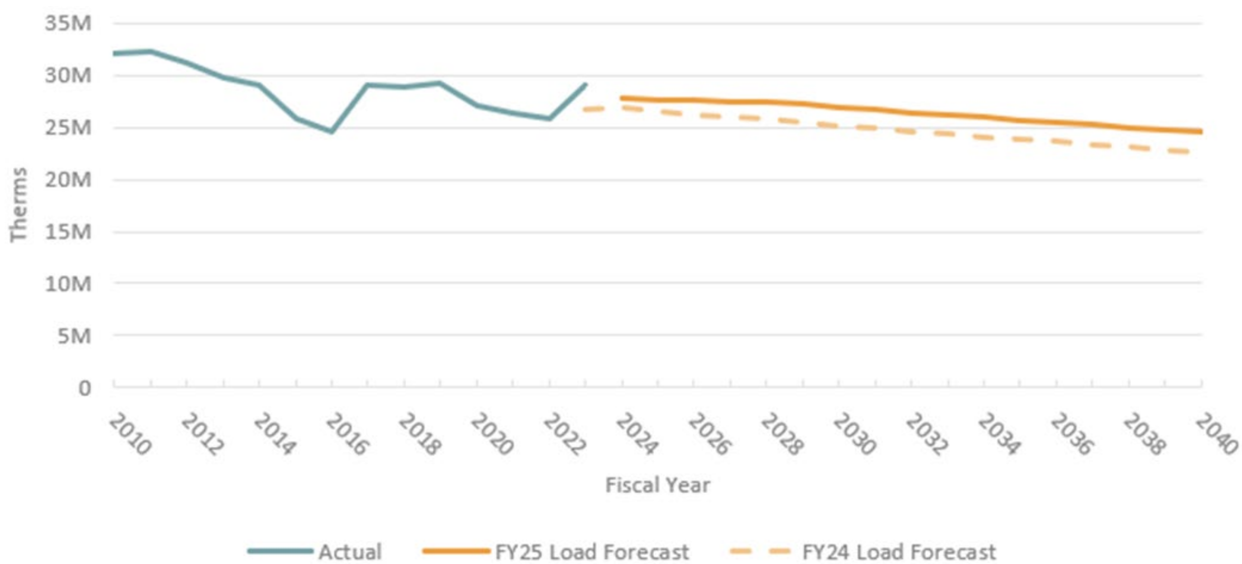
Figure 4: Historical Gas Supply Purchases



Gas usage in Palo Alto declined from FY 2020 to FY 2022, mainly due to the Covid pandemic and drought in California. The increase in gas usage in FY 2023 was likely due to modest usage recovery from Covid and lower than normal average temperature during the winter. However, as seen with prior economic and drought-related gas usage declines in the past, it is likely that consumption will not come back to pre-conservation/pandemic levels but will likely return to a long-run usage decline. Further changes, such as the voluntary replacement of gas appliances with electric appliances, increased building electrification in new construction, and customer behavior are also expected to lower long run usage. In addition, separate strategic planning and financial analysis will be performed separate from this Financial Plan to address a financial and infrastructure strategy for the gas utility during a transition to an electrified community. Any insights from separate analyses will be integrated into future Financial plans.

The latest forecast anticipates gas supply purchases for FY 2025 at 27,711,370 therms, about 4% higher than forecasted in the FY 2024 Financial Plan. This upward projection may have been influenced by increased consumption in FY 2023, which has slightly altered the long-term trend. Long term declining gas consumption will put upward pressure on rates, as a generally increasing cost to operate and distribute gas will be spread across fewer units of sale.

Figure 5: Gas Supply Purchases Forecast



SECTION 5A: FY 2019 TO FY 2023 COST AND REVENUE TRENDS

Figure 7 and *Appendix A: Gas Utility Financial Forecast Detail* show how costs have changed during the last five years as well as how staff project costs to change over the next five years.

While the gas utility strives to maintain a steady rate of funding for main replacement over time, this funding pattern was disrupted from FY 2015 to FY 2020. In FY 2015, no funding for gas main replacement was budgeted due to the fact that staff was completing a prior major gas main replacement project, the largest in utility history, which completed replacement of most of the ABS gas mains in Palo Alto. The next main replacement to be budgeted involved replacements of gas mains on University Avenue, a project that evolved into the Upgrade Downtown project involving a coordinated replacement of several different types of infrastructure to avoid multiple disruptions to the business district. This multi-year planning effort did not allow for design of other new projects, and the hiatus in starting a new main replacement project allowed the Gas Utility to temporarily keep rates lower. In FY 2021 the gas utility returned to routine funding for main replacement for the gas utility, though gas main replacement investment is likely to become more complex as the City plans for a transition to an electrified community.

Revenues have fluctuated but generally matched expenses in the years between FY 2019 and FY 2023. The absence of new budget for main replacement projects for several years, as well as the availability of relatively large reserves, reduced the need for rate increases until FY 2019.

The last adjustment to gas distribution rates was a 8% increase to the total system average gas rate (supply rates plus distribution rates) in July 2023. The commodity cost and revenue increases in FY 2023 were the result of higher market commodity prices, as shown in Figure 3 in Section 4G. Gas supply costs are passed through to customers, and change month to month with a cap of $4/therm.

Figure 7 shows the actual overall system average rate change from FY 2019 through FY 2024 (shown in grey) and the projected overall system average rate change for FY 2025 through FY 2029 (shown in red) both excluding supply-related rate changes. The rate increases only include the needed increase for the distribution rate as a percentage of the base gas utility sales revenue.

Figure 6: Gas Utility Expenses, Revenues, Rate Changes Excluding Supply-Related Changes
Actual Costs through FY 2023 and Projections through FY 2029

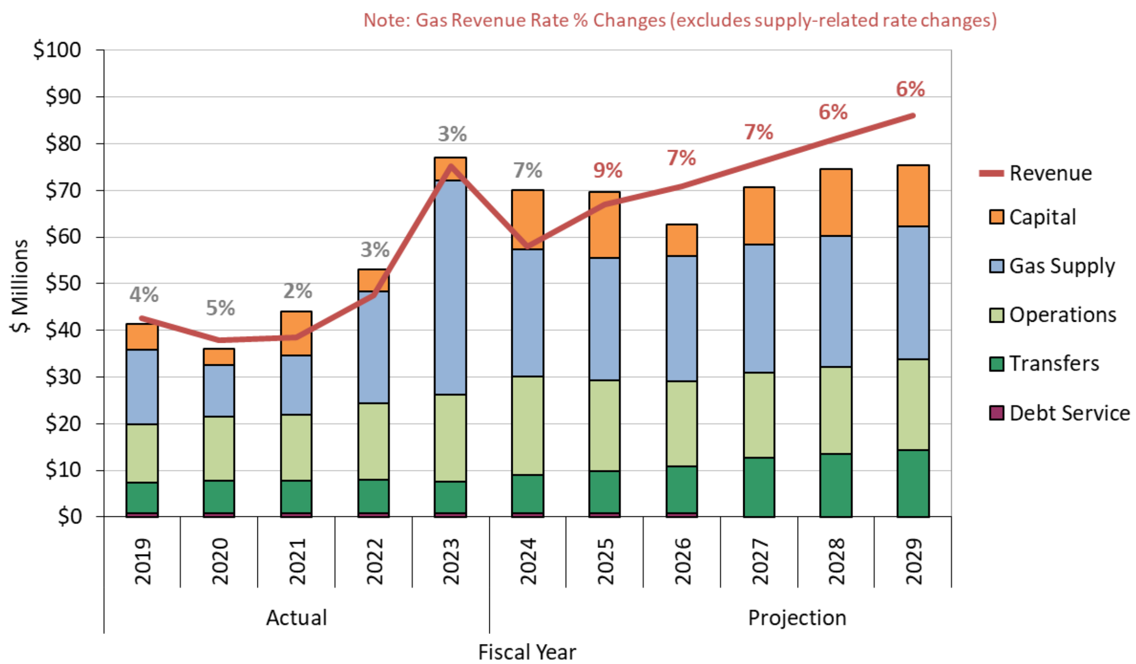
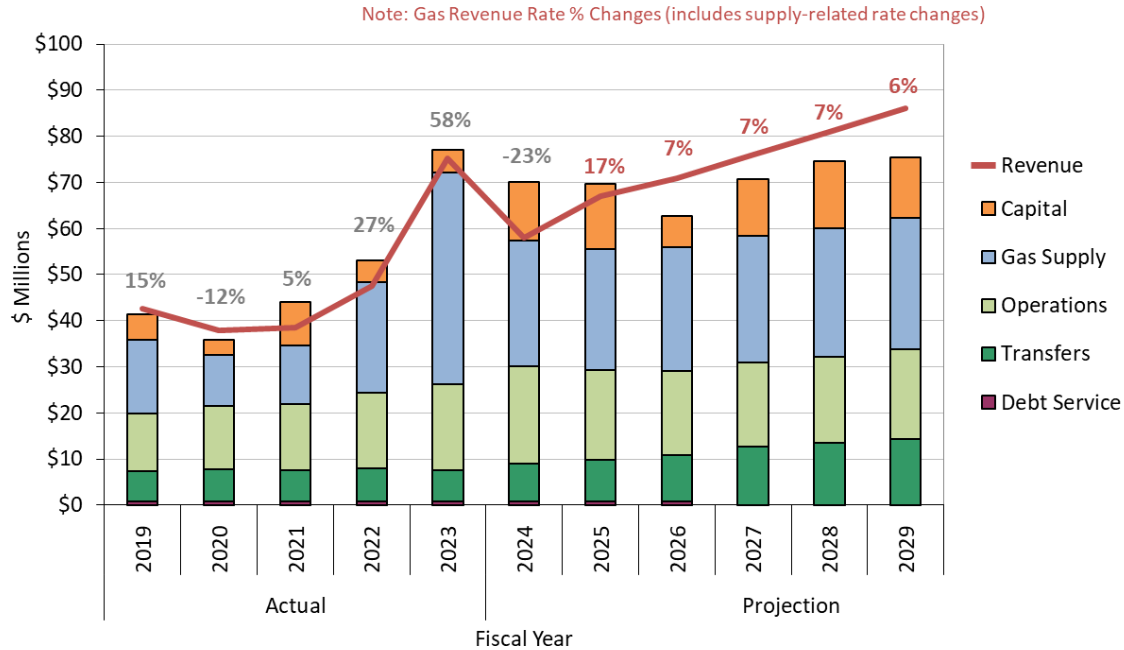


Figure 8 shows the actual overall system average rate change from FY 2019 through FY 2024 (shown in grey) and the projected overall system average rate increase for FY 2025 through FY 2029 (shown in red) including supply-related rate changes. The rate changes include the overall change in the rate as a percentage of the prior year's base sales revenue for the gas utility. These rate changes are sensitive to supply price spikes and as the commodity prices increased in FY 2022 and FY 2023, rate changes including supply related changes increased greatly. As commodity prices declined in FY 2024, this measure of rate changes dropped and then in FY 2025 is readjusting to more normal commodity prices and increasing distribution rates to cover costs.

Figure 7: Gas Utility Expenses, Revenues, Rate Changes Including Supply-Related Changes
Actual Costs through FY 2023 and Projections through FY 2029



SECTION 5B: FY 2023 RESULTS

Sales revenues were higher than projected in the FY 2023 Financial Plan by about $5.6 million, due to higher revenue from high gas commodity rates and higher gas usage, but other sources of funds were lower by $0.7 million due to lower service connection and capacity fees revenue. On the expense side, supply costs were about $2.1 million lower than projected due to lower market commodity costs and deferring of carbon offset purchases to FY24. Operational expenses were about $1.4 million lower than projected, due to lower operating administrative charges and lower cross-bore costs. Total FY 2023 expenses were $74 million compared to $83 million projected in the FY 2024 Financial Plan. Table 10 summarizes the variances from forecast.

Table 9: FY 2023 Actual Results vs. FY 2024 Financial Plan Forecast ($000)

	Net Cost/ (Benefit)	Type of Change
Sales increased due to higher usage and higher commodity prices	(5,647)	Revenue Increase
Lower interest income and non-sales revenues	741	Revenue Decrease
Lower gas purchase costs, offset deferred to FY24	(2,130)	Cost Decrease
Lower administration costs	(1,410)	Cost Decrease
Net Cost / (Benefit) of Variances	**(8,447)**	

SECTION 5C: FY 2024 PROJECTIONS

Overall costs for the Gas Utility are expected to be 11% lower in FY 2024 compared with FY 2023, due to the reduction in supply costs from the unprecedented winter price spike in FY 2023.

Current projections indicate that sales revenues will be lower than last year's forecast by about $5.9 million, due to lower consumption and commodity costs. Other revenues and transfers are projected to be higher by about $0.7 million. Gas purchase costs are projected to be $2.6 million lower due to lower than expected market commodity prices. Table 11 summarizes the projected variances from the FY 2024 Financial Plan.

Table 10: FY 2024 Projected Results vs. FY 2024 Financial Plan Forecast ($000)

	Net Cost/ (Benefit)	Type of Change
Sales decrease due to lower usage and lower commodity prices	5,937	Revenue Decrease
Lower connection & capacity fees but higher transfers in	(700)	Revenue Increase
Lower gas purchase costs but higher transportation costs	(2,553)	Cost Decrease
Collection and CIP costs projected to be about the same	30	Cost Increase
Net Cost / (Benefit) of Variances	**2,714**	

SECTION 5D: FY 2025-FY 2029 PROJECTIONS

Figure 7 above shows overall costs for the Gas Utility is expected to be slightly lower in FY 2025 compared with FY 2024, due to the reduction in supply costs but higher CIP costs. However, overall costs are expected to increase by 5% annually on average throughout the rest of the forecast period.

Gas commodity costs are the most variable component and represented the largest in costs in FY 2023. But commodity costs have stabilized in FY 2024 and are expected to gradually decline throughout the forecasting period. However, significant increases in transportation and environmental costs will offset the decrease in commodity costs. Staff projects Cap-and-Trade allowance costs will increase by 11% annually[12], transmission costs to increase steadily by about 4% annually[13], and Carbon offset costs are projected to increase by 10% annually throughout the forecasting period.

Staff anticipates annual capital expenditures will fluctuate during the forecast period due to planning for larger main replacement construction projects every other year instead of smaller projects annually. This main replacement schedule allows CPAU to meet its main replacement needs while addressing challenges in the current construction market and optimizing current staffing resources. Staff also anticipates additional costs from gas decommissioning projects and will set aside appreciate budget in the forecasting period. Overall CIP costs are expected to increase by around 9% on average annually from FY 2025 through FY 2029.

General inflationary increases for operating expenses are around 3-5% annually. Salaries and benefits expenses are projected to rise at 3-4% annually, per similar assumptions used in the City's Long-Range Financial Forecast.

[12] Based on allowance broker quotes.

[13] The transportation rates for calendar years 2023-2026 reflect the rates in the December 15, 2021 prepared testimony (A.21-09-018) regarding PG&E's 2023 Gas Transmission & Storage (GT&S) Cost Allocation and Rate Design (CARD), afterward a 3% escalation rate is applied.

As shown in Figure 9, the FY 2024 and FY 2025 reserve levels will be recovering from the sharp rise in commodity costs in FY 2023 and increasing CIP costs. By FY 2025, staff expects gas fund costs to align more closely with revenues and this will allow the Operations Reserve to begin to replenish.

At the end of FY 2024 there were balances in the Operations and CIP Reappropriations and Commitments Reserves, which is common because capital projects often cover multiple years. Figure 9 shows an assumption that the level of funding in the Operations and CIP Reappropriations and Commitments Reserves will be spent, split between FY 2024 and FY 2025.

Figure 10 shows the CIP Reserve has reduced to zero by the end of FY 2023. Once the Operations Reserve is replenished above minimum levels, staff will plan transfers to replenish the CIP Reserve, which is expected will begin in FY 2026 and should able the reserve to recover above minimum guideline level by FY 2027. Per the Reserves Management Practices (Appendix C), Section 6, any rate plan that does not return CIP reserves above minimum levels within one year requires Council approval.

Staff is planning to replenish the Supply Rate Stabilization and CIP Reserves from the Operations Reserve to stabilize rates and fund capital improvements. This approach will provide stability to the Operations Reserve by providing for a steady funding stream for CIP work and by reflecting fluctuations due to CIP such as project delays or accelerations in the CIP Reserve; ultimately, this should result in more stable customer rates. Conversely, other trends or factors affecting the Operations Reserve will be easier to identify and communicate. Without this change, both CIP costs and revenues flow solely through the Operations Reserve.

Figure 8: Gas Utility Reserves
Actual Reserve Levels for FY 2023 and Projections through FY 2029

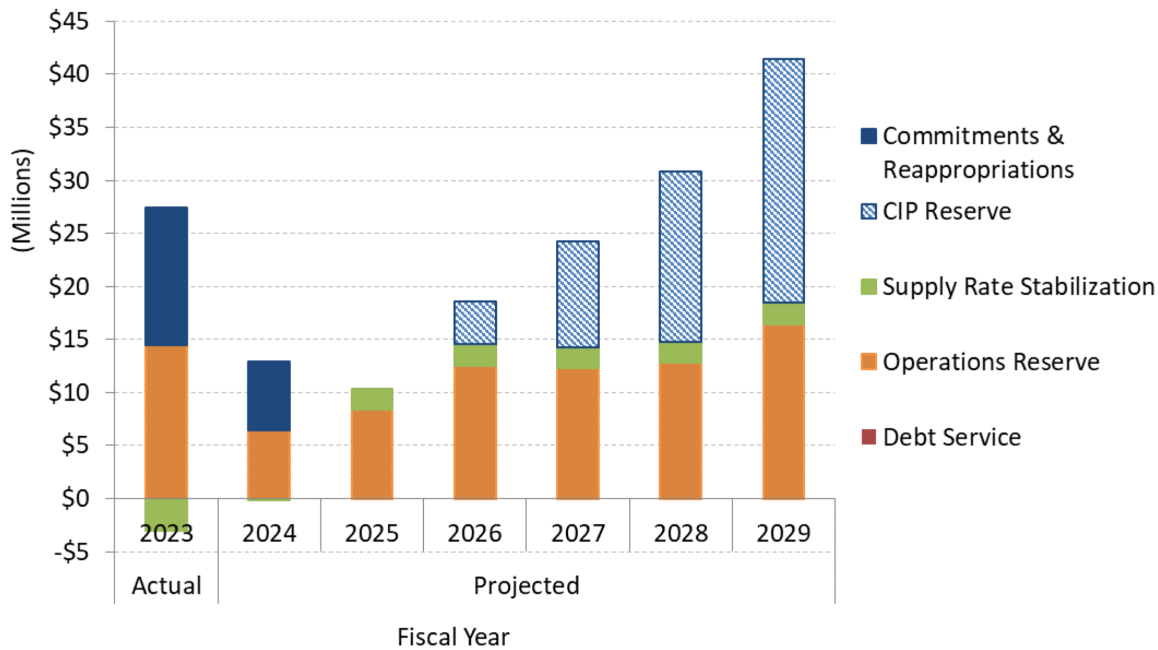
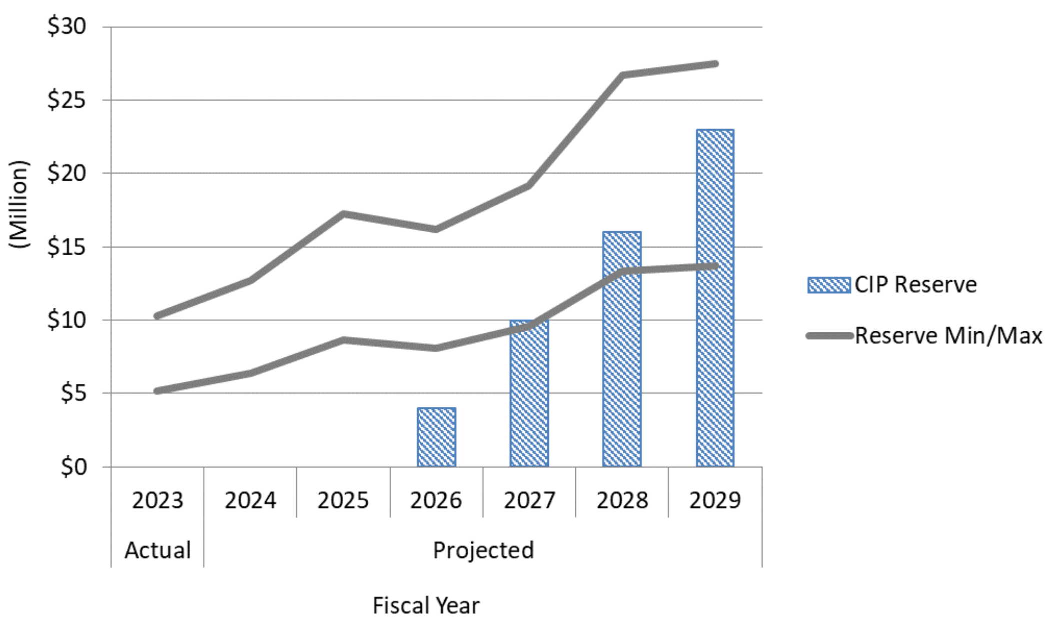


Figure 9: Gas CIP Reserve Levels for FY 2023 through FY 2029



SECTION 5E: RISK ASSESSMENT AND RESERVES ADEQUACY

As noted earlier, unprecedented high gas prices in FY 2023 and higher than expected CIP costs has significantly impacted the gas utility's reserves, and multi-year double-digit distribution rate increases would be required to return reserves to within guidelines. Staff predicted in the FY 2024 Financial Plan that the Gas Operations Reserve will be below the risk assessment levels in FY 2024 and FY 2025 and below the minimum guideline in FY 2026. Staff currently projects the same trajectory, except the Operations Reserve is expected to be above minimum guideline by the end of FY 2026, then return to reserve range by the end of FY 2029. Per the Reserves Management Practices (Appendix C) any rate plan that involves returning the Operations Reserve to within guideline levels in more than one year requires Council approval. Figure 11 shows the Operations Reserve alongside the guideline levels.

Figure 10: Operations Reserve Adequacy

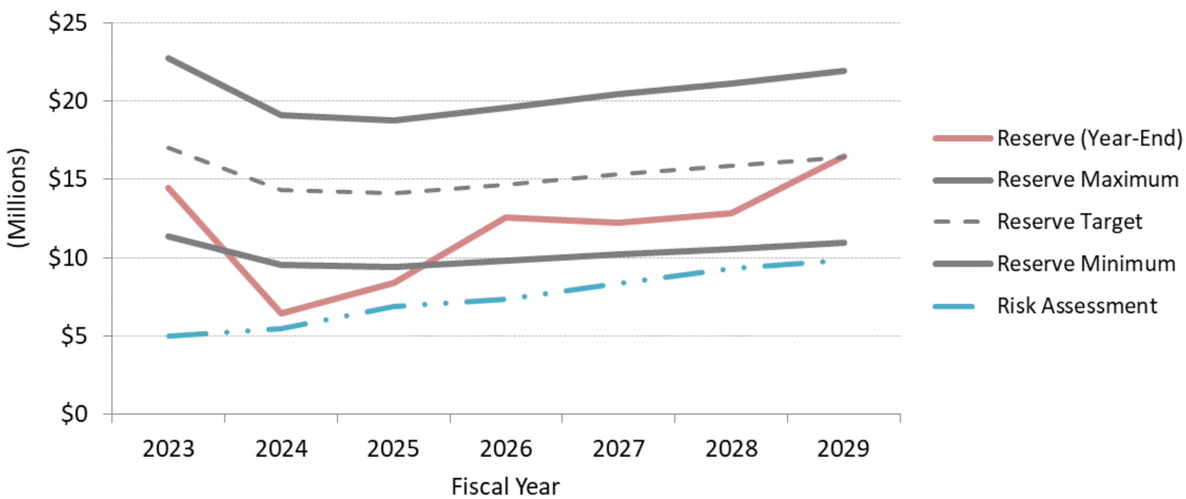


Table 12 summarizes the risk assessment calculation for the Gas Utility through FY 2029. The risk assessment includes the revenue shortfall that could accrue due to:

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

Table 11: Gas Risk Assessment ($000)

	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Total non-commodity revenue	30,227	38,237	42,670	47,298	51,897	56,305
Max. revenue variance (last 10 yrs)	16%	16%	16%	16%	16%	16%
Risk of revenue loss	4,836	6,118	6,827	7,568	8,304	9,009
CIP Budget	6,252	7,875	5,316	7,765	9,784	8,505
CIP Contingency @10%	625	788	532	777	978	850
Total Risk Assessment value	5,462	6,905	7,359	8,344	9,282	9,859

SECTION 5F: LONG-TERM OUTLOOK

It is difficult to predict commodity costs in the long-term as a variety of trends can impact them positively or negatively. For example, advancements in gas extraction technology like fracking has led to increased supplies of gas, but also face increased scrutiny for their environmental effects. Additionally, factors such as pipeline capacity for transporting natural gas, storage levels impacted by weather and changes in demand, and injection or withdrawal activity also play a role in determining commodity costs. On the demand side, a continued shift from coal to natural gas for electricity generation, an expansion of liquified natural gas export capabilities, or an increase in manufacturing in the U.S. might drive up natural gas prices, but other factors, such as an increased drive towards electrification, might drive gas demand lower. The State's cap-and-trade program also introduces additional uncertainties in predicting the long-term cost impacts on natural gas. The California Air Resource Board (CARB) is currently modeling alternatives to the range of potential emissions outcomes, which might affect future allowance allocations and price projections, therefore, assessing the magnitude of these cost impacts is challenging and requires ongoing monitoring of regulatory developments. In the face of this uncertainty, CPAU is able to protect the financial position of the Gas Utility by continuing its current strategy of passing these costs directly to its customers via month-varying rate adjustment mechanisms. The City introduced a price cap insurance product in the winter of FY 2024 and will also plans to evaluate future winter hedging program as needed. The City also pursues a policy of purchasing offsets to make gas usage in Palo Alto carbon neutral. The cost is not to exceed $0.10/therm.

Future CIP investment needs for the Gas Utility may be lower than in the past, although costs per foot for main replacement have increased substantially. CPAU is continuing to study and develop its future main replacements priorities and strategy. If customers transition away from natural gas, it will become necessary to scale back the rate of replacement of the existing gas system, but this will also require increased investment in electrification and gas decommissioning. However, staff believes it is necessary to continue the current efforts to replace older and higher-risk materials within the gas system to maintain safety and system integrity. This investment is recommended until a more defined plan on electrification and the transition away from natural gas is completed. The priority for the gas utility fund is continued safe operation to manage the overall risk and continue the reliable and safety delivery of natural gas throughout the City.

Long-term state or local climate goals will also have a major impact on the Gas Utility. The Global Warming Solutions Act, Assembly Bill 32, set a goal of reducing greenhouse gas (GHG) emissions to 1990 levels by 2020. In its December 2007 Climate Protection Plan, the City set a goal of lowering emissions to 15% below 2005 levels by 2020. As a community Palo Alto achieved these goals in 2012 even with continued use of natural gas for heating, cooking, and industrial processes. However, to achieve the recently adopted Sustainability and Climate Action Plan (S/CAP) goal of an 80% reduction in carbon emissions by 2030, or the State's adopted goal of an 80% reduction in emissions by 2050, extensive electrification of gas-using appliances is necessary. Extensive electrification could result in stranded investment and higher rates as the costs of the distribution system are recovered over a lower sales base. It is instructional that, in the recent discussion draft of its scoping plan update, CARB says, to meet those goals, natural gas use would have to be "mostly phased out."[14] Staff has begun to evaluate how to manage potential impacts of these trends. Staff expects gas utility costs associated with electrification including safely decommissioning gas pipes. This Financial Plan includes $4 million for gas decommissioning in the CIP budget for FY 2028 and additionally includes annual placeholders of $3 million for electrification and related costs each year from FY 2027 through FY 2029, although detailed cost estimates are not yet available. These costs will be refined as staff studies them in more detail,

[14] *Climate Change Scoping Plan, First Update, Discussion Draft for Public Review and Comment*, California Air Resources Board, October 2013, pg. 88.

and alternative funding sources may be required. The S/CAP Goals and Key Actions and Work Plan will include strategic planning for the gas utility for managing the transition to an electrified community, and this is also a strategic planning priority for the Utilities Department.

SECTION 5G: ALTERNATIVE GAS INCREASE PLANS

The gas utility's transfer to the City's General Fund is a component of the City's gas rates. City voters first authorized the transfer in 1950, and in November 2022 voters approved Measure L, affirming the continuation of this practice by amending the Municipal Code. Specifically, section 2.28.185, "Natural Gas Utility Transfer" states:

> Each fiscal year the City Council may transfer from the natural gas utility to the general fund an amount equal to 18% of the gross revenues of the gas utility received during the fiscal year two fiscal years before the fiscal year of the transfer. At its discretion, the City Council may decide to transfer a lesser amount. The projected cost of the transfer shall be included in the City's retail natural gas rates as part of the cost of providing gas service.

This Financial Plan proposes an 11.9% or $8,959,629 million transfer for FY 2025, which follows from Council's direction in FY 2024 to transfer a lesser amount and gradually increase the transfer up to 18%.

Staff proposes to transfer 11.9% of gross revenue in FY 2025 due to the substantial commodity revenues generated in FY 2023. FY 2023 was the year most affected by the high commodity prices, which led to high commodity revenues that year. Therefore staff proposes transferring less than 18% of FY 2023 gas utility gross revenues, which is the basis for the FY 2025 transfer amount. Staff anticipates requesting Council approval to transfer 16.5% of FY 2024 gas utility gross revenue in FY 2026 and 18% of FY 2025 gas utility gross revenue in FY 2027. This allows a steady rise to 18% in FY 2027. Alternatively, the Council may choose to transfer 18% of gas utility gross revenue each year starting in FY 2025. Both alternatives align with the voter-approved changes codified in PAMC 2.28.185.

Table 13 below shows the amount of the transfer both in dollars and as a percentage of utility revenue for each fiscal year, as well as the projected rate of annual growth in the transfer. Table 14 below shows the distribution rate increases (as a percentage of the total bill, excluding supply cost changes) associated with each alternative.

Table 12: Proposed / Projected and Alternate Transfers as % of Gross Revenues Two FY Prior[15]

	Approved (Council Resolution 10101)	Proposed / Alternate	Projected	
	FY 2024	**FY 2025**	**FY 2026**	**FY 2027**
Gas Utility Gross Revenue Two Fiscal Years Prior ($000)				
	$49,721	$75,291[16]	$61,032	$70,414[17]
				$73,618
Percent of gas utility gross revenue to transfer				
	15.5%	**11.9%**	16.5%	18%
		18%	18%	
Transfer amount ($000)				
Transfer 11.9%	$7,707	$8,960	$10,070	$12,674
Transfer 18%		$13,552	$10,986	$13,251
Change in Transfer Amount from Prior Fiscal Year (%)				
	7%	16%	12%	26%
		76%	-19%	21%

Table 13: Summary of Rate Changes for Alternatives (Excludes Supply Rate Changes)

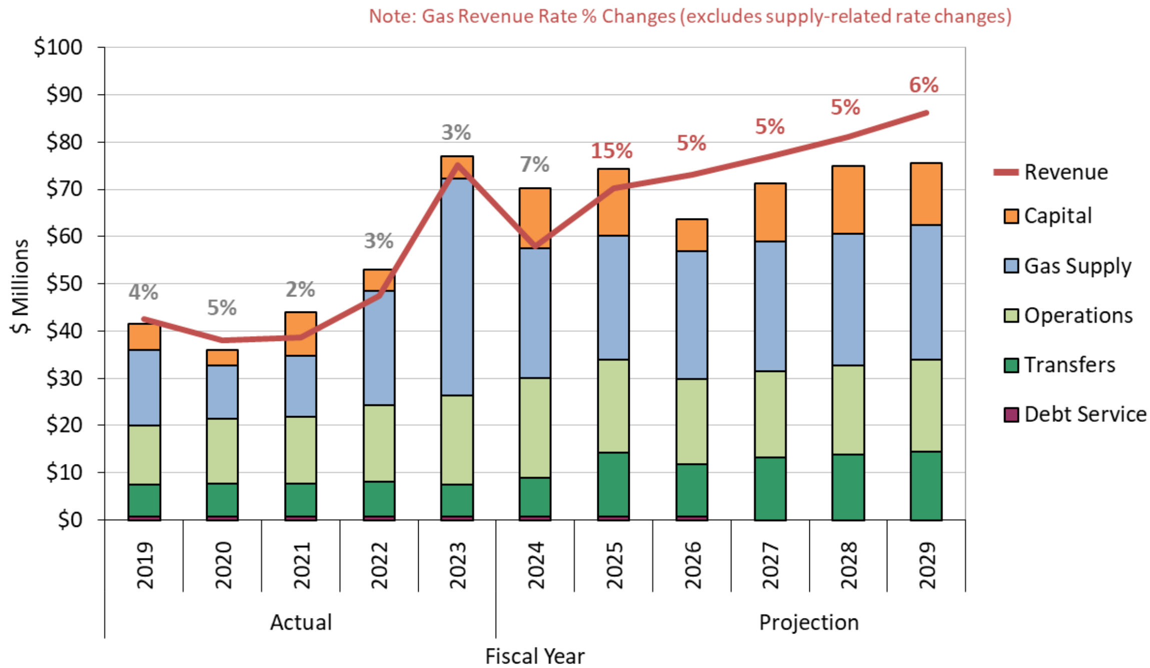
	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Transfer 11.9%	9%	7%	7%	6%	6%
Transfer 18%	15%	5%	5%	5%	6%

Figure 12 shows the Gas Utility's Expenses, Revenues and Rate Changes excluding the supply related rate changes at the General Fund 18% Transfer alternative.

[15] Measure L authorizes a transfer based on 18% (or a lesser percentage if approved by Council) of the revenue for two fiscal years prior, so the FY 2024 transfer is based on FY 2022 revenue.
[16] Represents actual gas utility gross revenues for FY 2023.
[17] There are two values for gross revenue in FY 2027 because there are two possible rate trajectories shown in Table 3 that would impact the forecasted revenue for FY 2025 (two fiscal years prior to FY 2027); the first would increase rates by 9% in FY 2025 leading to forecasted revenues of $70.414 million and the second would increase rates by 15% in FY 2025 leading to forecasted revenues of $73.618 million.

Figure 11: Gas Utility Expenses, Revenues, and Rate Changes Excluding Supply-Related Rate Changes (Transfer 18%)

Actual Costs through FY 2023 and Projections through FY 2029

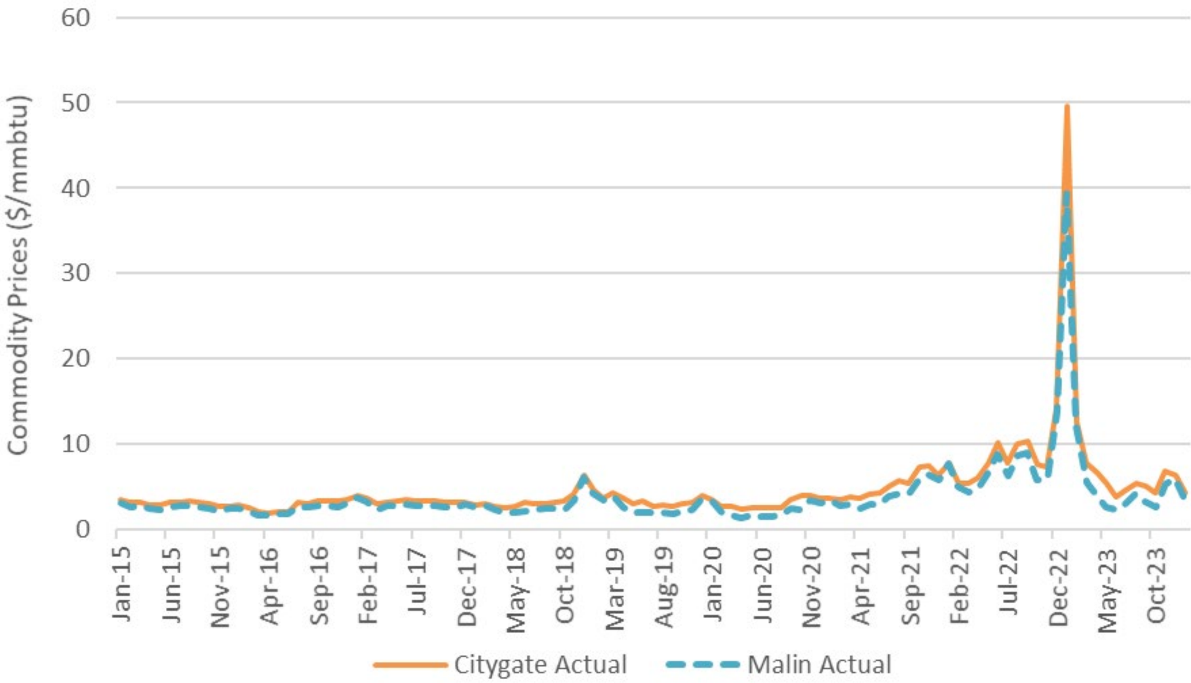


SECTION 6: DETAILS AND ASSUMPTIONS

SECTION 6A: GAS PURCHASE COSTS

The Gas Utility purchases much of its gas for delivery at Malin, Oregon which is almost always less expensive than delivery at PG&E Citygate, even including the costs of transmission from Malin to Citygate. The Gas Utility purchases gas on a month-ahead and day-ahead basis in the spot market. The years from FY 2009 through FY 2022 have seen gas prices in a relatively narrow but low band. Starting in late 2021, and becoming more acute starting in the summer of 2022, lower levels of natural gas in storage, along with colder than normal weather and transmission pipeline constraints on both the northern and southern borders of California has created short-term price spikes and increased volatility, as shown in Figure 13. These market conditions exacerbated and caused unprecedented price spikes during the winter of FY 2023 when Citygate prices reached as high as $49.52 on the monthly index and up to $57.07 on the daily index. Since the price spike, gas prices have stabilized, however, high amounts of volatility and uncertainty still remain in the market.

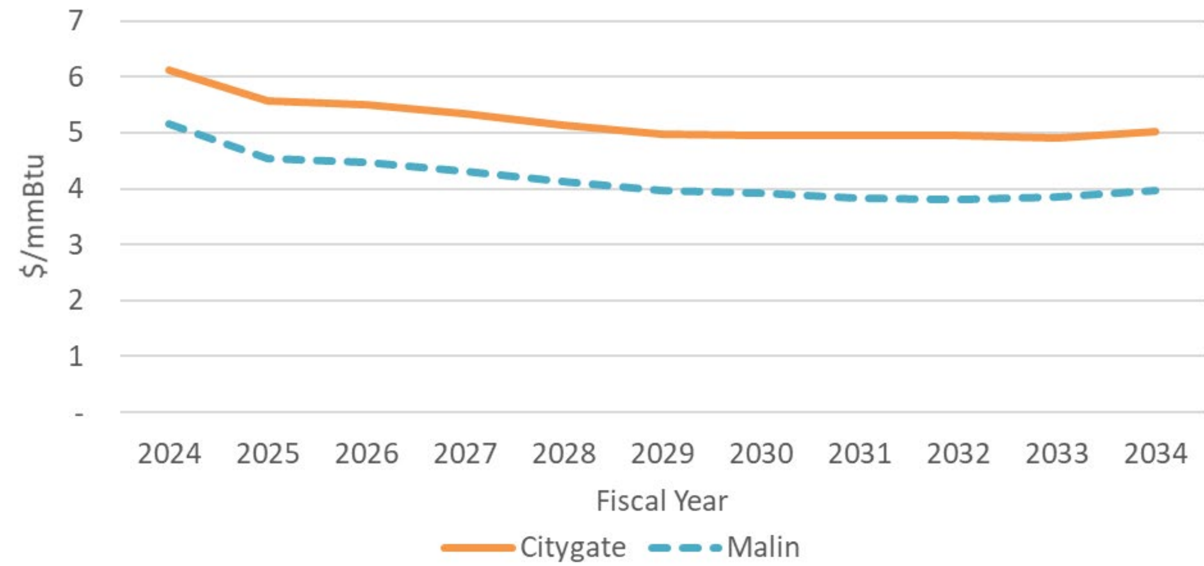
Figure 12: Gas Commodity Monthly Market Prices at Malin and PG&E Citygate



On September 15, 2014, Council adopted a resolution (Reso. #9451) authorizing the City's participation in a natural gas purchase from Municipal Gas Acquisition and Supply Corporation (MuniGas) for the City's entire retail gas load for a period of at least 10 years. The MuniGas transaction includes a mechanism for municipal utilities to utilize their tax-exempt status to achieve a discount on the market price of gas. As of November 1, 2018, gas began flowing under this program, reducing the City's gas commodity cost by about $1 million per year and saving gas customers approximately $0.03 per therm on the commodity portion of their bills.

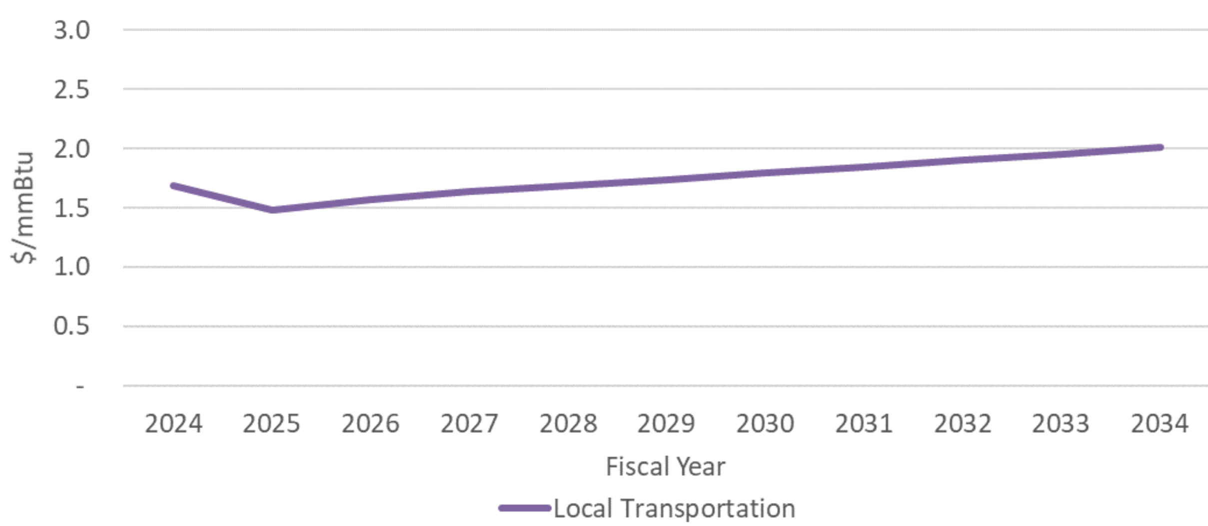
Gas commodity costs are forecasted to stay fairly steady over the next several years, but forecasts of commodity costs are very uncertain. Figure 14 shows the projected gas prices used to generate this forecast. Projections for transmission costs associated with transporting gas over PG&E's Redwood transmission pipeline (from Malin, Oregon to the PG&E Citygate) are based on rates adopted in the most recent update to the Gas Accord.

Figure 13: Annual Average Wholesale Gas Market Price Projections



PG&E's Local transportation rates have increased over the past few years and are projected to slowly increase annually in future years. Figure 15 shows the average annual PG&E gas transportation rates with the Cap-and-Trade exemption rates, projected up to FY 2034.

Figure 14: PG&E Gas Local Transportation Rates, Actual and Projected



For Cap and Trade compliance costs, the gas utility has been regulated under California's greenhouse house (GHG) regulations since January 2015 with a GHG emissions cap that declines over time. The gas utility receives carbon allowances equal to the emissions allowed under the cap and is required to auction off a portion (65% in 2023, increasing by 5% annually) of the allowances through the state Cap and Trade Program. To meet its annual GHG compliance obligation, the gas utility must purchase allowances based on actual gas load. Proceeds of allowance sales must be used within 10 years of their receipt. Palo Alto has started allocating funds from the Cap and Trade reserves to fund Heat Pump Water Heater related programs in FY 2024.

The auction price to either purchase or sell allowances also increases annually by 5% plus inflation. Given the rate of increased allowance purchases and the increasing market prices, these costs are anticipated to increase from $2.2 million in FY 2023 to $7.3 million in FY 2030, about an 19% increase per year on average.

The City also has a Carbon Neutral Natural Gas plan (Staff Report 7441[18]) whereby carbon offsets are purchased in an amount equal to the emissions generated by the communities' natural gas use. These high-quality carbon offsets support projects that reduce the amount of GHGs in the atmosphere, such as forest maintenance or capturing methane from dairy farms. Purchasing carbon offsets is a good first step towards reducing carbon in the atmosphere, but the longer-term goal is to reduce the community's use of natural gas by maximizing efficiency and switching to high-efficiency electric appliances where possible. Due to staff constraints, FY 2023 offset purchases were deferred to be purchased in FY 2024. The costs for these offsets are projected to increase from $1.2 million in FY 2024 to $3.1 million in FY 2029.

SECTION 6B: OPERATIONS

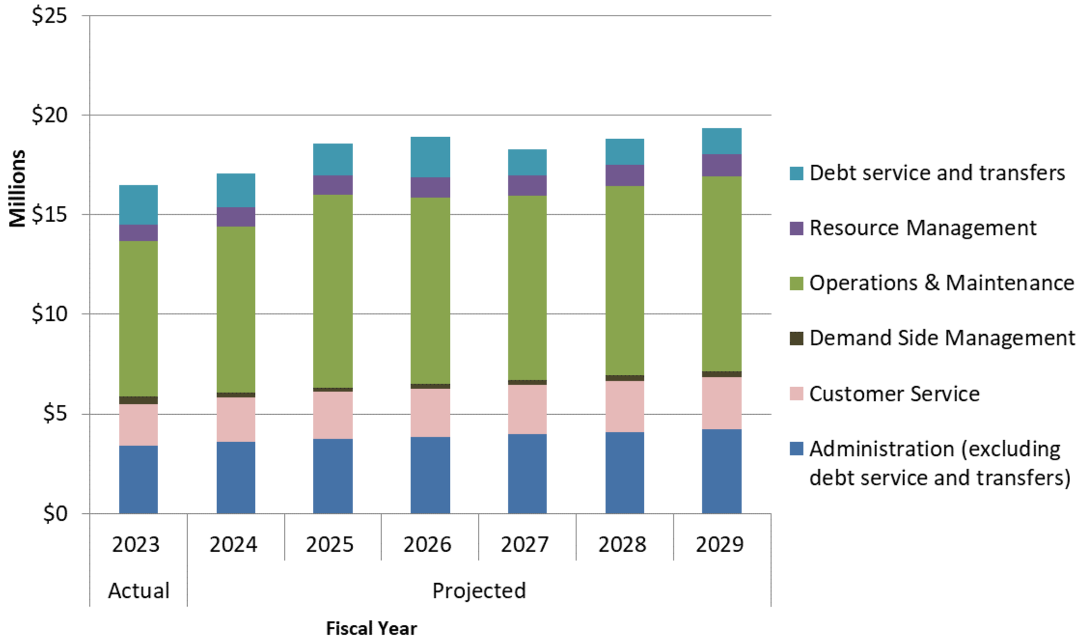
Operations costs include the Customer Service, Demand Side Management, Operations and Maintenance (including Engineering), Resource Management, and Administration categories in Figure 16, below. Debt service, rent, and transfers are also included in Operations costs (excluding the General Fund equity transfer). *Appendix D: Description of Gas Utility Cost Categories* includes detailed descriptions of the activities associated with these cost categories. Operations costs are generally projected to increase by 3 to 5% per year on average. Salary and benefits, inflation, and other assumptions match those used in the City's long-range financial forecast as closely as possible.

Operations costs include funding for the cross-bore program. In the 1970s CPAU, like many other utilities, adopted horizontal drilling as an alternative to trenching when installing new gas services. This created the possibility of cross-bores, which can happen when a gas service is bored through a sewer lateral. Though cross-bores are very rare, they can create a dangerous situation when a contractor attempts to clear a blocked sewer line, because if the cross-bored gas service is damaged during the line, clearing it can result in a gas leak. CPAU has been inspecting new gas services since 2001, and in 2011 began video inspections of the sewer laterals at the location of horizontally-drilled gas services installed before 2001. This inspection program cost roughly $1 million per year since FY 2012 and decreased in FY 2023 with the completion of Phase III of the cross-bore inspection project. While a majority of sewer laterals have been inspected, staff has come across several services which are not able to be scoped, either due to infiltration by roots or broken/collapsed pipe segments. CPAU planned to find and replace cross-bores over the last several years. This Financial Plan includes the estimated expense of $0.9 million in FY 2025 and $0.4 million in FY 2026 for the cross-bore program. However, if the Council approves a lower level

[18] https://www.cityofpaloalto.org/civicax/filebank/documents/54588

of funding for the program, staff would recommend the same rate trajectory and the operations reserve would recover more quickly to within the minimum guideline range.

Figure 15: Actual and Projected Operational Costs



SECTION 6C: CAPITAL IMPROVEMENT PROGRAM (CIP)

The Gas Utility's CIP consists of the following programs and budgets:

- The Gas Main Replacement Program, under which the Gas Utility replaces aging gas mains and mains ranked to have the greatest risk scores within the system in accordance with the City's Distribution Integrity Management Plan (DIMP).
- Customer Connections, which cover the cost when the Gas Utility installs new services or upgrades existing services at a customer's request. The Gas Utility charges a fee to these customers to cover the cost of these projects.
- Ongoing Projects, which cover the cost of routine meter, regulator, and service replacement, minor projects to improve reliability or increase capacity, and other general improvements.
- Tools and Equipment, which cover the cost of capitalized equipment, such as directional boring, gas pipeline maintenance and emergency equipment.
- One-time Projects, which represent occasional large projects that do not fall into any other category.

Table 15 shows the current status of these project categories and future projected spending.

Table 14: Budgeted Gas CIP Spending ($000)

Project Category	2024 Budget*	2025	2026	2027	2028	2029
Gas Main Replacement	13,295,809	6,775,000	4,443,664	6,665,496	4,936,537	7,404,806
Gas Tools and Equipment	100,000	100,000	100,000	100,000	100,000	100,000
Ongoing Projects	1,784,075	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000
Customer Connections	887,698	700,000	700,000	700,000	700,000	700,000
Electrification Transition	-	-	-	-	4,000,000	-
TOTAL	16,067,583	8,575,000	6,243,664	8,465,496	10,736,537	9,204,806

*Includes unspect funds from previous years carried forward or reappropriated into thte current fiscal year

Gas Main Replacements

The Gas Main Replacement (GMR) Program is the largest budgeted category in the gas fund and is used to replace ageing natural gas infrastructure throughout the City. This program improves safety and reliability of the natural gas system by replacing pipe material and components, prior to failure, with reliable polyethylene pipe and fittings.

The GMR Program completed a major milestone in 2013 with the replacement of gas mains made from Acrylonitrile-Butadiene-Styrene (ABS) plastic with Polyethylene (PE) pipe. The City's 2015 DIMP identified ABS pipe and components as suitable for replacement due to the pipe's brittleness and difficulty of repair. There are 0.1 miles of remaining ABS in the system, which is scattered throughout the City in very small sections.

After the replacement of ABS pipe, CPAU's 2015 Risk Assessment identified PVC pipe material as the next pipe material to be reviewed for replacement. In general, CPAU replaces about 4 miles (1.9% of the system) of pipe on each GMR project, accounting for approximately 75% of PVC and 25% of steel. The pipelines are replaced with PE pipe.

If customers transition away from natural gas, it may necessary to scale back the rate of replacement of the existing gas system. Staff is working to develop an efficient phasing plan for electrification and the scaling back of the gas infrastructure. However, staff believes it is necessary to continue the current efforts to replace older and higher-risk materials within the gas system to maintain safety and system integrity. This investment is recommended until a more defined plan on electrification and the transition away from natural gas is completed. That transition plan may involve aggressive electrification in areas with PVC pipe to avoid future investments in PVC pipe replacement. The priority for the gas utility fund is continued safe operation to manage the overall risk and continue the reliable and safety delivery of natural gas throughout the City. In the short term that requires investing in replacement of highest risk PVC pipe, prioritizing areas of the gas system that will be needed the longest during the transition to an electrified community, and gradually that will be integrated with a strategy to aggressively electrify neighborhoods and abandon PVC pipe rather than replace it.

Several factors are contributing to an increase in construction costs in the Bay Area, such as a greater focus on infrastructure improvement by many municipal agencies and the higher demand for utility contractors within these fields. The current budget for the GMR program has held steady over the last few years, which results in a reduction of replacement due to the steady increase in the replacement cost. CPAU recently posted the Gas Main Replacement 24A Project for competitive bidding and resulted in one contractor submitting a bid for almost two times the engineering estimate, even after it was bid a second time. Future GMR projects will require a budget increase to maintain a similar rate of PVC and steel main replacement. Currently, CPAU plans to replace as many aging mains as possible within its current budget. However, if this trend of higher construction cost continues, the Gas Utility may require larger CIP budgets and as a result, an increase in rates to maintain an adequate rate of replacement to relieve the risks of PVC and steel pipe in the system. Staff will continue to apply for federal grant opportunities to assist in offsetting the cost of replacement.

This Financial Plan addresses these challenges in a way that will allow CPAU to meet its main replacement needs. This plan includes approximately $8 million starting in FY 2025 and includes about a 5.4% annual construction cost inflationary increase. This will assist in keeping up with the increasing cost of replacement of PVC mains and steel mains as needed. Additionally, the GMR project schedule for gas will be staggered with water and wastewater (water and wastewater construction every even year and gas construction every odd year), which will ease scheduling difficulties for inspection coverage due to shared inspection staff across water, wastewater, gas, and large development services projects.

Construction of the GMR 24A project was completed in March 2023 (FY 2023). Construction of the GMR 24B project will commence at the end of January 2024 and is anticipated to be completed in May 2025. The GMR 24B project was not selected for a Natural Gas Distribution Infrastructure Safety and Modernization (NGDISM) grant opportunity. For the GMR 25 project, CPAU applied for a NGDISM grant opportunity in August 2023. A final determination for the grant opportunity is expected in February 2024. CPAU intends to apply each year for the grant funding opportunity, which would assist with the replacement of PVC and steel distribution mains in the gas system. If CPAU determines that grant funding is not likely to be awarded, CPAU will evaluate the merit of continuing to apply for the grant.

Tools and Equipment, Ongoing Projects, and Customer Connections

Staff estimates ongoing projects, tools and equipment, and customer connections to cost approximately $2.2 million through the end of the forecast period. In practice, these projects can fluctuate dramatically depending on prices of material, system conditions and the pace of development and redevelopment in the city. It is worth noting that fee revenue pays for the Customer Connections program, so when costs go up fees will be adjusted as well.

Aside from customer connections and transfers from other funds, the CIP plan for FY 2025 to FY 2029 is funded by utility rates. Appendix B: Gas Utility Capital Improvement Program (CIP) Detail shows the details of the plan.

SECTION 6D: DEBT SERVICE

The Gas Utility currently makes debt service payments on one bond issuance, the 2011 Series A Utility Revenue Refunding Bonds. This bond issuance was to refinance the $18 million principal remaining on the Utility Revenue Bonds, 2002 Series A issued for the Gas and Water Utilities to finance various improvements to the distribution systems. $9.4 million of this issuance was secured by the net revenues of the Gas Utility. Table 16 shows debt service for this bond for the financial forecast period. Debt service on this bond will continue through 2026.

Table 15: Gas Utility Debt Service ($000)

	FY 2025	FY 2026
2011 Utility Revenue Refunding Bonds, Series A	799	802

The 2011 bonds include two covenants stating that 1) the Gas Utility will maintain a debt coverage ratio of 125% of debt service, and 2) that the City will maintain "Available Reserves"[19] equal to five times the annual debt service. This Financial Plan complies with these covenants throughout the forecast period, as shown in Table 19 and Table 20.

Table 16: Debt Service Coverage Ratio ($000)

	FY 2025	FY 2026
Revenues	70,414	74,501
Expenses (Excluding CIP and Debt Service)	(47,080)	(47,910)
Net Revenues	23,334	26,592
Debt Service	799	802
Coverage Ratio	2919%	3317%

Table 17: Debt Service Minimum Reserves ($000)

	FY 2024	FY 2025	FY 2026
Gas and Water Utilities [a]	24,767	28,473	32,578
Debt Service [b]	1,459	1,454	1,457
Reserves Ratio [c]	17x	20x	22x

a) CIP, Rate Stabilization, Operations, and Unassigned Reserves
b) Gas and Water Utility's share of the debt service on the 2011 bonds.
c) Calculated using combined Gas and Water Utility reserves. The actual reserves ratio for the 2011 bonds is calculated based on the combined Electric, Gas, and Water Utility reserves and total debt service and is higher than shown here.

The Gas Utility's reserves and net revenue are also pledged as security for the bond issuances listed in Table 19, even though the Gas Utility is not responsible for the debt service payments. The Gas 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.

[19] Available Reserves as defined in the 2011 bonds include the reserves for the Water, Electric, and Gas Utilities

Table 18: Other Issuances Secured by Gas Utility's Revenues or Reserves

Bond Issuance	Responsible Utilities	Annual Debt Service ($000)	Secured by Gas Utility's	
			Net Revenues	Reserves
1999 Utility Revenue Bonds, Series A	Wastewater Collection Wastewater Treatment Storm Drain	$1,207	No	Yes
2009 Water Revenue Bonds (Build America Bonds)	Water	$1,977*	No	Yes
**Net of Federal interest subsidy*				

SECTION 6F: REVENUES

The Gas Fund receives most of its revenues from sales of gas, but about 8% comes from other sources including interest income, service connection and capacity fees, and sales of allowances related to California's cap-and-trade program. The Cap and Trade compliance charge is another revenue item related to the cap-and-trade program that is collected in customers' bills. While the State provides CPAU with a certain number of free allowances each year, the Gas Utility is required to sell a portion of those in accordance with the regulations. In order to have enough allowances to cover customers' natural gas emissions, CPAU must buy allowances at market, and subsequently passes through the cost of those allowances to customers. The regulations do not allow the revenue derived from the sale of the free allowances to offset allowance purchases, thus the pass-through rate component. These funds are recorded in the Carbon allowance revenue accounts in the Gas Supply Fund and the funds are then transferred to the Cap and Trade Reserve (see Section 3D: Proposed Reserve Transfers for more details).

This Financial Plan bases sales revenue projections on the load forecast in *Section 5A: Load Forecast.* Except where stated otherwise, these load forecasts are based on normal weather. Weather can vary substantially, however, and this can affect revenues substantially. Also, changes in customer behavior, as well as changes to more efficient gas appliances, or switching to electric appliances, will modify these forecasts. Staff continually evaluates forecasts to see when new trends emerge.

SECTION 6G: COMMUNICATIONS PLAN

The FY 2025 gas utility communications strategy covers these primary areas: natural gas market supply costs, revisions to the natural gas purchasing strategy, operations, infrastructure, safety, efficiency, carbon neutrality, and cost containment measures. The City of Palo Alto Utilities (CPAU) communication methods include the Utilities webpages, utility bill inserts, messaging on bills and envelopes, informational fliers and brochures, email newsletters, social media, print and digital ads in local publications, and participation in community outreach events.

CPAU purchases gas as a commodity on the market, therefore monthly gas rates can fluctuate for customers due to factors affecting the market. Staff post the monthly rates online at www.cityofpaloalto.org/RatesOverview and provide updates on the rate setting process for members of the public can be informed. During the FY 2023 winter, utilities across the region saw extremely high gas market prices projected for January and February; much higher than previous year winter prices, and the highest since the 2001 energy crisis. In September 2023, the Palo Alto City Council adopted a revised natural gas purchasing strategy for the 2023-2024 winter months to include the addition of insurance against very high prices. A longer-term strategy for mitigating against potential future gas price spikes may be considered by Council in 2024.

CPAU promotes gas use efficiency incentives year-round, but most heavily during winter months to impact heating activities. Messaging emphasizes the importance of saving energy to keep utility costs low even if gas prices are high or utility rates are increasing. Programs such as the Home Efficiency Genie and commercial energy efficiency programs help residents and businesses better understand energy usage, and activities or upgrades they can implement to improve efficiency and keep utility costs low. The MyCPAU online account management portal provides customers with direct access and more information about utility account and consumption data.

Consistent with the Utilities Strategic Plan, CPAU is instituting cost containment as an ongoing priority that is part of our annual cycle. Examples include implementing a mobile workforce application to reduce administrative data entry time, advanced metering infrastructure to improve efficiency, and establishing a cross-functional field crew to install water, gas, and sewer services simultaneously at new construction sites, reducing hours spent in the field and freeing up staff time to be reallocated for other projects. CPAU schedules larger capital improvement projects every other year to achieve efficiencies in project management and also better project proposals which lowers construction costs.

CPAU communicates about safety for all utility services year-round including the need to call USA (811) before digging to check for underground utility lines. Staff also emphasize the importance of contacting CPAU to check for potential sewer and gas line cross-bores prior to clearing a sewer line. Every year, CPAU publishes an updated gas safety awareness brochure and mails it to all customers in Palo Alto as well as other stakeholders. Staff talk with business customers at special facilities meetings and attend neighborhood safety and emergency preparedness fairs. While print materials and webpages still feature prominently, CPAU is increasing use of other outreach channels such as email newsletters, social media and online videos. The Gas Safety Public Awareness Plan contains saved copies of all outreach materials and activity logs.

APPENDICES

Appendix A: Gas Financial Forecast Detail

Appendix B: Gas Utility Capital Improvement Program (CIP) Detail

Appendix C: Gas Utility Reserves Management Practices

Appendix D: Description of Gas Utility Cost Categories

Appendix E: Gas Utility Communications Samples

APPENDIX A: GAS FINANCIAL FOREST DETAIL

CITY OF PALO ALTO

Gas Financial Details

($'000)

		Actual			Projected					
	Fiscal Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
1	**Distribution Rate Change %**	**4%**	**5%**	**6%**	**21%**	**15%**	**12%**	**11%**	**10%**	**9%**
2	**Rate Change % (excludes Commodity)**	**2%**	**3%**	**3%**	**7%**	**9%**	**7%**	**7%**	**6%**	**6%**
3	Total System Average Rate ($/Therm)	$1.417	$1.802	$2.538	$2.304	$2.383	$2.561	$2.756	$2.950	$3.156
4	Supply Average Rate ($/Therm)	$0.501	$0.948	$1.607	$1.131	$0.960	$0.989	$1.018	$1.036	$1.065
5	Retail Sales (Thousand Therms)	25,451	25,426	28,582	24,230	27,351	27,189	27,129	27,030	26,857
6	Retail Sales Revenue	36,071	45,816	72,528	55,835	65,189	69,640	74,764	79,752	84,753
7	Connection & Capacity Fees	840	475	414	888	700	700	700	700	700
8	Other Revenues & Transfers In	2,559	2,915	4,032	3,840	4,032	3,653	3,908	4,154	4,387
9	Interest	479	427	502	470	493	508	523	539	555
10	**REVENUES**	**39,950**	**49,634**	**77,476**	**61,032**	**70,414**	**74,501**	**79,895**	**85,144**	**90,395**
11	Commodity & Cap and Trade	9,891	20,591	41,782	22,912	22,154	22,565	22,932	23,278	23,807
12	Transportation	2,859	3,513	4,144	4,483	4,112	4,331	4,514	4,632	4,741
13	Total Supply Purchases	12,750	24,103	45,926	27,395	26,265	26,896	27,445	27,911	28,547
14	Administration (CIP & Operating)	3,248	4,403	3,395	3,576	3,749	3,862	3,978	4,097	4,220
15	Customer Service	1,904	2,035	2,109	2,257	2,349	2,420	2,492	2,567	2,644
16	Demand Side Management	417	306	354	225	235	242	249	257	264
17	Engineering (Operating)	571	659	515	550	573	591	608	626	645
18	Operations & Maintenance	6,600	7,422	7,314	7,822	9,082	8,744	8,640	8,899	9,166
19	Resource Management	551	668	824	934	971	1,000	1,030	1,061	1,093
20	Total Supply & Distribution Operations	13,291	15,493	14,511	15,364	16,960	16,859	16,997	17,507	18,032
21	Debt Service	801	803	803	802	799	802	-	-	-
22	Rent	471	481	501	515	528	543	557	572	588
23	General Fund Transfer	6,847	7,240	6,683	8,215	8,960	10,070	12,674	13,410	14,381
24	Cap-and-Trade Reserve Transfers	1,363	2,189	0	5,359	3,327	3,612	3,866	4,109	4,340
25	Other Transfers Out	512	277	679	375	293	712	721	732	742
26	CIP*	9,283	4,674	4,832	7,897	9,371	6,836	12,310	14,353	13,100
27	**EXPENSES**	**45,318**	**55,260**	**73,934**	**65,921**	**66,503**	**66,329**	**74,571**	**78,595**	**79,731**
28	**INTO / (OUT OF) RESERVES**	(3,339)	(2,368)	3,542	(4,890)	3,911	8,172	5,325	6,549	10,664
29	Reappropriations + Commitments	9,086	5,541	12,959	12,959	12,959	12,959	12,959	12,959	12,959
30	Plant Replacement	0	0	0	0	0	0	0	0	0
31	Debt Service Reserve	434	434	378	378	378	378	0	0	0
32	CIP Reserve	3,820	3,820	0	0	0	4,000	10,000	16,000	23,000
33	Rate Stabilization	2,766	(872)	(3,077)	(0)	2,000	2,000	2,000	2,000	2,000
34	Operations Reserve	11,981	11,300	14,437	6,471	8,382	12,555	12,258	12,808	16,473
35	Cap-and-Trade Reserve	4,542	6,731	6,731	12,090	15,417	19,029	22,895	27,004	31,344
36	Unassigned	0	0	0	0	0	0	0	0	0
37	Total Reserves (excludes Cap-and-Trade)	28,087	20,223	24,697	19,808	23,719	31,892	37,217	43,766	54,431
38	**Operations Reserve Guidelines**									
39	Max (120 Days Commodity + O&M)	12,102	15,560	22,719	19,076	18,783	19,559	20,469	21,121	21,906
40	Target (90 Days Commodity + O&M)	9,076	11,670	17,039	14,307	14,087	14,670	15,352	15,840	16,429
41	Min (60 Days Commodity + O&M)	6,051	7,780	11,359	9,538	9,392	9,780	10,235	10,560	10,953
42	Short Term Risk Assessment Value	4,625	4,291	4,987	5,462	6,905	7,359	8,344	9,282	9,859

*includes connection and capacity related costs

APPENDIX B: GAS UTILITY CAPITAL IMPROVEMENT PROGRAM (CIP) DETAIL

Fiscal Year	2024			2025	2026	2027	2028	2029
Projects	Carryover From FY23	CIP Funding	Adjusted Budget*	Projected				
GS-13001 - Gas Main Replacement - Project 23	-	63,266	63,266	-	-	-	-	-
GS-14003 - Gas Main Replacement - Project 24	8,422,203	85,341	8,507,544	-	-	-	-	-
GS-15000 - Gas Main Replacement - Project 25	-	4,725,000	4,725,000	5,775,000	-	-	-	-
GS-16000 - Gas Main Replacement - Project 26	-	-	-	-	4,216,000	6,665,496	-	-
GS-20000 - Gas Main Replacement - Project 27	-	-	-	-	-	-	4,683,622	7,404,806
GS-28X00 - Gas Decommissioning Project	-	-	-	-	-	-	4,000,000	-
GS-25001 - Design and Repair at Arastradero Creek	-	-	-	1,000,000	-	-	-	-
Subtotal - Gas Main Replacement Programs	**8,422,203**	**4,873,607**	**13,295,809**	**6,775,000**	**4,216,000**	**6,665,496**	**8,683,622**	**7,404,806**
GS-13002 - Gas Equipment and Tools	-	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Subtotal - Tools and Equipment	**-**	**100,000**	**100,000**	**100,000**	**100,000**	**100,000**	**100,000**	**100,000**
GS-03009 - System Extensions - Unreimbursed	-	-	-	-	-	-	-	-
GS-11002 - Gas Distribution System Improvements	505,796	745,796	1,251,592	500,000	500,000	500,000	500,000	500,000
GS-80019 - Gas Meters and Regulators	-	532,483	532,483	500,000	500,000	500,000	500,000	500,000
Subtotal - Ongoing Projects	**505,796**	**1,278,279**	**1,784,075**	**1,000,000**	**1,000,000**	**1,000,000**	**1,000,000**	**1,000,000**
GS-80017 - Gas System, Customer Connections	-	887,698	887,698	700,000	700,000	700,000	700,000	700,000
Subtotal - Customer Connections	**-**	**887,698**	**887,698**	**700,000**	**700,000**	**700,000**	**700,000**	**700,000**
Total CIP Expenses	**8,927,999**	**7,139,584**	**16,067,583**	**8,575,000**	**6,016,000**	**8,465,496**	**10,483,622**	**9,204,806**

* Includes unspent funds from previous years carried forward or reappropriated into the current fiscal year

APPENDIX C: GAS UTILITY RESERVES MANAGEMENT PRACTICES

The following reserves management practices shall be used when developing the Gas 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 Gas Utility's Supply Fund Balance is reserved for the following purposes:

a) For existing contracts, as described in Section 4 (Reserve for Commitments)
b) For operating and capital budgets re-appropriated from previous years, as described in Section 5 (Reserve for Re-appropriations)
~~b)~~c) For tracking unspent or unallocated revenues from the sale of carbon allowances freely allocated by the California Air Resources Board to the gas utility under the State's Cap and Trade Program, as described in Section 11 (Cap and Trade Program Reserve)

Section 3. Distribution Fund Reserves

a) For existing contracts, as described in Section 4 (Reserve for Commitments)
b) For operating and capital budgets re-appropriated from previous years, as described in Section 5 (Reserve for Re-appropriations)
c) For cash flow management and contingencies related to the Gas Utility's Capital Improvement Program (CIP), as described in Section 6 (CIP Reserve)
d) For rate stabilization, as described in Section 7 (Rate Stabilization Reserve)
e) For operating contingencies, as described in Section 8 (Operations Reserve)
f) 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 9 (Unassigned Reserves)

Section 4. Reserve for Commitments

At the end of each fiscal year the Gas Supply Fund and Gas Distribution Fund Reserve for Commitments will be set to an amount equal to the total remaining spending authority for all contracts in force for the Wastewater Collection Utility at that time.

Section 5. Reserve for Reappropriations

At the end of each fiscal year the Gas Supply Fund and Gas Distribution Fund Reserve for Reappropriations will be set to an amount equal to the amount of all remaining capital and non-capital budgets, if any, that will be re-appropriated to the following fiscal year for each fund in accordance with Palo Alto Municipal Code Section 2.28.090.

Section 6. 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:

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 based on the levels of CIP expense budgeted for that year.

Minimum Level	12 months of budgeted CIP expense
Maximum Level	24 months of budgeted CIP expense

a) 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.
b) Minimum Level:
   i) Funds held in the Reserve for Commitments may be counted as part of the CIP Reserve for the purpose of determining compliance with the CIP Reserve minimum guideline level.
   ii) 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.
c) Maximum Level: If, at any time, the CIP Reserve reaches its maximum level, no funds may be added to this reserve. If there are funds in this reserve in excess of the maximum level staff must propose to transfer these funds to another reserve or return them to ratepayers in the next Financial Plan. Staff may also seek Council approval to hold funds in this reserve in excess of the maximum level, if they are held for a specific future purpose related to the CIP.

Section 7. Rate Stabilization Reserve

Funds may be added to the Rate Stabilization Reserve by action of the City Council and held to manage the trajectory of future year rate increases. Withdrawal of funds from the Rate Stabilization Reserve requires Council action. If there are funds in the Rate Stabilization Reserve at the end of any fiscal year, any subsequent Gas Utility Financial Plan must result in the withdrawal of all funds from this Reserve by the end of the Financial Planning Period.

Section 8. Operations Reserve

The Operations Reserve is used to manage normal variations in costs and as a reserve for contingencies. Any portion of the Gas Utility's Fund Balance not included in the reserves described in Section 4-Section 7 above will be included in the Operations Reserve unless this reserve has reached its maximum level as set forth in Section 8 d) below. Staff will manage the Operations Reserve according to the following practices:

a) The following guideline levels are set forth for the 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 O&M and commodity expense
Target Level	90 days of O&M and commodity expense
Maximum Level	120 days of O&M and commodity expense

b) Minimum Level: If, at the end of any fiscal year, the funds remaining in the 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, and the Council may adopt, an alternative plan that takes longer than one year to replenish the reserve.
c) Target Level: If, at the end of any fiscal year, the Operations Reserve is higher or lower than the target level, any Financial Plan created for the Gas Utility shall be designed to return the Operations Reserve to its target level by the end of the forecast period.
d) Maximum Level: If, at any time, the Operations Reserve reaches its maximum level, no funds may be added to this reserve. Any further increase in the Gas Utility's Fund Balance shall be automatically included in the Unassigned Reserve described in Section 9, below.

Section 9. Unassigned Reserve

If the Operations Reserve reaches its maximum level, any further additions to the Gas Utility's Fund Balance will be held in the Unassigned Reserve. If there are any funds in the 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 Gas 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 2015, and the next Financial Planning Period is FY 2016 through FY 2020, the Financial Plan shall include a plan to return or assign any funds in the Unassigned Reserve by the end of FY 2016. Staff may present an alternative plan that retains these funds or returns them over a longer period of time.

Section 10. Intra-Utility Transfers Between Supply and Distribution Funds

The Gas Utility records costs in two separate funds: the Gas Supply Fund and the Gas Distribution Fund. At the end of each fiscal year staff is authorized to transfer funds between the Gas Supply Fund and Gas Distribution Fund if consistent with the purposes of the two reserves involved in the transfer and ~~an amount~~ in order to balance gas utility reserves to avoid negative balances. For example, Gas Distribution revenues are needed to pay for certain supply-related costs such as administration of the Gas Supply Fund. ~~equal to the difference between Gas Supply Fund costs and Gas Supply Fund Revenues, from the Gas Distribution Fund Operations Reserve to the Gas Supply Fund, or vice versa.~~ Such transfers shall be included in the ordinance closing the budget for the fiscal year.

Section 11. Cap and Trade Program Reserve

This reserve ~~tracks~~ holds revenues from the sale of carbon allowances freely allocated by the California Air Resources Board to the gas 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. At the end of each fiscal year, the Cap and Trade Program Reserve will be adjusted by the net of revenues and expenses associated with the Cap and Trade program.~~At the end of each fiscal year staff is authorized to transfer all revenues from the sale of allocated carbon allowances to this reserve.~~

APPENDIX D: DESCRIPTION OF GAS UTILITY COST CATEGORIES

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

Customer Service: This category includes the Gas 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 gas services.

Resource Management: This category includes gas procurement, contract management, rate setting, and tracking of legislation and regulation related to the gas industry.

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

- surveying the gas system (50% of the system each year) and repairing any leaks found;
- investigating reports of damaged mains or services and perform emergency repairs;
- building and replacing gas services for new or redeveloped buildings; and
- testing and replacing meters to ensure accurate sales metering.

This category also includes a variety of functions the utility shares with other City utilities, including:

- the Field Services team (which does field research of various customer service issues);
- the Cathodic Protection team (which monitors and maintains the systems that prevent corrosion in metal pipes and reservoirs); and
- the General Services team (which manages and maintains equipment, paves and restores streets after gas, water, or sewer main replacements, and provides welding services, including certified gas line welding services)

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

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

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

APPENDIX E: GAS UTILITY COMMUNICATIONS SAMPLES

APPENDIX C: GAS UTILITY RESERVES MANAGEMENT PRACTICES

The following reserves management practices shall be used when developing the Gas 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.
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c) "Net Assets" - The Government Accounting Standards Board defines a Utility's Net Assets as the difference between its assets and liabilities.
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Section 2. Supply Fund Reserves

The Gas Utility's Supply Fund Balance is reserved for the following purposes:

a) For existing contracts, as described in Section 4 (Reserve for Commitments)
b) For operating and capital budgets re-appropriated from previous years, as described in Section 5 (Reserve for Re-appropriations)
c) For tracking unspent or unallocated revenues from the sale of carbon allowances freely allocated by the California Air Resources Board to the gas utility under the State's Cap and Trade Program, as described in Section 11 (Cap and Trade Program Reserve)

Section 3. Distribution Fund Reserves

a) For existing contracts, as described in Section 4 (Reserve for Commitments)
b) For operating and capital budgets re-appropriated from previous years, as described in Section 5 (Reserve for Re-appropriations)
c) For cash flow management and contingencies related to the Gas Utility's Capital Improvement Program (CIP), as described in Section 6 (CIP Reserve)
d) For rate stabilization, as described in Section 7 (Rate Stabilization Reserve)
e) For operating contingencies, as described in Section 8 (Operations Reserve)
f) 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 9 (Unassigned Reserves)

Section 4. Reserve for Commitments

At the end of each fiscal year the Gas Supply Fund and Gas Distribution Fund Reserve for Commitments will be set to an amount equal to the total remaining spending authority for all contracts in force for the Wastewater Collection Utility at that time.

Section 5. Reserve for Reappropriations

At the end of each fiscal year the Gas Supply Fund and Gas Distribution Fund Reserve for Reappropriations will be set to an amount equal to the amount of all remaining capital and non-capital budgets, if any, that will be re-appropriated to the following fiscal year for each fund in accordance with Palo Alto Municipal Code Section 2.28.090.

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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:

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Minimum Level	12 months of budgeted CIP expense
Maximum Level	24 months of budgeted CIP expense

a) 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.
b) Minimum Level:
   i) Funds held in the Reserve for Commitments may be counted as part of the CIP Reserve for the purpose of determining compliance with the CIP Reserve minimum guideline level.
   ii) 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.
c) Maximum Level: If, at any time, the CIP Reserve reaches its maximum level, no funds may be added to this reserve. If there are funds in this reserve in excess of the maximum level staff must propose to transfer these funds to another reserve or return them to ratepayers in the next Financial Plan. Staff may also seek Council approval to hold funds in this reserve in excess of the maximum level, if they are held for a specific future purpose related to the CIP.

Section 7. Rate Stabilization Reserve

Funds may be added to the Rate Stabilization Reserve by action of the City Council and held to manage the trajectory of future year rate increases. Withdrawal of funds from the Rate Stabilization Reserve requires Council action. If there are funds in the Rate Stabilization Reserve at the end of any fiscal year, any subsequent Gas Utility Financial Plan must result in the withdrawal of all funds from this Reserve by the end of the Financial Planning Period.

Section 8. Operations Reserve

The Operations Reserve is used to manage normal variations in costs and as a reserve for contingencies. Any portion of the Gas Utility's Fund Balance not included in the reserves described in Section 4-Section 7 above will be included in the Operations Reserve unless this reserve has reached its maximum level as set forth in Section 8 d) below. Staff will manage the Operations Reserve according to the following practices:

a) The following guideline levels are set forth for the 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 O&M and commodity expense
Target Level	90 days of O&M and commodity expense
Maximum Level	120 days of O&M and commodity expense

b) Minimum Level: If, at the end of any fiscal year, the funds remaining in the 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, and the Council may adopt, an alternative plan that takes longer than one year to replenish the reserve.
c) Target Level: If, at the end of any fiscal year, the Operations Reserve is higher or lower than the target level, any Financial Plan created for the Gas Utility shall be designed to return the Operations Reserve to its target level by the end of the forecast period.
d) Maximum Level: If, at any time, the Operations Reserve reaches its maximum level, no funds may be added to this reserve. Any further increase in the Gas Utility's Fund Balance shall be automatically included in the Unassigned Reserve described in Section 9, below.

Section 9. Unassigned Reserve

If the Operations Reserve reaches its maximum level, any further additions to the Gas Utility's Fund Balance will be held in the Unassigned Reserve. If there are any funds in the 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 Gas 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 2015, and the next Financial Planning Period is FY 2016 through FY 2020, the Financial Plan shall include a plan to return or assign any funds in the Unassigned Reserve by the end of FY 2016. Staff may present an alternative plan that retains these funds or returns them over a longer period of time.

Section 10. Intra-Utility Transfers Between Supply and Distribution Funds

The Gas Utility records costs in two separate funds: the Gas Supply Fund and the Gas Distribution Fund. At the end of each fiscal year staff is authorized to transfer funds between the Gas Supply Fund and Gas Distribution Fund if consistent with the purposes of the two reserves involved in the transfer and in order to balance gas utility reserves to avoid negative balances. For example, Gas Distribution revenues are needed to pay for certain supply-related costs such as administration of the Gas Supply Fund. Such transfers shall be included in the ordinance closing the budget for the fiscal year.

Section 11. Cap and Trade Program Reserve

This reserve holds revenues from the sale of carbon allowances freely allocated by the California Air Resources Board to the gas 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. At the end of each fiscal year, the Cap and Trade Program Reserve will be adjusted by the net of revenues and expenses associated with the Cap and Trade program.

RESIDENTIAL GAS SERVICE

UTILITY RATE SCHEDULE G-1

A. APPLICABILITY:

This schedule applies to the following Customers receiving Gas Service from City of Palo Alto Utilities:

1. Separately-metered single-family residential Customers;
2. Separately-metered multi-family residential Customers in multi-family residential facilities.

B. TERRITORY:

This schedule applies anywhere the City of Palo Alto provides Gas Service.

C. UNBUNDLED RATES:

	Per Service
Monthly Service Charge:	$16.11~~4.01~~

	Per Therm
Tier 1 Rates:	
Supply Charges:	
1. Commodity (Monthly Market Based)	$0.10-$4.00
2. Cap and Trade Compliance Charge	$0.00-$0.25
3. Transportation Charge	$0.00-$0.25
4. Carbon Offset Charge	$0.00-$0.10
Distribution Charge:	$0.7828~~6807~~
Tier 2 Rates: (All usage over 100% of Tier 1)	
Supply Charges:	
1. Commodity (Monthly Market Based)	$0.10-$4.00
2. Cap and Trade Compliance Charge	$0.00-$0.25
3. Transportation Charge	$0.00-$0.25
4. Carbon Offset Charge	$0.00-$0.10
Distribution Charge:	$2.0016~~1.7406~~

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.

The Commodity Charge is based on the monthly natural gas Bidweek Price Index for delivery at PG&E Citygate, adjusted to account for delivery losses to the Customer's Meter. The Commodity Charge also includes adjustments to account for Council-approved programs implemented to reduce the cost of gas, including a municipal purchase discount[1], and a maximum $0.15/per therm cost for capped price winter natural gas purchases[2].

The Cap and Trade Compliance Charge reflects the City's cost of regulatory compliance with the state's Cap and Trade Program, including the cost of acquiring compliance instruments sufficient to cover the City's Gas Utility's compliance obligations. The Cap and Trade Compliance Charge will change in response to changing market conditions, retail sales volumes and the quantity of allowances required.

The Carbon Offset Charge reflects the City's cost to purchase offsets for greenhouse gases produced in the burning of natural gas. The Carbon Offset Charge will change in response to changing market conditions, changing sales volumes and the quantity of offsets purchased within the Council-approved per therm cap.

The Transportation Charge is based on the current PG&E G-WSL rate for Palo Alto, accounting for delivery losses to the Customer's Meter.

The Commodity, Cap and Trade Compliance, Carbon Offset and Transportation Charges will fall within the minimum/maximum ranges set forth in Section C. Current and historic per therm rates for the Commodity, Cap and Trade Compliance, Carbon Offset and

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1 Adopted via Resolution 9451, on September 15, 2014.
2 Adopted via Resolution 10126, on September 18, 2023.

Transportation Charges are posted on the City Utilities website.[3]

2. Seasonal Rate Changes:

The Summer period is effective April 1 to October 31 and the Winter period is effective from November 1 to March 31. When the billing period includes use in both 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 for each period. For further discussion of bill calculation and proration, refer to Rule and Regulation 11.

3. Calculation of Usage Tiers

Tier 1 natural gas usage shall be calculated and billed based upon a level of 0.667 therms per day during the Summer period and 2.0 therms per day during the Winter period, rounded to the nearest whole therm, based on meter reading days of service. As an example, for a 30 day bill, the Tier 1 level would be 20 therms during the Summer period and 60 therms during the Winter period months. For further discussion of bill calculation and proration, refer to Rule and Regulation 11.

{End}

3 Monthly gas and commodity and volumetric rates are available here, or by visiting https://www.cityofpaloalto.org/files/assets/public/utilities/rates-schedules-for-utilities/residential-utility-rates/monthly-gas-volumetric-and-service-charges-residential.pdf

RESIDENTIAL MASTER-METERED AND COMMERCIAL GAS SERVICE

UTILITY RATE SCHEDULE G-2

A. APPLICABILITY:

This schedule applies to the following Customers receiving Gas Service from the City of Palo Alto Utilities:

1. Commercial Customers who use less than 250,000 therms per year at one site;
2. Master-metered residential Customers in multi-family residential facilities.

B. TERRITORY:

This schedule applies anywhere the City of Palo Alto provides Gas Service.

C. UNBUNDLED RATES: Per Service

Monthly Service Charge: .... $149.24~~29.78~~

Per Therm

Supply Charges:

1.	Commodity (Monthly Market Based)	$0.10-$4.00
2.	Cap and Trade Compliance Charges	$0.00-$0.25
3.	Transportation Charge	$0.00-$0.25
4.	Carbon Offset Charge	$0.00-$0.10

Distribution Charge: .... $1.0282~~0.8941~~

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.

The Commodity Charge is based on the monthly natural gas Bidweek Price Index for delivery at PG&E Citygate, adjusted to account for delivery losses to the Customer's Meter. The Commodity Charge also includes adjustments to account for Council-approved programs implemented to reduce the cost of gas, including a municipal purchase discount[1], and a maximum $0.15/per therm cost for capped price winter natural

1 Adopted via Resolution 9451, on September 15, 2014.

gas purchases[2].

The Cap and Trade Compliance Charge reflects the City's cost of regulatory compliance with the state's Cap and Trade Program, including the cost of acquiring compliance instruments sufficient to cover the City's Gas Utility's compliance obligations. The Cap and Trade Compliance Charge will change in response to changing market conditions, retail sales volumes and the quantity of allowances required.

The Carbon Offset Charge reflects the City's cost to purchase offsets for greenhouse gases produced in the burning of natural gas. The Carbon Offset Charge will change in response to changing market conditions, changing sales volumes and the quantity of offsets purchased within the Council-approved per therm cap.

The Transportation Charge is based on the current PG&E G-WSL rate for Palo Alto, accounting for delivery losses to the Customer's Meter.

The Commodity, Cap and Trade Compliance, Carbon Offset and Transportation Charges will fall within the minimum/maximum ranges set forth in Section C. Current and historic per therm rates for the Commodity, Cap and Trade Compliance, Carbon Offset and Transportation Charges are posted on the City Utilities website.[3]

{End}

2 Adopted via Resolution 10126, on September 18, 2023.
3 Monthly gas and commodity and volumetric rates are available here, or by visiting https://www.cityofpaloalto.org/files/assets/public/utilities/business/business-rates/monthly-gas-volumetric-and-service-charges-commercial.pdf

LARGE COMMERCIAL GAS SERVICE

UTILITY RATE SCHEDULE G-3

A. APPLICABILITY:

This schedule applies to the following Customers receiving Gas Service from the City of Palo Alto Utilities:

1. Commercial Customers who use at least 250,000 therms per year at one site;
2. Customers at City-owned generation facilities.

B. TERRITORY:

This schedule applies anywhere the City of Palo Alto provides Gas Service.

C. UNBUNDLED RATES: Per Service

Monthly Service Charge: $682.85~~593.79~~

Per Therm

Supply Charges:

1. Commodity (Monthly Market Based).. $0.10-$4.00
2. Cap and Trade Compliance Charges .... $0.00-$0.25
3. Transportation Charge .... $0.00-$0.25
4. Carbon Offset Charge .... $0.00-$0.10

Distribution Charge: ....$1.0179~~0.8852~~

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.

The Commodity Charge is based on the monthly natural gas Bidweek Price Index for delivery at PG&E Citygate, adjusted to account for delivery losses to the Customer's Meter. The Commodity Charge also includes adjustments to account for Council-approved programs implemented to reduce the cost of gas, including a municipal purchase discount[1], and a maximum $0.15/per therm cost for capped price winter natural gas purchases[2].

The Cap and Trade Compliance Charge reflects the City's cost of regulatory compliance with the state's Cap and Trade Program, including the cost of acquiring compliance instruments sufficient to cover the City's Gas Utility's compliance obligations. The Cap and Trade Compliance Charge will change in response to changing market conditions, retail sales volumes and the quantity of allowances required.

The Carbon Offset Charge reflects the City's cost to purchase offsets for greenhouse gases produced in the burning of natural gas. The Carbon Offset Charge will change in response to changing market conditions, changing sales volumes and the quantity of offsets purchased within the Council-approved per therm cap.

The Transportation Charge is based on the current PG&E G-WSL rate for Palo Alto, accounting for delivery losses to the Customer's Meter.

The Commodity, Cap and Trade Compliance, Carbon Offset and Transportation Charges will fall within the minimum/maximum ranges set forth in Section C. Current and historic per therm rates for the Commodity, Cap and Trade Compliance, Carbon Offset and Transportation Charges are posted on the City Utilities website.[3]

2. Request for Service

A qualifying Customer may request service under this schedule for more than one account or meter if the accounts are located on one site. A site consists of one or more contiguous parcels of land with no intervening public right-of- ways (e.g. streets).

3. Changing Rate Schedules

Customers may request a rate schedule change at any time to any applicable City of Palo Alto full-service rate schedule.

{End}

1 Adopted via Resolution 9451, on September 15, 2014.
2 Adopted via Resolution 10126, on September 18, 2023.
3 Monthly gas and commodity and volumetric rates are available here, or by visiting https://www.cityofpaloalto.org/files/assets/public/utilities/business/business-rates/monthly-gas-volumetric-and-service-charges-commercial.pdf

COMPRESSED NATURAL GAS SERVICE

UTILITY RATE SCHEDULE G-10

A. APPLICABILITY:

This schedule applies to the sale of natural gas to the City-owned compressed natural gas (CNG) fueling station at the Municipal Service Center in Palo Alto.

B. TERRITORY:

Applies to the City's CNG fueling station located at the Municipal Service Center in City of Palo Alto.

C. UNBUNDLED RATES:

	Per Service
Monthly Service Charge:	$100.93~~87.77~~

	Per Therm
Supply Charges:	
Commodity (Monthly Market Based)	$0.10-$4.00
Cap and Trade Compliance Charges	$0.00-$0.25
Transportation Charge	$0.00-$0.25
Carbon Offset Charge	$0.00-$0.10
Distribution Charge	$0.0166~~45~~

D. SPECIAL CONDITIONS

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.

The Commodity Charge is based on the monthly natural gas Bidweek Price Index for delivery at PG&E Citygate, adjusted to account for delivery losses to the Customer's Meter. The Commodity Charge also includes adjustments to account for Council-approved programs implemented to reduce the cost of gas, including a municipal purchase discount[1], and a maximum $0.15/per therm cost for capped price winter natural gas purchases[2].

1 Adopted via Resolution 9451, on September 15, 2014.

2 Adopted via Resolution 10126, on September 18, 2023.

COMPRESSED NATURAL GAS SERVICE

UTILITY RATE SCHEDULE G-10

The Cap and Trade Compliance Charge reflects the City's cost of regulatory compliance with the state's Cap and Trade Program, including the cost of acquiring compliance instruments sufficient to cover the City's Gas Utility's compliance obligations. The Cap and Trade Compliance Charge will change in response to changing market conditions, retail sales volumes and the quantity of allowances required.

The Carbon Offset Charge reflects the City's cost to purchase offsets for greenhouse gases produced in the burning of natural gas. The Carbon Offset Charge will change in response to changing market conditions, changing sales volumes and the quantity of offsets purchased within the Council-approved per therm cap.

The Transportation Charge is based on the current PG&E G-WSL rate for Palo Alto, accounting for delivery losses to the Customer's Meter.

The Commodity, Cap and Trade Compliance, Carbon Offset and Transportation Charges will fall within the minimum/maximum range set forth in Section C. Current and historic per therm rates for the Commodity, Cap and Trade Compliance, Carbon Offset and Transportation Charges are posted on the City Utilities website.[3]

{End}

3 Monthly gas and commodity and volumetric rates are available here, or by visiting https://www.cityofpaloalto.org/files/assets/public/utilities/business/business-rates/monthly-gas-volumetric-and-service-charges-commercial.pdf

CITY OF PALO ALTO

PROPOSED GAS FINANCIAL PLAN AND RATE CHANGES FOR FY 2025

March 6, 2024

www.cityofpaloalto.org

Gas Rate Proposal

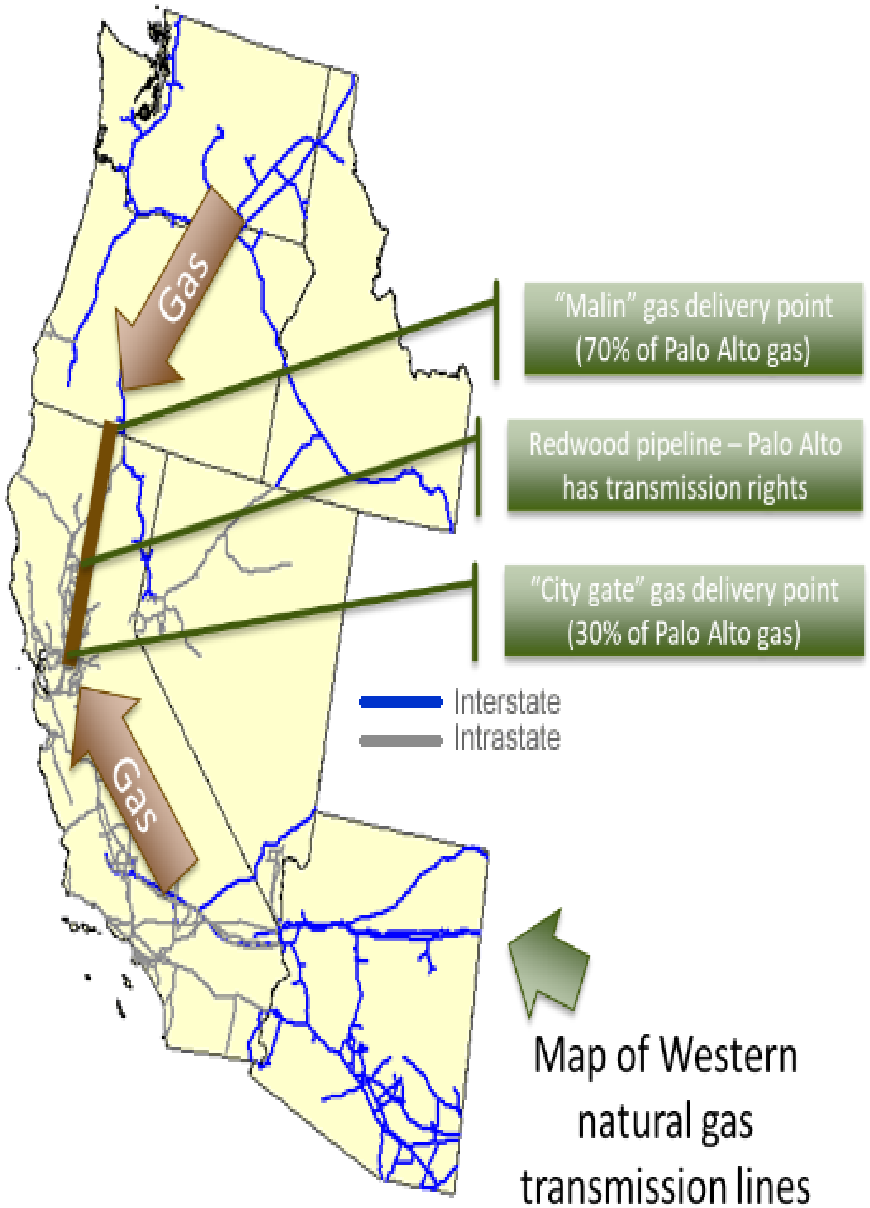
FY 2025 Rate Proposal

- 9% overall rate increase to customer bills, due to 15% distribution rate increase
- 7% overall rate increase in FY 2026 and FY 2027, 6% annually in FY 2028 and FY 2029
- Two General Fund Transfer Alternatives

Gas Utility Basics

City of Palo Alto gas distribution system:

- 20,000 meters
- 205 miles of mains
- 18,000 service lines

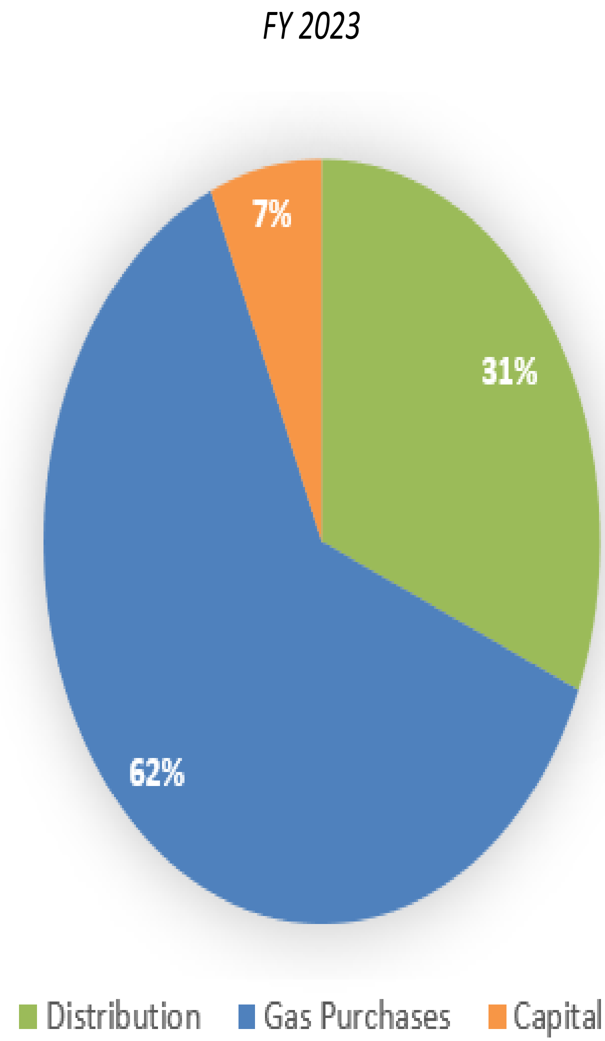


Map of Western natural gas transmission lines

Gas Rate Design

About one-third to two-third of the rate is “supply-related:” gas supply, transmission, and environmental charges. These rates vary monthly according to market-driven costs that are passed directly to customers

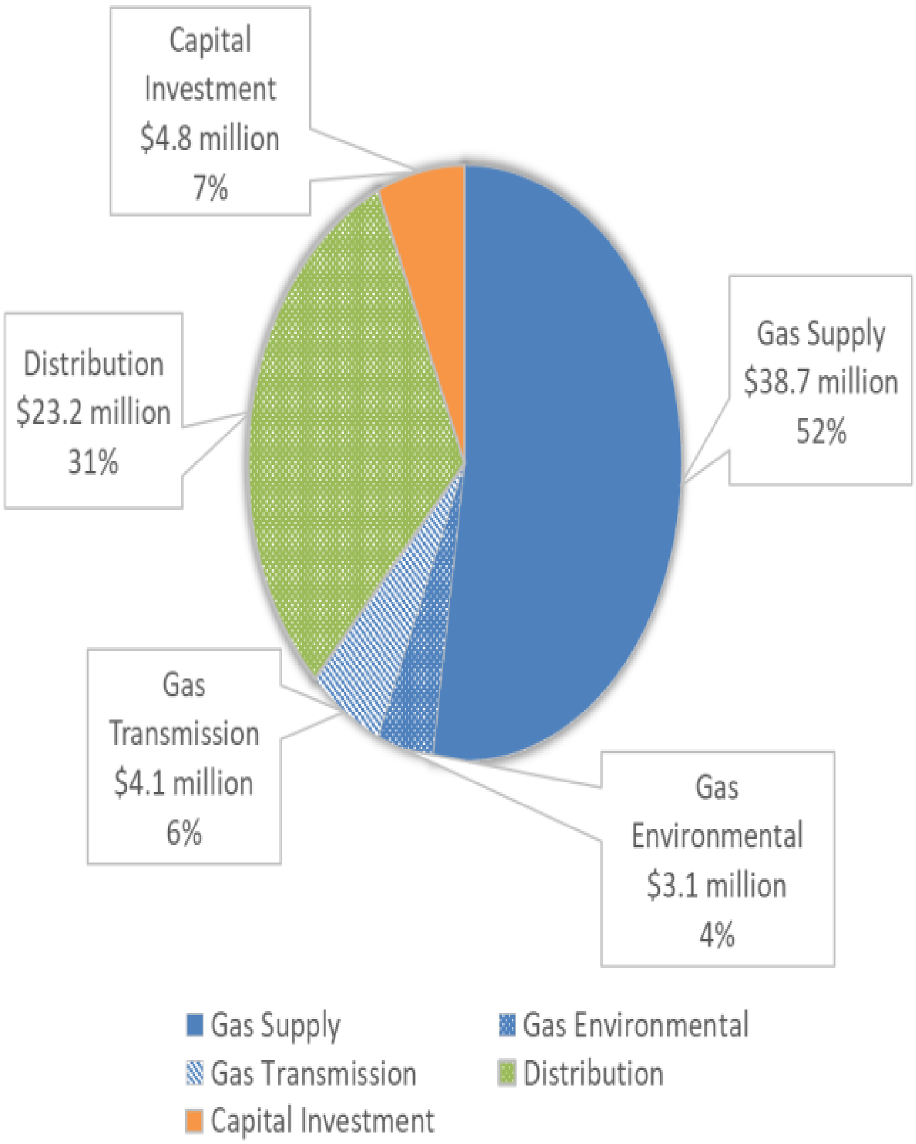
The remaining portion of the rate is set based on the City’s costs for maintaining its gas distribution system (gas mains, services, related equipment). **These rates are being discussed here tonight.**



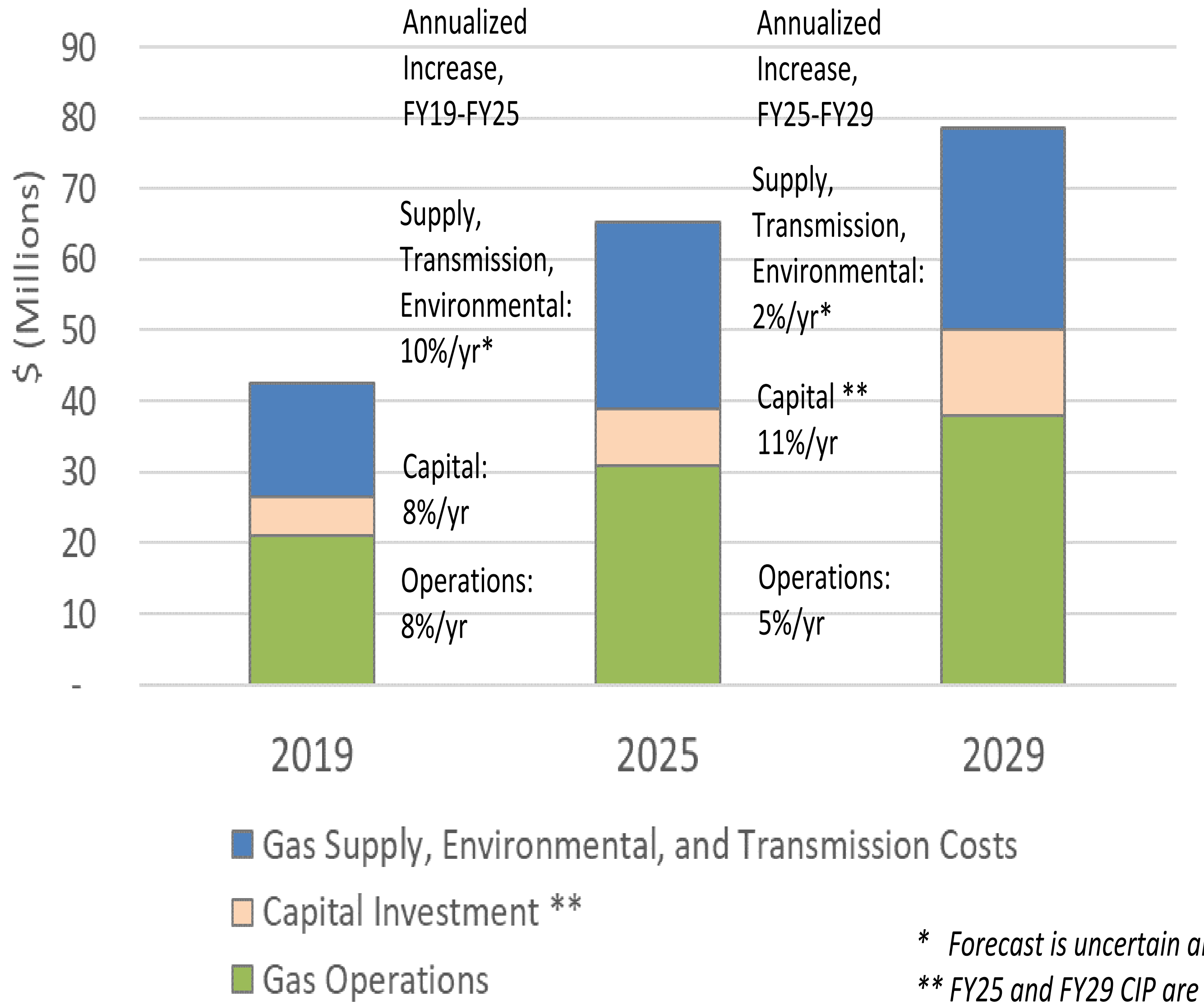
Gas Utility Cost Structure *(FY 2023)*

Gas Distribution (in Green): The cost to distribute gas within Palo Alto, including: maintaining and replacing gas infrastructure, customer service, billing, administration, etc.

Gas Supply, Transmission, and Environmental (in Blue):
All pass-through



Long Term Cost Trends



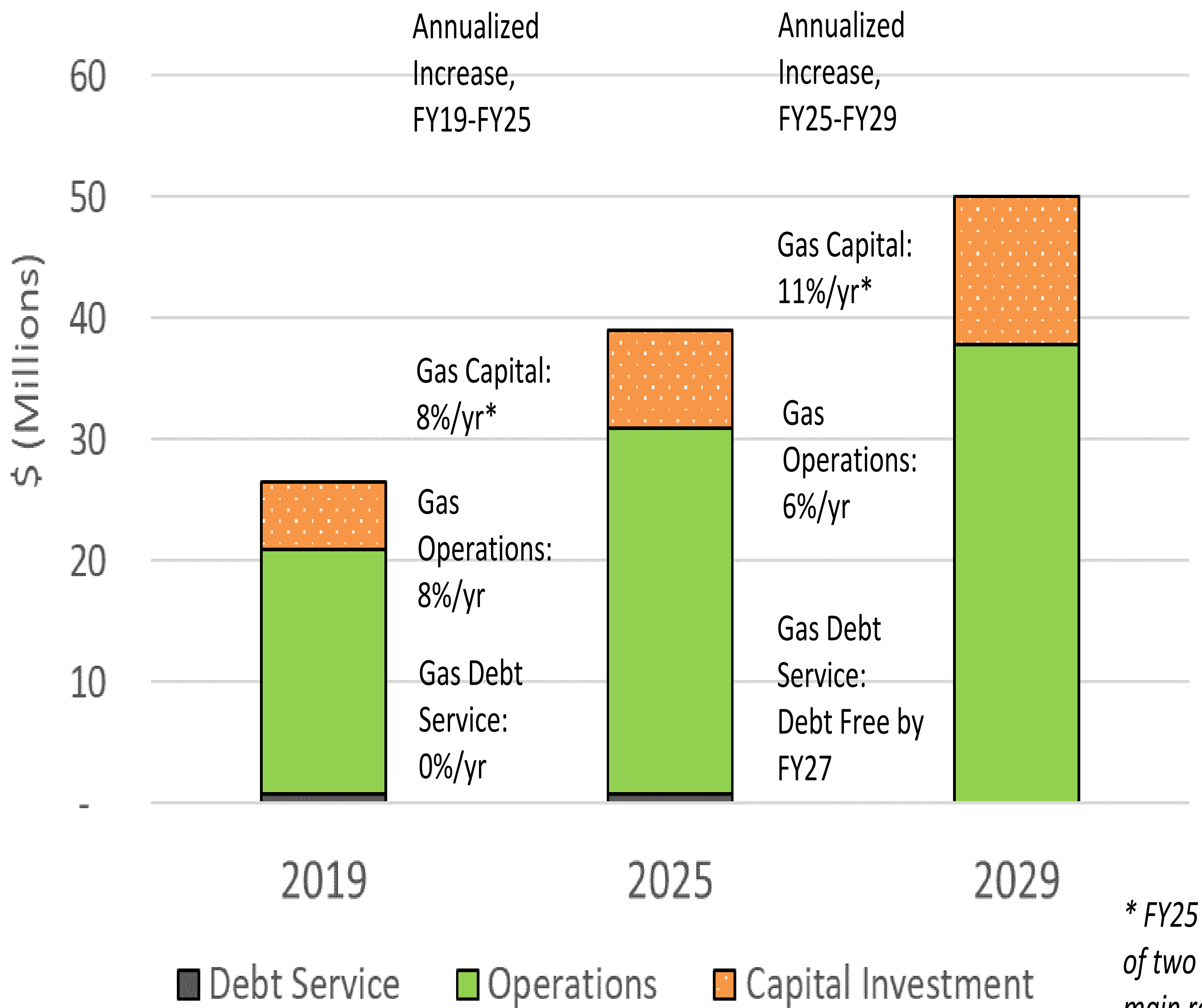
** Forecast is uncertain and will vary with market prices*
*** FY25 and FY29 CIP are an average of two years due to staggered main replacement schedule.*

Gas Supply Cost Drivers*

- PG&E gas transmission rates continue to rise steadily to fund safety investments
- Insurance purchased in response to winter 22/23 natural gas market volatility
- Cap and Trade costs continue to rise (as intended by design)
- Carbon Neutral Gas Plan; carbon offset purchases

** All of the above costs are pass-through and not included in rate increase*

Gas Distribution Cost Trends



** FY25 and FY 20 CIP is an average of two years due to staggered main replacement schedule.*

CITY OF PALO ALTO

Gas Distribution Cost Drivers

- Health, retirement, and associated overhead costs continue to increase
- Underground construction costs have increased substantially as well
- Continued funding for cross-bore investigations
- Replenish reserves to fund capital projects

Estimated Bill Changes

Residential

Usage (Therms/month)	Bill Amount (Current Rates)	Bill Amount (Proposed Rates)	Change	
			$/mo.	%
Summer				
10	$ 29	$ 32	$ 3	11%
18 (median)	42	45	4	9%
30	69	75	7	10%
45	106	116	10	10%
Winter				
30	$ 65	$ 70	$ 5	8%
54 (median)	105	113	8	7%
80	170	184	14	8%
150	362	396	34	9%

Commercial

Usage (Therms/month)	Bill under (Current Rates)	Bill under (Proposed Rates)	Change $/mo	Change %
250	$ 168	$ 190	$ 22	13%
1,000	281	312	31	11%
3,200	614	669	55	9%
35,000	5,429	5,839	441	8%
250,000	38,146	41,001	2,855	7%

Note: excludes supply-related rate changes

Current Gas Bill Comparisons *($/Mo. or Yr.)*

Residential

Season	Usage (Therms)	Palo Alto	PG&E Zone X	% Difference
Summer	10	$ 29	$ 21	29%
	(Median) 18	$ 42	$ 39	7%
	30	$ 69	$ 68	1%
	45	$ 106	$ 105	1%
Winter	30	$ 65	$ 72	(11%)
	(Median) 54	$ 105	$ 132	(25%)
	80	$ 170	$ 203	(20%)
	150	$ 362	$ 400	(11%)

Palo Alto median residential bill is projected to be about 11% below PG&E's median bill in FY 2024, based on actuals and projected supply rates

Commercial

Staff is in the process of doing a more extensive review of commercial competitiveness and will provide updates in the future

Gas General Fund Transfer

- Measure L: 18% of gas utility gross revenues from two fiscal years prior; Council may elect to transfer less
- Council approved transferring up to 15.5% of FY 2022 gas utility gross revenues to the general fund in FY 2024
- Equity Transfer Alternatives:
  - **Transfer 11.9% (Staff Recommended):** lower transfer amount due to high commodity revenue in FY 2023, gradual transition to 18% transfer by FY 2027
  - **Transfer 18%:** transfer full amount allowed under Measure L 18% cap

FY 2025 General Fund Transfer Alternatives and Gas Rate Projections

Summary of Overall Rate Changes

Fiscal Year	2024	2025	2026	2027	2028	2029
Transfer 11.9%	8%	9%	7%	7%	6%	6%
Transfer 18%	8%	15%	5%	5%	5%	6%
FY 2024 Financial Plan	8%	7%	5%	5%	5%	-

Percent of Gross Gas Utility Revenue to Transfer

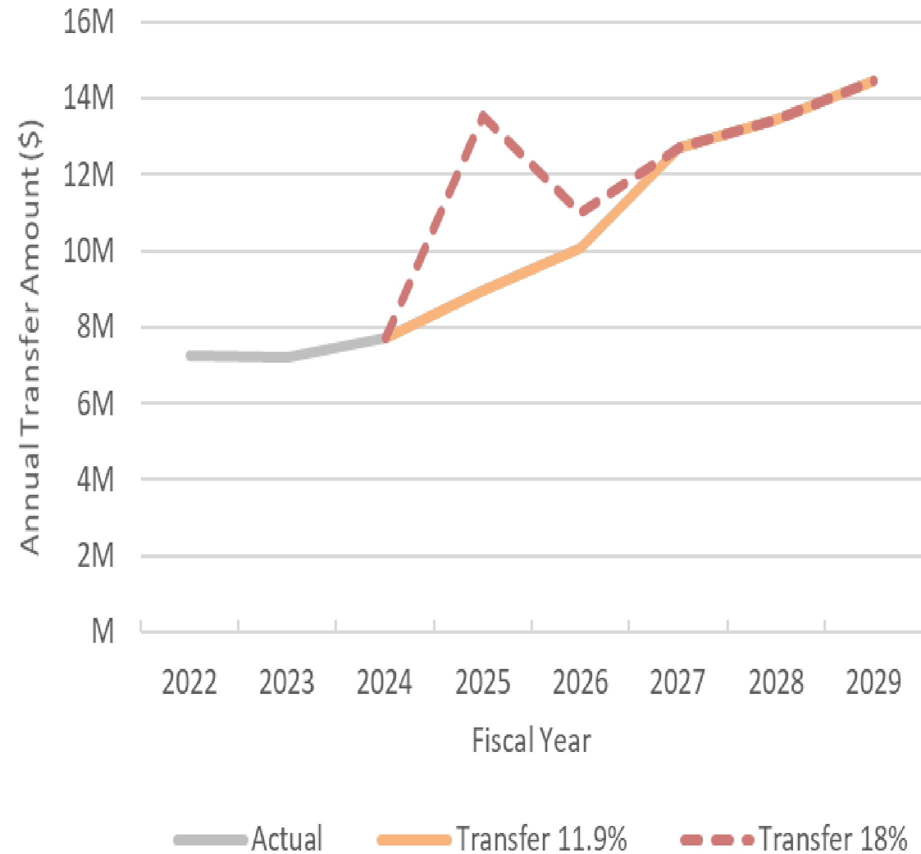
Fiscal Year	2024	2025	2026	2027	2028	2029
Transfer 11.9%	15.5%	11.9%	16.5%	18.0%	18.0%	18.0%
Transfer 18%	15.5%	18.0%	18.0%	18.0%	18.0%	18.0%
FY 2024 Financial Plan	15.5%	11.1%	12.9%	13.1%	12.8%	-

Transfer Amount ($,000)

Fiscal Year	2024	2025	2026	2027	2028	2029
Transfer 11.9%	7,707	8,960	10,070	12,674	13,410	14,381
Transfer 18%	7,707	13,552	10,986	12,674	13,410	14,381

Transfer Amount YOY% Change

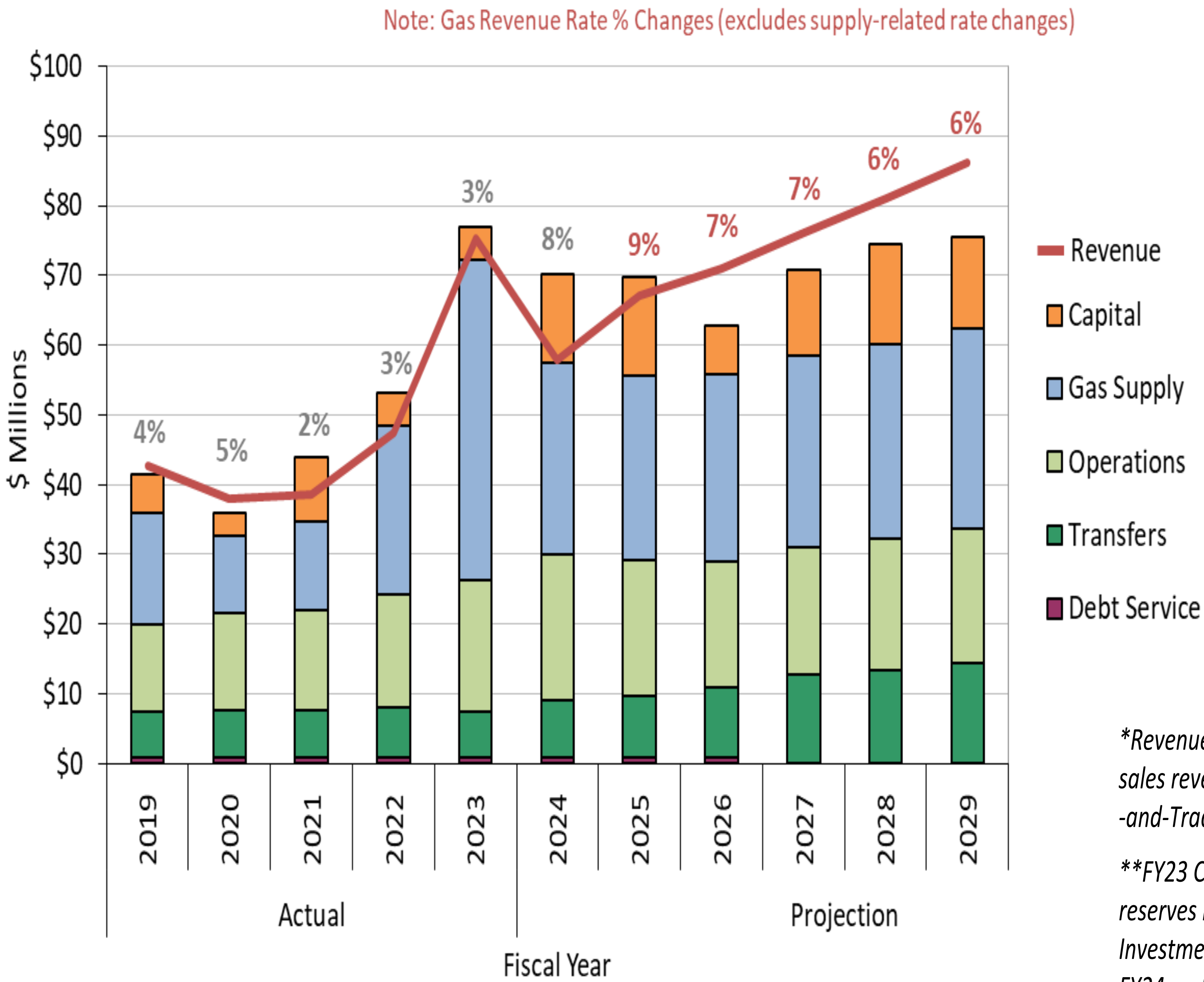
Fiscal Year	2024	2025	2026	2027	2028	2029
Transfer 11.9%	7%	16%	12%	26%	6%	7%
Transfer 18%	7%	76%	-19%	15%	6%	7%



Note: Projected revenues can fluctuate depending on gas commodity market prices

Gas Cost and Revenue Projections

Transfer 11.9%



**Revenue excludes Cap-and-Trade auction sales revenue, which goes directly to the Cap -and-Trade reserve*

***FY23 Commitments and Reappropriations reserves balances for Operations and Capital Investment are anticipated to be utilized in FY24 and FY25*

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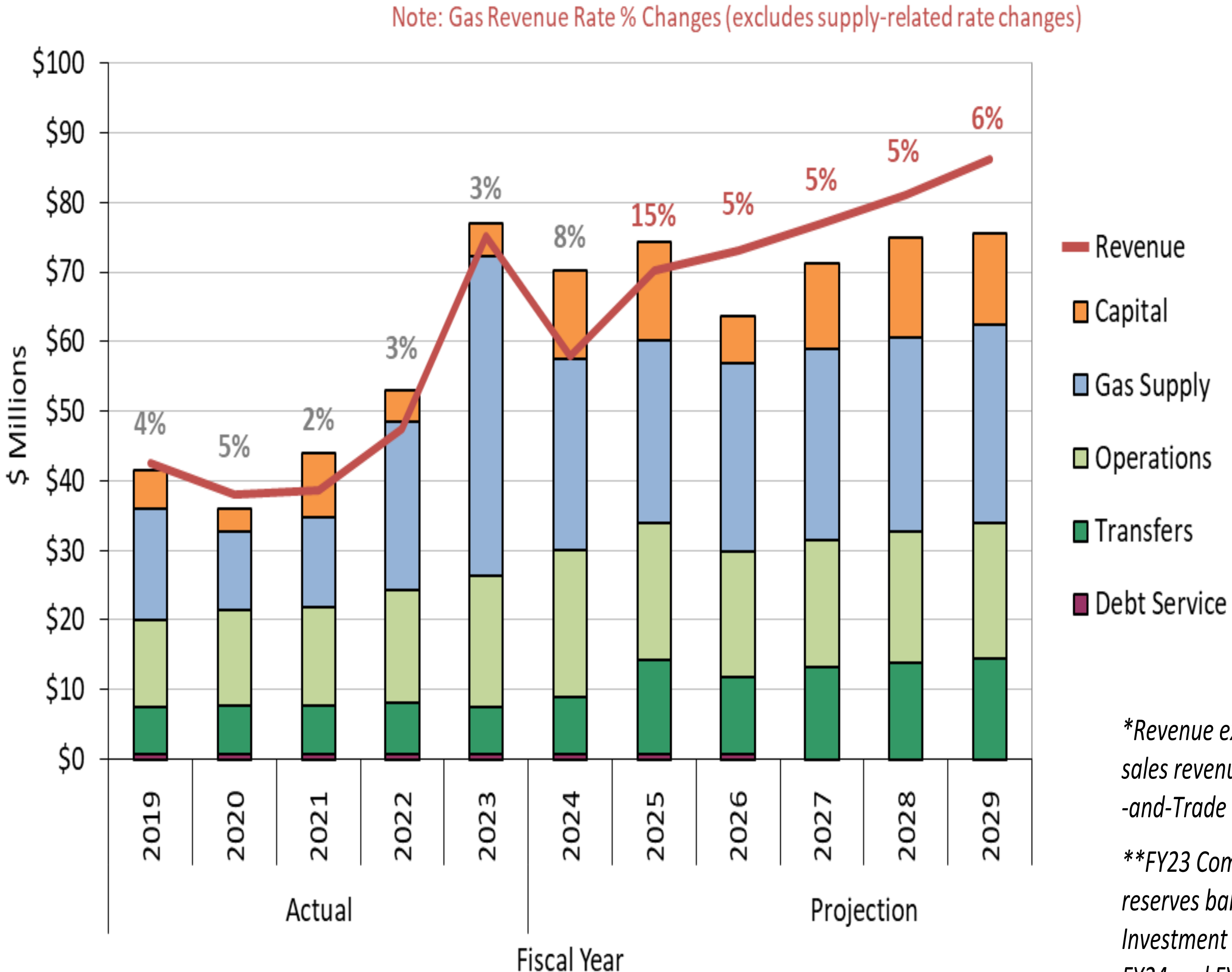
Gas Cost and Revenue Projections

Transfer 18%



**Revenue excludes Cap-and-Trade auction sales revenue, which goes directly to the Cap -and-Trade reserve*

***FY23 Commitments and Reappropriations reserves balances for Operations and Capital Investment are anticipated to be utilized in FY24 and FY25*

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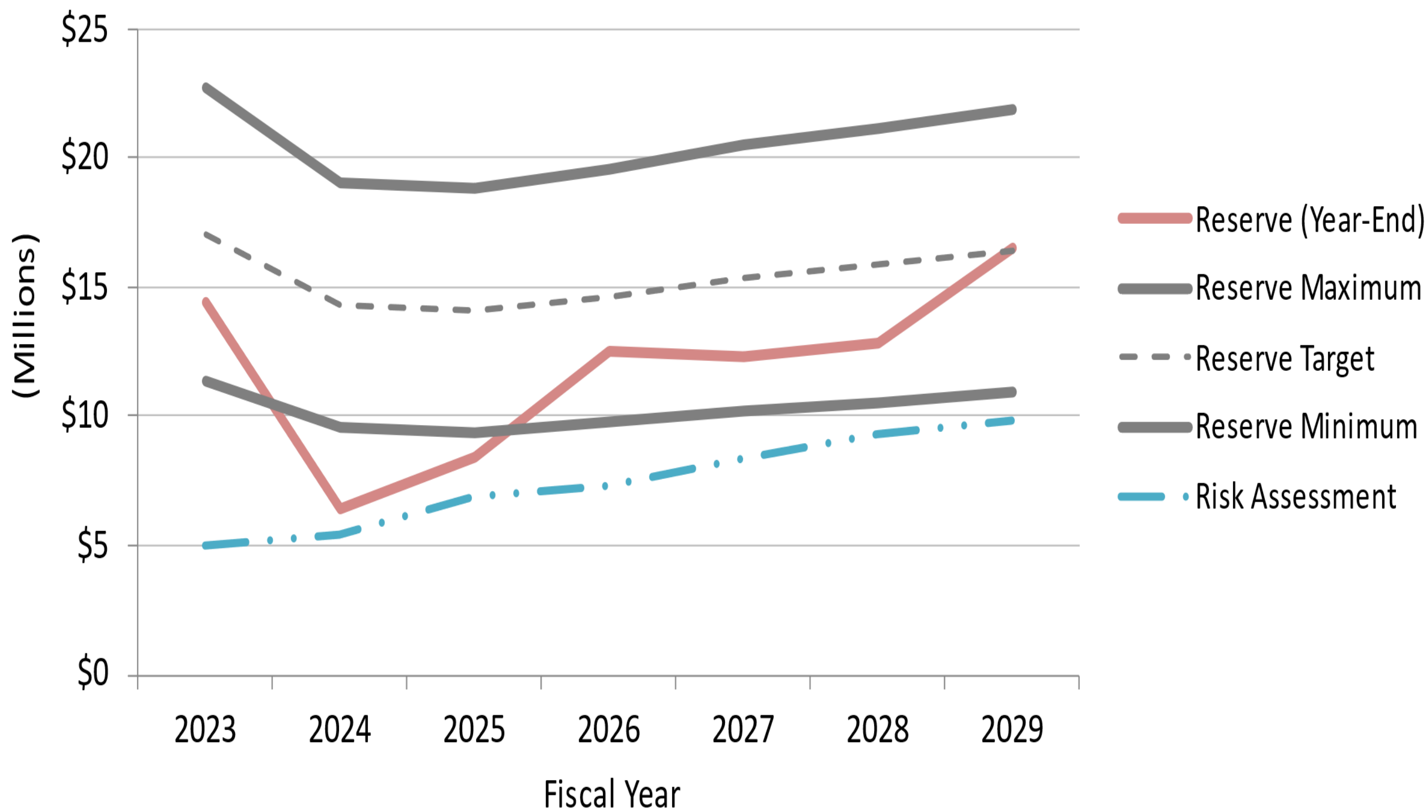
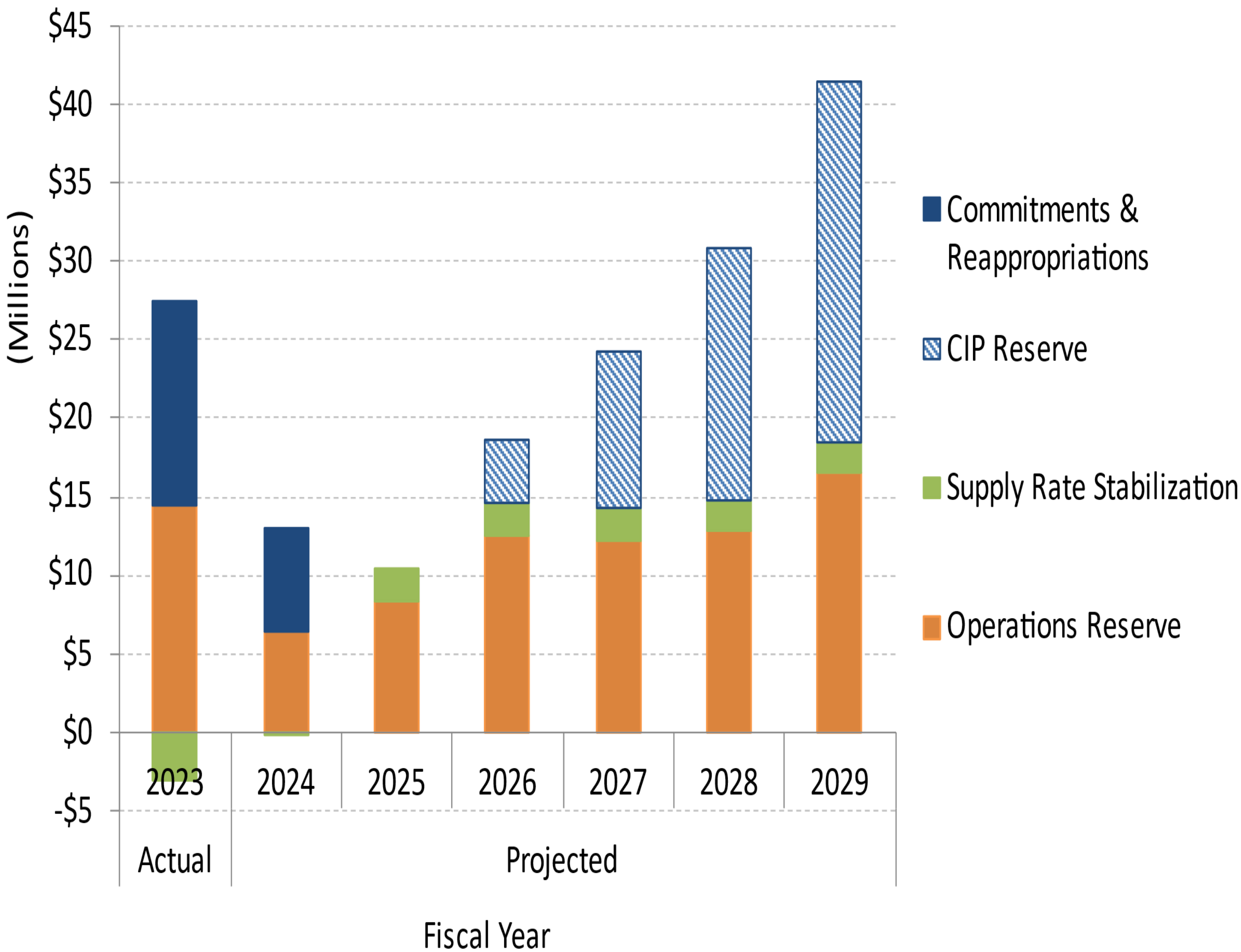
Gas Operations Reserve Projections

Transfer 11.9%



CITY OF PALO ALTO

Gas Reserve Projections



Note: Excludes Cap and Trade Reserve

Gas Rates Recommendation

Staff Recommend the Utilities Advisory Commission Recommend the Finance Committee Recommend that the City Council adopt a resolution:

A. Approving the FY 2025 Gas Utility Financial Plan, including amending the Gas Utility Reserve Management Practices; and

B. Transferring up to 11.9% of gas utility gross revenues received during FY 2023 to the general fund in FY 2025

C. Increasing gas rates by amending Rate Schedules G-1 (Residential Gas Service), G-2 (Residential Master-Metered and Commercial Gas Service), G-3 (Large Commercial Gas Service), and G-10 (Compressed Natural Gas Service)

Utilities Advisory Commission
Staff Report

From: Dean Batchelor, Director Utilities
Lead Department: Utilities

Meeting Date: March 6, 2024
Staff Report: 2401-2476

TITLE
Staff Recommends the Utilities Advisory Commission Recommend that City Council Adopt a Resolution Approving the Fiscal Year 2025 Water Utility Financial Plan, and Increase Water Rates by Amending Rate Schedules W-1 (General Residential Water Service), W-2 (Water Service From Fire Hydrants), W-3 (Fire Service Connections), W-4 (Residential Master-Metered and General Non-Residential Water Service), and W-7 (Non-Residential Irrigation Water Service)

RECOMMENDATION
Staff requests that the Utilities Advisory Commission (UAC) recommend that the Council: Adopt a resolution (Attachment A):
1. Approving the Fiscal Year (FY) 2025 Water Utility Financial Plan (Attachment A, Exhibit 1); and
2. Amending the following rate schedules to reflect increases effective July 1, 2024 (FY 2025): W-1 (General Residential Water service), W-2 (Water Service from Fire Hydrants), W-3 (Fire Service Connections), W-4 (Residential Master-Metered and General Non-Residential Water Service), and W-7 (Non-Residential Irrigation Water Service) (Attachment A, Exhibit 2)

EXECUTIVE SUMMARY

The City's water rate schedules consist of a volumetric charge for each CCF (100 Cubic Feet or 748 gallons) of water consumed during the billing period and a monthly service charge for each customer, based on water meter size. The volumetric charge has two parts: a wholesale commodity rate (or San Francisco Public Utilities Commission or SFPUC wholesale rate), and a customer volumetric rate. Water rates are designed to recover the City's costs of buying and distributing water while maintaining adequate financial reserves. The customer volumetric rate and the monthly service charge together are considered the distribution rates; revenue from those rates pay for the upkeep of Palo Alto's distribution system. Revenue from the wholesale commodity rate pays for the City's cost of buying water from the SFPUC.

The fiscal year (FY) 2025 Water Utility Financial Plan includes projections of the utility's costs and revenues for FY 2024 through FY 2029. The Financial Plan anticipates costs will rise by about 5.9%

per year on average over the next several years. Due to the drought and water conservation efforts together with near record-setting precipitation and snowpack in the winter of 2022-2023, the water utility's sales revenue declined in FY 2023 by $4.864 million or 10% compared with sales revenue in FY 2021. Funding from the Operations Reserve together with a $3 million transfer from the Rate Stabilization Reserve to the Operations Reserve offset the revenue declines. Net of supply cost savings, water sales were $2.4 million lower than forecasted. Demand recovery is projected to be slow, and as occurred following prior droughts, some conservation is projected to be permanent.

The Water Utility used available reserves to hold rates flat for two years (FY 2021 and FY 2022) and manage two years of drought-related sales revenue reductions so far (FY 2022 and FY 2023). The attached Financial Plan uses reserve funding from the Operations Reserve, Rate Stabilization Reserve and CIP Reserve together with rate increases to manage the continuing decreased sales revenue and increasing costs throughout the planning period. While these rate increases can be perceived as decreasing the benefit of conservation, bills for customers who conserve will be lower in the future than they would have been without conservation. Without the use of the Rate Stabilization Reserve in FY 2024 and FY 2025, water distribution rate increases of at least 22% would be needed in FY 2025. This Financial Plan projects that the Rate Stabilization Reserve will be exhausted by the end of FY 2026 and begin to be refilled in FY 2029.

Customers have a separate commodity rate for purchased water from the San Francisco Public Utilities Commission (SFPUC) relative to the rest of the distribution-related portion of the volumetric rates. This commodity charge was passed-through to customers for a five year period from July 1, 2020 through June 30, 2024 (Resolution 9844[1]). The commodity rate is currently $5.21 per hundred cubic feet (CCF) and will increase to $5.55 on July 1, 2024, according to SFPUC's February 15, 2024 forecast. The SFPUC will not determine its final wholesale customer rate for FY 2025 until May or June 2024. Staff will use the Prop 218 process to request Council approval to increase the commodity rate in accordance with SFPUC's projections on July 1, 2024. Additionally, staff will request Council approval to re-authorize the pass-through provision for the water commodity charge for another five-year period from 2024 through 2029[2] for possible future commodity charge increases during that time period.

BACKGROUND

[1] Resolution 9844 https://www.cityofpaloalto.org/files/assets/public/v/1/city-clerk/resolutions/reso-9844.pdf?t=69020.51

[2] California Government Code Section 53756 (established by AB-3030) became effective January 1, 2009. This section of the Code authorizes public agencies providing water, sewer, and garbage services to adopt automatic pass-through rate adjustments to account for increases in wholesale water charges or wastewater treatment charges, as well as inflation.

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

All of the City's potable water comes from the SFPUC's Hetch Hetchy Regional Water System or Regional Water System. This same system serves San Francisco and other Bay Area cities. San Francisco operates the system, but as much as two thirds of the water is used outside of San Francisco by 26 cities, water districts, and private utilities. These agencies, including the City, are frequently referred to as the "wholesale customers" (as compared to the SFPUC's "retail customers" in San Francisco). The Bay Area Water Supply and Conservation Agency (BAWSCA) represents the water supply and conservation interests of wholesale customers and negotiates with the SFPUC on their behalf. BAWSCA also ensures contract compliance through regular review of the SFPUC's accounting and capital expenditures.[3]

The Water Utility has two main costs: water supply costs (primarily the cost of water delivered to Palo Alto from the Regional Water System) and the costs of operating the distribution system (the system of pipes, pumps, reservoirs, and other infrastructure that carries water to Palo Alto customers). Both cost components have been increasing and are expected to continue to increase.

For many years, the largest cost increases have been on the water supply side. This is due primarily to major capital investments the SFPUC has made since 2010, which were undertaken partly due to pressure from wholesale customers. The Water System Improvement Program (WSIP) is a $4.8 billion capital improvement program, one of the largest in the country, to rehabilitate and seismically strengthen the lower portions of the Regional Water System. One of the goals is to achieve the capability to return to service within 24 hours after a major earthquake. Although much of the work is complete, some of the projects are still under construction and bond financing of WSIP projects over the next several years will continue to drive wholesale rates up. The program has greatly improved the resiliency of the Hetch Hetchy Regional Water System but has also led water supply costs to approximately double. Additionally, reduced regional water demand as a result of drought and drought rebound together with relatively wet weather in 2023 has put upward pressure on wholesale rates. The third driver of wholesale rate increases is the wholesale customer balancing account; SFPUC used a balance in this account owed to wholesale customers to hold rates constant for five years and mitigate the need for rate increases during the drought. However, the account is projected to have a $19.4 million balance owed to the City of San Francisco by the end of the current fiscal year.

CPAU's operational costs for the water utility have increased by approximately 6.5% per year over the last five years; Resource Management, Customer Service, and Operations and Maintenance costs were the primary reasons for the increase. Capital costs have fluctuated from

[3] For a video summary of BAWSCA's activities, see https://vimeo.com/283596665/5619ce2c11

year to year and are projected to increase due to construction inflation as well as one-time capital needs to replace or rehabilitate two reservoirs. This Financial Plan projects increases in capital and operational costs that align similarly with the City's Budget and Long-Range Financial Forecast and average approximately 4% - 6% per year over the next five years.

ANALYSIS

Staff annually assesses the financial position of the City's water utility to plan for adequate revenue to fund operations, in compliance with the cost of service requirements set forth in the California Constitution (Proposition 218). 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. The current rate proposals are also based on the cost of service (COS) methodology in the 2019 report by Raftelis Financial Consultants titled "Proposed FY 2020 Water Rates," (see Attachment Q[4] to staff report 10295[5]), which updated methodology originally described in the 2012 *Palo Alto Water Cost of Service & Rate Study*, and its subsequent updates in 2015

Proposed Actions

1. Increase rates for Rate Schedules W-1 (General Residential Water service), W-2 (Water Service from Fire Hydrants), W-3 (Fire Service Connections), W-4 (Residential Master-Metered and General Non-Residential Water Service), and W-7 (Non-Residential Irrigation Water Service); and
2. Transfer up to $3.461 million from the CIP Reserve to the Operations Reserve in FY 2024.
3. Transfer up to $2.069 million from the Rate Stabilization Reserve to the Operations Reserve in FY 2024.

The FY 2024 Water Utility Financial Plan describes these proposed actions in detail. Tables 1 through 4 below illustrate the current and proposed water distribution rates under the attached Financial Plan. The rates shown below are exclusive of the commodity rate charged to customers based on SFPUC supply charges. The commodity rate is currently $5.21 per CCF. SFPUC's proposed rate increase in FY 2025 is $5.55 per CCF (6.5% increase); the current rate would increase on or around July 1, 2024. SFPUC is also proposing to increase the SFPUC meter charge but has not yet finalized the impacts on that charge.

[4] Staff Report 10295 Attachment Q https://www.cityofpaloalto.org/files/assets/public/v/1/agendas-minutes-reports/reports/city-manager-reports-cmrs/attachments/attachment-q-6055187-water-cosa.pdf?t=48180.98

[5] A cost of service study (COS) is a study using industry-standard techniques to determine how the costs of running the utility should be recovered from its customers; charges to each customer are set in proportion to the cost of serving that customer.

Table 1: Current and Proposed Water Consumption Charges

	Current (7/1/2023)	Proposed (7/1/2024)	Change ($/CCF)	Change (%)
W-1 (Residential) Volumetric Rates ($/CCF)				
Tier 1 Rates	2.72	3.07	0.35	13%
Tier 2 Rates	6.33	7.15	0.82	13%
W-2 (Construction) Volumetric Rates ($/CCF)				
Uniform Rate	3.83	4.32	0.49	13%
W-4 (Commercial) Volumetric Rates ($/CCF)				
Uniform Rate	3.83	4.32	0.49	13%
W-7 (Irrigation) Volumetric Rates ($/CCF)				
Uniform Rate	5.83	6.58	0.75	13%

Table 2 and **Error! Reference source not found.**Table 3 show the current monthly service charges for rate schedules W-1, W-4 and W-7.

Table 2: Current and Proposed Monthly Service Charges for Residential W-1

Meter Size	Monthly Service Charge ($/month based on meter size)		Change	
	Current (7/1/2023)	Proposed (7/1/2024)	$	%
5/8”	21.48	24.27	2.79	13%
3/4”	21.48	24.27	2.79	13%
1”	21.48	24.27	2.79	13%
1 ½”	69.38	78.39	9.01	13%
2”	107.32	121.27	13.95	13%
3”	227.48	257.05	29.57	13%
4”	404.56	457.15	52.59	13%
6”	828.27	935.94	107.67	13%
8”	1,523.92	1,722.02	198.10	13%
10”	2,409.29	2,722.49	313.20	13%
12”	3,168.19	3,580.05	411.86	13%

Table 3: Current and Proposed Monthly Service Charges for W-4 and W-7

Meter Size	Monthly Service Charge ($/month based on meter size)		Change	
	Current (7/1/2023)	Proposed (7/1/2024)	$	%
5/8”	18.78	21.22	2.44	13%
3/4”	25.11	28.37	3.26	13%
1”	37.76	42.66	4.90	13%
1 ½”	69.38	78.39	9.01	13%
2”	107.32	121.27	13.95	13%
3”	227.48	257.05	29.57	13%
4”	404.56	457.15	52.59	13%
6”	828.27	935.94	107.67	13%
8”	1,523.92	1,722.02	198.10	13%
10”	2,409.29	2,722.49	313.20	13%
12”	3,168.19	3,580.05	411.86	13%

Table 4 shows the current and proposed monthly service charges for rate schedule W-3.

Table 4: Current and Proposed Monthly Service Charges for Fire Services (W-3)

Meter Size	Monthly Service Charge ($/month based on meter size)		Change	
	Current (7/1/2023)	Proposed (7/1/2024)	$	%
2”	4.42	4.99	0.57	13%
4”	27.38	30.93	3.55	13%
6”	79.51	89.84	10.33	13%
8”	169.45	191.47	22.02	13%
10”	304.74	344.35	39.61	13%
12”	492.24	556.23	63.99	13%

Bill Impact of Proposal

Table 5 and Table 6 show the impact of the proposed July 1, 2024 rate changes on the median residential, commercial and irrigation bills including the SFPUC commodity pass-through rate increase of 6.5% or $5.55 per CCF. The bill increases shown in Table 6 vary by usage because the SFPUC increase per CCF differs from the distribution rate increases.

Table 5: Impact of Proposed Water Rate Changes on Residential Bills

Usage (CCF/mo.)	Bill under Current Rates (7/1/2023)	Bill under Proposed Rates (7/1/2024)	Change	
			$/mo.	%
4	$53.20	$58.75	$5.55	10%
(Winter median) 7	$80.60	$88.69	$8.09	10%
(Annual median) 9	$103.68	$114.09	$10.41	10%
(Summer median) 14	$161.38	$177.59	$16.21	10%
25	$288.32	$317.29	$28.97	10%

Table 6: Impact of Proposed Water Rate Changes on Commercial Bills

Usage (CCF/mo.)	Bill under Current Rates (7/1/2023)	Bill under Proposed Rates (7/1/2024)	Change	
			$/mo.	%
Commercial (W-4) (5/8” meters)				
(Annual median) 12	$127.26	$139.66	$12.40	10%
(Annual average) 64	$597.34	$652.90	$55.56	9%
Irrigation (W-7) (1 ½” meters)				
(Winter median) 9	$168.74	$187.56	$18.82	11%
(Summer median) 37	$477.86	$527.20	$49.34	10%
(Winter average) 56	$687.62	$757.67	$70.05	10%
(Summer average) 199	$2,266.34	$2,492.26	$225.92	10%

Staff expects median quantities of water use to decrease from pre-drought levels, however, as calls for water conservation continue. Customers who conserve will experience less of a bill increase than those customers who are not reducing water consumption.

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

Table 7 shows the projected rate adjustments over the next five years and their impact on the annual median residential water bill for 5/8” customers. These projected rate adjustments include the impact of the commodity rate increasing consistent with SFPUC’s rate projection from the February 15, 2024 Wholesale Customer meeting which forecasted a 6.5% in FY 2025 to $5.55 per CCF followed by 1.4% in FY 2026, 5.3% in FY 2027, 7.4% in FY 2028 and 3.6% in FY 2029.

Table 7: Projected Rate Adjustments, FY 2025 to FY 2029 (5/8" meter)

Fiscal Year	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Water Utility	10%	8%	11%	11%	5%
Estimated Monthly Bill	$114.09	$123.78	$137.45	$152.35	$160.12
Estimated Bill Impact ($/mo)[1]	$10.41	$9.69	$13.67	$14.90	$7.77
1) estimated impact on median monthly residential water bill for customers with 5/8" meter, which is currently $103.68.					

Figures 1 and 2 below illustrate the projected increases in the Water Utility's costs between FY 2024 and FY 2029. Capital shown for FY 2024 includes an average of FY 2024 and FY 2023 and reflects CIP dollars budgeted in prior years carried forward to FY 2024. Capital costs are increasing more than supply and operations due to the replacement or rehabilitation of two reservoirs.

Figure 1: Projected FY 2024 and FY 2029 costs

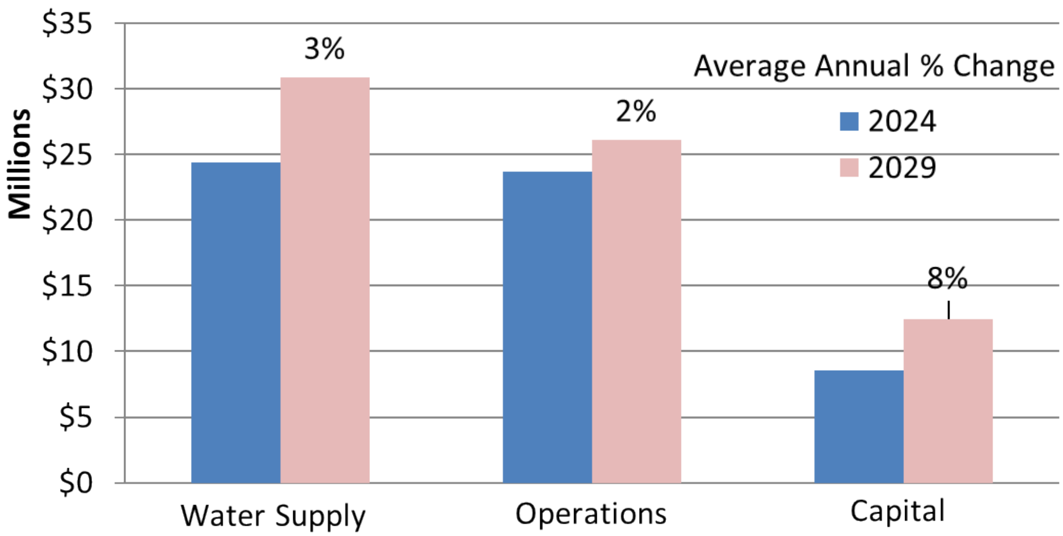
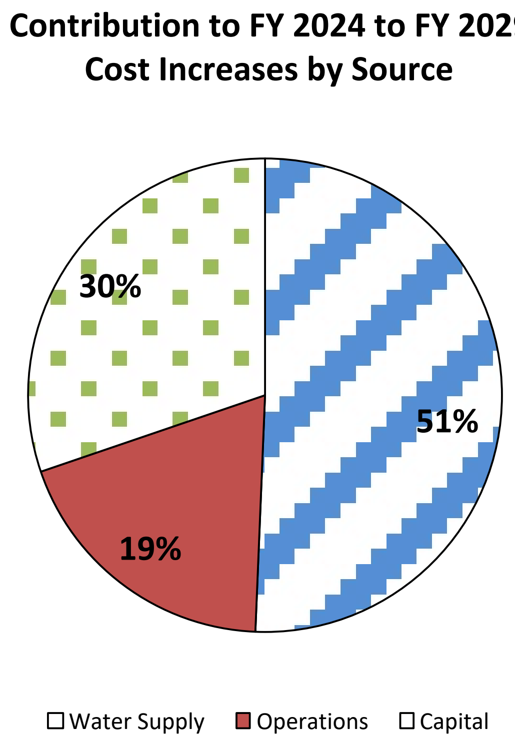


Figure 2: Percentage of Total Cost Increase From FY 2024 to FY 2029 Attributed to Supply, Capital, and Operations Costs



Water Supply Costs

The cost of water is a major driver for the increase in the Water Utility's costs (and therefore rates) in FY 2025. Wholesale water costs are adopted by the SFPUC, and generally have changed on an annual basis. The SFPUC is currently engaged in a $4.8 billion Water System Improvement Program (WSIP) for regional projects. As of June 30, 2023, 99.2% of the WSIP regional construction contracts are complete.[6] WSIP will continue to result in large increases in the annual debt service costs assigned to wholesale customers like Palo Alto. After each WSIP project is completed, wholesale customers must start paying the debt service costs within 3 to 4 years. For most of those costs, funded with bond financing, the costs will be paid off over approximately 30 years.

[6] Fourth Quarter FY 2022 - 2023 WSIP Regional Quarterly Report, https://sfpuc.org/sites/default/files/documents/WSIP_Quarterly%20Report_FY2022-23_Q4.pdf The currently estimated WSIP completion date is February 7, 2027, as adopted by the SFPUC in April of 2022.

As the SFPUC completes WSIP projects, the SFPUC is pursuing a suite of other capital improvement work; dam safety improvements and Mountain Tunnel (a critical piece of infrastructure used to move water from the Hetch Hetchy Reservoir to the Bay Area) repairs are rate increase drivers during the next 10-year timeframe. Future and in-progress construction work will require bond funding.

BAWSCA Revenue Bond Refunding

On January 5, 2023, BAWSCA completed the settlement of BAWSCA's revenue bond series 2023A to refund bonds issued in 2013 at a lower rate. BAWSCA locked-in the bond rates in October 2021 at an all-in true interest rate of 2.06%. The refunding bond transaction will generate approximately $27.1 million in net present value savings over the term of the bonds, or an average of approximately $2.5 million of savings per year for all Wholesale Customers, starting in fiscal year 2022-23. The estimated net present value of savings per year for Palo Alto is approximately $175,000.

Capital Projects & Reserves

The capital budget includes one-time seismic water system upgrades and/or replacements for the Park and Dahl reservoirs to improve earthquake resiliency. This work will improve protection from water loss at these reservoirs in a seismic event.

The attached Financial Plan also updates the transfer proposals due to project cost increases and available reserve balances. For CIP, the Financial Plan assumes funding from rates will cover $7.461 million of planned CIP in FY 2024. This figure is the portion of planned CIP in FY 2024 that will not be paid for through funds collected in prior years (the FY 2024 Capital budget, less funds available in the Reappropriations and Commitments Reserves at FY 2023 year's end), shown in line 13 of Table 9 for FY 2024. This capital budget is projected to be funded by the capital program contribution of $4 million in FY 2024 together with $3.461 million from the CIP Reserve. Because withdrawals from the CIP Reserve for use on capital projects require Council action,[7] staff requests Council approval to transfer up to $3.461 million from the CIP Reserve to the Operations Reserve. The need for each of the transfers will be re-evaluated once the year-end reserve balances for FY 2024 are known. The capital program contribution is lower than in future years because reservoir rehabilitation project moved from FY 2024 to FY 2028 which delayed the need for approximately $6 million of the capital funding by four years. Figure 3 shows the CIP Reserve year-end balances.

[7] *See* Section 5(b) of the Water Utility Reserves Management Practices; Appendix C to the attached Water Financial Plan.

Figure 3: Actual FY 2023 and Projected Capital Reserve Balances FY 2024 to FY 2029

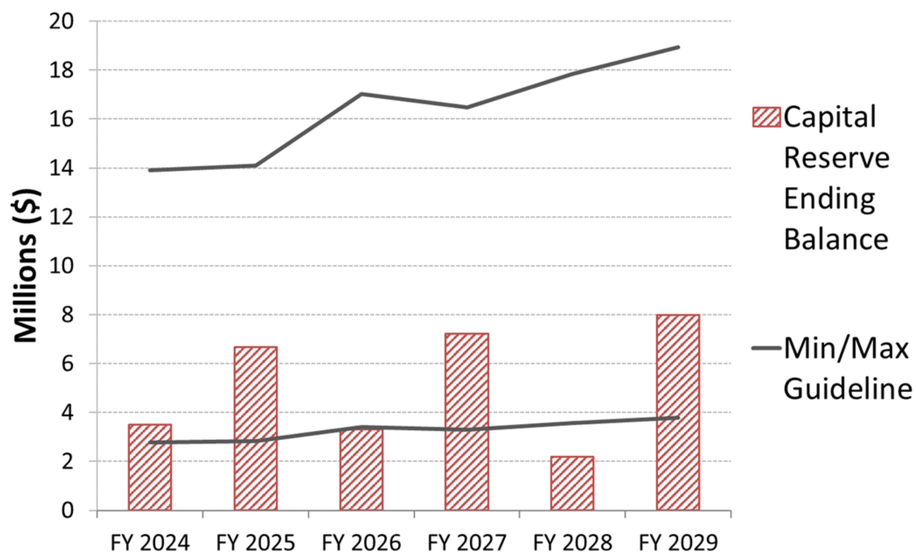
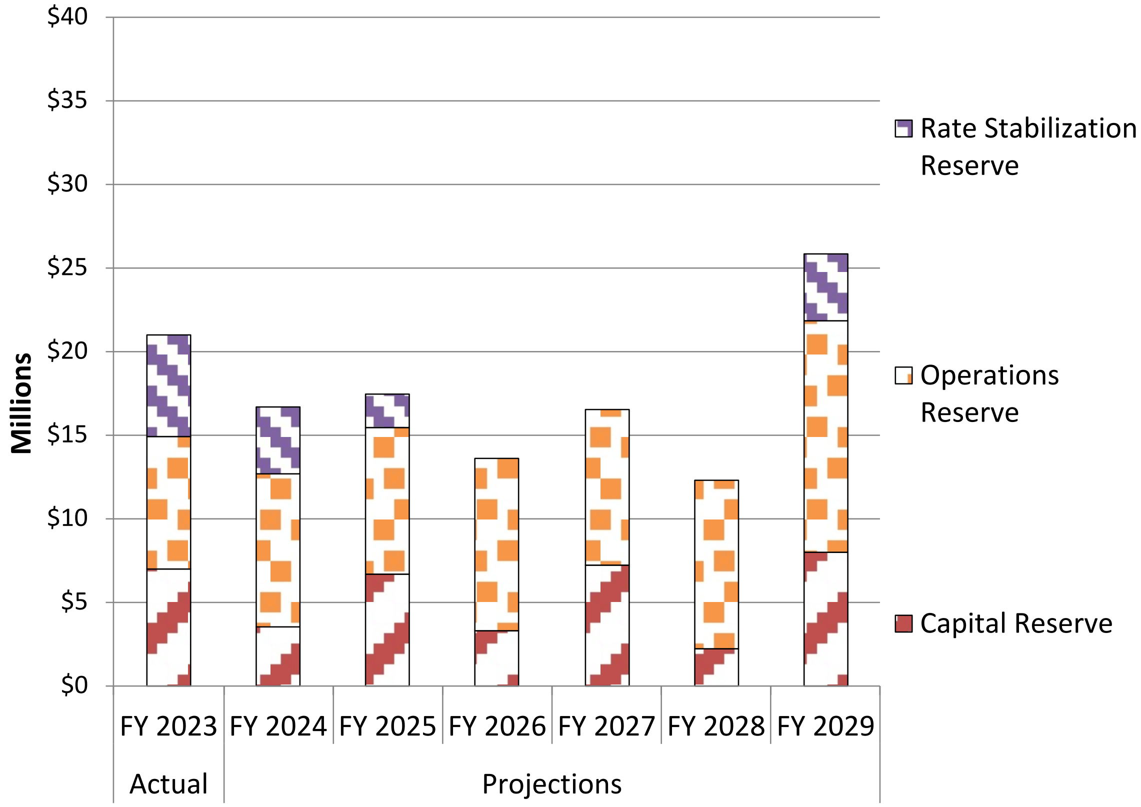


Figure 4 illustrates the year-end reserve balances for FY 2023 (actual) and projected through FY 2029. Although the CIP Reserve drops below the minimum guideline range in FY 2028, this is temporary and is due to one-time reservoir replacement as one of the planned reservoir seismic upgrades. The CIP Reserve returns to within the guideline in the following year and in all future years. In accordance with the Water Utility Reserves Management Practices Section 5(c) (included as Appendix C to the attached Financial Plan), the Council may approve a plan to address a CIP Reserve below the minimum level within one or more years.

Water Utility Operation Reserve levels remain within guideline ranges at year-end FY 2023: the CIP Reserve ending balance was $6.961 million and the Operations Reserve year-end balance for FY 2023 was $7.957 million. There is also $6.069 million available in the Rate Stabilization Reserve at year-end FY 2023. This Financial Plan uses reserve funding (from the Operations Reserve, Rate Stabilization Reserve and CIP Reserve) together with rate increases to manage the decreased sales revenue and increasing costs from FY 2025 through FY 2029.

Figure 4: Actual Reserve Levels for FY 2023 and Projections through FY 2029



<u>Rate Stabilization Reserve</u>

Staff plans to use the Rate Stabilization Reserve balances to buffer the impact of current and anticipated future rate increases. Staff expects to transfer $2.069 million from the Rate Stabilization Reserve to the Operations Reserve in FY 2024 and $2 million from the Rate Stabilization Reserve to the Operations Reserve in FY 2025, and in FY 2026. Utilizing the Rate Stabilization Reserve balances in this manner, along with the cost and revenue projections outlined in this Financial Plan, is anticipated to minimize the potential water distribution rate increases to a level lower than they would be otherwise. This approach allows for smoothing of rate increases across multiple years and ensures ongoing funding of crucial capital projects. This Financial Plan projects that the Rate Stabilization Reserve will be exhausted by the end of FY 2026 (see line 7 in Table 9).

Table 9: Operations & Unassigned, Rate Stabilization and CIP Reserves Starting and Ending Balances, Revenues, Transfers To/(From) Reserves and Capital Program Contribution To/(From) Reserves Projected for FY 2024 to FY 2029 ($000)

		FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
	Starting Balance						
(1)	Operations/Unassigned	7,957	9,180	8,799	10,267	9,333	10,089
(2)	Rate Stabilization	6,069	4,000	2,000	-	-	-
(3)	CIP	6,961	3,500	6,679	3,312	7,233	2,190
	Revenues						
(4)	Total Revenue	49,904	55,887	61,743	67,713	74,059	76,834
(5)	Transfers In	342	353	363	373	389	400
	Transfers						
(6)	Operations/Unassigned	3,040	2,000	600	(6,100)	(6,500)	(4,000)
(7)	Operating Commitments	(971)	-	-	-	-	-
(8)	Rate Stabilization	(2,069)	(2,000)	(2,000)	-	-	4,000
(9)	CIP	-	-	1,400	6,100	6,500	-
	Capital Program Contribution						
(10)	Operations/Unassigned	(4,000)	(9,000)	(9,486)	(9,998)	(11,790)	(12,427)
(11)	CIP	4,000	9,000	9,486	9,998	11,790	12,427
	Expenses						
(12)	Total Expenses other than CIP	(46,341)	(49,141)	(50,991)	(52,157)	(54,631)	(56,252)
(13)	Planned CIP	(7,461)	(5,821)	(14,253)	(12,177)	(23,334)	(6,627)
(14)	Transfers Out	(1,721)	(480)	(761)	(765)	(770)	(775)
	Ending Balance						
(1)+(4)+(5)+(6)+(10)+(12)+(14)	Operations/Unassigned	9,180	8,799	10,267	9,333	10,089	13,869
(2)+(8)	Rate Stabilization	4,000	2,000	-	-	-	4,000
(3)+(9)+(11)+(13)	CIP	3,500	6,679	3,312	7,233	2,190	7,989
	Operations Reserve Guideline Levels						
(15)	Minimum Guideline Level	7,901	8,157	8,507	8,700	9,107	9,374
(16)	Maximum Guideline Level	15,801	16,314	17,014	17,399	18,214	18,749

* Planned CIP (item 13) is reflected as an expense in the CIP Reserve and does not include CIP funded through Reappropriations or Commitments reserves. This will be funded with the $4 million Capital Program Contribution (item 11) and $3.461 million from the CIP Reserve.

Water Bill Comparison with Surrounding Cities

Table 10 compares water bills for residential customers to those in surrounding communities as of January 2024 (under current the City's current water rates). Palo Alto customers have some of the highest monthly bills of the group, although bills for smaller water users are lower than in some surrounding communities. The bill difference between Palo Alto and neighboring communities has decreased over the past several years as other agencies invest more in capital improvement. It is unclear at this time what water rate changes may be implemented in surrounding communities for FY 2025. The average community rate calculated in the following table is the mean of the six surrounding communities listed. These communities are the same six that Palo Alto compares itself to in the annual budget across Water, Wastewater, Gas and Electric industries.

Table 10: Residential Monthly Water Bill Comparison

Usage (CCF/month)	Residential monthly bill comparison ($/month)* As of February 2024							
	Palo Alto	Menlo Park	Mountain View	Hayward	Redwood City	Santa Clara	Los Altos	Average of Surrounding Communities
4	$53.20	$65.20	$46.95	$45.17	$64.16	$31.88	$58.71	$52.01
(Winter median) 7	80.60	91.00	72.69	69.59	86.27	55.79	79.51	75.81
(Annual median) 9	103.68	108.19	89.85	85.87	112.31	71.73	93.38	93.55
(Summer median) 14	161.38	155.10	132.75	135.87	180.22	111.58	131.23	141.12
25	288.32	271.23	278.63	245.87	340.49	199.25	233.01	261.41

*Based on the FY 2013 BAWSCA survey, the percentage of SFPUC as the source of potable water supply was 100% for Palo Alto, 95% for Menlo Park, 100% for Redwood City, 87% for Mountain View, 10% for Santa Clara and 100% for Hayward. Los Altos does not receive water supply from SFPUC.

Changes from Last Year's Financial Plan

Table 11 shows rate projections from the last two Financial Plans for FY 2022 and FY 2023 as well as the impact of SFPUC's wholesale rate increase projections when combined with Palo Alto's distribution rate increase.

Table 11: Proposed and Projected Water Revenue Changes for FY 2024 to FY 2028

Projection	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
FY 2025 Plan (Current)	10%	8%	11%	11%	5%
FY 2024 Plan	4%	3%	4%	6%	-
FY 2023 Plan	3%	2%	0%	-	-

Table 12 shows the FY 2025 Plan proposed water rate increases across the five-year forecast period through FY 2029, separated out by increases to commodity revenues to cover the costs of purchasing water from SFPUC (Table 12 line 1), and by the distribution revenue increases necessary to pay for the upkeep of Palo Alto's water distribution system (Table 12 line 2). Key changes are the commodity increases projected by SFPUC, and for distribution rates, the reduced water sales in Palo Alto and cost increases both in operating and capital costs over the forecast period.

Table 12: Proposed Commodity and Distribution Water Rate Changes FY 2025 to FY 2029

Projection	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Commodity Rate (SFPUC Wholesale Rate increases to $5.55 in FY 2025)	7%	1%	5%	7%	4%
Distribution Rate	13%	14%	15%	13%	6%
Total Rate	10%	8%	11%	11%	5%

This plan uses the Rate Stabilization Reserve to stabilize rates while anticipating 6.5% wholesale water rate increase in FY 2025 and funding needed for critical water CIP budgets.

FISCAL/RESOURCE IMPACT

Staff projects estimated revenue for the Water Utility in FY 2025 to increase approximately 10% ($4.9 million) as a result of the proposed rate increases. The FY 2025 Budget is being developed concurrent with these rates and, depending on the final rates, adjustments to the budget may be necessary. See the FY 2025 Water Utility Financial Plan for a more comprehensive overview of the projected cost and revenue changes for the next five years.

STAKEHOLDER ENGAGEMENT

At the Utilities Advisory Commission (UAC) January 2024 meeting, the Commission reviewed a preliminary rate trajectory with 5% overall water rate increases each year. Staff did not request a recommendation at that meeting; staff sought input from Commissioners regarding the preliminary rate adjustment recommendations. Some Commissioners commented that staff should consider higher rate increases and expressed concern about low reserve balances across the utilities. Staff increased the rate trajectory for the distribution rates and discussed the revised proposals with the Finance Committee on February 21, 2024; the Finance Committee's feedback will be described to the UAC during the March UAC meeting.

The Finance Committee in April will consider the water rate changes to recommend for Council's adoption. Assuming the Finance Committee supports the proposed rate adjustments, staff will send notification of the potential rate increases to customers as required by Article XIIID of the State Constitution (added by Proposition 218) expected in April 2024. The City Council will consider the proposed Financial Plans and amended rate schedules with the FY 2025 budget, expected in June, at which time the public hearing required by Article XIIID of the State Constitution will be held.

ENVIRONMENTAL REVIEW

The UAC's review and recommendation to Council on the FY 2025 Water Financial Plan and rate adjustments does not meet the definition of a project requiring California Environmental Quality Act (CEQA) review under Public Resources Code Section 21065 thus no environmental review is required.

ATTACHMENTS
Attachment A: Water FY25 Resolution
Attachment B: Water FY25 Presentation

AUTHOR/TITLE:
Dean Batchelor, Director of Utilities
Staff: Lisa Bilir, Senior Resource Planning

Resolution No.__________
Resolution of the Council of the City of Palo Alto Approving the FY 2025 Water Utility Financial Plan and Reserve Transfers, and Increasing Water Rates by Amending Rate Schedules W-1 (General Residential Water Service), W-2 (Water Service from Fire Hydrants), W-3 (Fire Service Connections), W-4 (Residential Master-Metered and General Non- Residential Water Service), and W-7 (Non-Residential Irrigation Water Service)

R E C I T A L S

A. Each year the City of Palo Alto ("City") 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. The City 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_________, 2024, the City Council held a full and fair public hearing regarding the proposed rate increase and considered all protests against the proposals.

E. As required by Article XIII D, Section 6 of the California Constitution and applicable law, notice of the______, 2024 public hearing was mailed to all City of Palo Alto Utilities water customers by __________________, 2024.

F. The City Clerk has tabulated the total number of written protests presented by the close of the public hearing, and determined that it was less than fifty percent (50%) of the total number of customers and property owners subject to the proposed water rate amendments, therefore a majority protest does not exist against the proposal.

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

SECTION 1. The Council hereby adopts the FY 2025 Water Utility Financial Plan.

SECTION 2. The Council hereby approves a transfer from the Capital Improvement Program Reserve to the Operations Reserve of up to $3,461,000 in FY 2024 as described in the FY 2025 Water Utility Financial Plan.

SECTION 3. The Council hereby approves a transfer from the Rate Stabilization Reserve to the Operations Reserve of up to 2,069,000 in FY 2024 as described in the FY 2025 Water Utility Financial Plan.

SECTION 4. Pursuant to Section 12.20.010 of the Palo Alto Municipal Code, Utility Rate Schedule W-1 (General Residential Water Service) is hereby amended to read as attached and incorporated. Utility Rate Schedule W-1, as amended, shall become effective July 1, 2024.

SECTION 5. Pursuant to Section 12.20.010 of the Palo Alto Municipal Code, Utility Rate Schedule W-2 (Water Service from Fire Hydrants) is hereby amended to read as attached and incorporated. Utility Rate Schedule W-2, as amended, shall become effective July 1, 2024.

SECTION 6. Pursuant to Section 12.20.010 of the Palo Alto Municipal Code, Utility Rate Schedule W-3 (Fire Service Connections) is hereby amended to read as attached and incorporated. Utility Rate Schedule W-3, as amended, shall become effective July 1, 2024.

SECTION 7. Pursuant to Section 12.20.010 of the Palo Alto Municipal Code, Utility Rate Schedule W-4 (Residential Master-Metered and General Non-Residential Water Service) is hereby amended to read as attached and incorporated. Utility Rate Schedule W-4, as amended, shall become effective July 1, 2024.

SECTION 8. Pursuant to Section 12.20.010 of the Palo Alto Municipal Code, Utility Rate Schedule W-7 (Non-Residential Irrigation Water Service) is hereby amended to read as attached and incorporated. Utility Rate Schedule W-7, as amended, shall become effective July 1, 2024.

SECTION 9. The City Council finds as follows:

a. Revenues derived from the water rates approved by this resolution do not exceed the funds required to provide water service.

b. Revenues derived from the water rates approved by this resolution shall not be used for any purpose other than providing water service, and the purposes set forth in Article VII, Section 2, of the Charter of the City of Palo Alto.

c. The amount of the water rates imposed upon any parcel or person as an incident of property ownership shall not exceed the proportional cost of the water service attributable to the parcel.

SECTION 10. The Council finds that 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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SECTION 11. The Council finds that the adoption of this resolution approving the FY 2025 Water Financial Plan and Reserve transfers 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 review is required. The Council finds that the adoption of this resolution changing water 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 A, Exhibit 1

FY 2025 WATER UTILITY FINANCIAL PLAN

FY 2025 TO FY 2029

FY 2025 WATER UTILITY FINANCIAL PLAN

FY 2025 TO FY 2029

TABLE OF CONTENTS

SECTION 1: DEFINITIONS AND ABBREVIATIONS

BAWSCA Bay Area Water Supply and Conservation Agency
CCF The standard unit of measurement for water delivered to water customers, equal to one hundred cubic feet, or roughly 748 gallons.
CIP Capital Improvement Program
CPAU City of Palo Alto Utilities Department
O&M Operations and Maintenance
RFC Raftelis Financial Consultants, Inc.
SFPUC San Francisco Public Utilities Commission
SFWD San Francisco Water Department
UAC Utilities Advisory Commission
WSIP The SFPUC's Water System Improvement Program to seismically strengthen the transmission lines of the Hetch Hetchy Regional Water System.

SECTION 2: EXECUTIVE SUMMARY AND RECOMMENDATIONS

This document presents a Financial Plan for the City's Water Utility for FY 2025 through FY 2029. This Financial Plan provides for revenues to cover the costs of operating the utility safely over that period 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 City's water rate schedules currently consist of a volumetric charge for each CCF (100 Cubic Feet or 748 gallons) of water consumed during the billing period and a monthly service charge for each customer, based on water meter size. The volumetric charge has two parts: a wholesale commodity rate (or San Francisco Public Utilities Commission or SFPUC wholesale rate), and a customer volumetric rate. Water rates are designed to recover the City's costs of buying and distributing water while maintaining adequate financial reserves. The customer volumetric rate and the monthly service charge together are considered the distribution rates; revenue from those rates pay for the upkeep of Palo Alto's distribution system. Revenue from the wholesale commodity rate pays for the City's cost of buying water from the SFPUC.

The fiscal year (FY) 2025 Water Utility Financial Plan includes projections of the utility's costs and revenues for FY 2024 through FY 2029. Due to the drought restrictions (SFPUC declared a drought emergency on November 23, 2021 through June 11, 2023 when voluntary conservation reductions ended) and water conservation efforts together with near record-setting precipitation and snowpack in the winter of 2022-2023, the water utility's sales revenue declined in FY 2023 by $4.864 million or 10% compared with sales revenue in FY 2021. Funding from the Operations Reserve together with a $3 million transfer from the Rate Stabilization Reserve to the Operations Reserve offset the revenue declines. Water sales, net of supply cost savings, were $2.4 million lower than forecasted. Staff expects water sales revenue to rebound in FY 2024 and FY 2025. Demand recovery is projected to be slow and as occurred following prior droughts, some conservation is projected to be permanent. Overall costs in the Water Utility are projected to rise on average by about 5.3% per year from Fiscal Year (FY) 2024 to 2029. Operations cost projections rise on average by about 4% annually from FY 2024 to 2029, excluding one-time transfers and debt service. Debt service is expected to decline by 4.5% during this time because one bond is to be retired in 2026. SFPUC's FY 2024 wholesale water rate is $5.21 per CCF. On February 15, 2024, SFPUC estimated its July 1, 2024 rate increase as $5.55/CCF. Section 6A: Water Purchase Costs includes details. Staff plans to request authorization from the City Council to extend Palo Alto's pass-through provision for the SFPUC wholesale rate increase effective July 1, 2024 (see Section 3A: Rate Design for more detail).

Overall, this Financial Plan uses reserve funding (from the Operations Reserve, Rate Stabilization Reserve and CIP Reserve) together with rate increases to manage the decreased sales revenue and increasing costs from FY 2024 through FY 2029. While these rate increases can be perceived as decreasing the benefit of conservation, bills for customers who conserve will be lower in the future than they would have been without conservation.

Table 1 shows the costs for the Water Utility from FY 2023 through FY 2029. The "CIP" row in Table 1 includes capital expenditure and increased capital funding for reappropriations and commitments in FY 2023 and planned contributions from the Operations Reserve to the CIP Reserve for FY 2024 through FY 2029. This does not include the additional one-time transfers from the Operations Reserve to the CIP Reserve, shown in Table 4. This also differs from planned CIP which is shown in line 13 of Table 4, and is reflected as an expense in the CIP Reserve.

Table 1: Expenses for FY 2023 to FY 2029 (Thousand $'s)*

Expenses ($000)	FY 2023 (act.)	FY 2024 (est.)	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Water Purchases	21,744	24,383	26,435	27,505	28,516	30,145	30,892
Operations	21,961	23,679	23,186	24,247	24,406	25,256	26,135
CIP	13,084	4,000	9,000	9,486	9,998	11,790	12,427
TOTAL	56,789	52,062	58,621	61,238	62,921	67,191	69,454

*Note: numbers in are rounded to the nearest thousand dollars.

End of Drought Water Use Restrictions

On November 23, 2021, the SFPUC declared a local water shortage emergency calling for voluntary system-wide 10% water use reductions.[1] In alignment with State requirements, on May 24, 2022, SFPUC adopted a system-wide voluntary water use reduction of 11% compared to baseline water use during FY 2020, effective July 1, 2022.[2] SFPUC serves retail customers in San Francisco as well as in Palo Alto and 25 other wholesale customers in the Bay Area. The collective voluntary water purchase cutback level for the wholesale customers was 16% from FY 2020 levels, while Palo Alto's voluntary water purchase cutback level was 8% from FY 2020 levels.[3] The

[1] SFPUC Resolution No. 21-0177
[2] SFPUC Resolution No. 22-0098
[3] During water shortages up to 20% system-wide, the "Tier 1" formula allocates water between retail and wholesale customers; the "Tier 2" formula then allocates water among wholesale customers in accordance with an agreement

Palo Alto City Council implemented the water use restrictions in Stage I of the Water Shortage Contingency Plan on March 7, 2022 and added the water use restrictions in Stage II on June 20, 2022. Additionally, on June 20, 2022, the City Council restricted potable irrigation of ornamental landscape and lawn to two days per week other than to ensure the health of trees.[4]

SFPUC's April 17, 2023 Water Supply Availability Update noted precipitation well above long-term median levels and all-time record snowpack. On April 11, 2023, the SFPUC adopted a resolution to rescind its water shortage emergency that became effective on June 10, 2023 when the State Water Board's drought emergency regulations expired that required the SFPUC to implement the drought response actions of its Water Shortage Contingency Plan. Palo Alto's water use restrictions track both the State's regulation and SFPUC's water use regulation and also expired on June 10, 2023.

Additionally, Palo Alto's Stage I water use restrictions were effective through December 2023[5] and the State's requirement for no use of drinking water for watering decorative grass in commercial, industrial and institutional areas remains effective until June 2024.[6]

The cost of SFPUC water supply is increasing over the forecast period due to increasing debt service for a series of major capital projects on the Hetch Hetchy Regional Water System or Regional Water System as well as decreased water demand system-wide and also due to the draw down of the wholesale customer balancing account. SFPUC's water supply rates remained flat from FY 2017 through FY 2022 as SFPUC returned accumulated reserves to customers. On July 1, 2022, SFPUC increased the supply rate by 15.9% from \$4.10 per CCF to \$4.75 per CCF of water delivered to Palo Alto. Again on July 1, 2023, SFPUC increased the supply rate by 9.7% from \$4.75 per CCF to the current rate of \$5.21 per CCF. On February 15, 2024, the SFPUC notified Palo Alto that the wholesale rate is expected to be \$5.55 on July 1, 2024 (a 6.5% increase from current rates). For more information, see *Section 6A: Water Purchase Costs*. Staff expects SFPUC to provide a final rate notice around May 2024.

Capital Improvement Program

Staff plans for a water main replacement construction project every other year. Actual capital costs vary from year to year; however, this Financial Plan continues with a stable annual capital contribution from the Operations Reserve to the Capital Improvement Program Reserve (CIP Reserve). *Section 6C: Capital Improvement Program (CIP)* provides more detail.

Rate Proposal

This Financial Plan projects that the Water Utility will need to implement the rate increases shown in Table 2 in order to generate sufficient revenues to cover costs and maintain reserves within

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among the wholesale customers. The Tier 2 formula considers each agency's Individual Supply Guarantee (or equivalent), seasonality of water usage and applies minimum and maximum cutbacks.

[4] For more information see https://www.cityofpaloalto.org/Departments/Utilities/Sustainability/Water-Conservation-and-Drought-Updates

[5] https://www.cityofpaloalto.org/files/assets/public/v/1/city-clerk/resolutions/resolutions-1909-to-present/2022/reso-10022.pdf

[6] https://www.waterboards.ca.gov/press_room/press_releases/2023/pr20230601-decorative-watering.pdf

guideline levels. This Financial Plan also projects that water supply costs will increase 1.4% in FY 2025 and then increase 5.3% in FY 2027, 7.4% in FY 2028 and 3.6% in FY 2029, consistent with SFPUC staff's February 15 projection). Staff expects some water conservation measures implemented during the drought to be permanent while some water sales rebound over the next 3 years. There is little or no expected increase in non-sales revenue, such as interest, connection fees and capacity fees.

Table 2 shows the rate projections from the previous financial plan for FY 2023, as well as the expected impact of SFPUC's expected 6.5% wholesale rate increase when combined with Palo Alto's distribution rate increase.

Table 2: Proposed and Projected Water Revenue Changes for FY 2025 to FY 2029

Projection	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
FY 2025 Plan (Current)	10%	8%	11%	11%	5%
FY 2024 Plan	4%	3%	4%	6%	-

Table 3 shows the proposed water rate increases broken out into the needed increases to commodity revenues, to cover the costs of purchasing water from SFPUC, and separately the distribution revenue increases to pay for the upkeep of Palo Alto's water distribution system. Given the uncertainty regarding drought conditions, the SFPUC wholesale rate forecast is highly uncertain after FY 2025.

Table 3: Proposed Commodity and Distribution Water Rate Changes FY 2025 to FY 2029

Projection	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Commodity Rate (SFPUC Wholesale Rate)	7%	1%	5%	7%	4%
Distribution Rate	13%	14%	15%	13%	6%
Total Rate	10%	8%	11%	11%	5%

Reserve Changes

The Water Utility's Rate Stabilization Reserve provides funding to smooth rate increases over several years. At the end of FY 2023, the balance in the reserve was $6.07 million. The use of the Rate Stabilization Reserve, together with the cost and revenue projections in this Financial Plan allow expected CPAU water distribution rates to increase by only 13% in FY 2025 and between 6 - 15% annually from FY 2026 through FY 2029. Without the use of the Rate Stabilization Reserve in FY 2024 and 2025, water distribution rate increases of at least 22% would be needed in FY 2025. This Financial Plan projects that the Rate Stabilization Reserve will be exhausted by the end of FY 2026 and begin to be refilled in FY 2029.

Table 4 shows the starting and ending balances for the Operations & Unassigned Reserves combined, Rate Stabilization Reserve, and CIP Reserve, minimum and maximum Operations Reserve guideline levels and projected reserve transfers over the forecast period.

This Plan updates the transfer proposals due to project cost and timing changes and available reserve balances. One-time transfers from the Operations Reserve to the CIP Reserve in FY 2027 through FY 2029 total $14 million and will fund the one-time water reservoir rebuild or rehabilitations for the Park and Dahl water reservoirs. In FY 2024, FY 2025 and FY 2026, transfers from the Rate Stabilization Reserve to the Operations Reserve will manage the trajectory of future year rate increases. This Financial Plan requests Council approval for the $2.07 million transfer from the Rate Stabilization Reserve to the Operations Reserve in FY 2024. Staff will request Council approval for the remaining transfers in future Financial Plans, if needed, once the year-end FY 2024 reserve balances are known.

Line 10 of Table 4 shows the anticipated CIP Reserve transfers, or capital program contributions, in FY 2024 through FY 2029 from the Operations/Unassigned Reserve to the CIP Reserve. There is also approximately $16 million in CIP budgeted in FY 2023 or prior years that is reappropriated or carried forward from previous years and is currently in the CIP Reappropriations and CIP Commitments Reserves. See Appendix B: Water Utility Capital Improvement Program (CIP) Detail for detailed information.

The CIP Reserve aims to stabilize uneven annual funding associated with ongoing CIP projects including water main replacements scheduled to occur every other year and is a source for one-time or immediately needed projects. In June 2020, Council approved consistent annual funding from the Operations to the CIP Reserves (Resolution 9904). This Financial Plan projects a capital program contribution of approximately $9 million annually, increasing with inflation, (see line 10 of Table 4) from the Operations Reserve to the CIP Reserve based upon actual and projected revenue and expenses as well as FY 2023 year-end reserve balances (FY 2024 and FY 2025 are lower because the timeline for one reservoir replacement was moved from FY 2024 to FY 2027).

This Financial Plan projects that rate funding is needed to cover $7.461 million of planned CIP in FY 2024. This figure is the portion of planned CIP in FY 2024 that will not be paid for through funds collected in prior years (the FY 2024 capital budget, less funds available in the CIP Reappropriations and Commitments Reserves), shown in line 13 of Table 4 for FY 2023. This capital budget is projected to be funded by the capital program contribution of $4 million together with $3.461 million from the CIP Reserve (calculated as the $7.461 million minus $4 million capital program contribution). Withdrawals from the CIP Reserve for use on capital projects require Council action.[7] This Financial Plan therefore requests Council approval to transfer up to $3.461 million from the CIP Reserve to the Operations Reserve. The need for the transfer will be re-evaluated once the year-end reserve balances and final CIP spending for FY 2024 are known. Figure 10: Projected CIP Reserve Balances FY 2024 to FY 2029 shows the CIP Reserve year-end balances.

[7] *See* Section 5(b) of the Water Utility Reserves Management Practices; Appendix C to the attached Water Financial Plan.

Table 4: Operations & Unassigned, Rate Stabilization and CIP Reserves Starting and Ending Balances, Revenues, Transfers To/(From) Reserves and Capital Program Contribution To/(From) Reserves Projected for FY 2024 to FY 2029 ($000)

		FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
	Starting Balance						
(1)	Operations/Unassigned	7,957	9,180	8,799	10,267	9,333	10,089
(2)	Rate Stabilization	6,069	4,000	2,000	-	-	-
(3)	CIP	6,961	3,500	6,679	3,312	7,233	2,190
	Revenues						
(4)	Total Revenue	49,904	55,887	61,743	67,713	74,059	76,834
(5)	Transfers In	342	353	363	373	389	400
	Transfers						
(6)	Operations/Unassigned	3,040	2,000	600	(6,100)	(6,500)	(4,000)
(7)	Operating Commitments	(971)	-	-	-	-	-
(8)	Rate Stabilization	(2,069)	(2,000)	(2,000)	-	-	4,000
(9)	CIP	-	-	1,400	6,100	6,500	-
	Capital Program Contribution						
(10)	Operations/Unassigned	(4,000)	(9,000)	(9,486)	(9,998)	(11,790)	(12,427)
(11)	CIP	4,000	9,000	9,486	9,998	11,790	12,427
	Expenses						
(12)	Total Expenses other than CIP	(46,341)	(49,141)	(50,991)	(52,157)	(54,631)	(56,252)
(13)	Planned CIP	(7,461)	(5,821)	(14,253)	(12,177)	(23,334)	(6,627)
(14)	Transfers Out	(1,721)	(480)	(761)	(765)	(770)	(775)
	Ending Balance						
(1)+(4)+(5)+(6) +(10)+(12)+(14)	Operations/Unassigned	9,180	8,799	10,267	9,333	10,089	13,869
(2)+(8)	Rate Stabilization	4,000	2,000	-	-	-	4,000
(3)+(9)+(11)+ (13)*	CIP	3,500	6,679	3,312	7,233	2,190	7,989
	Operations Reserve Guideline Levels						
(15)	Minimum	7,901	8,157	8,507	8,700	9,107	9,374
(16)	Maximum	15,801	16,314	17,014	17,399	18,214	18,749

* Planned CIP (item 13) is reflected as an expense in the CIP Reserve and does not include CIP funded through Reappropriations or Commitments reserves.

Cost Savings for Palo Alto from BAWSCA Bond Refunding

In 2013, BAWSCA used bond financing to directly pay a debt the BAWSCA agencies (including Palo Alto) owed to SFPUC. This lowered the cost of repaying the debt. Since 2013, BAWSCA agencies, including Palo Alto have been separately paying the debt service for these bonds and those costs are separate from the wholesale water rate and add about $0.35 to $0.45 per CCF to the wholesale rate.

On January 5, 2023, BAWSCA completed the settlement of BAWSCA's revenue bond series 2023A to refund the 2013A bonds at an even lower rate. BAWSCA locked-in the bond rates in October 2021 at an all-in true interest rate of 2.06%. The refunding bond transaction will generate approximately $27.1 million in net present value savings over the term of the bonds, or an average of approximately $2.5 million of savings per year for all Wholesale Customers, starting in fiscal year 2022-23.

SECTION 2B: SUMMARY OF PROPOSED ACTIONS

Staff proposes the following Council action for the Water Utility in FY 2024 and FY 2025:

Adopt a resolution (Attachment A):

1. Approving the Fiscal Year (FY) 2025 Water Utility Financial Plan; and
2. Amending the following rate schedules to reflect increases effective July 1, 2024 (FY 2025): W-1 (General Residential Water service), W-2 (Water Service from Fire Hydrants), W-3 (Fire Service Connections), W-4 (Residential Master-Metered and General Non-Residential Water Service), and W-7 (Non-Residential Irrigation Water Service) (Attachment B)

SECTION 3: DETAIL OF FY 2025 RATE AND RESERVES PROPOSALS

SECTION 3A: RATE DESIGN

The Water Utility's rates are evaluated and implemented in compliance with the cost of service requirements and procedural rules set forth in Article XIII D of the California Constitution (Proposition 218) and applicable statutory law. The City structured current rates based on staff's assessment of the financial position of the Water Utility, and updated current rates using the methodology and rate structures developed by Raftelis Financial Consultants, Inc. (RFC) [8]. Staff plans to update the cost of service study in 1 to 2 years, unless any major changes occur to the utility's operations or customer base that would necessitate an earlier study. Before conducting any new cost of service study, staff will review current water rates and the scope of the study with the Utilities Advisory Commission (UAC) and Council to determine the City's policy priorities.

The Water Utility's rates are based on RFC's 2019 update to the 2015 cost of service study, which reviewed the City's most recent cost of service methodologies and rate structures and declared both fundamentally sound. With the onset of the COVID-19 pandemic, usage amongst residential customer classes increased as people worked and stayed at home rather than going to the workplace. Businesses operations were also affected by the COVID-19 pandemic and their collective water usage decreased. Additionally, calls for water conservation due to drought conditions, water use restrictions in Palo Alto, and weather influenced customer water usage patterns. In order to move toward full cost recovery while minimizing rate impacts in light of

[8] RFC has developed 3 cost studies for the City: the March 2012 *Palo Alto Water Cost of Service & Rate Study*, a 2015 study reviewing the 2012 methodology and analyzing drought rates entitled, *Memorandum: Proposed Water Rates,* and a 2019 Memorandum analyzing the 2015 methodology and rate structure, titled "Proposed FY 2020 Water Rates".

pandemic-related economic challenges, staff recommends a distribution rate increase to all customer classes of 13%.

SECTION 3B: CURRENT AND PROPOSED RATES

The current rates and surcharges became effective on July 1, 2023. CPAU has five rate schedules: separately metered residential customers (W-1), commercial and master-metered multi-family residential customers (W-4), irrigation-only services (W-7), services to fire sprinkler systems in buildings and private hydrants (W-3), and service to fire hydrant rental meters used for construction (W-2). All customers pay a monthly service charge based on the size of their inlet meter. This charge represents meter reading, billing, and other customer service costs, and also the cost of maintaining the capability to deliver a peak flow for that customer based on their meter size.

All customers are also charged for each CCF (one hundred cubic feet) of water used. Separately metered residential customers are charged on a tiered basis, with the first 0.2 CCF per day (6 CCF for a 30-day billing period) charged at the first-tier price per CCF, and all additional units charged a higher tier price per CCF. Commercial customers, including most multi-family customers, pay a uniform price for each CCF used. A separate rate per CCF exists for separately metered irrigation service.

Water rates are composed of two general types of costs: commodity and distribution. For July 1, 2024, staff proposes to increase the SFPUC wholesale water rate in accordance with SFPUC's rate notice in May 2024 (expected to be 6.5%) and to increase distribution rates by 13%.

Customers have a separate commodity rate for purchased water from SFPUC relative to the rest of the distribution-related portion of the volumetric rates. California Government Code Section 53756 (established by AB-3030) became effective January 1, 2009. This section of the Code authorizes public agencies providing water, sewer, and garbage services to adopt automatic pass-through rate adjustments to account for increases in wholesale water charges or wastewater treatment charges, as well as inflation. Pass-throughs must be adopted via the Proposition 218 process and can be effective for up to five years without additional Prop 218 authorization. In 2019 Palo Alto used the Prop 218 process and the Council adopted the pass-through process effective July 1, 2019 through June 30, 2024 pursuant to Resolution 9844. The separate commodity charge passed-through SFPUC rate increases to customers. All customers pay this separate commodity rate, currently $5.21 per CCF, for each unit of water in addition to the volumetric rate that is applicable for their customer class. The rates shown below are in addition to the pass-through commodity rate charged to Palo Alto's customers based on SFPUC supply charges. This year, Palo Alto staff plan to utilize the Prop 218 process to request Council approval to increase the commodity rate on July 1, 2024 while also asking Council approval to re-authorize the pass-through provision for the water commodity charge for another five-year period from July 1, 2024 through June 30, 2029 for use with commodity charge increases in future years. For further information and details about the proposed commodity rate, see Section 6A: Water Purchase Costs.

Distribution rates cover all the costs to deliver water within the City, such as operations, maintenance, metering, billing, and capital improvements. Through annual Council approvals, the water utility provides steady funding to the CIP Reserve, which reflects actual fluctuations in CIP expenditures (money spent on actual projects in a given year). Previously, CIP expenditures were reflected in the Operations Reserve. In this way, although CIP expenditures fluctuate from year to year, staff projects the capital program contribution to the CIP reserve to remain fairly constant over the next five years. An exception to this is the one-time reservoir replacement costs that will be partly funded through one-time transfers from the Operations Reserve to the CIP Reserve. Once these reservoirs are replaced or rehabilitated, these costs will no longer be included in the ongoing CIP budget needs for the water utility. More detail regarding reserve transfers is in Section 3D: Proposed Reserve Transfers. Operations costs are discussed in *Section 6B: Operations*, below.

Table 5 shows the current and proposed consumption charges, which are distribution rates.

Table 5: Current and Proposed Water Distribution Charges

	Current (7/1/2023)	Proposed (7/1/2024)	Change ($/CCF)	Change (%)
W-1 (Residential) Volumetric Rates ($/CCF)				
Tier 1 Rates	2.72	3.07	0.35	13%
Tier 2 Rates	6.33	7.15	0.82	13%
W-2 (Construction) Volumetric Rates ($/CCF)				
Uniform Rate	3.83	4.32	0.49	13%
W-4 (Commercial) Volumetric Rates ($/CCF)				
Uniform Rate	3.83	4.32	0.49	13%
W-7 (Irrigation) Volumetric Rates ($/CCF)				
Uniform Rate	5.83	6.58	0.75	13%

Table 6 and Table 7 show the current monthly service charges for rate schedules W-1, W-4 and W-7. These monthly service charges are also considered distribution rates.

Table 6: Current and Proposed Monthly Service Charges for Residential W-1

Meter Size	Monthly Service Charge ($/month based on meter size)		Change	
	Current (7/1/2023)	Proposed (7/1/2024)	$	%
5/8”	21.48	24.27	2.79	13%
3/4”	21.48	24.27	2.79	13%
1”	21.48	24.27	2.79	13%
1 ½”	69.38	78.39	9.01	13%
2”	107.32	121.27	13.95	13%
3”	227.48	257.05	29.57	13%
4”	404.56	457.15	52.59	13%
6”	828.27	935.94	107.67	13%
8”	1,523.92	1,722.02	198.10	13%
10”	2,409.29	2,722.49	313.20	13%
12”	3,168.19	3,580.05	411.86	13%

Table 7: Current and Proposed Monthly Service Charges for W-4 and W-7

Meter Size	Monthly Service Charge ($/month based on meter size)		Change	
	Current (7/1/2023)	Proposed (7/1/2024)	$	%
5/8”	18.78	21.22	2.44	13%
3/4”	25.11	28.37	3.26	13%
1”	37.76	42.66	4.90	13%
1 ½”	69.38	78.39	9.01	13%
2”	107.32	121.27	13.95	13%
3”	227.48	257.05	29.57	13%
4”	404.56	457.15	52.59	13%
6”	828.27	935.94	107.67	13%
8”	1,523.92	1,722.02	198.10	13%
10”	2,409.29	2,722.49	313.20	13%
12”	3,168.19	3,580.05	411.86	13%

Table 8 shows the current and proposed monthly service charges for rate schedule W-3.

Table 8: Current and Proposed Monthly Service Charges for Fire Services (W-3)

Meter Size	Monthly Service Charge ($/month based on meter size)		Change	
	Current (7/1/2023)	Proposed (7/1/2024)	$	%
2”	4.42	4.99	0.57	13%
4”	27.38	30.93	3.55	13%
6”	79.51	89.84	10.33	13%
8”	169.45	191.47	22.02	13%
10”	304.74	344.35	39.61	13%
12”	492.24	556.23	63.99	13%

SECTION 3C: BILL IMPACT OF PROPOSED RATE CHANGES

Table 9 shows the impact of the proposed July 1, 2024 rate changes on the median residential bill. The system average increase is projected to be 10 percent, but some customers will see higher or lower increases due to changes in the composition of the customer’s utilization of the system over time, as well as changes in the utility’s costs. Table 9 shows the impact of the proposed July 1, 2024 rate changes on the median commercial bill.

Table 9: Impact of Proposed Water Rate Changes on Residential Bills

Usage (CCF/mo.)	Bill under Current Rates (7/1/2023)	Bill under Proposed Rates (7/1/2024)	Change	
			$/mo.	%
4	$53.20	$58.75	$5.55	10%
(Winter median) 7	$80.60	$88.69	$8.09	10%
(Annual median) 9	$103.68	$114.09	$10.41	10%
(Summer median) 14	$161.38	$177.59	$16.21	10%
25	$288.32	$317.29	$28.97	10%

Table 10: Impact of Proposed Water Rate Changes on Commercial Bills

Usage (CCF/mo.)	Bill under Current Rates (7/1/2023)	Bill under Proposed Rates (7/1/2024)	Change	
			$/mo.	%
Commercial (W-4) (5/8" meters)				
(Annual median) 12	$127.26	$139.66	$12.40	10%
(Annual average) 64	$597.34	$652.90	$55.56	9%
Irrigation (W-7) (1 ½" meters)				
(Winter median) 9	$168.74	$187.56	$18.82	11%
(Summer median) 37	$477.86	$527.20	$49.34	10%
(Winter average) 56	$687.62	$757.67	$70.05	10%
(Summer average) 199	$2,266.34	$2,492.26	$225.92	10%

SECTION 3D: PROPOSED RESERVE TRANSFERS

A transfer of approximately $2.07 million in FY 2024, $2 million in FY 2025 and $2 million in FY 2026 from the Rate Stabilization Reserve to the Operations Reserve will mitigate the need for distribution rate increases. See Table 4 above, row 8, for a summary of the projected reserve transfers out of the Rate Stabilization Reserve. This meets the requirement in the Water Utility Reserves Management Practices that states if there are funds in the Rate Stabilization Reserve at the end of any fiscal year, any subsequent Water Utility Financial Plan must result in the withdrawal of all funds from this reserve by the end of the Financial Planning Period. Note that in FY 2029, this Financial Plan replenishes the Rate Stabilization Reserve with $4 million.

Section 2A: Overview of Financial Position describes the proposed transfers to and from the CIP Reserve. Table 4 shows the proposed capital program contributions in row 11.

This Financial Plan projects one-time transfers from the Operations Reserve to the CIP Reserve to fund reservoir work for the upcoming Dahl and Park reservoir replacement or rehabilitation costs. These one-time transfers total $14 million between FY 2026 and FY 2028, which is equal to the total estimated cost of replacing the two reservoirs. Table 4 shows these one-time transfers from the Operations Reserve to the CIP Reserve on line 9. Additionally, Section 4E: Reserves Structure and Appendix A: Water Utility Financial Forecast Detail shows details of reserves levels.

SECTION 4: UTILITY OVERVIEW

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

SECTION 4A: WATER UTILITY HISTORY

The Water Utility was established on May 9, 1896, two years after the City was incorporated. Voters of the 750-person community approved a $40,000 bond to buy local, private water companies who operated one or more shallow wells to serve the nearby residents. The city grew and the well system expanded until nine wells were in operation in 1932. Palo Alto began receiving water from the San Francisco Water Department (SFWD) in 1937 to supplement these sources.

A 1950 engineering report noted, "the capricious alternation of well waters and the San Francisco Water Department water…has made satisfactory service to the average customer practically impossible". By 1950, only eight wells were still in operation. Despite this, groundwater production increased in the 1950s leading to lower groundwater tables and water quality concerns. In 1962, a survey of water softening costs to CPAU customers determined that CPAU should purchase 100% of its water supply needs from the SFWD. CPAU signed a 20-year contract with SFWD, and CPAU's wells were placed in standby condition. The SFWD later became known as the SFPUC. Since 1962 (except for some very short periods) CPAU's entire supply of potable water has come from the SFPUC.

As the city grew, so did the number of mains in the water system, while existing sections of the system continued to age. In the mid-1980s, the number of breaks in cast iron mains installed during the 1940s and earlier started to accelerate. In FY 1994, to combat deterioration of older sections of the system, CPAU performed an analysis of cost-effective system improvements and increased the rate of main replacement from one mile per year to three. CPAU began a plan to replace 75 miles of deficient mains within 25 years.

In 1999, a study of system reliability concluded that the distribution system needed major upgrades to provide adequate water supply during a natural disaster. This ultimately resulted in the $40 million Emergency Water Supply and Storage Project, completed in 2013, which involved a new underground reservoir in El Camino Park, the siting and construction of several emergency supply wells, and the upgrade of several existing wells and the Mayfield pump station. Upon completion, the City began to focus reliability efforts on its system of water storage reservoirs and transmission lines in the Foothills.

At the same time that CPAU was evaluating the reliability of its own system, the SFPUC, in consultation with BAWSCA members, was evaluating the reliability of the Hetch Hetchy Regional Water System, which crosses two major fault lines between the Sierras and the Bay Area. That evaluation concluded that major upgrades to the system were required for improved seismic resilience. This planning process culminated in the SFPUC's $4.8 billion Water System Improvement Project (WSIP), which is ongoing. This has resulted and will continue to result in large increases in the annual debt service costs assigned to wholesale customers like Palo Alto. After SFPUC completes each WSIP project, wholesale customers must start paying the debt service costs within 3 to 4 years. Wholesale customers will pay off the majority of those costs, funded with bond financing, over approximately 30 years. The SFPUC continues to evaluate its aging system for other needed infrastructure improvements; future major improvements include dam safety and Mountain Tunnel repairs.

SECTION 4B: CUSTOMER BASE

CPAU's Water Utility provides water service to the residents and businesses of Palo Alto, plus a handful of residential customers not in Palo Alto (primarily in Los Altos Hills). There are approximately 20,200 customers connected to the water system. Approximately 17,300 (86%) of these are separately metered residential customers and approximately 2,900 (14%) of these are commercial, master-metered residential, irrigation, and fire service customers.

Judging from seasonal consumption patterns, Palo Alto's customers collectively use between 35% and 50% of the water for irrigation, and that consumption is heavily weather dependent. It also varies significantly by season. As a result of these two factors, there is significant variability in the amount of water demanded from the system month to month and year to year.

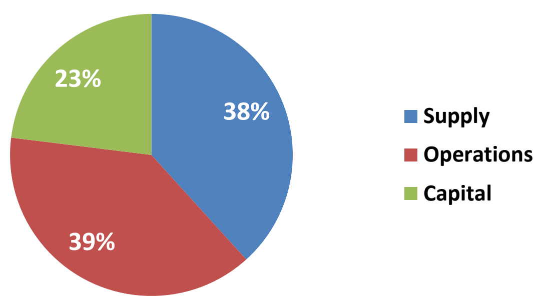
SECTION 4C: DISTRIBUTION SYSTEM

To deliver water to its customers, CPAU owns and operates roughly 236 miles of mains (which transport the water from the SFPUC meters at the city's borders to the customer's service laterals and meters), eight wells (to be used in emergencies), five water storage reservoirs (also for emergency purposes) and several tanks used to moderate pressure and deal with peaks in flow and demand (due to fire suppression, heavy usage times, etc.). These represent the vast majority of the infrastructure used to distribute water in Palo Alto.

SECTION 4D: COST STRUCTURE AND REVENUE SOURCES

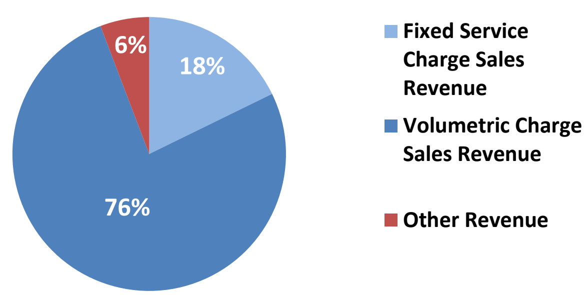
Figure 1 shows that in FY 2023, 38% of the Water Utility's costs were for water commodity purchases, 39% were for operations and maintenance costs, and the remaining 23% were for capital investment. Staff projects these percentage distributions to remain similar over the forecast period.

Figure 1: Cost Structure (FY 2023)



The Water Utility's revenue comes mainly from the sale of water, with the rest coming from capacity and connection fees, interest on reserves, and other sources. About 18% of the utility's revenues come from fixed service charges, though most of the utility's costs are fixed. *Appendix A: Water Utility Financial Forecast Detail* provides more detail on the utility's cost and revenue structures.

Figure 2: Revenue Structure (FY 2023)



SECTION 4E: RESERVES STRUCTURE

CPAU maintains six reserves for its Water Utility to manage various types of contingencies. The descriptions below summarize these reserves; see *Appendix C: Water Utility Reserves Management Practices* for more detailed definitions and guidelines for reserve management:

- **Reserve for Commitments:** A reserve equal to the utility's outstanding contract liabilities for the current fiscal year. Most City funds, including the General Fund, have a Commitments Reserve.
- **Reserve for Reappropriations:** A reserve for funds dedicated to projects reappropriated by the City Council, nearly all of which are capital projects. Most City funds, including the General Fund, have a Reappropriations Reserve.
- **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 the CIP. This type of reserve is used in other utility funds (Electric, Gas, and Wastewater Collection) as well.
- **Rate Stabilization Reserve:** This reserve is intended to be empty unless the city anticipates one or more large rate increases 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 (Electric, Gas, and Wastewater Collection) as well.
- **Operations Reserve:** This is the primary contingency reserve for the Water Utility, and is used to manage yearly variances from the budget for operational water supply costs. This type of reserve is used in other utility funds (Electric, Gas, and Wastewater Collection) as well.
- **Unassigned Reserve:** This reserve is for any funds not assigned to the other reserves and funds in this reserve are assigned or returned to Water Utility ratepayers by the end of the first fiscal year of the next financial planning period.

SECTION 4F: COMPETITIVENESS

Table 11 compares the current water bills for single-family residential customers in Palo Alto with those of neighboring communities. While Palo Alto is among the highest monthly bills among these communities, the difference between Palo Alto's bills and those of the surrounding cities has decreased in recent years as other agencies have increased their capital investments. Additionally, bills for smaller water users in Palo Alto are lower than in some neighboring communities. These comparison cities are the ones that Palo Alto compares itself to in the annual budget across all industries.

Table 11: Single-Family Residential Monthly Water Bill Comparison

Usage (CCF/month)	Residential monthly bill comparison ($/month)* As of February 2024							
	Palo Alto	Menlo Park	Mountain View	Hayward	Redwood City	Santa Clara	Los Altos	Average of Surrounding Communities
4	$53.20	$65.20	$46.95	$45.17	$64.16	$31.88	$58.71	$52.01
(Winter median) 7	80.60	91.00	72.69	69.59	86.27	55.79	79.51	75.81
(Annual median) 9	103.68	108.19	89.85	85.87	112.31	71.73	93.38	93.55
(Summer median) 14	161.38	155.10	132.75	135.87	180.22	111.58	131.23	141.12
25	288.32	271.23	278.63	245.87	340.49	199.25	233.01	261.41

** Based on the FY 2013 BAWSCA survey, the percentage of SFPUC as the source of potable water supply was 100% for Palo Alto, 95% for Menlo Park, 100% for Redwood City, 87% for Mountain View, 10% for Santa Clara and 100% for Hayward. Los Altos does not receive water supply from SFPUC.*

SECTION 5: UTILITY FINANCIAL PROJECTIONS

SECTION 5A: LOAD FORECAST

Figure 3 shows 48 years of water consumption history in Palo Alto. Despite population growth, average water use has trended downward over time. This is due to significant water use reductions particularly during drought periods, such as 1976-77, 1988-92 and 2014-17, and 2021-23. During these periods, customers invested in efficient equipment and modified their behavior to achieve water reduction goals. These reductions persisted even after the droughts ended. Additionally, water sales decreased during the 2007-2009 recession and drought and again during the 2014-2017 drought. Water usage returned to pre-drought levels in 2018 after the drought. However, the Covid-19 pandemic led to an increase in water use in Palo Alto in 2020-21. During the months affected by pandemic impacts, but prior to Governor Newsom's Executive Order N-10-21 calling on Californians to voluntarily reduce water use 15% from 2020 levels, (March 2020 – June 2021), overall water sales increased approximately 3-6% from recent years. Because weather was also dry during the same time period, which also tends to increase water sales, pandemic-related sales impacts are not able to be determined with specificity. During FY 2022 and FY 2023 water use restrictions due to drought also reduced water demand. Staff will continue to monitor water sales and will recommend adjustments in next year's financial plan as needed.

Figure 3: Historical Palo Alto Water Purchases (Rolling 12-Month)

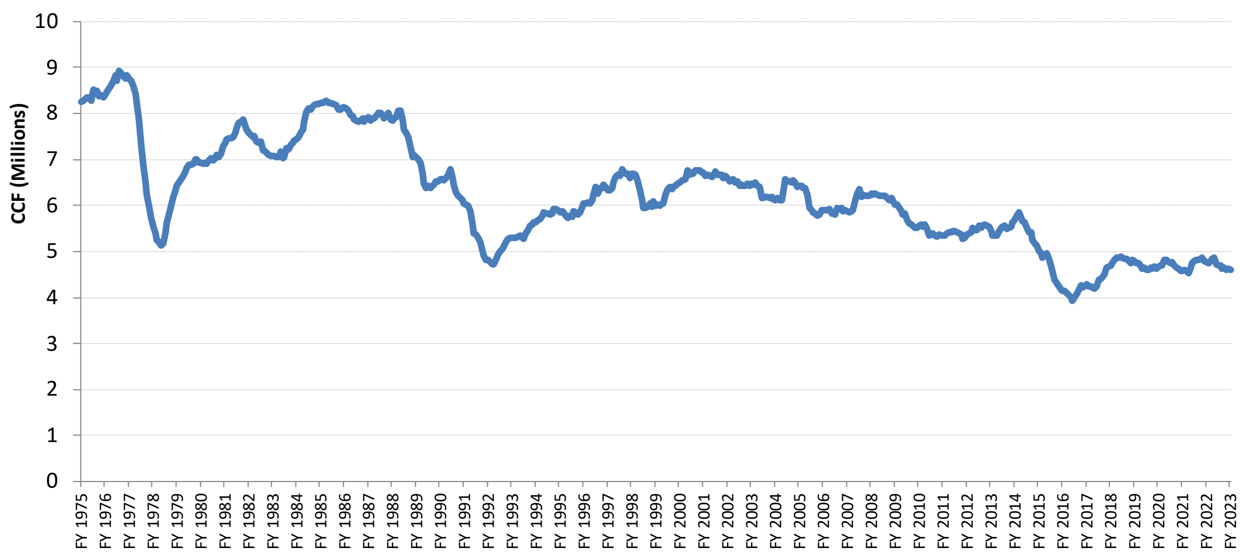
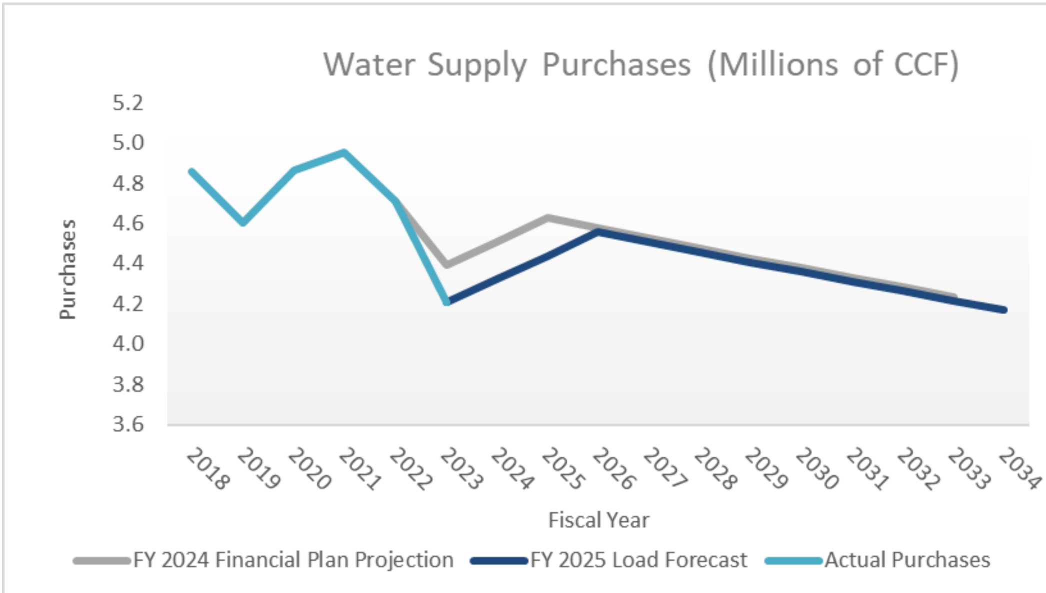


Figure 4 shows the FY 2025 Financial Plan water purchases forecast, compared to the projected water purchases in the FY 2024 Financial Plan.

Figure 4: Projected Palo Alto Water Purchases



Actual water purchases in FY 2023 were 4,210,399 CCF, about 4.1% lower than projected in the FY 2024 Financial Plan and 10.6% lower than actual water purchases in FY 2022. This forecast begins with the most recent water purchases and assumes a drought recovery over three years back to the pre-drought long-term trend (average annual decrease of 1.1% observed from FY 2002 to FY 2021). The current forecast for FY 2024 is 4,322,676 CCF and 4,437,947 CCF in FY 2025.

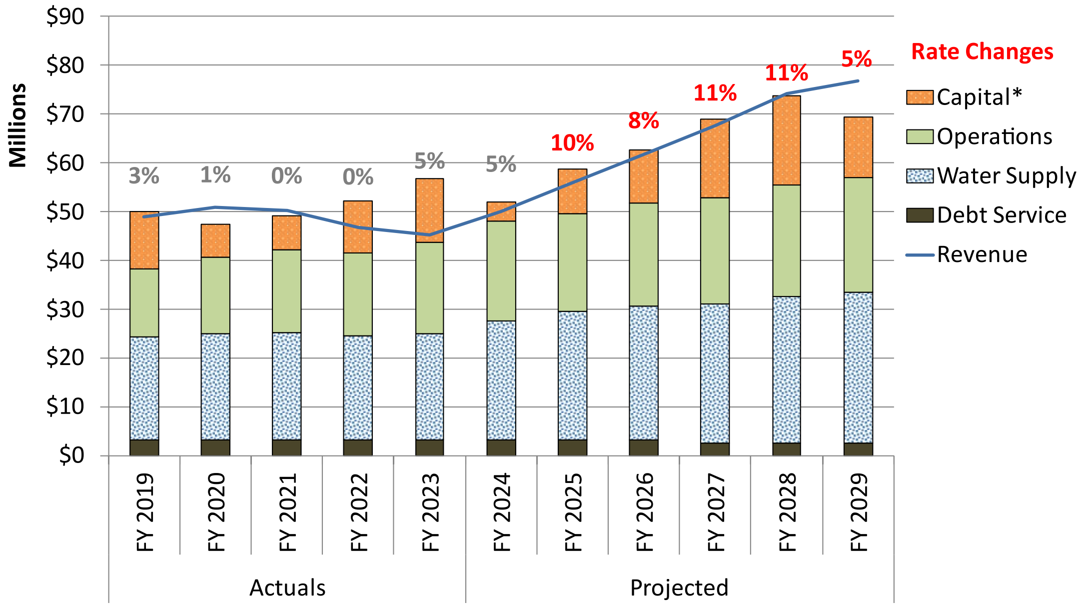
SECTION 5B: FY 2019 TO FY 2023 COST AND REVENUE TRENDS

Figure 5 and the tables in *Appendix A: Water Utility Financial Forecast Detail* show how costs have changed during the last five years as well as how staff projects they will change over the next five years.

The annual expenses for the Water Utility rose by 3.2% annually on average between FY 2019 and FY 2023. The increases were primarily related to operations costs. SFPUC held its wholesale water rate at $4.10 from July 2016 to June 2022 and then increased the rate to $4.75 on July 1, 2022. At the same time that prices increased in FY 2023, customers used less water and the utility's overall purchase costs remained fairly flat over this time period growing at an average of 0.6% annually from FY 2019 to FY 2023. *Section 6A: Water Purchase Costs* contains a more in-depth discussion of water purchase costs. Operations costs other than purchased water and CIP increased by about 6.5% annually from FY 2019 to FY 2023, primarily due to increases in allocated costs, rent, one-time transfers out for capital projects, resource management, engineering and customer service. CIP costs have generally increased but fluctuated down in certain years. In FY 2024 there is $16 million of CIP Reappropriations and Commitments budgeted in previous years and carried over to FY 2024. One reservoir replacement is being moved from FY 2024 to FY 2027 which is the reason a lower capital contribution is expected to be needed in FY 2024. Section 6B:

Operations contains more detail regarding operations costs and Section 6C: Capital Improvement Program (CIP) provides more detail regarding CIP costs.

Figure 5: Water Utility Expenses, Revenues, and Rate Changes:
Actual Expenses through FY 2023 and Projections through FY 2029 (Including SFPUC's rate increase of 6.5% in the "Water Supply" cost bar)



* Note: in Figure 5, Capital Investment in the projected years reflects one-time transfers from the Operations Reserve to the CIP Reserve, the annual capital program contribution to the CIP Reserve, as well as increases in CIP Reappropriations and Commitments.

SECTION 5C: FY 2023 RESULTS

Actual sales revenues for FY 2023 were 7.3% lower than projected in the FY 2024 Financial Plan ($42.6 million vs. $45.9 million). Water losses also increased in FY 2023 and water purchase volume was only 4.1% below forecasted. Correspondingly, actual FY 2023 water purchase costs were 4.1% lower than forecast. During the first half of FY 2023, Palo Alto implemented voluntary water use restrictions due to ongoing drought conditions as well as a drought declaration by the SFPUC, Palo Alto's water supplier. During the winter of 2022-2023 the drought ended due to very wet weather. Other revenues were 5.4% lower than forecasted in the FY 2024 Financial Plan primarily due to reductions in transfers in.

In FY 2022, unrealized gains/losses were separated out from the operations reserve into a separate reserve. There was a subsequent accounting adjustment to the year-end FY 2022 operations reserve balance to also remove unrealized gains/losses from prior years from the Operations Reserve and reflect those in the unrealized gains/losses reserve. This reduced the operations reserve by $0.7 million. Additionally, operating expenses were higher than expected due to a transfer out to the capital projects fund. CIP related costs for FY 23 including CIP reappropriations and commitments totaled $25.8 million in the FY 2024 Financial Plan estimate for FY 2023 and the actual spending plus pending CIP reappropriations and commitments for FY 2023 is $26.1, a difference of $0.3 million or 1%.

Table 12 summarizes the variances from forecast.

Table 12: FY 2023, Actual Results vs. Financial Plan Forecast

	Net Cost/ (Benefit) ($000)	Type of change
Lower sales revenues	$3,336	Lower revenues
Lower other revenue	$148	Lower revenues
Capital-related costs including CIP reappropriations/commitments	$292	Cost increase
Water purchases lower than expected	$(939)	Cost decrease
Expense higher than expected	$677	Cost increase
Accounting adjustment to Operations Reserve	$671	Cost increase
Net Cost / (Benefit) of Variances	$4,185	

SECTION 5D: FY 2024 PROJECTIONS

Staff estimates sales revenues in FY 2024 to be $2.6 million or 4.5% lower than forecasted in the FY 2024 Financial Plan as a result of reductions in water use due to drought and drought rebound. Of this total, about $1.3 million is reduction in distribution sales revenue. Staff currently estimates water sales volumes to be 9.6% lower than the FY 2024 Financial Plan forecast, which had assumed some drought recovery in FY 2024. This puts additional upward pressure on water rates. Staff expects other revenue to be higher than forecasted in the FY 2024 Financial Plan by $0.2 million in FY 2024 primarily due to increases in income based on the most recent year. Revenue reductions are offset by approximately $1.1 million in lower water purchase costs also resulting from the lower sales forecast.

The allocated cost forecast decreased by $0.4 million while transfers out increased due to an expected one-time transfer true-up in FY 2024. The estimate for resource management costs increased by 0.2 million, while operations and maintenance and engineering cost estimates decreased by $0.6 million. Total operations and maintenance costs other than water purchases increased by $1.4 million. Table 13 summarizes the changes.

The FY 2024 Financial Plan estimated a 5-year capital project budget for FY 2024 through FY 2028 of $54.7 million (not including carry-forward budgets from prior years). This budget increased 1.2% in the current Financial Plan to $55.3M. The FY 2024 capital budget in the FY 2024 Financial Plan was $13.0 million, including allocated costs; in the FY 2025 Financial Plan, the FY 2024 capital budget is $7.5 million. This reduction is because the reservoir tank replacement/rehabilitation construction completion date was delayed to FY 2028 to allow time for additional analysis and project phasing. This delayed the capital funding need. Additionally, the FY 2024 budgeted $2.9 million for ongoing projects in FY 2024 and based upon current estimates, the CIP Reappropriations and Commitments reserve funding will cover more of this budget and only $1.6 million is expected to need to be recovered from rate funding in FY 2024 (a difference of $1.3 million). Additional CIP-related costs increased in the current Financial plan including CIP allocated overhead and unallocated salaries and benefits together increased $0.85 million in FY 2024.

In addition to the items described above and shown in Table 13, operating commitments grew by $1 million, and CIP-Commitments and Reappropriations together grew by $3.9 million and both of those reduced the Operations Reserve FY 23 year-end balance.

Table 13: FY 2024 Change in Projected Results, 2024 Forecast vs 2025 Forecast ($000)

	Net Cost/ (Benefit)	Type of Change
Sales Revenue	$2,545	Revenue decrease
Other Revenue	$(195)	Revenue decrease
Water Purchases	($1,064)	Cost savings
Capital costs (project, allocated, and unallocated salaries and benefits)	($6,748)	Cost deferral
Other Operating Costs	$1,359	Cost decrease
Net Cost / (Benefit) of Variances	**($4,102)**	

SECTION 5E: FY 2025 – FY 2029 PROJECTIONS

On average the Water Utility's costs projected to increase by 4.3% annually from FY 2025 through FY 2029 (see Figure 5 and Table 14).

Table 14: Average Annual Percentage Cost Change for Water Utility Expenses

Water Utility Expense	Average annual percentage cost change FY 2025 – FY 2029
Capital Program Contribution	8.4%
Operations (other than debt service)	4.2%
Water Supply	4.0%
Debt Service	(4.5%)
Total	**4.3%**

This plan anticipates that water supply costs will increase 4.3% annually on average over the forecast period FY 2025 – FY 2029. Staff projects operations costs other than debt service to increase by 4.2% annually on average and capital contributions to the CIP Reserve to increase 8.4% on average each year. While staff has revised future CIP costs upwards to reflect the higher construction costs seen in recent projects, there is still uncertainty with regard to the utility's future costs for water main replacements. See *Section 6: Details and Assumptions* for more detail on the costs that make up these projections, as well as the various assumptions underlying the projections. Debt service costs are declining during the FY 2025 – FY 2029 time period because the 2011 Utility Revenue Refunding Bond, Series A, is scheduled to be retired in 2026.

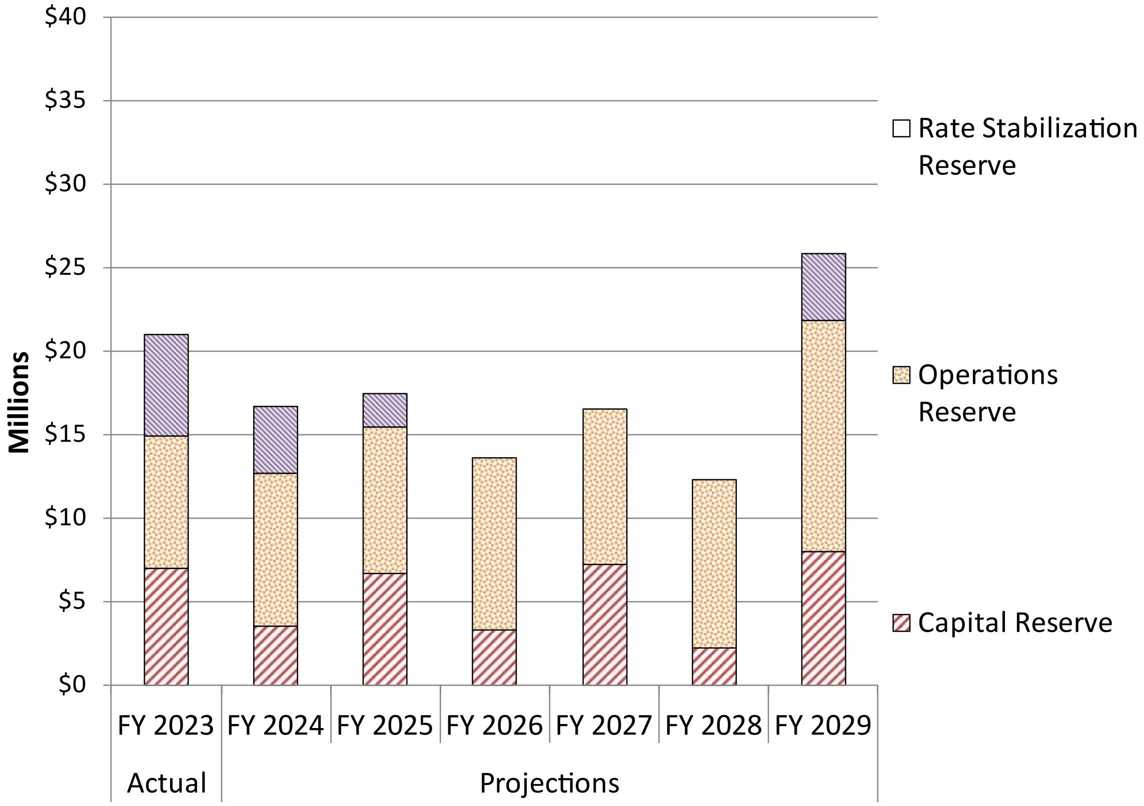
Both the FY 2024 and current Financial Plans utilize all of the $6.06 million in the Rate Stabilization Reserve by the end of FY 2026 to stabilize rates and cover operational and capital costs.

As shown in Table 3, the Water Utility requires distribution rate increases between 6% and 13% per year through FY 2029 to provide sufficient revenues to fund annual expenses for the distribution system. The overall average system rate increase needed with SFPUC's projected rate increase is 10% per year through FY 2029.

Figure 6 shows reserves trends based on these cost and revenue projections. The figure shows the transfers from the Rate Stabilization Reserve to the Operations Reserve in FY 2023 through FY 2026 and that the fund is able to return $4 million to the Rate Stabilization Reserve in FY 2029.

Staff expects the Operations Reserve, the main contingency reserve, to be within the target range throughout the forecast period, and that this reserve will be adequate to meet all identified risks, as discussed in *Section 5F: Risk Assessment and Reserves Adequacy*.

Figure 6: Water Utility Reserves
Actual Year End Reserve Levels for FY 2023 and Projections through FY 2029



SECTION 5F: RISK ASSESSMENT AND RESERVES ADEQUACY

The Water Utility's main contingency reserve is the Operations Reserve, and this Financial Plan projects the Operations reserve to remain within the guideline levels throughout the forecast period, as shown in Figure 7. Staff will consider funds in the Operations Reserve in excess of the maximum to be unassigned. Staff projects the Operations Reserve to exceed both the minimum reserve level and the short-term risk assessment level throughout the forecast period.

Figure 7: Operations Reserve Adequacy

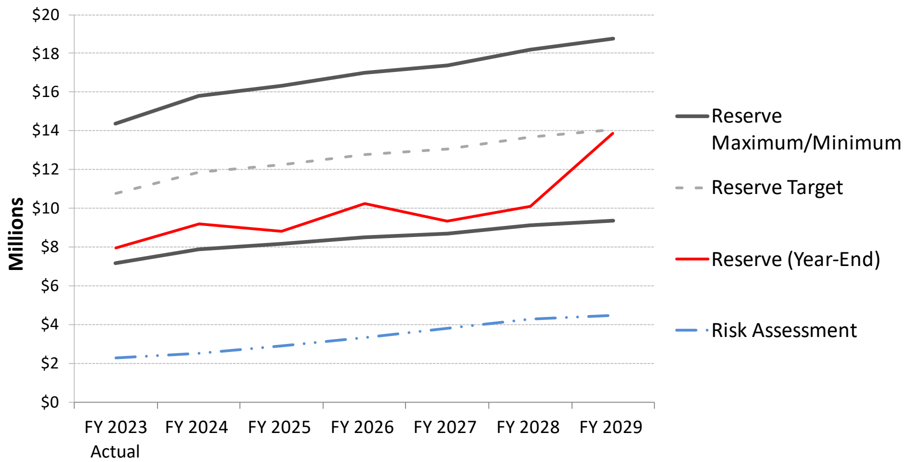


Table 15 summarizes the risk assessment calculation for the Water Utility through FY 2029. The risk assessment includes the revenue shortfall of 14% that could accrue due to lower than forecasted sales revenue.

Table 15: Water Risk Assessment ($000)

	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Total Non-Commodity Revenue	$30,103	$34,958	$39,878	$44,609	$46,680
Max. Revenue Variance, Previous Ten Years	14%	14%	14%	14%	14%
Risk of Revenue Loss	$2,884	$3,349	$3,820	$4,273	$4,471
Total Risk Assessment Value	$2,884	$3,349	$3,820	$4,273	$4,471

SECTION 5G: ALTERNATE SCENARIO

There is no alternate scenario included in this Financial Plan.

SECTION 5H: LONG-TERM OUTLOOK

CPAU has put its Water Utility on strong footing by investing in its distribution system infrastructure and emergency water facilities over the last 20 years. The Water System Master Plan, completed in FY 2016, evaluated the current state of the distribution system and determined the necessary rate of main replacement in the next 20 years. This study factored in seismically vulnerable mains as well as deteriorating mains. In addition, CPAU's water supplier, the SFPUC, has replaced and seismically strengthened its water transmission infrastructure, which will benefit Palo Alto and all Hetch Hetchy Regional Water System customers over the long term.

The opportunities for CPAU's Water Utility to obtain additional supplies over the long term may be in alternative water supplies such as recycled water, groundwater, and water from Valley Water. Staff have analyzed these alternatives in the past and analyzed them again most recently in the 2017 Water Integrated Resource Plan.[9] Some of these alternatives may provide cost savings or increased drought protection. For example, in November, 2019, the City of Palo Alto entered into an agreement with Valley Water and the City of Mountain View that will provide (1) funding for a salt removal facility at the Regional Water Quality Control Plant in Palo Alto to improve the quality of non-potable recycled water used in Palo Alto and Mountain View, (2) a transfer of treated wastewater from Palo Alto to Valley Water for use in the county south of Mountain View, and (3) Palo Alto and Mountain View will have a future option to request new potable or non-potable water supply from Valley Water, if needed.

Climate change may begin to present challenges for the Water Utility over the next 20 to 40 years. Availability of water from SFPUC's Regional Water System may change with changing seasonal precipitation patterns. Water consumption patterns may change. Consumption could increase due to drier weather or decrease as customers become even more focused on water conservation. Droughts may become more frequent. The risk of wildfire in the foothills could increase, possibly threatening utility infrastructure or placing greater demands on it. Sea level rise could result in greater exposure of utility infrastructure to inundation, possibly resulting in higher maintenance and replacement costs. As part of the Sustainability/Climate Action Plan, CPAU is currently working on a Climate Change Adaptation Roadmap that will begin to assess some of these risks.

Palo Alto staff is in the process of developing a One Water supply plan to enhance and preserve Palo Alto's potable water supply. The Palo Alto City Council approved a Contract with Carollo Engineers for this work in June 2022 (Staff Report #13434). The One Water Plan will be used as an adaptable water supply plan for implementing a One Water portfolio over a 20-year planning horizon. This work aims to address how Palo Alto can mitigate the impact of future uncertainties such as severe multi-year drought, changes in climate, water demand and regulations through integrated water resources supply planning. More information is available on the One Water webpage.

SFPUC recently conducted a study of long-term vulnerabilities of the Regional Water System in partnership with The Water Research Foundation. The Long-Term Vulnerability Assessment covers the risks associated with potential climate change in the context of effects from other drivers of change.

SECTION 6: DETAILS AND ASSUMPTIONS

SECTION 6A: WATER PURCHASE COSTS

CPAU purchases all of its potable water supplies from the SFPUC, which owns and operates the Hetch Hetchy Regional Water System. CPAU is one of several agencies that purchase water from

[9] 2017 Water Integrated Resource Plan: https://www.cityofpaloalto.org/civicax/filebank/documents/56088

the SFPUC, all of whom are members of the Bay Area Water Supply and Conservation Agency (BAWSCA). Palo Alto uses roughly 7% of the water delivered by the SFPUC to BAWSCA member agencies.

On February 15, 2024 SFPUC notified BAWSCA that it expects the FY 2025 Wholesale Water Rate to be $5.55/CCF (an increase of between 6.5% from the current rate of $5.21/CCF. Additionally, SFPUC disclosed that it is updating the fixed monthly service charges to reflect new meter types being installed and update the charges for all existing meters.

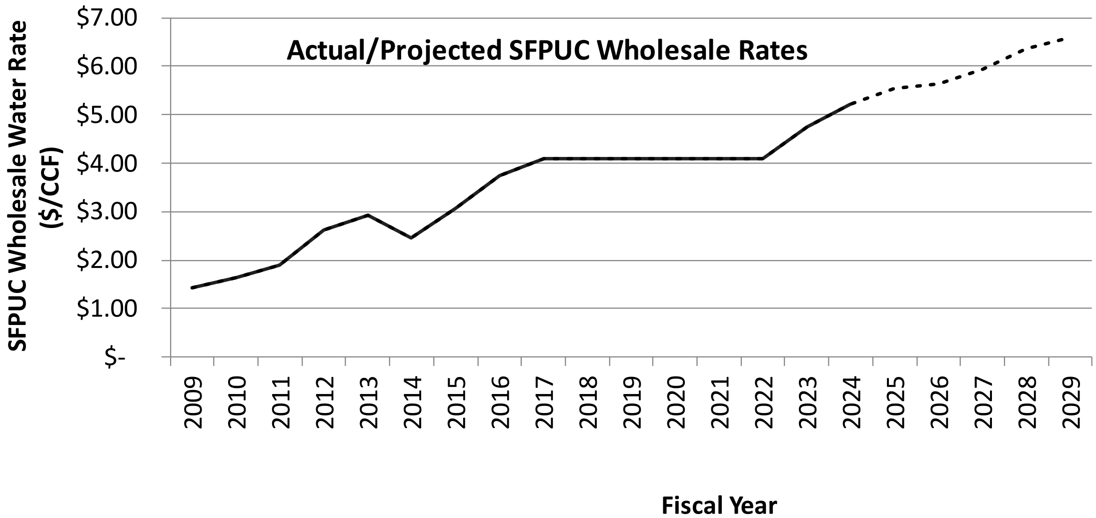
SFPUC cited three main drivers for the rate increase – growth in capital spending, continued low water sales volumes, and the draw down of the balancing account. Capital costs are rising due to increased debt service on existing and newly-issued bonds. Water sales volumes are uncertain due to uncertainty about the amount that customers will rebound from drought and unpredictable weather conditions affecting water usage patterns. During FY 2017 through FY 2021, the balancing account for SFPUC's wholesale customers built up an over-collection of revenue due to wholesale customer revenues exceeding costs. There are several reasons contributing to this: SFPUC sold more wholesale water than its sales projection, there were cost savings in the wholesale revenue requirement due to the SFPUC's debt refinancing, and BAWSCA's annual review of the wholesale revenue requirement resulted in credits applied to the balancing account. However, during the drought years of FY 2022 and FY 2023 and during the current year, SFPUC has been returning the over-collection in the balancing account. SFPUC's estimated balance in the balancing account at the end of FY 2024 is $19.4 million owed to retail customers and the projection includes a deferral of up to $10 million of this to be paid back in future years.

The Hetch Hetchy Regional Water System begins with a system of reservoirs and tunnels in the high Sierra in Tuolumne County and water is transported by a gravity-fed pipeline to the Bay Area. Currently, the SFPUC is in the midst of a $4.8 billion bond-financed capital improvement program (the Water System Improvement Program, or WSIP) to seismically retrofit the facilities that transport water to the Bay Area. As of June 30, 2023, 99.2% of the WSIP regional construction contracts are complete.[10] This has resulted and will continue to result in large increases in the annual debt service costs assigned to wholesale customers like Palo Alto. After each WSIP project is completed, wholesale customers must start paying the debt service costs within 3 to 4 years. The currently estimated WSIP completion date is February 7, 2027, as adopted by the SFPUC in April of 2022. In large part because of these WSIP-related debt service costs, the SFPUC's wholesale water rate increased from $1.43 per CCF in FY 2009 to $5.21 per CCF currently. Figure 8 shows the SFPUC's actual wholesale water rate since FY 2009 and SFPUC's projected rates for FY 2025through FY 2029. Note that the wholesale water rate decreased in FY 2014, but the apparent rate decrease is due to a debt the BAWSCA agencies owed to SFPUC being

[10] Fourth Quarter FY 2022 - 2023 WSIP Regional Quarterly Report, https://sfpuc.org/sites/default/files/documents/WSIP_Quarterly%20Report_FY2022-23_Q4.pdf

directly paid by the BAWSCA agencies via bond financing, which lowered the cost of repaying the debt (described in more detail in Section 2A: Overview of Financial Position).

Figure 8: Historical and Projected SFPUC Wholesale Water Rate



Parts of SFPUC's system not included in the WSIP will also need rehabilitation after the WSIP is completed, and some of these projects are already included in the SFPUC's rate projections, such as additional Transmission, Supply, Storage and Treatment system upgrade projects, and dam safety work slated to occur during the next 10 years. The SFPUC is also conducting condition assessments of other "up-country" facilities, located in the Sierras, in the coming years. Estimates from 2021 are that $1.8 billion will be needed between FY 2019 and FY 2028 primarily for these non-WSIP projects, but if these assessments identify other facilities that need replacement, it may result in additional rate increases as new debt is issued to finance the projects.

SFPUC coordinates the development of wholesale rate adjustments with its annual budget process and will decided on the final rate increase around May 2024 and be effective around July 1, 2024. SFPUC provides written notice to Palo Alto 30 days before the Commission meeting to increase wholesale rates, and the rate adjustment will be effective no sooner than 30 days after the Commission adopts the wholesale rate (the 2018 Amended and Restated Water Supply Agreement Section 6.03.A. describes the details of budget coordinated rate adjustments). Staff will request Council approval to extend the pass-through provision for the wholesale rate (commodity charge) for another five years from July 1, 2024 through June 30, 2029.

SECTION 6B: OPERATIONS

CPAU's Water Utility operations include the following activities:

- Administration, a category that includes charges allocated to the Water Utility for administrative services provided by the General Fund and for Utilities Department administration, as well as debt service and other potential transfers. Additional detail on Water 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

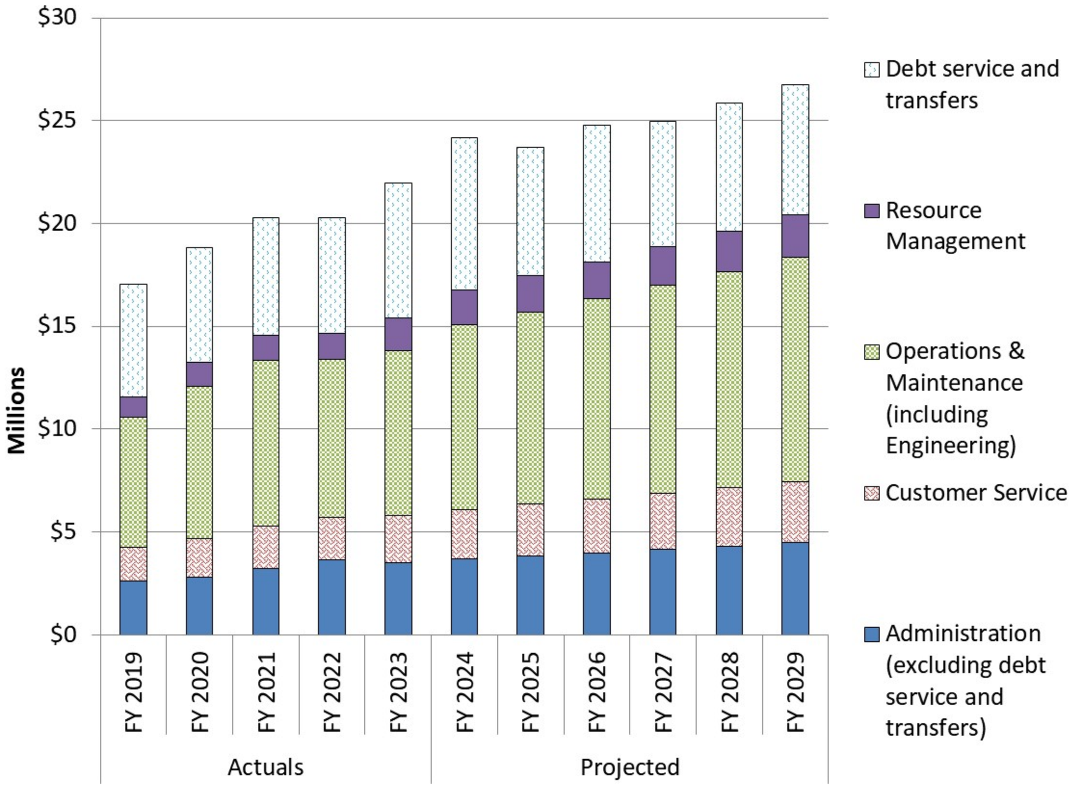
Appendix D: Description of Water Utility Operational Activities includes detailed descriptions of the work associated with each of these activities.

From FY 2019 to FY 2023, overall operations costs increased 6.5% per year on average. Resource Management costs increased at 13.5% per year on average while customer service increased by 8.8% and administration increased 7.8%. Operations and Maintenance increased 6.1% annually on average. Transfers have varied from year to year, but staff expect transfers to remain relatively stable through the forecast period.

Staff anticipates inflationary increases for all operations costs with underlying assumptions for salary and benefit costs, consumer price index, and other cost projections that align as much as possible with the City's Long Range Financial Forecast.[11] This plan anticipates operations costs to increase by 4% per year, on average, over the forecast period. For salary and benefit assumptions, this Financial Plan uses estimated annual percentage increases applied to the actual FY 2023 salaries and benefits of 6% in FY 2024 and 4% per year in FY 2025 through FY 2029. These percentage estimates may change as the budget is refined and finalized this fiscal year.

[11] Finance Committee Staff Report #2307-1773 December 5, 2023, https://cityofpaloalto.primegov.com/api/compilemeetingattachmenthistory/historyattachment/?historyId=5b63b0b2-ba53-4346-94a2-c2a2858f2915

Figure 9: Historical and Projected Operational Costs



SECTION 6C: CAPITAL IMPROVEMENT PROGRAM (CIP)

The Water Utility's CIP consists of the following types of projects:

- One-time projects, or large, non-recurring replacement of system assets (such as reservoir rehabilitation).
- Water main replacement, which represents the ongoing replacement of aging water mains and the services associated with those mains, as well as seismically vulnerable mains located in areas where soil is prone to liquefaction.
- Ongoing projects, which represent the cost of replacing aging and under-recording meters and degraded boxes and covers, minor replacements of various types of distribution system equipment, and the cost of capitalized tools and equipment.
- Customer connections, which represents the cost when the Water Utility installs new services or upgrades existing services at a customer's request in response to development or redevelopment. CPAU charges a fee to these customers to cover the cost of these projects.

Table 16 shows the FY 2024 projected budget and the five-year CIP spending plan, although these figures are preliminary pending ongoing budget discussions.

Table 16: Budgeted Water Utility CIP Spending ($000)

Project Category	Current Budget*	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
One Time Projects	2,866	300	300	7,000	7,900	1,000
Water Main Replacement	11,488	425	9,407	472	10,450	525
Ongoing Projects	6,680	2,656	2,019	2,087	2,220	2,273
Customer Connections	1,072	961	989	1,019	1,100	1,100
TOTAL	22,106	4,342	12,715	10,578	21,670	4,898

*Includes unspent funds from previous years carried forward or reappropriated into the current fiscal year

This budget does not include allocated overhead, estimated to be $0.7 million in FY 2024 and escalating at 4% annually thereafter as shown in the table below. This budget also does not include unallocated salaries and benefits, which are CIP-related salaries and benefits not included in the project budgets, estimated to be $0.8 million annually. Allocated overhead and unallocated salaries and benefits are added to the capital budget.

Table 17: Allocated Overhead and Unallocated CIP Salaries and Benefits

	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Allocated Overhead	$651,736	$677,806	$704,918	$733,115	$762,439	$792,937
Unallocated CIP Salaries and Benefits	$770,000	$770,000	$770,000	$770,000	$770,000	$770,000

The Water Main Replacement (WMR) program funds the replacement of deteriorating water mains or water mains in liquefaction zones. The water system consists of over 236 miles of mains, approximately 2,000 fire hydrants, and over 20,000 metered service connections spanning 9 pressure zones over a 26 square mile service area. In recent years, CPAU has replaced many miles of the most leak-prone and deteriorated pipes. Since the CIP program started in the early 1990s, 61 miles or 26% of water mains have been replaced. CPAU continues to pursue a pipe replacement program of mains that are subject to recurring breaks based on maintenance history, and 11.6 miles of mains that were identified in the 2015 water system study. CPAU also coordinates with the Public Works street maintenance program to avoid cutting into newly repaved streets. The main replacement schedule in this Financial Plan will allow CPAU to replace these mains on schedule.

Costs for the water main replacement program are increasing for a variety of reasons:

- Fire flow requirements for larger diameter pipe.
- CPAU has switched to high-density polyethylene (HDPE) for its mains. Installation costs for this material are slightly higher, though lifecycle costs are lower, and the material performs better. Joints in distribution mains are the most likely place for failure, and sections of HDPE pipe are fused together rather than connected with fittings. In the long run, this will reduce water losses and maintenance costs.
- To take full advantage of HDPE's fusibility, CPAU is now replacing the services along with the water mains with new HDPE services. In the past, the existing services were

reconnected, regardless of the material. This new practice costs more in the short run, but will provide long term benefits.

- Lastly, material, fuel, and labor costs have escalated due to inflation, leading to higher bids.

These factors have created some uncertainty in future water main replacement costs. As bids for recent projects have consistently come in higher over the last few years, future main replacement project budgets have been increased to reflect expected bid estimates. If the cost of water main replacement continues to rise at its current levels, budgets may need to be revised further. In 1993, the long-term water main replacement program focused on replacing the oldest and most degraded parts of the system. Then in 2015, CPAU initiated a master planning process that was completed in FY 2016 to evaluate the current state of the distribution system and determine the necessary rate of main replacement in the next 20 years. This study factored in seismically vulnerable mains as well as deteriorating mains. Mains with recurring maintenance issues are added to projects as they are identified. Preparing for the future, CPAU is in the process of evaluating the utility's asbestos cement pipe (ACP) water mains. Over half the mains in the system are ACP. The ACP pipe has performed very well, but CPAU wants to verify its life expectancy and plan for its future replacement in over the next 30 years.

This Financial Plan addresses these challenges in a way that will allow CPAU to meet its main replacement needs. This Financial Plan includes approximately $8.5 million every other year for main replacement construction, assuming inflation of 5.4% annually on the main replacement budget. Staff anticipates that larger main replacement construction projects every other year will attract more contractors to bid on the larger projects and alleviate the burden of insufficient inspection coverage.

Included in the one-time project budget are seismic water system upgrades and/or replacement for the Park and Dahl Tanks, two water distribution storage reservoirs, located in the Palo Alto Foothills. This work will improve protection from water loss and damage to these storage tanks during seismic events. Significant earthquake damage could lead to a loss of water for firefighting, sanitation, and domestic and commercial drinking water uses. A rupture and failure of the storage tanks during an earthquake could cause property damage, mudslides, and environmental damage. Staff contracted with an engineering specialist and investigated and analyzed the structural integrity and condition of the Park Tank Reservoir. The engineering specialist recommended a full roof replacement of the Park Tank Reservoir in addition to a seismic retrofit of the tank. Staff solicited proposals for an engineering firm to prepare plans and cost estimates for the seismic retrofit and roof replacement of Park Tank and to perform a condition assessment of Dahl Tank. If full tank replacement is needed for either Dahl or Park Tank, the estimated cost for design and construction of Dahl and Park reservoirs is approximately $7 million each in FY 2027 and FY 2028. The cost to replace tank roofs and seismically retrofit the tanks is approximately $4 million per tank.

Staff prepared and solicited bids for a capital improvement project for a seismic improvement of the California and Page Mill Turnouts, two water receiving stations from the San Francisco Public Utilities Commission's water distribution system, and the City awarded the contract in FY 2023. The Page Mill Turnout work was completed in September 2023. The California Turnout work started in January 2024 and is anticipated to be completed in May 2024.The California Turnout work involves replacement of all the water piping and valving in the City of Palo Alto's water utility vault on California Avenue and a replacement of the vault roof.

Ongoing projects are expected to cost approximately $4.7 million on average annually for FY 2024 and FY 2025 for the purchase of generators and security cameras at the water pumping facilities. However, this CIP category will then reduce to between $2.0 and $2.3 million annually through the end of the forecast period. Actual expenses fluctuate annually depending on how many defective meters are discovered and replaced during routine maintenance.

For customer connections, expenses also fluctuate annually depending on how much development and redevelopment is going on that prompts the replacement or upgrade of water services. Property owners pay a fee for water service replacement or expansion during redevelopment, so when the number of projects go up (meaning higher costs for this activity), so does fee revenue.

Aside from customer connections, the CIP plan for FY 2024 to FY 2029 is funded by revenue from utility rates and capacity fees. *Appendix B: Water Utility Capital Improvement Program (CIP) Detail* shows the details of the plan.

Figure 10 below shows the projected CIP Reserve balances from FY 2024 through FY 2029. Figure 11 below shows the projected CIP expenditure fluctuating from year to year with the staggered main replacement schedule and one-time reservoir replacements/rehabilitations, relative to the steadier capital program contributions to the CIP Reserve. This Financial Plan projects a $4 million capital program contribution to the CIP Reserve in FY 2024 and approximately a $9 million capital program contribution to the CIP Reserve annually from FY 2025 through FY 2027 and approximately $12 million in FY 2028 and FY 2029. Additionally, this Financial Plan includes a request for Council approval to transfer up to $3.461 million out of the CIP Reserve to the Operations Reserve to pay for estimated CIP in FY 2024. Appendix A: Water Utility Financial Forecast Detail shows the amount of the capital program contributions under "Expenses" for FY 2024 through FY 2029.

Figure 10: Projected CIP Reserve Balances FY 2024 to FY 2029

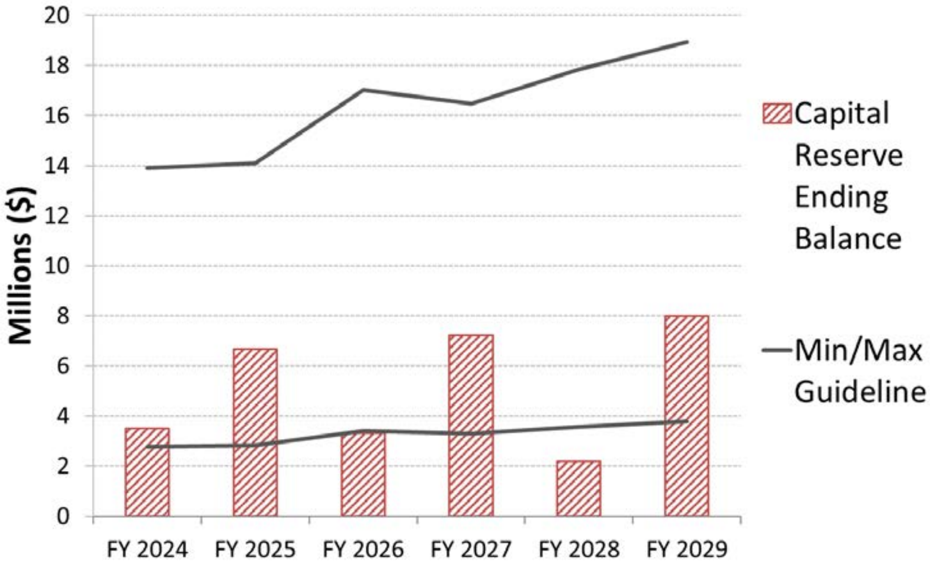
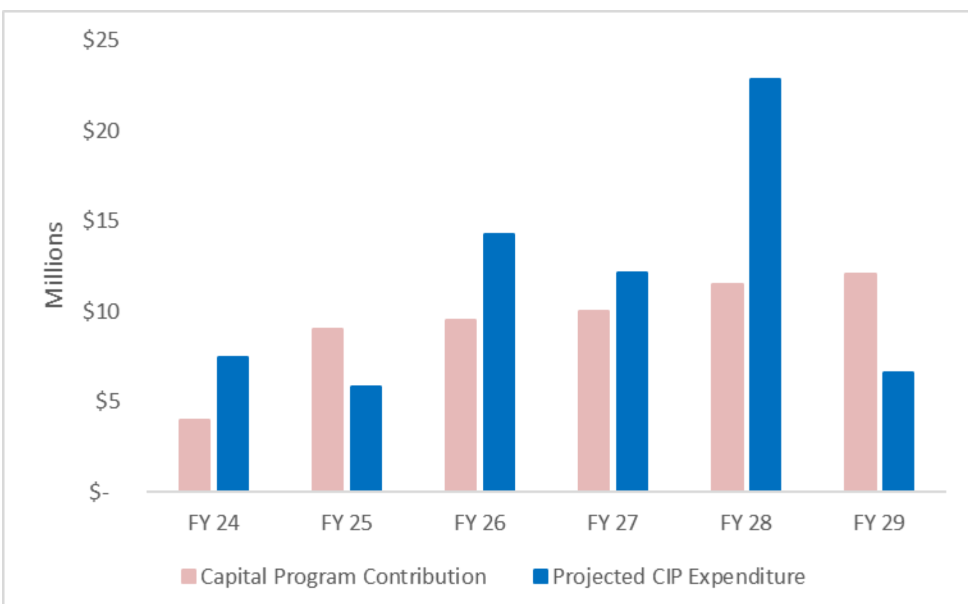


Figure 11: Projected CIP Expenditure,and Projected Capital Program Contribution, FY 2024 to FY 2029



SECTION 6D: DEBT SERVICE

The Water Utility's annual debt service is roughly $3.2 million per year, which is offset by a federal subsidy of approximately $300K to $430K annually. The debt service is associated with two bond issuances, one requiring payments through 2026, the other through 2035. CPAU is in compliance with all covenants on both bonds.

The first bond is the 2009 Water Revenue Bond, Series A, issued for $35 million to finance construction of the Emergency Water Supply and Storage project (the El Camino Reservoir, new wells, and rehabilitation of existing wells and tanks) which will be retired by 2035. As part of the 'Build America' bond program, there is an interest payment subsidy from the Federal Government of 33 to 35%.

The second bond issuance is the 2011 Utility Revenue Refunding Bond, Series A, which is to be retired in 2026. This $17.2 million issuance refinanced an earlier Water and Gas Utility bond issuance, the 2002 Utility Revenue Bonds, Series A, which was issued to finance various capital improvements for both systems. The Water Utility's share of the issuance was roughly $7.8 million.

Table 18 shows the cost of debt service for the Water Utility's share of these bond issuances for the financial forecast period:

Table 18: Water Utility Debt Service ($000)

	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028
2009 Water Revenue Bond, Series A (net of subsidy)	2,158	2,181	2,201	2,225	2,251	2,280
2011 Utility Revenue Refunding Bond, Series A	656	654	656	0	0	0
Total	2,814	2,835	2,857	2,225	2,251	2,280

Both the 2009 and 2011 Bonds include the following covenants: 1) net revenues plus Available Reserves shall at least equal 125% of the maximum annual debt service, and 2) Available Reserves shall be at least 5 times the maximum annual debt service. Note that "Available Reserves," as defined for both bonds, include the reserves for the Gas and Electric systems, not just the Water system. This Financial Plan maintains compliance with these covenants throughout the forecast period, as shown in *Appendix A: Water Utility Financial Forecast Detail*.

SECTION 6E: OTHER REVENUES

The Water Utility receives most of its revenues from sales of water. The next largest source in FY 2023 was service connection fee revenue, which represented 38% of revenue from sources other than water sales; interest income represented 35% of revenue from sources other than water sales, and grants represented 16% of revenue from sources other than water sales. The remainder consisted of a variety of miscellaneous charges and transfers.

Connection fees are charged to new developments that need new or replacement service connections, while capacity fees are charged to development that put additional demands on the water distribution system. Revenue from these sources fluctuate from year to year. In FY 2023, capacity fee revenue was almost as low as it was in FY 2022, which was the lowest level in any of the prior ten years. Service Connection fee revenue also continued at a low level similar to the level seen in FY 2022. Staff estimates this decrease is due to more tenant improvements permits rather than new service connection permits where the improvements are inside the buildings and the utility infrastructure remains the same. This financial plan forecasts connection fee and capacity fee revenue using the most recent year recorded amounts increasing at an average of 3% per year in subsequent years. Connection and capacity fee revenue is reflected in the Operations Reserve.

Other revenue sources are projected to stay stable through the forecast period, though interest income fluctuates depending on changes in interest rates. Some uncertainty also exists related to the Federal government's commitment to continuing to pay the interest subsidy on the Build America Bonds.

SECTION 6F: SALES REVENUES

Staff based the sales revenue projections on the load forecast in *Section 5A: Load Forecast* and the projected rate changes shown in Figure 5. Precipitation can vary substantially, and this can affect revenues substantially. In dry, non-drought years customers use more water, increasing revenues, and in wet years they use less. It is difficult to predict customer usage recovery from drought together with impacts from weather from year to year. Staff will continue to monitor these patterns and adjust projections accordingly in subsequent financial plans.

SECTION 7: COMMUNICATIONS PLAN

The FFY 2025 Water Utility communications strategy covers these primary areas: cost drivers and cost containment measures, efficiency programs and services, capital improvement and maintenance for infrastructure safety and reliability. The City of Palo Alto Utilities (CPAU) communication methods include use of the utilities website, utility bill inserts, messaging on utility bills and MyCPAU online account management platform, email newsletters, print and digital ads in local publications, social media, community messaging platforms, and through direct mailings of the Home Water Reports and online WaterSmart portal.

A Water Utility rate increase is necessary because the year-end operations reserve is near the minimum guideline due to the drought. Water sales were much lower than forecasted as a result of CPAU encouraging conservation during the drought. These water use reductions impact water rates because the primarily fixed costs of the system are spread among fewer units of water sales. Expenses are also higher than forecasted. Market economics have continued to drive up labor and material costs for construction projects. As a not for profit public utility, CPAU must recover its costs primarily through revenue generated by rates. Any increased supply costs are passed through rates to CPAU customers, including for capital improvement. The cost to deliver water supply to Palo Alto and for CPAU to distribute water to customers is high, as it includes maintaining and replacing water infrastructure, customer service, billing, and administration.

CPAU's communication about Water Utility rates will focus on the costs passed down from Palo Alto's water supplier, the San Francisco Public Utilities Commission (SFPUC), capital improvement and infrastructure upgrades, and what CPAU is doing to keep costs down. Maintaining water pipes, mains, and service connections is necessary to prevent leaks, which cost the utility and rate payers money, and prevents damage to infrastructure which could exacerbate safety and reliability concerns in the long term.

CPAU promotes water use efficiency programs and easy water-saving behaviors to aid in our water saving efforts and help customers keep utility costs low. Messaging reinforces that although rates may increase, efficient usage can help customers avoid seeing a significant water cost increase on the utility bill. The City is also exploring opportunities to expand use of alternative water supplies through the development of a One Water Plan for that purpose to further reduce demands on potable water supplies.

Staff maintain a dedicated webpage[12], to provide an overview on all utility rates costs to the utility, updates to financial forecasts and proposed rate changes. While print materials such as bill inserts and ads feature prominently, CPAU is exploring additional ways to communicate directly to customers utilizing unique programs like the relatively new WaterSmart portal and Home Water Reports. Staff continue to maintain an active presence in social media and are expanding outreach through citywide email newsletters. Staff attend community outreach events and host educational workshops on these related topics.

APPENDICES

Appendix A: Water Utility Financial Forecast Detail

Appendix B: Water Utility Capital Improvement Program (CIP) Detail

Appendix C: Water Utility Reserves Management Practices

Appendix D: Description of Water Utility Operational Activities

Appendix E: Sample of Water Utility Outreach Communications

[12] https://www.cityofpaloalto.org/Departments/Utilities/Customer-Service/Utilities-Rates

APPENDIX A: WATER UTILITY FINANCIAL FORECAST DETAIL

1	**FISCAL YEAR**	**FY 2021**	**FY 2022**	**FY 2023**	**FY 2024**	**FY 2025**	**FY 2026**	**FY 2027**	**FY 2028**	**FY 2029**
2										
3	**WATER SUPPLY**									
4	Purchases (CCF)	4,785,384	4,709,184	4,210,399	4,322,676	4,437,947	4,556,293	4,506,173	4,456,605	4,407,583
5	Sales (CCF)	4,770,922	4,458,594	3,866,832	4,075,166	4,183,837	4,295,406	4,248,156	4,201,427	4,155,211
6										
7	**BILL AND RATE CHANGES**									
8	Variable Charge (Supply)	0%	0%	16%	10%	7%	1%	5%	7%	4%
9	Residential Variable Charge (Distribution)	0%	4%	2%	13%	14%	15%	13%	6%	6%
10	System Average Rate	-1%	-1%	11%	0%	10%	8%	11%	11%	5%
11	Average Customer Bill (projected)					10%	8%	11%	11%	5%
12										
13	**STARTING RESERVES**									
14	Reappropriations (Non-CIP)	70,000	41,000	-	-	-	-	-	-	-
15	Commitments (Non-CIP)	796,000	444,000	1,766,000	2,737,000	-	-	-	-	-
16	Restricted for Debt Service	3,260,000	2,906,000	2,906,000	2,813,000	2,813,000	2,813,000	2,813,000	2,813,000	2,813,000
17	Emergency Plant Replacement	-	-	-	-	-	-	-	-	-
18	Reappropriations & Commitments	11,036,000	10,147,000	12,168,000	16,066,000	16,066,000	16,066,000	16,066,000	16,066,000	16,066,000
19	Capital Reserve	5,726,096	10,707,096	10,707,096	6,961,000	3,499,617	6,679,051	3,312,351	7,233,495	2,189,878
20	Rate Stabilization Reserve	9,069,437	9,069,437	9,069,437	6,069,000	4,000,000	2,000,000	-	-	-
21	Operations Reserve	13,351,122	13,876,597	13,653,963	7,957,000	9,180,500	8,798,968	10,266,940	9,332,824	10,089,086
22	Unassigned	5,484,833	6,469,360	338,378	-	-	-	-	-	-
23	TOTAL STARTING RESERVES	48,793,488	53,660,490	50,608,874	42,603,000	35,559,116	36,357,018	32,458,291	35,445,319	31,157,963
24										
25	**REVENUES**									
26	Net Sales	47,434,047	44,058,867	42,570,047	47,232,255	53,168,761	58,977,120	64,898,741	71,194,833	73,924,132
27	Other Revenues and Transfers In	3,294,442	2,950,590	2,620,375	3,013,531	3,070,643	3,128,368	3,187,701	3,252,758	3,309,659
28	TOTAL REVENUES	50,728,489	47,009,457	45,190,422	50,245,786	56,239,404	62,105,488	68,086,441	74,447,591	77,233,790
29										
30	**EXPENSES**									
31	Water Purchases	21,935,250	21,248,651	21,744,025	24,383,194	26,434,809	27,504,830	28,516,089	30,145,396	30,891,662
32	Operating Expenses									
33	Administration									
34	*Allocated Charges*	*3,224,030*	*3,646,012*	*3,524,964*	*3,695,899*	*3,843,735*	*3,997,484*	*4,157,384*	*4,323,679*	*4,496,626*
35	*Rent*	*2,225,372*	*2,270,000*	*2,365,000*	*2,459,600*	*2,557,984*	*2,660,303*	*2,766,715*	*2,877,384*	*2,992,479*
36	*Debt Service*	*3,222,843*	*3,219,993*	*3,222,938*	*3,220,173*	*3,219,316*	*3,219,331*	*2,563,683*	*2,565,598*	*2,563,503*
37	*Transfers and Other Adjustments*	*267,645*	*137,903*	*945,092*	*1,721,249*	*479,635*	*760,690*	*765,211*	*769,867*	*774,663*
38	Subtotal, Administration	8,939,890	9,273,908	10,057,995	11,096,921	10,100,670	10,637,809	10,252,993	10,536,529	10,827,272
39	Resource Management	1,215,567	1,261,514	1,590,945	1,681,208	1,748,456	1,818,394	1,891,130	1,966,775	2,045,446
40	Operations and Mtc	7,400,625	7,195,632	7,531,468	7,956,888	8,275,163	8,606,170	8,950,417	9,308,433	9,680,771
41	Engineering (Operating)	662,832	492,438	508,307	534,606	555,991	578,230	601,359	625,414	650,430
42	Customer Service	2,053,820	2,058,662	2,272,586	2,409,469	2,505,848	2,606,082	2,710,325	2,818,738	2,931,488
43	Subtotal, Operating Expenses	20,272,734	20,282,154	21,961,300	23,679,092	23,186,127	24,246,685	24,406,224	25,255,889	26,135,407
44	Capital Program Contribution^	4,981,000	10,551,269	13,083,836	4,000,000	9,000,000	9,486,000	9,998,244	11,790,044	12,426,706
45	TOTAL EXPENSES	47,188,984	52,082,074	56,789,162	52,062,286	58,620,936	61,237,516	62,920,557	67,191,329	69,453,775
46										
47	**ENDING RESERVES**									
53	Capital Reserve	10,707,096	10,707,096	6,961,000	3,499,617	6,679,051	3,312,351	7,233,495	2,189,878	7,989,317
54	Rate Stabilization Reserve	9,069,437	9,069,437	6,069,000	4,000,000	2,000,000	-	-	-	4,000,000
55	Operations Reserve	13,876,597	13,653,963	7,957,000	9,180,500	8,798,968	10,266,940	9,332,824	10,089,086	13,869,101
56	Unassigned	6,469,360	338,378	-	-	-	-	-	-	-
57	TOTAL ENDING RESERVES	53,660,490	50,608,874	42,603,000	35,559,116	36,357,018	32,458,291	35,445,319	31,157,963	44,737,418

^ Capital Program Contribution represents CIP funding transferred from the Operations Reserve to the CIP Reserve beginning in FY 2021

Appendix A (continued)

FISCAL YEAR	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
REVENUES											
Net Sales	89%	92%	94%	94%	94%	94%	95%	95%	95%	96%	96%
Other Revenues and Transfers In	11%	8%	6%	6%	6%	6%	5%	5%	5%	4%	4%
TOTAL REVENUES	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
EXPENSES											
Water Purchases	42%	49%	50%	41%	38%	47%	45%	45%	45%	45%	44%
Operating Expenses											
Administration											
Allocated Charges	*5%*	*6%*	*7%*	*7%*	*6%*	*7%*	*7%*	*7%*	*7%*	*6%*	*6%*
Rent	*4%*	*4%*	*5%*	*4%*	*4%*	*5%*	*4%*	*4%*	*4%*	*4%*	*4%*
Debt Service	*6%*	*7%*	*7%*	*6%*	*6%*	*6%*	*5%*	*5%*	*4%*	*4%*	*4%*
Transfers and Other Adjustments	*1%*	*1%*	*1%*	*0%*	*2%*	*3%*	*1%*	*1%*	*1%*	*1%*	*1%*
Subtotal, Administration	16%	19%	20%	18%	18%	21%	17%	17%	16%	16%	16%
Resource Management	2%	3%	3%	2%	3%	3%	3%	3%	3%	3%	3%
Operations and Mtc	12%	16%	17%	14%	13%	15%	14%	14%	14%	14%	14%
Engineering (Operating)	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
Customer Service	3%	4%	5%	4%	4%	5%	4%	4%	4%	4%	4%
Allowance for Unspent Budget	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Subtotal, Operating Expenses	34%	42%	46%	39%	39%	45%	40%	40%	39%	38%	38%
Capital Program Contribution	24%	9%	5%	20%	23%	8%	15%	15%	16%	18%	18%
TOTAL EXPENSES	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
RISK ASSESSMENT DETAIL (PROJECTED)											
Distribution Revenue Variance					2,304,806	2,505,351	2,883,512	3,348,609	3,819,936	4,273,078	4,471,496
Total Risk Asssessment Value					2,304,806	2,505,351	2,883,512	3,348,609	3,819,936	4,273,078	4,471,496
Projected Operations Reserve					7,957,000	9,180,500	8,798,968	10,266,940	9,332,824	10,089,086	13,869,101
Operations Reserve, % of Risk Value					345%	366%	305%	307%	244%	236%	310%
OPERATIONS RESERVE											
Min (60 days of non-capital expenses)	6,289,573	6,675,561	6,938,299	6,826,982	7,184,437	7,900,650	8,156,866	8,507,098	8,699,558	9,107,061	9,374,313
Target (90 days of non-capital expenses)	9,434,359	10,013,342	10,407,448	10,240,472	10,776,656	11,850,975	12,235,299	12,760,648	13,049,338	13,660,591	14,061,469
Max (120 days of non-capital expenses)	12,579,145	13,351,122	13,876,597	13,653,963	14,368,874	15,801,300	16,313,733	17,014,197	17,399,117	18,214,121	18,748,625
Risk Assessment Value					2,304,806	2,505,351	2,883,512	3,348,609	3,819,936	4,273,078	4,471,496
DEBT SERVICE COVERAGE RATIO											
Net Revenues (125% of Debt Service)	1088%	1161%	1210%	1190%	1256%	1393%	1441%	1508%	1964%	2059%	2125%
Available Reserves (5x Debt Service)*	13.1	13.9	15.6	14.3	11.5	10.2	10.4	9.2	12.7	11.0	16.4

**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 meet its debt covenants.*

APPENDIX B: WATER UTILITY CAPITAL IMPROVEMENT PROGRAM (CIP) DETAIL

Project #	Project Name	Reappropriated / Carried Forward from Previous Years /Accruals (A)	Current Year Estimate (B)	Current Year Funding (B-A)	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
ONE TIME PROJECTS									
WS-07000	Regulation Station Imp.	1,257,060	1,275,380	18,320	-	-	-	-	
WS-07001	Water Recycling Facilities		391,000	391,000		-	-	-	
WS-08001	Water Reservoir Coating			-	-	-	-	-	
WS-09000	Seismic Water System	7,184,534	1,200,000	(5,984,534)	300,000	300,000	7,000,000	7,900,000	1,000,000
Subtotal, One-time Projects		**8,441,594**	**2,866,380**	**(5,575,214)**	**300,000**	**300,000**	**7,000,000**	**7,900,000**	**1,000,000**
WATER MAIN REPLACEMENT PROGRAM									
WS-14001	WMR - Project 28	1,792,990	1,925,581	132,591	-	-	-	-	
WS-15002	WMR - Project 29	605,861	9,137,100	8,531,239		-	-	-	
WS-16001	WMR - Project 30		425,000	425,000	425,000	8,959,000		-	
WS-19001	WMR - Project 31			-	-	447,950	472,139	9,952,696	
WS- XXXXX	WMR - Project 32							497,635	524,507
WS- XXXXX	WMR - Project 33								
WS- XXXXX	WMR - Project 34								
WS- XXXXX	WMR - Project 35								
Subtotal, Water Main Replacement Prog.		**2,398,851**	**11,487,681**	**9,088,830**	**425,000**	**9,406,950**	**472,139**	**10,450,331**	**524,507**
Project #	**Project Name**	**Reappropriated / Carried Forward from Previous Years**	**Current Year Estimate**	**Current Year Funding**	**FY 2025**	**FY 2026**	**FY 2027**	**FY 2028**	**FY 2029**
ONGOING PROJECTS									
WS-80014	Services/Hydrants	-	200,000	200,000	412,000	424,000	437,000	450,100	464,000
WS-80015	Water Meters	846,740	1,599,841	753,101	300,000	321,000	340,000	400,000	412,000
WS-02014	W-G-W Utility GIS Data	492,623	789,055	296,432	528,800	544,000	560,000	583,000	600,000
WS-13002	Equipment/Tools	-	50,000	50,000	50,000	50,000	50,000	50,000	50,000
WS-11003	Dist. Sys. Improvements	475,269	769,768	294,499	305,000	314,000	323,000	335,000	345,000
WS-11004	Supply Sys. Improvements	3,271,340	3,271,340	(0)	1,060,660	366,000	377,000	402,000	402,000
WS-19000	Mayfield Reservoir	-		-	-	-	-	-	-
Subtotal, Ongoing Projects		5,085,972	6,680,004	1,594,032	2,656,460	2,019,000	2,087,000	2,220,100	2,273,000
CUSTOMER CONNECTIONS (FEE FUNDED)									
WS-80013	Water System Extensions	140,158	1,072,157	931,999	960,500	989,000	1,018,700	1,100,000	1,100,000
Subtotal, Customer Connections		**140,158**	**1,072,157**	**931,999**	**960,500**	**989,000**	**1,018,700**	**1,100,000**	**1,100,000**
GRAND TOTAL		**16,066,575**	**22,106,222**	**6,039,647**	**4,341,960**	**12,714,950**	**10,577,839**	**21,670,431**	**4,897,507**
Funding Sources									
Connection/Capacity Fees				931,999	960,500	989,000	1,018,700	1,100,000	1,100,000
Other Utility Funds (Asset Mgmt, GIS Systems)				342,000	352,533	362,667	373,333	388,667	400,000
Utility Rates				4,765,648	3,028,927	11,363,283	9,185,806	20,181,765	3,397,507
CIP-RELATED RESERVES DETAIL		**6/30/2023 Actual**							
Reappropriations & Commitments		16,066,575							

APPENDIX C: WATER UTILITY RESERVES MANAGEMENT PRACTICES

The following reserves management practices shall be used when developing the Water 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, for the Water Utility Financial Plan delivered in conjunction with the FY 2015 budget, FY 2015 to FY 2021 is 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. Reserves

The Water Utility's Fund Balance is reserved for the following purposes:

a) For existing contracts, as described in Section 3 (Reserve for Commitments)
b) For operating and capital budgets re-appropriated from previous years, as described in Section 4 (Reserve for Re-appropriations)
c) For cash flow management and contingencies related to the Water Utility's Capital Improvement Program (CIP), as described in Section 5 (CIP Reserve)
d) For rate stabilization, as described in Section 6 (Rate Stabilization Reserve)
e) For operating contingencies, as described in Section 7 (Operations Reserve)
f) 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 8 (Unassigned Reserves).

Section 3. Reserve for Commitments

At the end of each fiscal year the Reserve for Commitments will be set to an amount equal to the total remaining spending authority for all contracts in force for the Water Utility at that time.

Section 4. Reserve for Re-appropriations

At the end of each fiscal year the Reserve for Re-appropriations will be set to an amount equal to the amount of all remaining capital and non-capital budgets, if any, that will be re-appropriated to the following fiscal year in accordance with Palo Alto Municipal Code Section 2.28.090.

Section 5. 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)[13] CIP budget, for 48 months of budgeted CIP expenses[14]

b) Changes in Reserves: Staff is authorized to transfer funds between the CIP Reserve and the Reserve for Commitments when funds are added or removed from to that reserve 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: 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.

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, return the funds to ratepayers, or designate a specific use of the 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 6. Rate Stabilization Reserve

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

Section 7. Operations Reserve

The Operations Reserve is used to manage normal variations in costs and as a reserve for contingencies. Any portion of the Water Utility's Fund Balance not included in the reserves described in Section 3-Section 6 above will be included in the Operations Reserve unless this reserve has reached its maximum level as set forth in Section 7(d) below. Staff will manage the Operations Reserve according to the following practices:

a) The following guideline levels are set forth for the 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.

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

[14] 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.

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

b) Minimum Level: If, at the end of any fiscal year, the funds remaining in the 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, and the Council may adopt, an alternative plan that takes longer than one year to replenish the reserve.

c) Target Level: If, at the end of any fiscal year, the Operations Reserve is higher or lower than the target level, any Financial Plan created for the Water Utility shall be designed to return the Operations Reserve to its target level within four years.

d) Maximum Level: If, at any time, the Operations Reserve reaches its maximum level, no funds may be added to this reserve. Any further increase in the Water Utility's Fund Balance shall be automatically included in the Unassigned Reserve described in Section 8, below.

Section 8. Unassigned Reserve

If the Operations Reserve reaches its maximum level, any further additions to the Water Utility's Fund Balance will be held in the Unassigned Reserve. If there are any funds in the 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 Water 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 2015, and the next Financial Planning Period is FY 2016 through FY 2021, the Financial Plan shall include a plan to return or assign any funds in the Unassigned Reserve by the end of FY 2016. Staff may present an alternative plan that retains these funds or returns them over a longer period of time.

APPENDIX D: DESCRIPTION OF WATER UTILITY OPERATIONAL ACTIVITIES

This appendix describes the activities associated with the various operational activities referred to in *Section 6B: Operations* of this Financial Plan.

Administration: Accounting, purchasing, legal, and other administrative functions provided by the City's General Fund staff, as well as shared communications services, CPAU administrative overhead, and billing system maintenance costs. This category also includes Water Utility debt service and rent paid to the General Fund for the land associated with reservoirs and various other facilities.

Customer Service: This category includes the Water 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 water services.

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

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

- investigating reports of damaged mains or services and performing emergency repairs;
- testing and operating valves;
- monitoring water quality and reservoir levels;
- monitoring the status of the different pressure zones;
- flushing water at hydrants and other closed end points of the system;
- building and replacing water services for new or redeveloped buildings; and
- testing and replacing meters to ensure accurate sales metering.

This category also includes a variety of functions the utility shares with other City utilities, including:

- the Field Services team (which does field research of various customer service issues);
- the Cathodic Protection team (which monitors and maintains the systems that prevent corrosion in metal tanks and reservoirs); and
- the General Services team (which manages and maintains equipment, paves and restores streets after gas, water, or sewer main replacements, and provides welding services)

Resource Management: This category includes water procurement, contract management, water resource planning, interaction with BAWSCA, the SFPUC, and Valley Water, and tracking of legislation and regulation related to the water industry.

APPENDIX E: SAMPLE OF WATER UTILITY OUTREACH COMMUNICATIONS

GENERAL RESIDENTIAL WATER SERVICE

UTILITY RATE SCHEDULE W-1

A. APPLICABILITY:

This schedule applies to separately metered single-family residential dwellings receiving Water Service from the City of Palo Alto Utilities.

B. TERRITORY:

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

C. RATES:

Monthly Service Charge:	Per Meter Per Month
For meters 5/8-inch to 1 inch	$ 24.27~~21.48~~
For 1 1/2 inch meter	78.39~~69.38~~
For 2-inch meter	121.27~~107.32~~
For 3-inch meter	257.05~~227.48~~
For 4-inch meter	457.15~~404.56~~
For 6-inch meter	935.94~~828.27~~
For 8-inch meter	1,722.02~~1,523.92~~
For 10-inch meter	2,722.49~~2,409.29~~
For 12-inch meter	3,580.05~~3,168.19~~

Volumetric Rates: (To be added to Service Charge, applicable to all pressure zones.)	Per Hundred Cubic Feet Per Month
Commodity Rate:	
Water Delivery Charge from SFPUC	$ 5.55~~5.21~~
Distribution Rate:	
Tier 1 usage	$3.07~~2.72~~
Tier 2 usage (All usage over 100% of Tier 1)	7.15~~6.33~~

GENERAL RESIDENTIAL WATER SERVICE

UTILITY RATE SCHEDULE W-1

Drought Surcharges (deactivated):

A drought surcharge will be added to the Customer's applicable commodity rate for Tier 1 and Tier 2 Water usage when the City Council has determined that a Water reduction level is in effect for the City as described in Section D.4. The drought surcharges in the table below are measured in dollars per hundred cubic feet (ccf).

Water Usage Reduction level	**Level 1 (10/15%)**	**Level 2 (20%)**	**Level 3 (25%)**
Tier 1	0.20	0.43	0.64
Tier 2	0.58	1.21	1.85

Temporary Service – Developers

Temporary unmetered service to residential subdivision developers, per connection .... $ 6.00

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. Commodity Rate

The Commodity Charge is based on the water delivery rate per the San Francisco Public Utility Commission (SFPUC) Water Rate Schedule W-25: Wholesale Use with Long-Term Contract. The Commodity Charge will be passed through automatically via periodic rate adjustments to account for increases in wholesale water charges, as well as inflation. The pass-through period will be effective for fiscal years 2020 through 2024, inclusive. Customers will be provided notice of any adjustments via their billing statements or by any other mailing by CPAU to the customer's regular billing address.

3. Calculation of Usage Tiers

Tier 1 Water usage shall be calculated and billed based upon a level of 0.2 ccf per day rounded to the nearest whole ccf, based on Meter reading days of Service. As an example, for a 30-day bill, the Tier 1 level would be 0 through 6 ccf. For further discussion of bill calculation and proration, refer to Rule and Regulation 11.

4. Drought Surcharge

During period of Water shortage or restrictions on local Water use, the City Council may, by resolution, declare the need for citywide Water conservation at the 10/15%, 20% or 25% level. While such a resolution is in effect, a drought surcharge will apply. The purpose of the drought surcharge is to recover revenues lost as a result of reduced consumption.

{End}

WATER SERVICE FROM FIRE HYDRANTS

UTILITY RATE SCHEDULE W-2

A. APPLICABILITY:

This schedule applies to all Water taken from fire hydrants for construction, maintenance, and other uses in conformance with provisions of a Hydrant Meter Permit.

B. TERRITORY:

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

C. RATES:

1. Monthly Service Charge.

METER SIZE

5/8 inch .... $ 50.00
3 inch 125.00

2. Volumetric Rate: (per hundred cubic feet)

Commodity Rate:
Water Delivery Charge from SFPUC .... $ 5.55~~5.21~~

Distribution Rate: .... $ 4.32~~3.83~~

4. Drought Surcharges (deactivated):

A drought surcharge will be added to the Customer's applicable Commodity rate when the City Council has determined that a Water reduction level is in effect for the City as described in Section D.6. The drought surcharges in the table below are measured in dollars per hundred cubic feet (ccf).

Water Usage Reduction level	**Level 1 (10/15%)**	**Level 2 (20%)**	**Level 3 (25%)**
Surcharge	0.26	0.53	0.77

WATER SERVICE FROM FIRE HYDRANTS

UTILITY RATE SCHEDULE W-2

D. SPECIAL NOTES:

1. Monthly charges shall include the applicable monthly Service Charge in addition to usage billed at the commodity rate.

2. The Commodity Charge is based on the water delivery rate per the San Francisco Public Utility Commission (SFPUC) Water Rate Schedule W-25: Wholesale Use with Long-Term Contract. The Commodity Charge will be passed through automatically via periodic rate adjustments to account for increases in wholesale water charges, as well as inflation. The pass-through period will be effective for fiscal years 2020 through 2024, inclusive. Customers will be provided notice of any adjustments via their billing statements or by any other mailing by CPAU to the customer's regular billing address.

3. Any person or company using a hydrant without first obtaining a valid Hydrant Meter Permit shall pay a fee of $50.00 for each day of such use in addition to all other costs and fees provided in this schedule. A hydrant permit may be denied or revoked for failure to pay such fee.

4. A Meter deposit of $750.00 may be charged any applicant for a Hydrant Meter Permit as a prerequisite to the issuance of a permit and Meter(s). A charge of $50.00 per day will be added for delinquent return of hydrant Meters. A fee will be charged for any Meter returned with missing or damaged parts.

5. Any person or company using a fire hydrant improperly or without a permit, or who draws Water from a hydrant without a Meter installed and properly recording usage shall, in addition to all other applicable charges be subject to criminal prosecution pursuant to the Palo Alto Municipal Code.

6. During period of Water shortage or restrictions on local Water use, the City Council may, by resolution, declare the need for citywide Water conservation at the 10/15%, 20% or 25% level. While such a resolution is in effect, a drought surcharge will apply. The purpose of the drought surcharge is to recover revenues lost as a result of reduced consumption.

{End}

FIRE SERVICE CONNECTIONS

UTILITY RATE SCHEDULE W-3

A. APPLICABILITY:

This schedule applies to all public fire hydrants and private fire Service connections.

B. TERRITORY:

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

C. RATES:

1. Monthly Service Charges

Public Fire Hydrant .... $ 5.00

Private Fire Service:
2-inch connection .... $ 4.99 ~~4.42~~
4-inch connection .... 30.93 ~~27.38~~
6-inch connection .... 89.84 ~~79.51~~
8-inch connection .... 191.47 ~~169.45~~
10-inch connection .... 344.35 ~~304.74~~
12-inch connection .... 556.23 ~~492.24~~

2. Commodity (To be added to Service Charge unless Water is used for fire extinguishing or testing purposes.)

Per Hundred Cubic Feet

All water usage .... $ 10.00

D. SPECIAL NOTES:

1. Service under this schedule may be discontinued if Water is used for any purpose other than fire extinguishing or testing and repairing the fire extinguishing facilities. Using hydrants and fire Services for other purposes is illegal and will be subject to the commodity charge as noted above, fines, and criminal prosecution pursuant to the Palo Alto Municipal Code.

2. For a combination Water and fire Service, the Water Service schedule shall apply.

FIRE SERVICE CONNECTIONS

UTILITY RATE SCHEDULE W-3

3. Utilities Rule and Regulation No. 21 provides additional information on Automatic Fire Services.

4. Repairs and testing of fire extinguishing facilities are not considered unauthorized use of Water if records and documentation are supplied by the Customer.

{End}

RESIDENTIAL MASTER-METERED AND GENERAL NON-RESIDENTIAL WATER SERVICE

UTILITY RATE SCHEDULE W-4

A. APPLICABILITY:

This schedule applies to Water Services to non-residential buildings, and multi-family residential dwellings served through a Master-Meter.

B. TERRITORY:

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

C. RATES:

Monthly Service Charge		Per Meter Per Month
For	5/8-inch meter	$ 21.22 ~~18.78~~
For	3/4-inch meter	28.37 ~~25.11~~
For	1-inch meter	42.66 ~~37.76~~
For	1 ½-inch meter	78.39 ~~69.38~~
For	2-inch meter	121.27 ~~107.32~~
For	3-inch meter	257.05 ~~227.48~~
For	4-inch meter	457.15 ~~404.56~~
For	6-inch meter	935.94 ~~828.27~~
For	8-inch meter	1,722.02 ~~1,523.92~~
For	10-inch meter	2,722.49 ~~2,409.29~~
For	12-inch meter	3,580.05 ~~3,168.19~~

Volumetric Rates: (to be added to Service Charge, applicable to all pressure zones)	Per Hundred Cubic Feet Per Month
Commodity Rate:	
Water Delivery Charge from SFPUC	$ 5.55 ~~5.21~~
Distribution Rate:	4.32 ~~3.83~~

RESIDENTIAL MASTER-METERED AND
GENERAL NON-RESIDENTIAL WATER SERVICE

UTILITY RATE SCHEDULE W-4

Drought Surcharges (deactivated):

A drought surcharge will be added to the Customer's applicable commodity rate when the City Council has determined that a Water reduction level is in effect for the City as described in Section D.3. The drought surcharges in the table below are measured in dollars per hundred cubic feet (ccf).

Water Usage Reduction level	**Level 1 (10/15%)**	**Level 2 (20%)**	**Level 3 (25%)**
Surcharge	0.26	0.53	0.77

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. Commodity Rate

The Commodity Charge is based on the water delivery rate per the San Francisco Public Utility Commission (SFPUC) Water Rate Schedule W-25: Wholesale Use with Long-Term Contract. The Commodity Charge will be passed through automatically via periodic rate adjustments to account for increases in wholesale water charges, as well as inflation. The pass-through period will be effective for fiscal years 2020 through 2024, inclusive. Customers will be provided notice of any adjustments via their billing statements or by any other mailing by CPAU to the customer's regular billing address.

3. Drought Surcharge

During period of Water shortage or restrictions on local Water use, the City Council may, by resolution, declare the need for citywide Water conservation at the 10/15%, 20% or 25% level. While such a resolution is in effect, a drought surcharge will apply. The purpose of the drought surcharge is to recover revenues lost as a result of reduced consumption.

{***End***}

NON-RESIDENTIAL IRRIGATION WATER SERVICE

UTILITY RATE SCHEDULE W-7

A. APPLICABILITY:

This schedule applies to non-residential Water Service supplying dedicated irrigation Meters.

B. TERRITORY:

This schedule applies everywhere the City of Palo Alto provides Water Services.

C. RATES:

Monthly Service Charge		Per Meter Per Month
For	5/8-inch meter	$ 21.22~~18.78~~
For	3/4-inch meter	28.37~~25.11~~
For	1-inch meter	42.66~~37.76~~
For	1 1/2 inch meter	78.39~~69.38~~
For	2-inch meter	121.27~~107.32~~
For	3-inch meter	257.05~~227.48~~
For	4-inch meter	457.15 ~~404.56~~
For	6-inch meter	935.94 ~~828.27~~
For	8-inch meter	1,722.02~~1,523.92~~
For	10-inch meter	2,722.49~~2,409.29~~
For	12-inch meter	3,580.05~~3,168.19~~

Volumetric Rates: (to be added to Service Charge, applicable to all pressure zones)	Per Hundred Cubic Feet Per Month
Commodity Rate:	
Water Delivery Charge from SFPUC	$ 5.55 ~~5.21~~
Distribution Rate:	6.58~~5.83~~

NON-RESIDENTIAL IRRIGATION WATER SERVICE

UTILITY RATE SCHEDULE W-7

Drought Surcharges (deactivated):

A drought surcharge will be added to the Customer's applicable commodity rate when the City Council has determined that a Water reduction level is in effect for the City as described in Section D.3. The drought surcharges in the table below are measured in dollars per hundred cubic feet (ccf).

Water Usage Reduction level	**Level 1 (10/15%)**	**Level 2 (20%)**	**Level 3 (25%)**
Surcharge	0.53	1.25	2.02

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. Commodity Rate

The Commodity Charge is based on the water delivery rate per the San Francisco Public Utility Commission (SFPUC) Water Rate Schedule W-25: Wholesale Use with Long-Term Contract. The Commodity Charge will be passed through automatically via periodic rate adjustments to account for increases in wholesale water charges, as well as inflation. The pass-through period will be effective for fiscal years 2020 through 2024, inclusive. Customers will be provided notice of any adjustments via their billing statements or by any other mailing by CPAU to the customer's regular billing address.

3. Drought Surcharge

During period of Water shortage or restrictions on local Water use, the City Council may, by resolution, declare the need for citywide Water conservation at the 10/15%, 20% or 25% level. While such a resolution is in effect, a drought surcharge will apply. The purpose of the drought surcharge is to recover revenues lost as a result of reduced consumption.

{End}

CITY OF
PALO ALTO

WATER UTILITY FINANCIAL PLAN AND PROPOSED RATE CHANGES FOR FY 2025

March 6, 2024

www.cityofpaloalto.org

Preliminary Water Rate Projections

- **Proposal FY 2025: 10% total water rate increase (13% distribution rate increase)**
  - FY 2023 year-end Operations Reserve near minimum guideline due to drought
  - Projected Water Distribution Rate Changes

Fiscal Year	2024	2025	2026	2027	2028	2029
Current Projection	2%	13%	14%	15%	13%	6%
FY 2024 Plan	2%	7%	6%	6%	6%	-

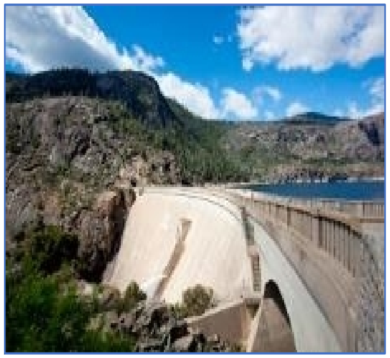
  - Projected Total Water Rate Changes

Fiscal Year	2024	2025	2026	2027	2028	2029
Current Projection	5%	10%	8%	11%	11%	5%
FY 2024 Plan	5%	4%	3%	4%	6%	-

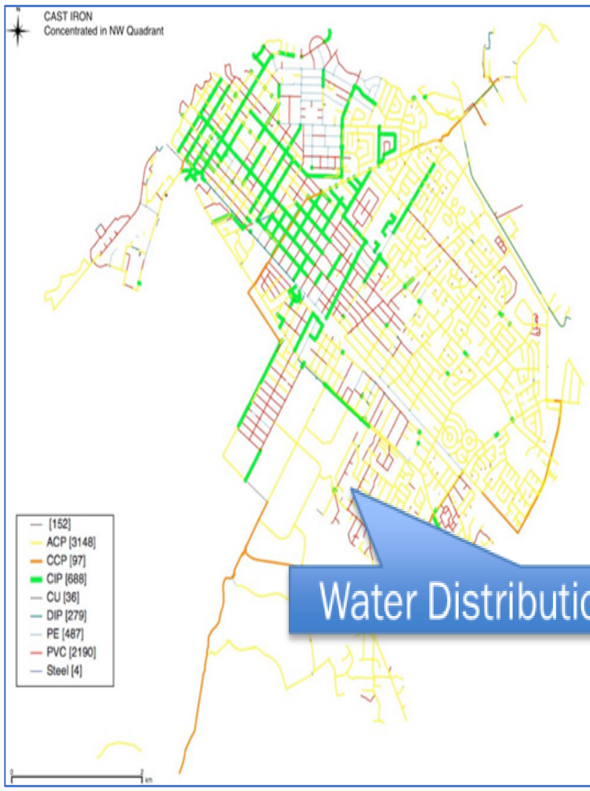
    - Commodity rate projected to increase to $5.55/CCF

CITY OF PALO ALTO

WATER UTILITY BASICS



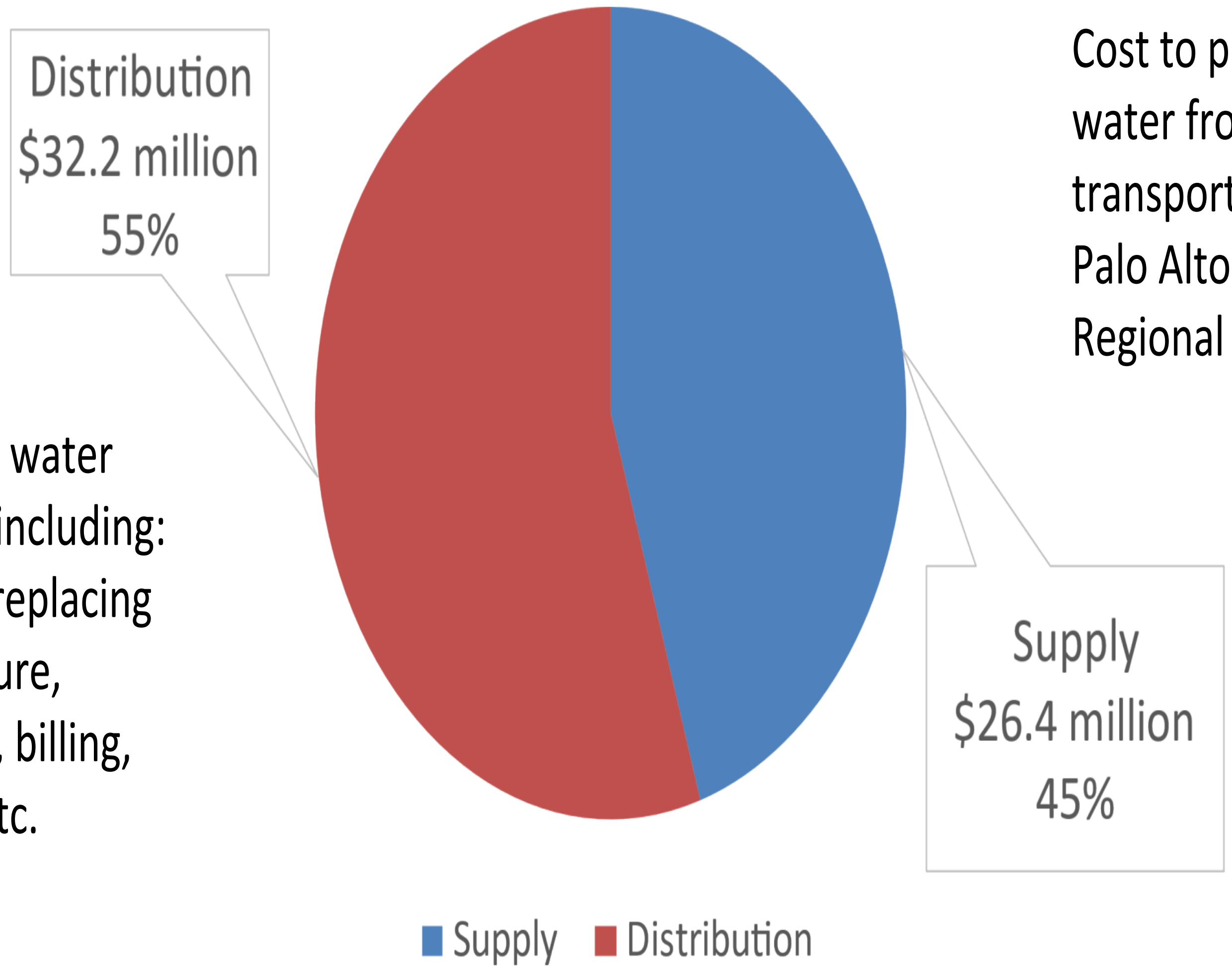
Water Supply from Sierras (SFPUC's Hetch Hetchy system)



Water Distribution in Palo Alto

CITY OF PALO ALTO

WATER UTILITY COST STRUCTURE

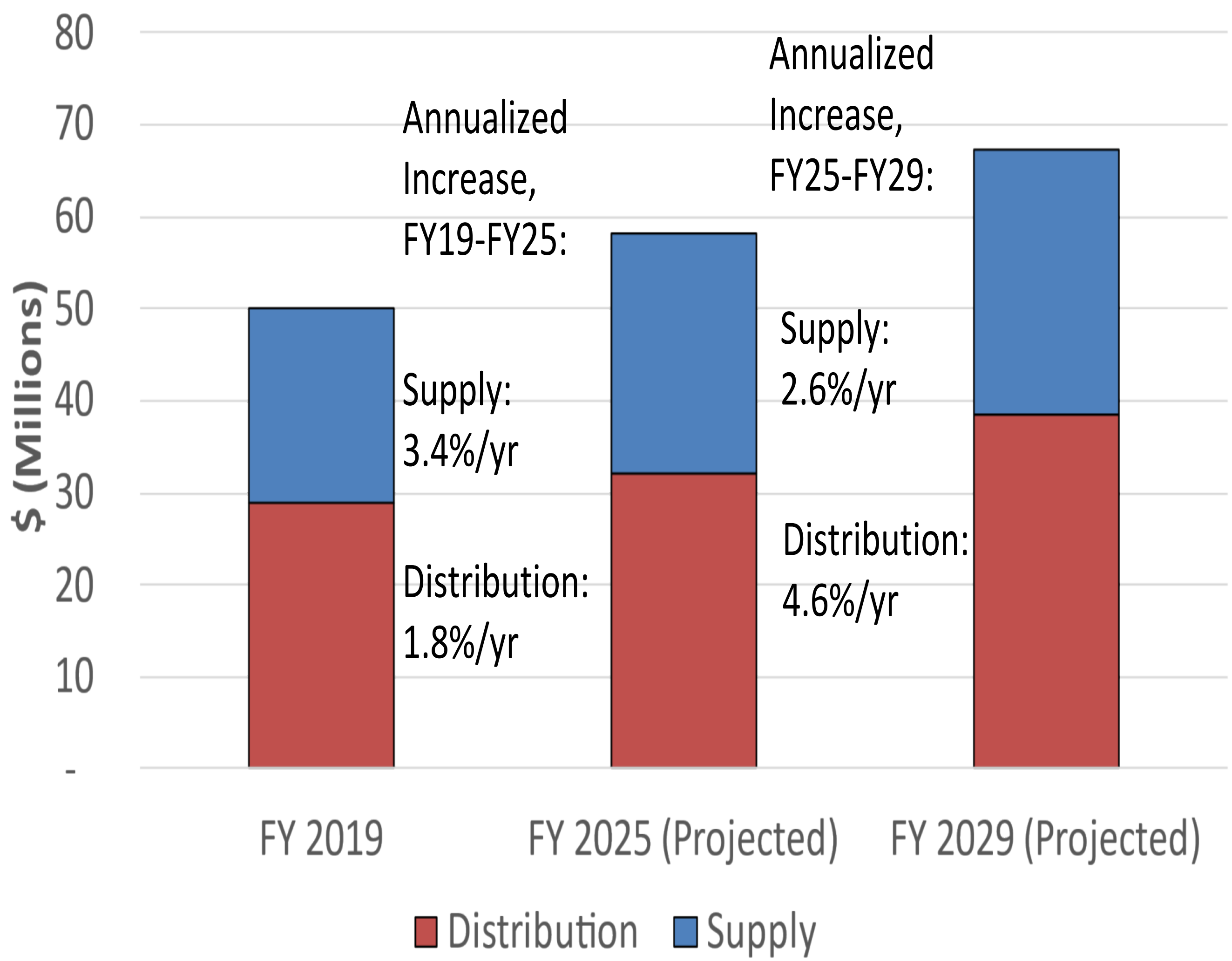


Cost to purchase the water from SFPUC who transports the water to Palo Alto through the Regional Water System

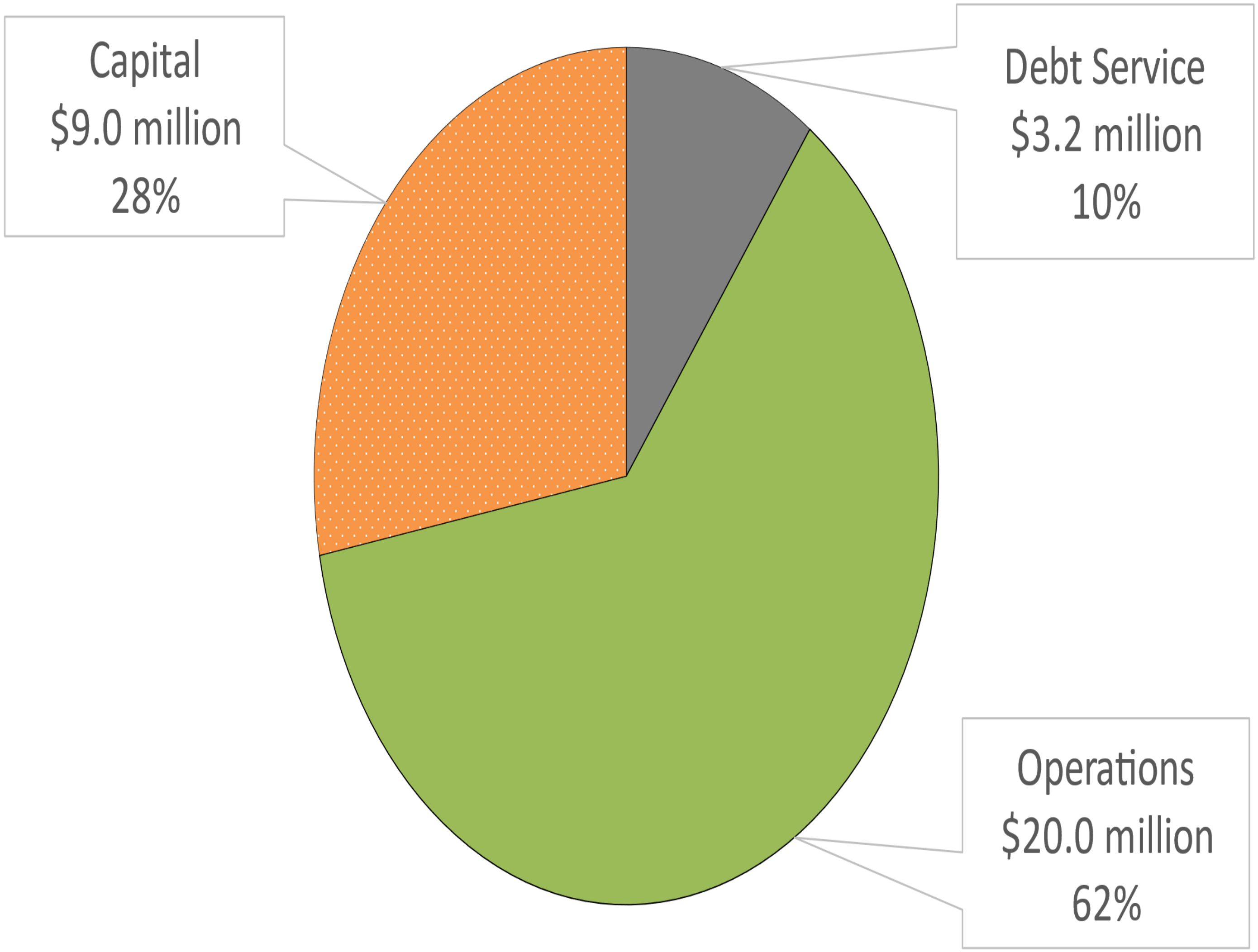
Cost to distribute water within Palo Alto, including: maintaining and replacing water infrastructure, customer service, billing, administration, etc.

CITY OF PALO ALTO

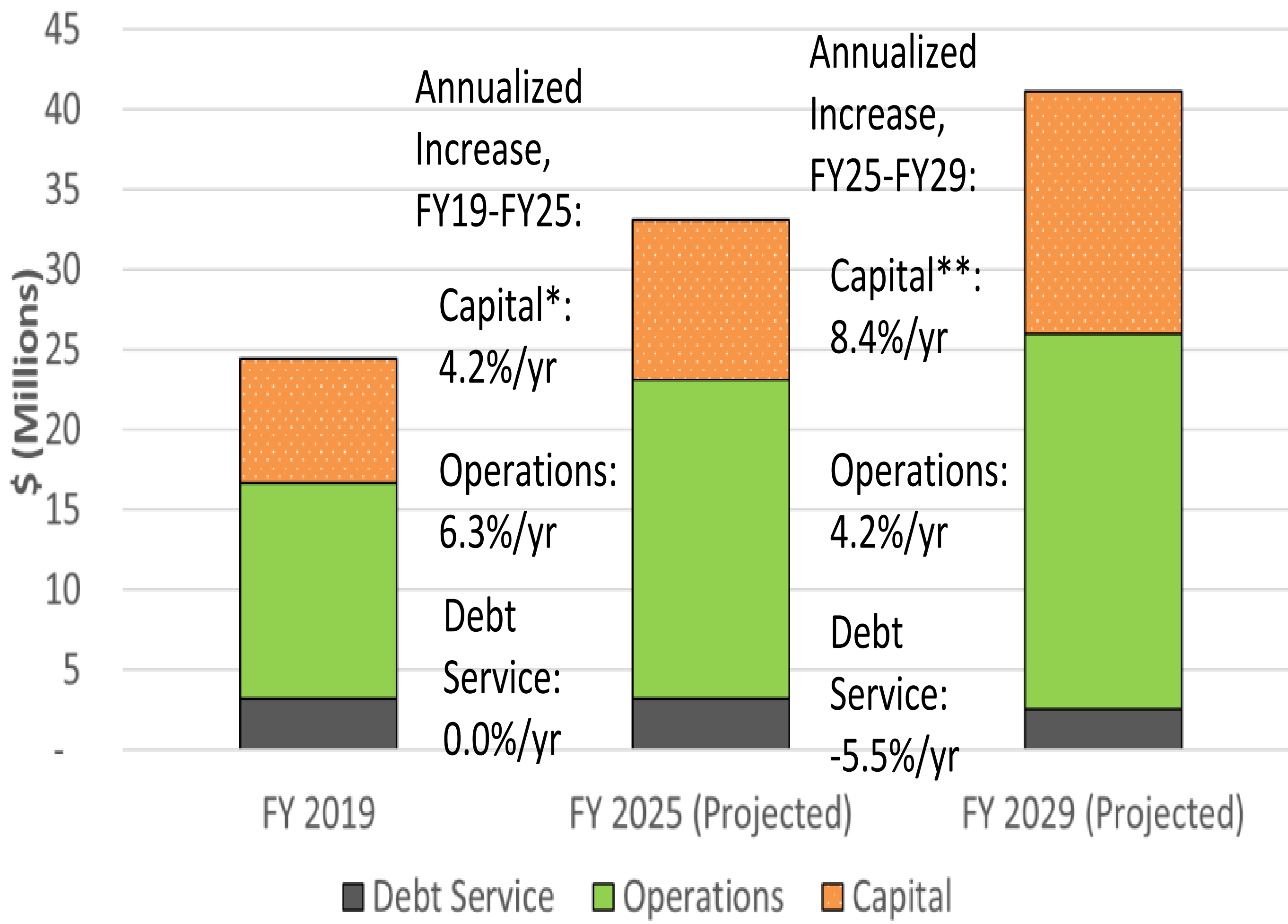
LONG TERM COST TRENDS



WATER DISTRIBUTION COSTS



WATER DISTRIBUTION COST TRENDS



* Capital in FY 2019 includes an average of FY 2019 and FY 2020

** Capital in FY 2025 and FY 2029 includes capital contribution to the CIP Reserve

CITY OF PALO ALTO

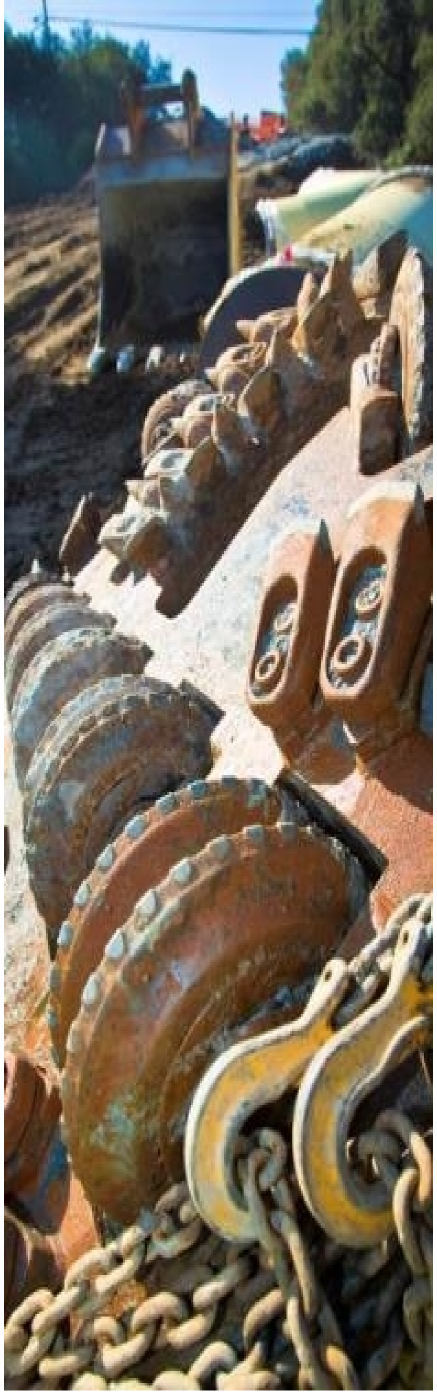
WATER OPERATIONS & CAPITAL COST DRIVERS

Operating

- Drought-related water sales reductions
- Health, retirement, and associated overhead costs continue to increase
- Planned increase in costs for rental of generator backup at pumping stations and for emergencies

Capital

- Construction costs continue to rise in the Bay Area
- Large one-time costs for reservoir rehabilitation/replacement



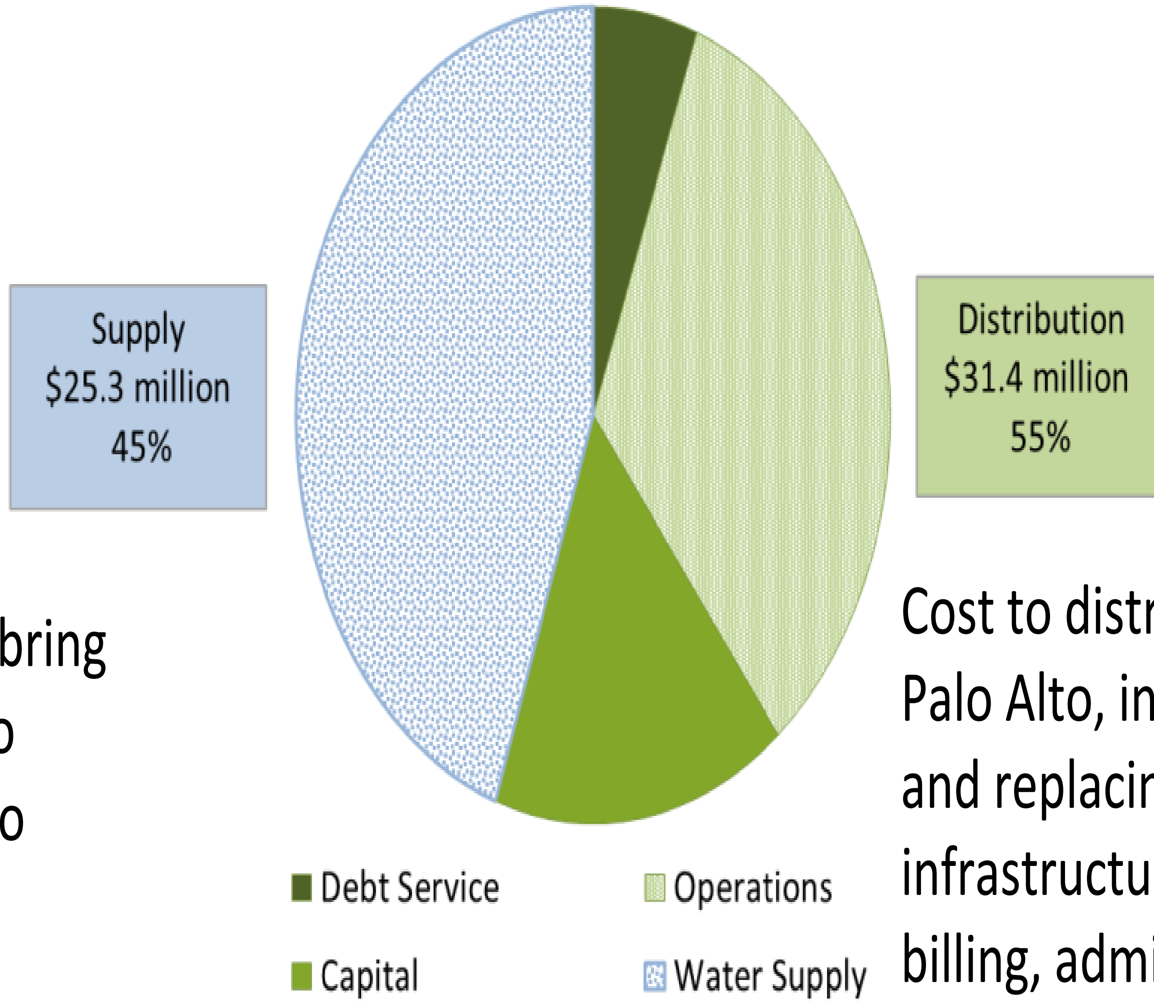
WATER SUPPLY COST DRIVERS

- Water System Improvement Program (WSIP)
- 2002: advocacy by wholesale customers results in AB 1823 requiring SFPUC to adopt and implement the WSIP
- In 2010 construction began - $4.8B, one of the largest water projects in the nation
- Level of service goal: return to service in 24 hours after an earthquake

WATER SUPPLY COST DRIVERS

- WSIP spending 99.2% of construction contracts complete as of June 30, 2023
- "Upcountry" system in the Sierra still needs work
- Wholesale customers (via BAWSCA) advocating for improvements in long-term capital planning
- Necessary and improves reliability, but supply costs will increase in the future as a result

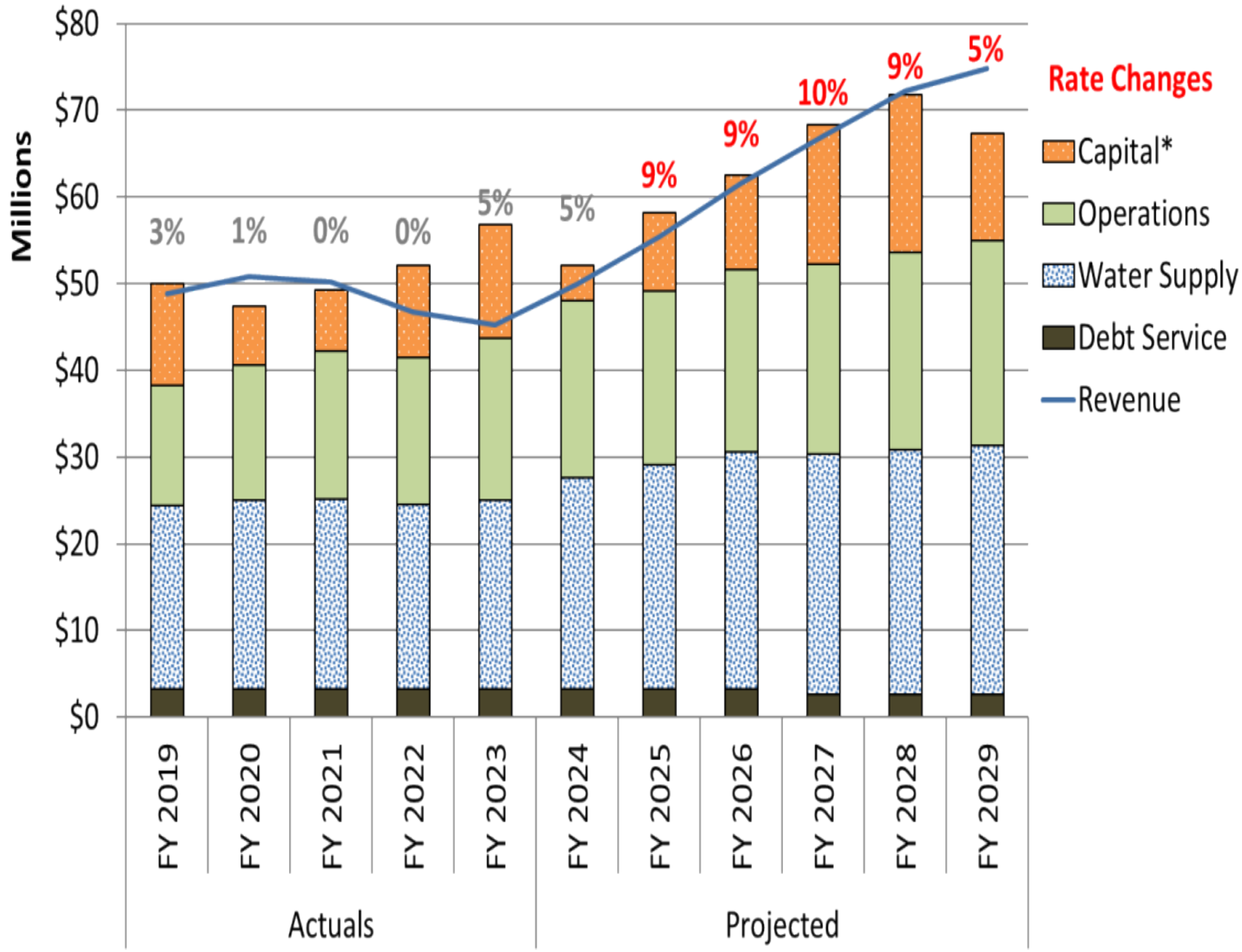
WATER UTILITY COST STRUCTURE (FY 2024)



Cost to bring water to Palo Alto

Cost to distribute water within Palo Alto, including: maintaining and replacing water infrastructure, customer service, billing, administration, etc.

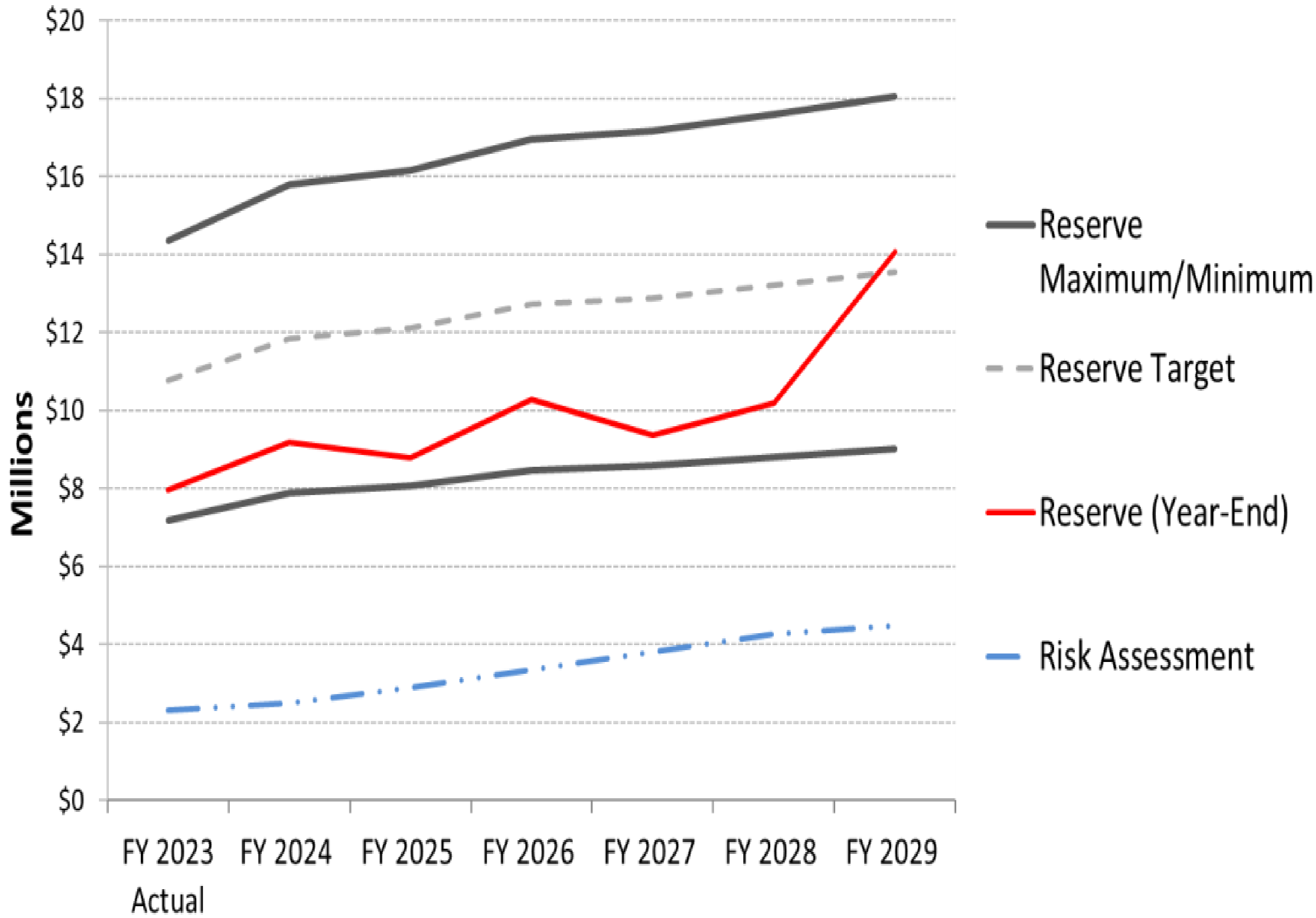
WATER COST AND REVENUE PROJECTIONS



* Includes changes due to commitments/reappropriations and funds transferred to the CIP Reserve

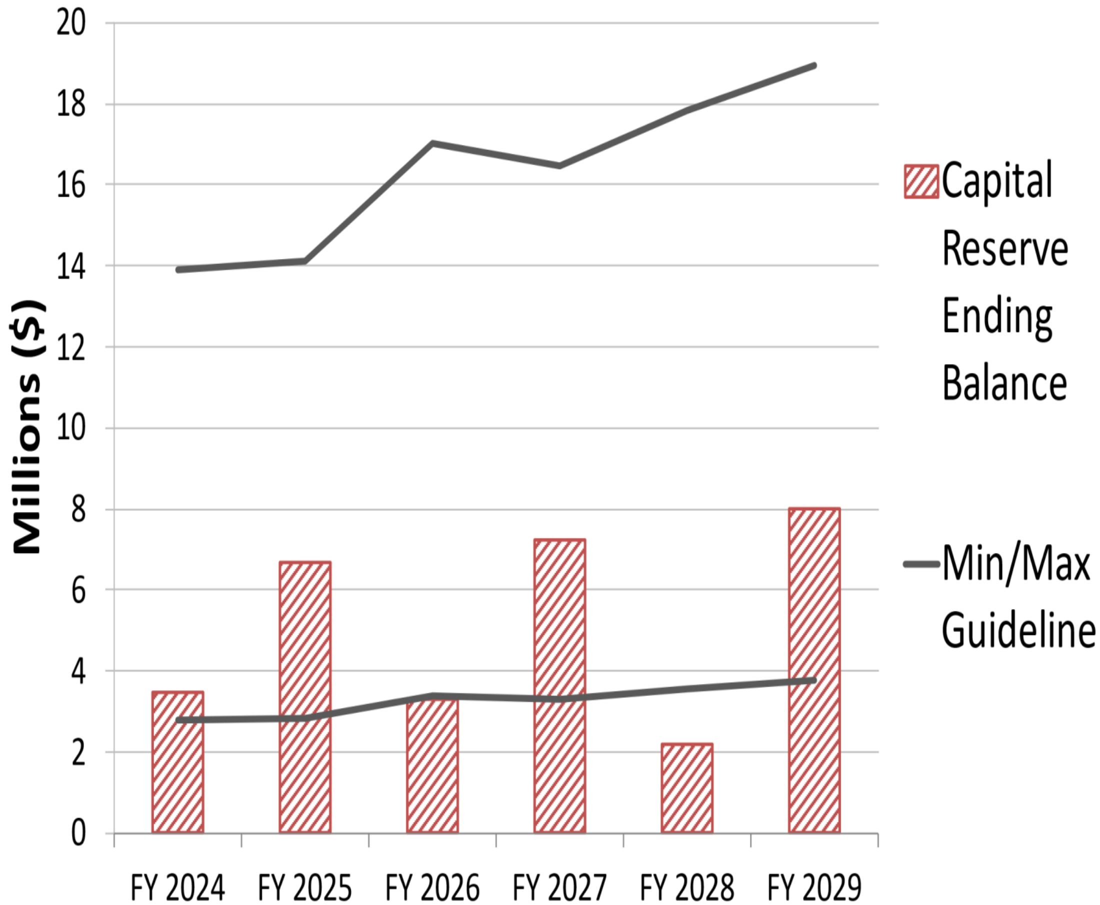
CITY OF PALO ALTO

WATER OPERATIONS RESERVE PROJECTIONS



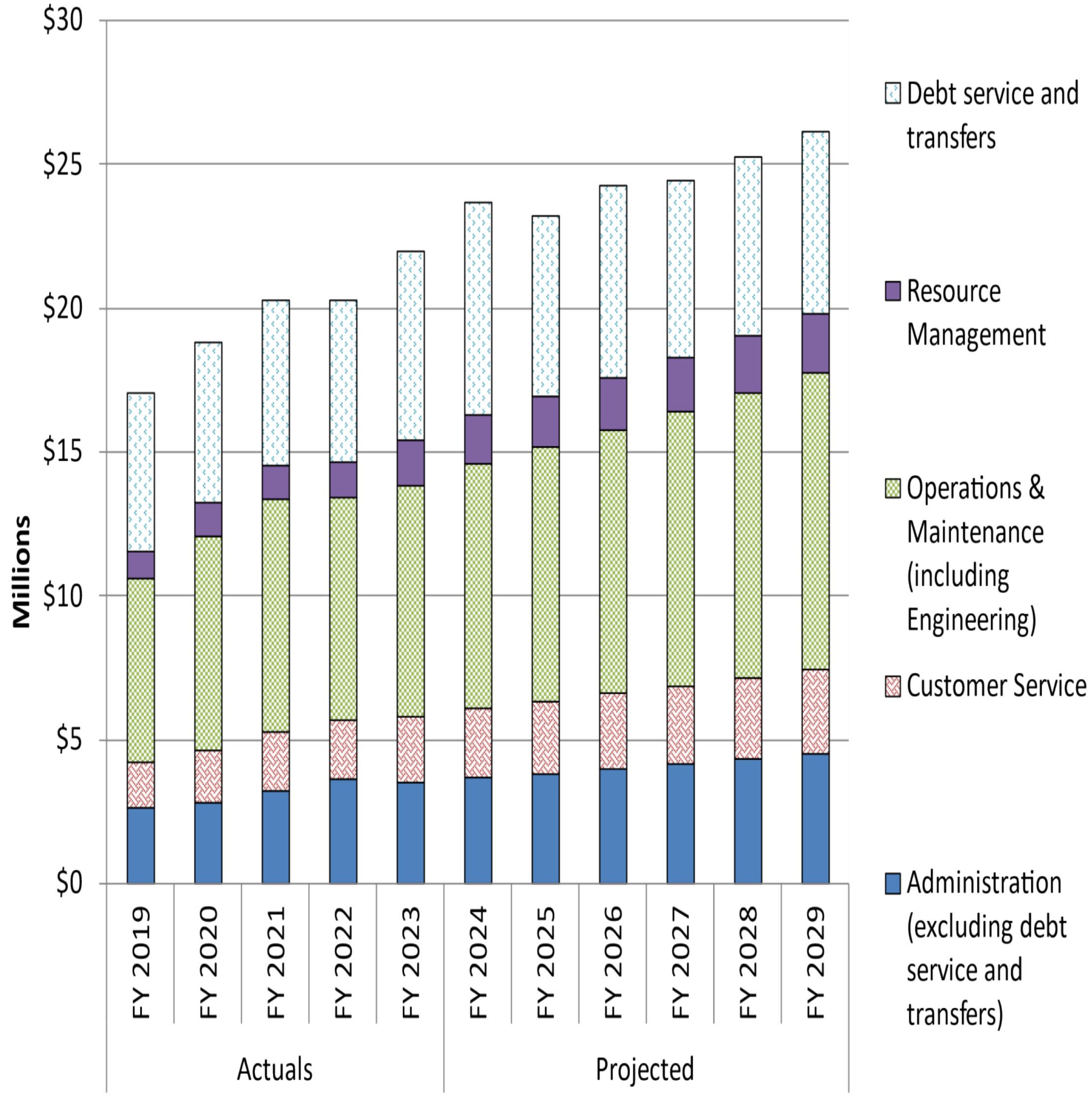
CITY OF PALO ALTO

WATER CIP RESERVE PROJECTIONS



CITY OF PALO ALTO

WATER OPERATIONS COST PROJECTIONS



CITY OF PALO ALTO

ESTIMATED RESIDENTIAL BILL CHANGES

Usage (CCF/Month)	Bill Under Current Rates (7/1/2023)	Bill under Proposed Rates (7/1/2024)	Change $/mo.	Change %
4	$53.20	$58.75	$5.55	10%
(Winter median) 7	$80.60	$88.69	$8.09	10%
(Annual median) 9	$103.68	$114.09	$10.41	10%
(Summer median) 14	$161.38	$177.59	$16.21	10%
25	$288.32	$317.29	$28.97	10%

CITY OF PALO ALTO

ESTIMATED COMMERCIAL BILL CHANGES

Usage (CCF/Month)	Bill under Current Rates (7/1/2023)	Bill under Proposed Rates (7/1/24)	Change $/mo.	Change %
Commercial (W-4) (5/8" meters)				
Annual median 12	$127.26	$139.66	$12.40	10%
Annual average 64	$597.34	$652.90	$55.56	9%
Irrigation (W-7) (1 1/2" meters)				
Winter median 9	$168.74	$187.56	$18.82	11%
Summer median 37	$477.86	$527.20	$49.34	10%
Winter average 56	$687.62	$757.67	$70.05	10%
Summer average 199	$2,266.34	$2,492.26	$225.92	10%

CITY OF PALO ALTO

MONTHLY WATER BILL COMPARISON

Single-Family Residential

Palo Alto is 11% above comparison city average at 9 CCF/month

Usage (CCF/month)	Residential monthly bill comparison ($/month)* As of February 2024							
	Palo Alto	Menlo Park	Mountain View	Hayward	Redwood City	Santa Clara	Los Altos	Average of Surrounding Communities
4	$53.20	$65.20	$46.95	$45.17	$64.16	$31.88	$58.71	$52.01
(Winter median) 7	80.60	91.00	72.69	69.59	86.27	55.79	79.51	75.81
(Annual median) 9	103.68	108.19	89.85	85.87	112.31	71.73	93.38	93.55
(Summer median) 14	161.38	155.10	132.75	135.87	180.22	111.58	131.23	141.12
25	288.32	271.23	278.63	245.87	340.49	199.25	233.01	261.41

*Based on the FY 2013 BAWSCA survey, the percentage of SFPUC as the source of potable water supply was 100% for Palo Alto, 95% for Menlo Park, 100% for Redwood City, 87% for Mountain View, 10% for Santa Clara and 100% for Hayward. Los Altos does not receive water supply from SFPUC.

MONTHLY WATER BILL COMPARISON

Commercial

Palo Alto is 2% above comparison city average

	Palo Alto	Neighboring Communities						Neighboring Community Average
		Redwood City	Menlo Park (Cal Water)	Mountain View	Hayward	Santa Clara	Los Altos	
Commercial (12 CCF)	$ 127.26	$ 133.40	$ 168.60	$ 122.01	$ 107.01	$ 117.12	$ 132.42	$ 130.09
Commercial (64 CCF)	$ 597.34	$ 545.24	$ 766.16	$ 568.17	$ 493.89	$ 531.56	$ 603.78	$ 584.80
Commercial (300 CCF)	$ 2,730.78	$ 2,414.36	$ 3,478.16	$ 2,593.05	$ 2,509.73	$ 2,412.48	$ 2,743.03	$ 2,691.80
Based on rates as of February 2024								

RECOMMENDATION

Staff requests that the Utilities Advisory Commission (UAC) recommend that the Council: Adopt a resolution approving:

1) FY 2025 Water Utility Financial Plan

2) Amending the following rate schedules to reflect increases effective July 1, 2024 (FY 2025): W-1 (General Residential Water Service), W-2 (Water Service from Fire Hydrants), W-3 (Fire Service Connections), W-4 (Residential Master-Metered and General Non-Residential Water Service), and W-7 (Non-Residential Irrigation Water Service)