

4. Residential Electric Service Time-of-Use Rates (E-1 TOU) **ACTION** 8:15PM – 9:00PM, *Staff, Lisa Bilir, Senior Resource Planner*



Utilities Advisory Commission Staff Report

From: Alan Kurotori, Director of Utilities
Lead Department: Utilities

Meeting Date: June 4, 2025
Report #: 2503-4361

TITLE

Residential Electric Service Time-of-Use Rates (E-1 TOU)

RECOMMENDATION

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

- Adding voluntary Rate Schedule E-1 TOU applicable to separately metered single-family residential dwellings receiving electric service effective January 1, 2026 (Attachment B: Rate Schedule E-1 TOU).

EXECUTIVE SUMMARY

Staff recommends introducing a residential time-of-use rate plan on January 1, 2026 (E-1 TOU Rate Schedule). Separately metered single-family residential dwellings receiving electric service from the City of Palo Alto with Advanced Metering Infrastructure (AMI) meters may opt-in to this new E-1 TOU rate plan.

The proposed E-1 TOU rates align with the cost of electricity at the time of use, which reflects an accurate price signal to customers. Moreover, it provides customers the opportunity to take advantage of lower-cost and lower carbon intensity time periods for electric vehicle charging or other electric use.

The TOU periods for this rate plan are designed with consideration of several factors including:

1. Marginal cost of energy
2. Distribution system capacity and peak demand
3. Greenhouse gas intensity of market energy
4. Best practices in ratemaking.

BACKGROUND

At the December 4, 2024 UAC meeting, Staff presented preliminary rate proposals for FY 2026 and provided an update on TOU rates as an informational item for discussion purposes.¹

The Electric Utility's FY 2026 rates to be effective on July 1, 2025 do not include the E-1 TOU rates. Staff recommends a January 1, 2026 implementation date for E-1 TOU to allow sufficient time to prepare for its implementation. Staff estimates that all residential customers will have AMI meters installed by the end of December 2025.

ANALYSIS

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 E-1 TOU recommendation reflects the proposed FY 2026 costs and revenues for the Electric Utility that are reflected in the financial forecast that will be considered by the Council on June 16, 2025, and the *"City of Palo Alto Electric Cost of Service and Rate Study"* by EES Consulting, Inc. in 2023/2024 (FY 2024 COS Study), supplemented by EES's April 1, 2025 memo on *"Electric Time of Use Rate Design for E-1: Residential Customer Class"* (Attachment C: COSA Study's E-1 TOU Supplement).

The new E-1 TOU rates are designed to produce the same FY 2026 revenue as the standard E-1 rates, assuming customers do not change their electric usage patterns. Because the number of customers opting in to E1-TOU will grow over time, the revenue risk to the Electric Utility will be minimal as adjustments to the rate will be implemented over time as more data is available regarding changes in customers' electric usage patterns.

These residential TOU rates align with the cost of electricity at the time of use which reflects an accurate price signal to customers. Moreover, this rate plan provides residential customers who opt-in to this rate with the opportunity to take advantage of lower-cost time periods for electric vehicle charging. Other appliances with flexible loads can also take advantage of this rate.

As presented in the COSA Study's E-1 TOU Supplement, the TOU periods are designed with consideration of several factors including marginal cost of energy, distribution system capacity and peak demand, greenhouse gas intensity of market energy, and best practices in ratemaking.

1. Marginal cost of energy

The TOU periods are structured to reflect the marginal cost of energy, which refers to the cost of producing or purchasing one additional unit of electricity. This cost fluctuates throughout the day based on overall demand, fuel availability, and market dynamics. By aligning TOU pricing periods with periods of higher or lower marginal cost, utilities can send price signals that encourage consumers to shift their energy usage to times when electricity is cheaper to purchase. This not only reduces strain on the grid but also improves overall economic efficiency in the energy market. Because of the large penetration of solar resources in California, the lowest priced

¹ The transcript from the meeting is available on the City's website:

<https://cityofpaloalto.primegov.com/Public/CompiledDocument?meetingTemplateId=15106&compileOutputType=1>.

periods typically occur in the sunny mid-day hours, while the highest priced periods typically occur in the evening hours just after sunset.

2. Distribution system capacity and peak demand

TOU periods are also influenced by the capacity of the distribution system and the timing of peak demand. Electricity systems must be built to meet the highest expected load, even if those peaks occur infrequently. By identifying and pricing peak hours higher, TOU rates encourage customers to shift consumption away from peak periods, which enhances grid reliability and optimizes use of existing infrastructure, delaying or reducing the need for costly infrastructure upgrades. This also reduces the utility's need to purchase additional local and system resource adequacy capacity, as these procurement requirements are set based on the utility's actual peak demand levels.

3. Greenhouse gas intensity of market energy

Another important consideration in TOU design is the greenhouse gas (GHG) intensity of the energy supply during different times of the day. Energy generated during peak hours often comes from fossil-fuel-based plants that produce higher emissions compared to cleaner sources like solar, which are more prevalent during mid-day hours. TOU rates can incentivize customers to use electricity when the grid is powered by cleaner energy, thereby supporting emissions reductions and climate goals. (Note that although CPAU has a carbon neutral electricity supply, the utility is still responsible for countering the effects of the marginal emissions that occur as a result of its electricity consumption through the purchase of additional renewable energy; therefore, it lowers the utility's costs to have customers use electricity primarily in lower emissions periods.)

4. Best practices in ratemaking

TOU rate plans also reflect established best practices in utility ratemaking, which aim to balance fairness, efficiency, and transparency. This involves designing rates that are cost-reflective, encourage customer responsiveness, and promote long-term sustainability of the electric system. Best practices ensure that TOU pricing is not only effective in achieving grid and environmental objectives, but also understandable and equitable for customers, including protections for vulnerable populations.

It has been shown that consumers are more able to shift energy use to lower-priced periods when the high-priced period is shorter in duration. The recommended peak period is from 4 pm to 9 pm. This 5-hour period captures the highest marginal energy costs, the highest average GHG intensities, and the timing of both the distribution system peak and residential class peak demand.

The Residential TOU program will enable CPAU to gauge customer interest in electric TOU rates and assess the behavioral changes of customers who opt into these TOU rates. In the absence of any E-1 TOU customer data, the TOU rate design assumed the E-1 customer class load profile and the TOU rates were designed to recover the same revenue requirement.

Table 1 shows the proposed E-1 TOU rates, compared to the proposed E-1 rates for FY 2026.

Table 1: FY 2026 Rates for E-1 and E-1 TOU

	Commodity	Distribution	Public Benefits	Total
E-1 TOU Rate Schedule – Proposed in this Staff Report, effective date January 1, 2026				
E-1 TOU Volumetric Rate, \$/kWh (No Baseline)				
Summer: June 1 – September 30				
Peak: 4pm to 9pm	0.23354	0.09351	0.00604	0.33309
Off-Peak: 9pm to 4pm, 3pm to 4pm	0.08249	0.09351	0.00604	0.18204
Super Off-Peak: 9am to 3pm	0.06690	0.09351	0.00604	0.16645
Winter: October 1 – May 31				
Peak: 4pm to 9pm	0.16705	0.09351	0.00604	0.26660
Off-Peak: 9pm to 4pm, 3pm to 4pm	0.11033	0.09351	0.00604	0.20988
Super Off-Peak: 9am to 3pm	0.07835	0.09351	0.00604	0.17790
E-1 TOU Customer Charge				
Customer Charge, \$/month	5.15			
E-1 Rate Schedule – Proposed effective date July 1, 2025				
E-1 Volumetric Rate, \$/kWh (Baseline at 450 kWh)				
E-1 Tier 1 (up to 450 kWh)	0.10373	0.09593	0.00604	0.20570
E-1 Tier 2 (over 450 kWh)	0.13372	0.08968	0.00604	0.22944
E-1 TOU and E-1 Customer Charge				
Customer Charge, \$/month	5.15			

Figures 1 and 2 below show the E-1 and E-1 TOU volumetric rates for summer and winter for FY 2026.

Figure 1: E-1 (Tier 1 and Tier 2) and Summer E-1 TOU Volumetric Rates for FY 2026

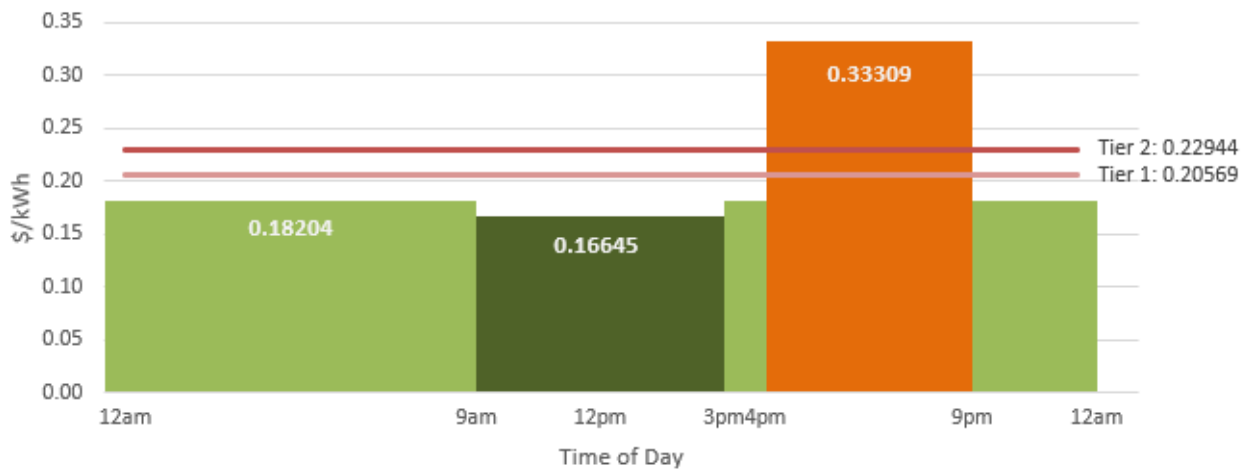
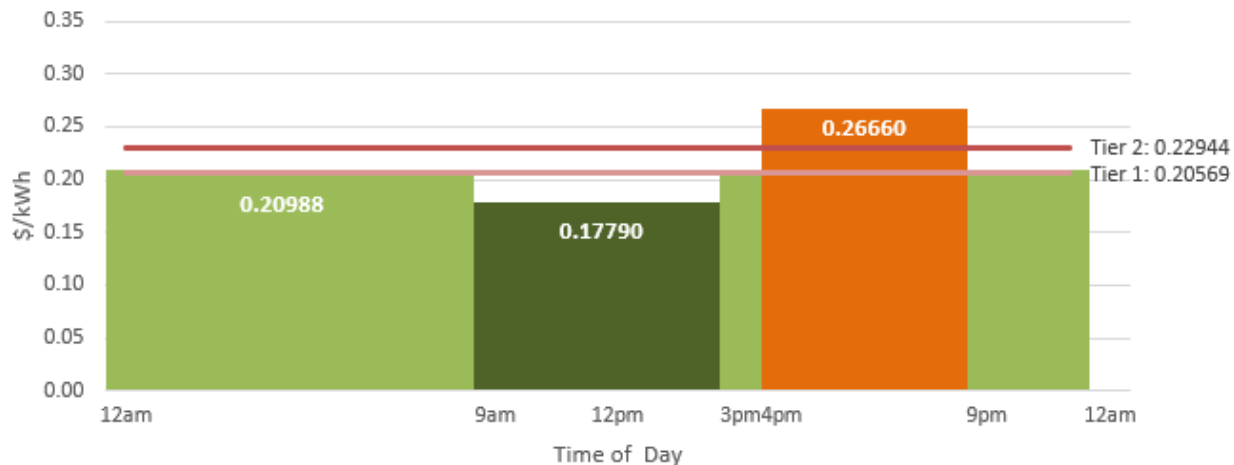


Figure 2: E-1 (Tier 1 and Tier 2) and Winter E-1 TOU Volumetric Rates for FY 2026



Customers electing the E-1 TOU rate plan must remain on the plan for a minimum of six months. After six months, E-1 TOU customers may request a change to any applicable rate schedule; however, once a customer switches to a rate schedule other than E-1 TOU, they cannot re-elect E-TOU for the next 12 billing cycles. Other utilities have similar restrictions regarding customers switching between rate plans². For Palo Alto, six months is a reasonable balance between offering flexibility to customers and protecting the utility from customers switching rate plans frequently based upon which season the rate plan benefits the customer thereby generating additional administration for the utility.

Net Energy Metering (NEM) customers³ will not be eligible to opt-in to the Residential TOU rate plan due to existing constraints in the billing system. Staff is working to address these constraints.

Implementation Plan

Staff has begun the process of updating the billing system to accept energy consumption data from the AMI system to compute TOU customer bills. Planning and implementation activities include modifying the billing system and developing logistics related to customer enrollment, customer informational tools and communication plan. To ensure a smooth roll-out of this new rate, staff anticipates an initial testing period with a small group of customers beginning in January 2026 followed by a modulated increase in customer enrollments. Staff plans to present marketing and communication and customer-centric details of this new rate implementation to the UAC in Fall 2025.

² This proposed rule is slightly different from that implemented by California's three largest electric utilities. For PG&E, customers may request a rate plan change up to two times in a rolling 12-month period; however, once a customer makes the 2nd rate change, they will have to remain on that plan for the next 12 billing cycles. For Southern California Edison and San Diego Gas & Electric Company, customers switching to TOU rate will not be able to make another switch for a full 12 months.

³ NEM customers are those who receive compensation for the energy generated by photovoltaic systems installed at their residences.

FISCAL/RESOURCE IMPACT

The rate level of E-1 TOU is based on the FY 2026 cost estimates and is therefore designed to produce the same revenue increase percentage as that expected from the standard E-1 rates proposed to take effect on July 1, 2025.

STAKEHOLDER ENGAGEMENT

Staff provided an update on the development of E-1 TOU rates at the December 4, 2024 UAC meeting and plans to present the E-1 TOU rates to the Finance Committee in August 2025. Staff plans to present to the UAC in Fall 2025 a more detailed implementation plan. Staff met with the UAC Budget Subcommittee twice and the Subcommittee will be bringing a recommendation to the UAC.

ENVIRONMENTAL REVIEW

The UAC's review and recommendation to the Finance Committee on the E-1 TOU Rate Plan 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: Draft Resolution

Attachment B: Rate Schedule E-1 TOU

Attachment C: COSA Study's E-1 TOU Supplement

Attachment D: Presentation

AUTHOR/TITLE:

Alan Kurotori, Director of Utilities

Staff: Lisa Bilir, Senior Resource Planner

* NOT YET APPROVED *

Resolution No. _____

Resolution of the Council of the City of Palo Alto Approving
Utility Rate Schedule E-1 TOU (Residential Electric Time of Use Service)

R E C I T A L S

A. On June 16, 2025, the City Council heard and approved the fiscal year (FY) 2026 Electric Utility Financial Forecast, updating residential electric service rates at a noticed public hearing, and an additional voluntary Time of Use electric service rate is now proposed for residential customers consistent with that Financial Forecast.

B. 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.

C. On Month Day, 2025, the City Council heard and approved the proposed rates for the voluntary Residential Time of Use (TOU) electric service at a noticed public hearing.

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

SECTION 1. Pursuant to Section 12.20.010 of the Palo Alto Municipal Code, Utility Rate Schedule E-1 TOU (Residential Electric Time of Use Service) shall become effective January 1, 2026;

SECTION 2. The Council finds that 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.

SECTION 3. 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.

//

//

//

//

* NOT YET APPROVED *

SECTION 4. The Council finds that approving the Residential Electric Time of Use rate 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 introduce an optional Residential Time of Use rate 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

RESIDENTIAL ELECTRIC TIME OF USE SERVICE

UTILITY RATE SCHEDULE E-1 TOU

A. APPLICABILITY:

This voluntary Rate Schedule applies to separately metered single-family residential dwellings receiving Electric Service from the City of Palo Alto Utilities (CPAU). This Rate Schedule is not available to Net Energy Metered (NEM) customers and is provided at the sole discretion of CPAU.

B. TERRITORY:

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

C. UNBUNDLED RATES:

<u>Per kilowatt-hour (per kWh)</u>	<u>Commodity</u>	<u>Distribution</u>	<u>Public Benefits</u>	<u>Total</u>
<u>Summer Period</u>				
Energy Charge				
Peak	\$ 0.23354	\$ 0.09351	\$ 0.00604	\$ 0.33309
Off-Peak	0.08249	0.09351	0.00604	0.18204
Super Off-Peak	0.06690	0.09351	0.00604	0.16645
<u>Winter Period</u>				
Energy Charge				
Peak	\$ 0.16705	\$ 0.09351	\$ 0.00604	\$ 0.26660
Off-Peak	0.11033	0.09351	0.00604	0.20988
Super Off-Peak	0.07835	0.09351	0.00604	0.17790
Customer Charge (\$/month)				5.15

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.

CITY OF PALO ALTO UTILITIES

Issued by the City Council



Sheet No **E-1-TOU-1**
Effective 1-1-2026

RESIDENTIAL ELECTRIC TIME OF USE SERVICE

UTILITY RATE SCHEDULE E-1 TOU

2. Definition of Seasonal Periods

Summer Period: Service from June 1 to September 30

Winter Period: Service from October 1 to May 31

SEASONAL RATE CHANGES: When the Billing Period includes use in both Summer and Winter periods, 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. Definition of Time Periods

Peak: 4:00 p.m. to 9:00 p.m. Every day

Off-Peak: 9:00 p.m. to 9:00 a.m. Every day
3:00 p.m. to 4:00 p.m.

Super Off-Peak: 9:00 a.m. to 3:00 p.m. Every day

4. Changing Rate Schedules

Customers electing to be served under E-1 TOU must remain on said Rate Schedule for a minimum of 6 months. Should the Customer so wish, at the end of 6 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-hour usage. However, once a customer elects a rate other than E-1 TOU, they cannot re-elect E-TOU for the next 12 billing cycles.

{End}

MEMORANDUM

TO Lisa Bilir
FROM Amber Gschwend
DATE April 1, 2025
RE Electric Time-of-Use Rate Design for E-1: Residential Customer Class

As part of the electric cost of service study, a rate design analysis is prepared to support the implementation of time of use (TOU) rates for the E-1 class. It is estimated that over 90% of residential customers will have Advanced Metering Infrastructure (AMI) installed by July 1, 2025, and optional TOU rates could be offered at that time. The proposed rate developed in this memo would be implemented on a voluntary basis. The bill impacts provided at the end of the analysis show that consumers with higher use could benefit from the program. Bills at any usage level can be reduced with changes in behavior.

TOU RATE DESIGN BACKGROUND

Time-of-use rate design has many benefits including appropriate price signaling to customers and the potential for customers to modify electric use to fall in periods of lower overall system costs, to reduce bills and utility power costs. Investor-owned utilities (IOUs) in California have defaulted residential customers to TOU rates, with the exception of low-income program customers.¹

As a voluntary program, it is expected that customers who opt into the TOU rate would be those customers who can modify electric consumption timing, and these customers may be more aware of their energy use profiles in general. Customers with electric vehicles (EV) can benefit by choosing to charge vehicles during lower energy cost periods. Under the current tiered rate, electric vehicle charging would likely fall under the higher Tier 2 electric rate, based on higher household consumption. Therefore, the TOU rate offers the opportunity for EV owners to reduce electric bills without increasing costs for other customers. Additionally, when combined with demand response programs, TOU rates could also incentivize customers to purchase programmable appliance controls (e.g., battery energy storage systems, water heaters) further allowing customers to reduce electric usage during high-priced periods.

TOU program participation in the United States, when voluntary, typically ranges from 1% to 10% of the total number of eligible households.² As of 2023, approximately one in three residential customers in Palo Alto own EVs, therefore, the adoption rate in Palo Alto is likely to be higher. If Palo Alto decides to implement TOU as the default option, while allowing customers to opt back to a tiered rate option, TOU program participation would likely increase to 75-90%. Alternatively, the City may require TOU rate design for all customers in the class, resulting in 100% participation.

¹ Pirro, Michael. The Evolution and Challenges of Time-of-Use Rate Designs. GridX. August 29, 2024. The Evolution and Challenges of Time-of-Use Rate Designs.

² Eligible households are those with appropriate meeting infrastructure or some other factor as determined by the utility.

RECOMMENDED PALO ALTO RESIDENTIAL TOU PROGRAM

A voluntary E-1 TOU program will provide useful information to the City. Peak demand reduction estimates can be made by comparing E-1 TOU participant demands to standard E-1 class demands over the same period. This information will help the City plan for future program roll-out design as well as reduce its future power costs. Based on PG&E's program, it is expected that peak demand reduction on the order of 3-6% could be achieved through TOU rate design.³ Note: The residential customer share of Palo Alto's overall peak demand is estimated at 12%, therefore, a reduction in residential class peak of 3-6% results in an overall system peak reduction of 0.4 to 0.7%.

A voluntary program will also help the City determine with greater certainty the impact of TOU rate design on utility revenues and expenses. As customers modify their behavior, it is expected that the revenue collected will decrease and that power supply expenses will also decrease. It is recommended that the TOU program revenues be analyzed annually, and retail rates updated so that the utility remains financially stable. This initial rate design proposal considers the recovery of fixed and variable costs by including fixed cost recovery in rate components that do not vary depending on the time of day energy is used. This design mitigates potential impacts to revenue collection resulting from changed behavior from TOU rate implementation.

Table 1 below summarizes the recommended TOU rate design methodology. The balance of the memo describes the data and results of the analysis.

TABLE 1: RECOMMENDED TOU RATE DESIGN METHODOLOGY

Rate Schedule	Current Rate Design	Recommended Rate Methodology
Residential Electric Service	<ul style="list-style-type: none">• E-1: Not Time of Use• Inclining Rate with Two Tiers• Baseline Use (Tier 1) is 450 kWh/month• Higher Use (Tier 2) is over 450 kWh/month	<ul style="list-style-type: none">• E-1 TOU: Billing Periods Based on Differential in Marginal Cost, Distribution System Capacity and Peak Demand, Greenhouse Gas Intensity, and Best Practices in Rate Design• Commodity Rate Based on Marginal Cost• Optional Rate Plan

TOU RATES FOR NET ENERGY METERED (NEM) CUSTOMERS

Due to technical hurdles associated with the electric billing system, CPAU is currently unable to implement TOU rates for Net Energy Metered (NEM1 and NEM2) customers, who have energy generation and/or storage capacity from solar panels and batteries. When CPAU overcomes NEM2 billing system hurdles, TOU NEM2 will be developed.

³ Rate design and season impacts the peak demand reduction estimates. Pacific Gas and Electric (PG&E) study authors note that peak demand impacts may diminish over time. Reference: Christensen Associates. 2023 Load Impact Evaluation of Pacific Gas and Electric Company's Residential Time-of-Use Rates Ex Post and Ex-Ante Report. CALMAC Study ID PGE0496. April 1, 2024.

https://www.calmac.org/publications/2. PGE_2023_Res_TOU_Rpt_PUBLIC.pdf

REVENUE REQUIREMENT

The rate level for E-1 TOU is based on the FY2026 budget. The FY2026 budget is the FY2025 budget plus a 1% increase to power supply expenses, and an 11% increase for distribution expenses for an average adjustment of 5% overall. Therefore, the proposed rates are equal to the FY2025 cost of service analysis plus 5%. For E-1, the total revenue target for FY2026 is \$29.4 million compared with \$27.9 million for FY2025. This is equivalent to 17% of the total electric utility retail revenue target of \$172.9 million.

TOU COST JUSTIFICATION

TOU rate design is recommended to promote the efficient use of electricity by providing more accurate cost-based pricing.

1. TOU rates are based on the marginal cost of electrical energy and electrical capacity at the time of usage, reflecting accurate market price signals.
2. TOU rate design may lower the impact of increased EV charging on distribution feeder and transformer loadings, by providing customer incentives to reduce or shift energy use away from higher-priced periods.
3. TOU rates will provide customers with the opportunity to take advantage of lower-cost time periods for EV charging or other electric use.
4. TOU rates support electrification by not penalizing high energy use if it occurs during lower market priced periods.

Typically, the goal of TOU rate design is to provide more accurate cost-based pricing to retail customers. In addition to this goal, TOU may also be used as a program to reduce overall power supply costs to the utility and, to the extent possible, lower the peak load on the distribution system infrastructure. These lowered costs are then passed to consumers through updated rate studies. A reduction in power costs may be realized if customers conserve energy during high-priced periods, or if customers shift their energy use to lower-priced periods. Similarly, reducing the peak loading of the distribution system will lower the need for system upgrades and will also result in lower system energy losses.

DETERMINATION OF APPROPRIATE TOU PERIODS

As noted in Table 1, TOU periods are designed with consideration of several factors including:

1. Marginal cost of energy
2. Distribution system capacity and peak demand
3. Greenhouse gas intensity of market energy
4. Best practices in ratemaking.

Each of these considerations is described below.

Marginal Cost of Energy

The primary goal of the rate design is to accurately reflect the cost of service depending on the time of day energy is used. Typically, higher-priced energy results from the combination of high electricity demands and constrained resource output, which occurs after the sun sets when lower-cost solar resources are no longer producing energy. The marginal cost of energy for the City is considered to be the hourly market prices at the NP15 (North of Path 15) trading hub, adjusted for the Palo Alto service area location. Hourly prices are commonly referred to as Default Load Aggregation Point (DLAP). The NP15 trading hub is the closest wholesale market transacting location. This pricing data is utilized in other areas

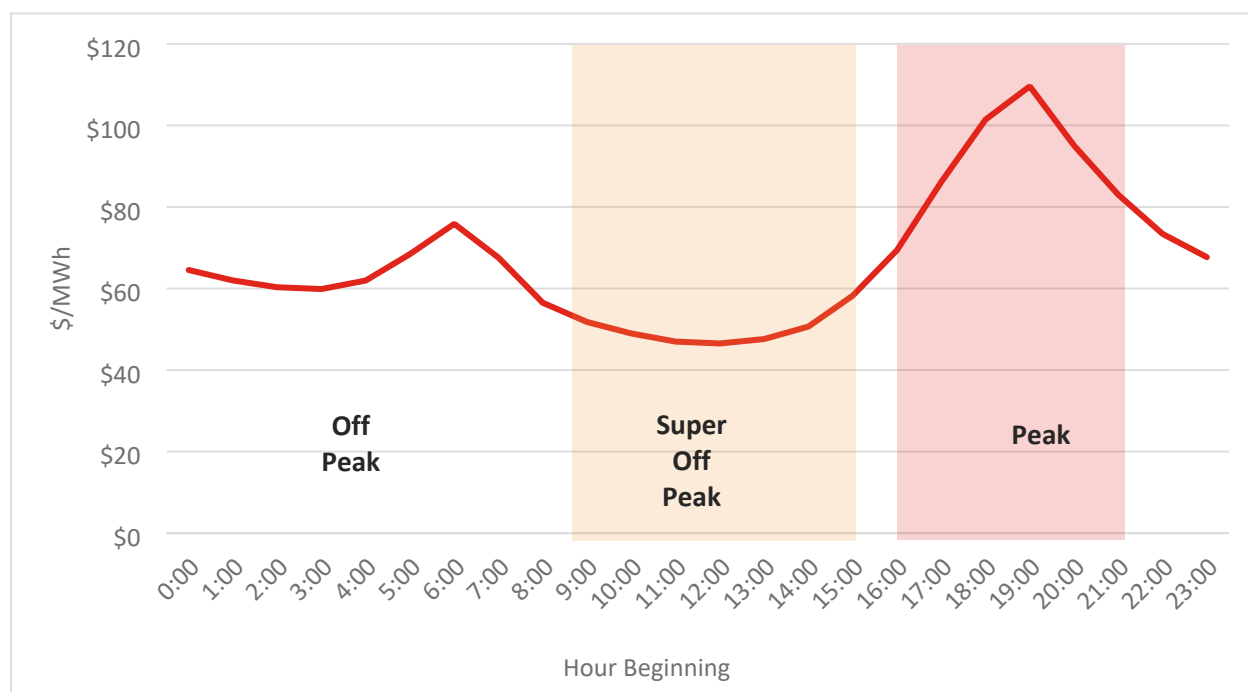
of the City’s utility planning and ratemaking and is the appropriate marginal cost metric for electric TOU rate design.

Because of the large penetration of solar resources in the California markets, the highest priced periods typically occur in the evening. This is demonstrated in the average hourly market pricing data shown in Figure 1.⁴ These market prices are the marginal cost of electricity. In case of resource production surpluses or shortages, the City would sell or purchase energy at these prices.

Figure 1 illustrates the average hourly market pricing for the 3-year period August 2021-July 2024. This period is the most relevant to the analysis since it is the most recent data available. While the natural gas shortage in winter 2023 inflated pricing in that period, removing that data from the analysis did not result in significant differences. This is because the shape of the pricing curves is more important than the pricing levels.

Figure 1 shows three periods for pricing. The red shaded period (peak) is the highest priced period between 4 pm and 9 pm, averaging \$95/MWh annually. The lowest priced period is between 9 am and 3 pm daily at \$49/MWh on average (super off-peak). The average price for the remaining hours (off-peak) is \$65/MWh. The relative prices in these three periods are used to determine commodity rates.

FIGURE 1: AVERAGE HOURLY MARKET PRICES: 8/2021-7/2024



The recommended rate design has the same pricing periods for winter and summer seasons. Keeping the time of day pricing periods the same year-round is simpler from the customer perspective and follows Bonbright’s criteria of desirable rate structure where he emphasizes simplicity and understandability of

⁴ Average hourly prices for NP15 (DLAP Palo Alto), August 2021-July 2024.

rate design.⁵ A more complicated rate design with multiple TOU periods would more precisely reflect marginal costs, but it would also be more difficult for customer understanding and implementation. For this reason, a simpler rate design is recommended.

Distribution System Capacity and Peak Demand

The second consideration for the TOU periods is the peak at the distribution system level. This peak is the maximum peak achieved when combining customer electric demands. A peak can be analyzed in various ways such as system total (all City loads) or a subset of customers such as those being served from a particular asset (substation, feeder, transformer). The peak on the distribution system drives distribution system investments. Therefore, managing peak demands on the system can defer or avoid investments in system expansion.

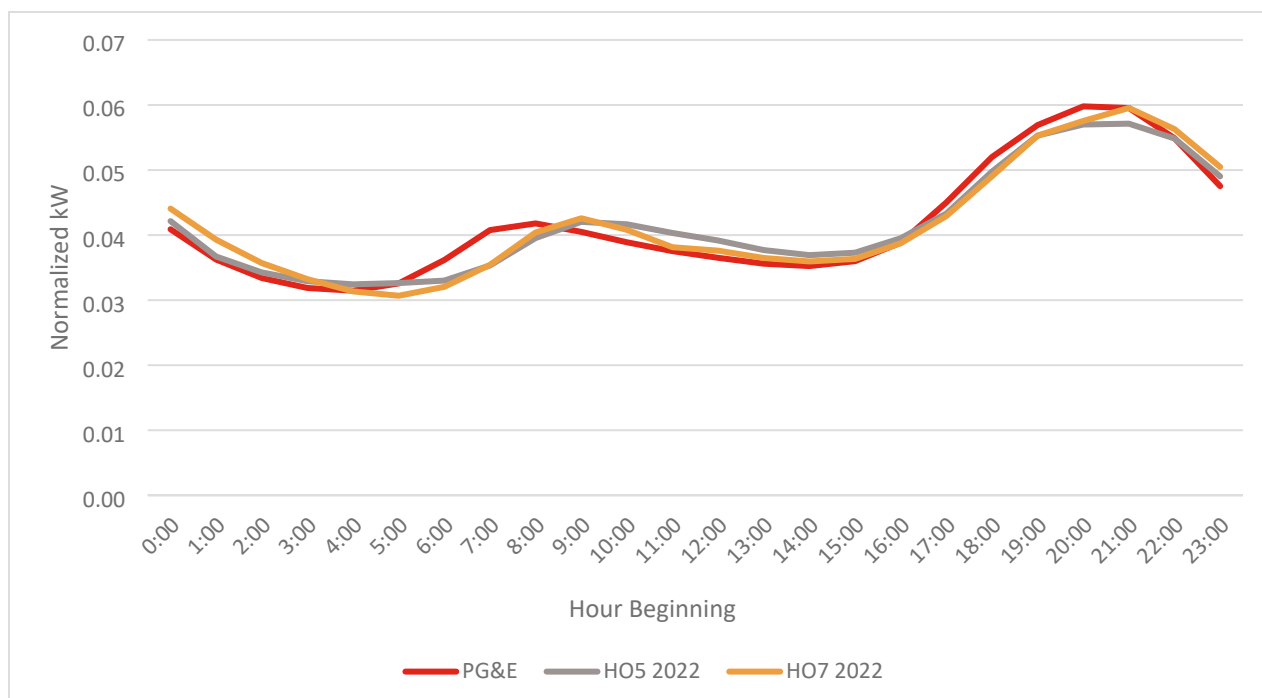
Typically, the distribution system peak coincides with the timing of higher-priced electricity. To test this, the 12 monthly peaks (maximum demand) for the City's entire system were analyzed. The three highest monthly peaks on the system occur within the 4 pm to 9 pm time period. While the system peaks during this time period, each class of customer contributes to that peak differently. Class system peaks help define the capacity requirements across the distribution system. If the residential class peak were to occur during a low marginal cost period for energy, the recommended TOU rate design could result in increased distribution system costs. Shifting loads toward the residential class peak could result in an increase to the distribution system capacity needs. To ensure that the recommended TOU rate periods do not place undue upgrade costs on the distribution system, EES analyzed residential class load profile data.

At the time of this analysis, the City does not have hourly load profile data available for its residential class. The City is currently installing AMI, which will provide usage data for future cost analysis and rate making. Because hourly meter data is unavailable, EES evaluated hourly usage data for substation feeders: Hopkins feeder 5 (HO5) and Hopkins feeder 7 (HO7). These feeders serve a total of 1,208 customers. Of these, 1,200 customers are residential. Based on the customer count data, the hourly data from these feeders should be a good approximation for residential load profiles for the City of Palo Alto. To further test this theory, the hourly data from these feeders was compared with PG&E residential load profiles for PG&E's baseline territory "T." This territory is adjacent to the City of Palo Alto and similar in climate. The comparison further validates that the hourly Palo Alto feeder data is appropriate Palo Alto residential TOU rate design.

Figure 2 compares the average hourly load shape for the 12 months beginning September 2022 for both Hopkins feeders, and a similar-climate load shape from PG&E dynamic load profile data. The average is calculated by averaging electric demand over the entire year for each hour ending (1-24). Figure 2 shows normalized kW which is equal to kW in each hour divided by the average. Normalizing each curve makes the curves comparable even if the data sets have different means.

⁵ Bonbright, James C. *Principles of Public Utility Rates*. Columbia University Press, 1961 (Reprinted 2005). Page 291. [powellgoldstein-bonbright-principlesofpublicutilityrates-1960-10-10.pdf](https://www.powellgoldstein.com/wp-content/uploads/2016/10/powellgoldstein-bonbright-principlesofpublicutilityrates-1960-10-10.pdf)

FIGURE 2: RESIDENTIAL HOURLY LOAD PROFILE AVERAGE: 9/2022-8/2023



Using the feeder data, an analysis of monthly peaks indicated that the 4 pm to 9 pm period captures the two maximum feeder peaks (August and September for HO5 and December and September for HO7). This is also supported in Figure 2 where the average daily peak occurs in the same window. Therefore, both the system and feeder peak analyses support an on-peak period in the later afternoon/evening.

Palo Alto's overall system peak, across all customer classes also occurs between 4 pm and 9 pm in the highest 9 monthly peaks. This also supports setting the peak period between 4 pm and 9 pm.

Greenhouse Gas (GHG) Content

The third consideration for TOU periods is the carbon content of market purchases during lower-cost periods. While not perfectly correlated, marginal cost, system peak demands, and high GHG content are all highest during the same evening period. Figure 3, on the next page, shows the average hourly emission intensity by month for energy transactions located within the management area of the California Independent System Operator (CAISO). Emissions data are represented as metric tons (MT) of carbon dioxide equivalent (CO₂e) per megawatt hour (MWh) of electricity. The highest emission intensities are between 7 pm and 7 am, when solar resources are not generating. The emission intensity data supports a third TOU period during the day that represents the lower costs associated with both the low GHG intensity and low marginal cost.

FIGURE 3: AVERAGE CAISO EMISSION INTENSITY 2023, MT CO₂ PER MWH

	Hour Beginning																							
	0:00	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00
1	0.31	0.31	0.32	0.32	0.31	0.29	0.29	0.28	0.24	0.21	0.2	0.2	0.2	0.2	0.2	0.22	0.26	0.29	0.29	0.29	0.3	0.3	0.31	0.31
2	0.31	0.32	0.31	0.31	0.3	0.29	0.28	0.27	0.21	0.17	0.17	0.17	0.17	0.17	0.17	0.18	0.23	0.28	0.29	0.29	0.29	0.3	0.31	0.31
3	0.28	0.28	0.28	0.28	0.27	0.26	0.26	0.24	0.19	0.17	0.16	0.16	0.17	0.16	0.16	0.16	0.17	0.21	0.24	0.26	0.26	0.27	0.28	0.28
4	0.25	0.25	0.25	0.25	0.25	0.24	0.24	0.2	0.12	0.1	0.09	0.08	0.08	0.07	0.07	0.06	0.07	0.1	0.18	0.23	0.25	0.24	0.25	0.25
5	0.26	0.26	0.26	0.26	0.26	0.26	0.24	0.18	0.14	0.12	0.12	0.11	0.1	0.08	0.07	0.07	0.08	0.12	0.17	0.23	0.25	0.25	0.26	0.26
6	0.24	0.24	0.24	0.24	0.24	0.24	0.22	0.16	0.13	0.11	0.1	0.09	0.08	0.06	0.05	0.05	0.07	0.1	0.14	0.19	0.22	0.23	0.24	0.24
7	0.28	0.28	0.28	0.28	0.28	0.28	0.25	0.21	0.19	0.17	0.15	0.14	0.13	0.13	0.13	0.14	0.16	0.18	0.21	0.26	0.28	0.29	0.29	0.29
8	0.31	0.31	0.31	0.31	0.3	0.3	0.29	0.26	0.23	0.21	0.19	0.17	0.16	0.16	0.17	0.18	0.2	0.22	0.25	0.29	0.3	0.3	0.31	0.31
9	0.29	0.29	0.29	0.29	0.29	0.29	0.28	0.25	0.2	0.18	0.16	0.15	0.14	0.12	0.12	0.13	0.15	0.19	0.24	0.26	0.27	0.27	0.28	0.29
10	0.34	0.34	0.34	0.35	0.34	0.33	0.32	0.3	0.24	0.21	0.19	0.18	0.17	0.16	0.15	0.16	0.19	0.26	0.3	0.31	0.31	0.32	0.33	0.34
11	0.33	0.34	0.34	0.34	0.33	0.32	0.3	0.27	0.22	0.2	0.2	0.2	0.19	0.19	0.18	0.21	0.26	0.28	0.29	0.29	0.3	0.31	0.32	0.32
12	0.32	0.33	0.33	0.33	0.32	0.31	0.3	0.28	0.23	0.2	0.19	0.19	0.19	0.19	0.2	0.24	0.28	0.28	0.29	0.29	0.29	0.3	0.31	0.32

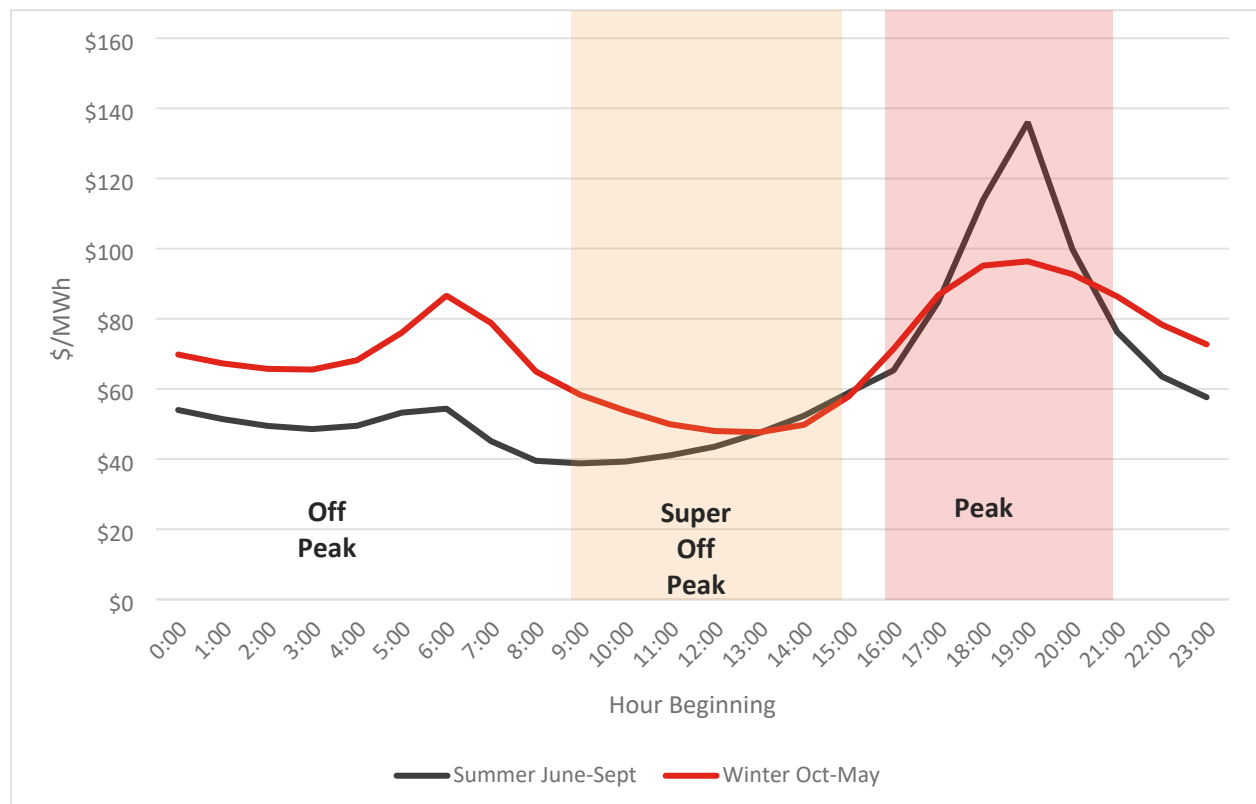
Best Practices

The last consideration for TOU periods is based on ratemaking best practices. First, it has been shown that consumers are more able to shift energy use to lower priced periods when the high-priced period is shorter in duration. As such, there is a trade-off in cost-based rates between peak usage pricing that is significantly higher than off peak but for a shorter period versus smaller price differentials over a longer period. The recommended peak period is from 4 pm to 9 pm. This 5-hour period captures high marginal energy costs, high average GHG intensity, and the timing of both the distribution system peak and residential class peak demand.

TOU RATE RECOMMENDATIONS

It is recommended that TOU rates be calculated for two seasons: summer and winter. The recommended summer season is from June 1 through September 30. This choice of season is based on the annual system peak typically in August or September and the local capacity requirement (determined by the annual peak). Additionally, the seasonal rate design is necessary to pass through the differences in marginal costs between seasons. In particular, the months of June through September are the peak cooling months where the impact of solar on marginal costs is slightly less compared to winter. The recommended seasonal definition results in a larger difference in pricing during summer hours as demonstrated by the higher peak and lower troughs in Figure 4. Winter hours are priced closer together.

FIGURE 4: AVERAGE HOURLY MARKET PRICES BY SEASON: 8/2021-7/2024



Based on the above analysis, the following TOU periods are recommended:

TABLE 2: RECOMMENDED TOU RATE PERIODS

	Time of Day
Summer: June 1 – September 30 and Winter: October 1 – May 31	
Peak	4 pm to 9 pm
Off-Peak	9 pm to 9 am and 3 pm to 4 pm
Super Off-Peak	9 am to 3 pm

Based on these TOU periods, marginal cost data, and the seasonal rate period, the recommended rate differentials are developed. During the summer season, peak period prices average 85% higher than off-peak prices. In winter, October 1 through May 31, the peak period prices average 23% higher than off-peak prices. Super off-peak prices coincide with the time of day with the lowest marginal cost and lowest greenhouse gas emission intensity. Prices during super off-peak periods during the summer are 19% lower than off-peak summer prices and prices during super off-peak periods during the winter are 29% lower than winter off-peak prices.

Table 3 summarizes the marginal cost data for the 3-year period analyzed, August 2021-July 2024. This data was also analyzed by excluding the high winter prices in 2023 caused by natural gas shortages. This event was unusual; however, the resulting price differentials between the recommended TOU periods were not significantly different when the event is excluded.

Note that the marginal cost is not used directly for rate-setting. The marginal cost levels are adjusted to reflect the utility's actual all-in power costs; however, the ratio of peak, off-peak, and super off-peak prices is maintained.⁶ By maintaining the relative cost of power, the resulting rates reflect the marginal cost attributes while collecting the power supply costs allocated to residential customers in the cost of service study.

⁶ This methodology differs from the Export Electricity Compensation rate (EEC) used to credit excess generation value to Net Energy Metering (NEM) customers. The EEC rate considers the marginal cost of energy plus other costs avoided when customers generate electricity locally.

TABLE 3: TOU MARGINAL COST: COMMODITY

	Average DLAP ¹ Price \$/MWh	Difference from Seasonal Off Peak Price
Summer: June 1 – September 30		
Peak: 4 pm to 9 pm	\$99.98	+ 85%
Off-Peak: 9 pm to 9 am and 3 pm to 4 pm	\$53.96	0%
Super Off-Peak: 9 am to 3 pm	\$43.76	-19%
Winter: October 1 - May 31		
Peak: 4 pm to 9 pm	\$88.49	+23%
Off-Peak: 9 pm to 9 am and 3 pm to 4 pm	\$72.17	0%
Super Off-Peak: 9 am to 3 pm	\$51.25	-29%

1. DLAP or Default Load Aggregation Point is the industry name for hourly wholesale electricity prices for the relevant trading point. In this case, the PG&E delivery point is the appropriate trading node.

The commodity rates for E-1 TOU are developed such that the pricing differentials in Table 3 are maintained for the energy-related portion of the rate. The commodity costs that are demand-related are added to the peak commodity rates. Demand-related commodity costs are spread evenly across summer and winter seasons and applied only to peak commodity rates. Finally, because local capacity costs are based on peak demand, 72% of these costs occur in summer, while 28% occur in the winter and these costs are correspondingly included in the summer and winter volumetric rates. Table 4 summarizes the cost components in each TOU commodity rate.

TABLE 4: TOU RATE DESIGN COST COMPONENTS

Commodity Cost Component	Energy Related	Demand Related
Summer Peak	187% of Off Peak Price	72% of Local Capacity Costs Summer Demand Costs
Summer Off-Peak	Marginal Cost Scaled Based on Embedded Power Costs (Calculated in COSA)	None
Summer Super-Off Peak	84% of Off Peak Price	None
Winter Peak	121% of Off Peak Price	28% of Local Capacity Costs Winter Demand Costs
Winter Off-Peak	Marginal Cost Scaled Based on Embedded Power Costs (Calculated in COSA)	None
Winter Super Off-Peak	73% of Off Peak Price	None

LOAD CHARACTERISTICS

The billing determinants for each TOU pricing period are estimated from the load profile data obtained from the HO5 and HO7 feeders. Table 5 summarizes the estimated share of annual energy within each TOU period. For the average customer using 450 kWh per month (5,400 kWh/year), 31.6% or 1,706 kWh are consumed in the winter off peak period.

TABLE 5: RESIDENTIAL LOAD SHARE BY TOU PERIOD

	Share of Annual Energy
Summer: June 1 – September 30	
Peak: 4 pm to 9 pm	8.0%
Off-Peak: 9 pm to 9 am and 3 pm to 4 pm	9.2%
Super Off-Peak: 9 am to 3 pm	14.2%
Winter: October 1 - May 31	
Peak: 4 pm to 9 pm	15.7%
Off-Peak: 9 pm to 9 am and 3 pm to 4 pm	31.6%
Super Off-Peak: 9 am to 3 pm	21.3%

Table 6 compares the recommended E-1 TOU rate with the standard E-1 rate adjusted for FY2026. The commodity rates are developed by scaling the marginal costs for the TOU periods (Table 3) so that when combined with the billing determinants resulting from Table 5, the revenue collected equals the commodity revenue requirement. The fixed customer charge is the same as the recommended fixed customer charge for the E-1 class. The distribution costs for FY2026 are estimated at \$14.1 million (11% increase from FY2025 distribution costs). After an 11% increase in the customer charge, the remaining distribution costs are \$12.4 million. This translates to \$0.09351/kWh. This distribution rate is the same between E-1 and E-1-TOU.⁷ The Public Benefits Charge (PBC) is also the same across time periods and across the Tiered E-1 rate compared to the E-1-TOU rate.

**TABLE 6: RECOMMENDED RESIDENTIAL TOU RATE FY2026
(PRICES PER KWH UNLESS OTHERWISE STATED)**

	Commodity	Distribution	PBC	Total
E-1				
Customer Charge, \$/month				\$5.15
Tier 1 (up to 450 kWh)	\$0.10373	\$0.09593	\$0.00604	\$0.20569
Tier 2 (> 450 kWh)	\$0.13372	\$0.08968	\$0.00604	\$0.22944
E-1-TOU				
Customer Charge, \$/month				\$5.15
Summer (June 1 to Sept 30)				
Peak: 4 pm to 9 pm	\$0.23354	\$0.09351	\$0.00604	\$0.33309
Off Peak: 9 pm to 9 am and 3 pm to 4 pm	\$0.08249	\$0.09351	\$0.00604	\$0.18204
Super Off Peak: 9 am to 3 pm	\$0.06690	\$0.09351	\$0.00604	\$0.16645
Winter (Oct 1 to May 31)				
Peak: 4 pm to 9 pm	\$0.16705	\$0.09351	\$0.00604	\$0.26660
Off Peak: 9 pm to 9 am and 3 pm to 4 pm	\$0.11033	\$0.09351	\$0.00604	\$0.20988
Super Off Peak: 9 am to 3 pm	\$0.07835	\$0.09351	\$0.00604	\$0.17790

⁷ The average distribution rate of \$0.09351/kWh is required to recover the \$12.4 million in residential class distribution system costs. The Standard E-1 Rate is based on a tiered rate design which results in the same collection of \$12.4 million in revenues.

The FY2026 average annual volumetric rate for both for E-1 and E-1 TOU is \$0.21486/kWh. If all residential customers select the E-1 TOU rate plan, and did not modify behavior, the revenue collected would total \$29.4 million.

BILL IMPACTS

The bill impacts from switching from E-1 to E-1-TOU will depend on the monthly electric use. Higher usage in any month will make the TOU rate more attractive to customers. Average monthly use is estimated at 450 kWh, the Tier 1 baseline. Table 7 compares residential monthly bills under two rate plans at the same average monthly use. In every month, the E-1 rate results in a lower bill. The annual difference is \$37.96. This suggests that customers near the average use, and with a usage profile consistent with the feeder data, should prefer to stay on the E-1 rate unless they plan to change their usage patterns.

TABLE 7: BILL IMPACTS: AVERAGE USE

Month	Average Use kWh	Bill: E-1-TOU	Bill: E-1	Difference (E-1 TOU bill – E-1 bill)
1	408	\$92.05	\$89.07	\$2.98
2	440	\$98.38	\$95.66	\$2.72
3	385	\$86.90	\$84.34	\$2.56
4	388	\$87.81	\$84.96	\$2.85
5	436	\$98.16	\$94.83	\$3.33
6	438	\$98.59	\$95.24	\$3.35
7	619	\$138.83	\$136.49	\$2.34
8	523	\$119.46	\$114.46	\$5.00
9	523	\$117.50	\$114.23	\$3.27
10	418	\$94.52	\$91.13	\$3.39
11	407	\$91.80	\$88.87	\$2.93
12	417	\$93.96	\$90.72	\$3.24
Total		\$1,217.96	\$1,180.00	\$37.96

Table 8 shows the same analysis for the case where 200 kWh per month is added to the 450 kWh/month usage. It is assumed that this use is due to electrification (such as electric vehicle charging). We assume a 50/50 split between off-peak and super off-peak period usage for the additional kWh. Table 8 demonstrates that for EV charging timed to avoid the peak cost period, the E-1-TOU rate is beneficial, saving customers approximately \$55 per year.

TABLE 8: BILL IMPACTS: AVERAGE USE PLUS 200 KWH EV CHARGING

Month	Average Use kWh	Bill: E-1-TOU	Bill: E-1	Difference
1	653	\$130.83	\$133.96	-\$3.14
2	689	\$137.16	\$141.31	-\$4.14
3	627	\$125.68	\$128.69	-\$3.01
4	631	\$126.59	\$129.37	-\$2.78
5	684	\$136.94	\$140.39	-\$3.45
6	687	\$133.44	\$140.85	-\$7.41
7	888	\$173.68	\$182.38	-\$8.69
8	781	\$154.31	\$160.35	-\$6.04
9	781	\$152.35	\$160.12	-\$7.77
10	664	\$133.30	\$136.26	-\$2.96
11	652	\$130.58	\$133.73	-\$3.15
12	663	\$132.74	\$135.80	-\$3.06
Total		\$1,667.59	\$1,723.20	-\$55.61

Finally, Table 9 shows a range of potential bill impacts for low, average, and high levels of monthly kWh use. Even with no changes in behavior to avoid peak cost periods, residential customers with higher use could potentially reduce their bills by switching to the TOU rate option. The analysis assumes that customer usage profiles are consistent with the feeder data. Refer back to Table 5 for the share of annual energy consumption in each seasonal TOU period. This profile is used to calculate monthly bills at different levels of consumption ranging from 200 kWh/month to 1,600 kWh/month.

TABLE 9: BILL IMPACTS: LOW, AVERAGE, AND HIGH USAGE LEVELS

	Bill: E-1 TOU	Bill: E-1	Difference
200 kWh	\$47.96	\$46.29	\$1.68
450 kWh (Tier 1 Baseline)	\$101.48	\$97.71	\$3.77
600 kWh	\$133.59	\$132.13	\$1.46
800 kWh	\$176.41	\$178.02	-\$1.61
1,600 kWh	\$347.66	\$361.57	-\$13.91