



Demand Side Analytics

DATA DRIVEN RESEARCH AND INSIGHTS

FINAL REPORT

CALMAC ID: SDGo374

2025 Load Impact Evaluation of San Diego Gas and Electric's Electric Vehicle Time-of-Use (TOU) Rates



ACKNOWLEDGEMENTS

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ABSTRACT

This report summarizes the evaluation findings of San Diego Gas and Electric's (SDG&E) Electric Vehicle TOU (Whole Home) Rates. In total, over 2.9M light-duty vehicles (LDVs) are registered with the California DMV in SDG&E's service territory, which includes all of San Diego County and portions of Orange County. Electric vehicles (EVs) are growing as a share of LDVs and SDG&E has enrolled roughly 80,000 homes on EV rates. On the top 5 load days for CAISO gross loads, these customers curtailed demand during peak hours by 11.4% (20.59 MW) on average and increased energy use during the lower priced super off-peak hours. The change in load patterns coincides with the enrollment on TOU rates for electric vehicles and is sustained throughout the first year of participation. Moreover, customers delivered larger demand reductions on the highest system load days and when conditions were hotter.

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1 EXECUTIVE SUMMARY

This report summarizes the evaluation findings for San Diego Gas and Electric's (SDG&E) EV-TOU-2, EV-TOU-5, and TOU-ELEC whole-home time-of-use rates for residential electric vehicle (EV) drivers. Note that while SDG&E also has a small number of customers on an EV-only sub-metered rate called EV-TOU that are not included in this evaluation, we will refer to the EV-TOU-2, EV-TOU-5, and TOU-ELEC rates collectively as EV-TOU_{WH} (whole home) throughout this report. SDG&E's whole home EV-TOU rates are voluntary time-of-use rate programs designed to offer electric bill saving for EV drivers, while also promoting charging during periods when the grid historically experiences lower demand and has excess capacity. These rates aim to encourage the electrification of the transportation sector, increase access to EV adoption, and reduce the impact of EVs on peak grid conditions. This report provides an overview of the program's history, methods, and impacts, including a summary of the Program Year 2025 ex-post and ex-ante impacts for incremental customers on San Diego Gas and Electric's (SDG&E) TOU rates for EVs.

1.1 KEY FINDINGS

SDG&E has two main residential time-of-use rates for electric vehicles: EV-TOU₂ and EV-TOU₅, both of which are whole-home rates. Moreover, SDG&E recently introduced a new pricing plan, TOU-ELEC, for customer who own an electric vehicle, energy storage, and/or an electric heat pump water heater. On 2025 high load days, SDG&E had about 80,000 homes enrolled across their electric vehicle rates. Table 1 shows participants' aggregate and average load impact during the top 5, 10, and 20 load days for CAISO Gross Loads, CAISO Net Loads, and SDG&E Gross Loads. On the top 5 load days for CAISO Gross loads, participant loads peaked at 160 MW, and participants curtailed peak period demand by 20.6 MW in aggregate. For the top 5 load days for SDG&E Gross loads, participant loads peaked at 193 MW, and participants curtailed peak demand by 19.2 MW in aggregate.

Table 1: Ex-post Demand Reductions on Highest System Load Days (4-9 PM)

System	Month	Sample ^[1]	New Accounts	Total Accounts	Daily avg. temp ^[2]	Avg. Customer (kW)			New Load Impact (MW)	Total Load Impact (MW)
						Reference Load	Load Impact	% Change		
CAISO Gross Loads	Top 05 load day(s)	2,965	22,378	80,440	80.2	2.3	-0.26	-11.4%	-5.73	-20.59
	Top 10 load day(s)	2,965	22,378	80,440	77.6	1.9	-0.23	-11.9%	-5.05	-18.17
	Top 20 load day(s)	2,965	22,378	80,440	76.9	1.8	-0.22	-12.2%	-4.88	-17.53
CAISO Net Loads	Top 05 load day(s)	2,965	22,378	80,440	81.5	2.4	-0.23	-9.5%	-5.21	-18.71
	Top 10 load day(s)	2,965	22,378	80,440	78.5	2.1	-0.24	-11.9%	-5.47	-19.66
	Top 20 load day(s)	2,965	22,378	80,440	76.5	1.8	-0.21	-11.7%	-4.73	-17.01
SDG&E Gross Loads	Top 05 load day(s)	2,965	22,378	80,440	83.8	2.6	-0.24	-9.0%	-5.33	-19.17
	Top 10 load day(s)	2,965	22,378	80,440	80.7	2.3	-0.24	-10.3%	-5.26	-18.91
	Top 20 load day(s)	2,965	22,378	80,440	78.6	2.0	-0.24	-12.0%	-5.38	-19.35

[1] Estimating sample is lower than populations because it excludes sites that whose transition to EV TOU_{WH} coincided with the arrival of the electric vehicle or with solar or battery installation.

[2] Participant weighted average temperature. SDG&E maps all customers to eight distinct weather stations.

2 INTRODUCTION AND BACKGROUND

This report presents the program year 2025 results for SDG&E's electric vehicle time-of-use rates (EV-TOU_{WH}). The program is designed to encourage the electrification of the transportation sector, reduce barriers to EV adoption, reduce greenhouse gas (GHG) emissions, and encourage customers to reduce demand during peak hours and charge during hours when energy is more abundant and less costly. The report has two primary objectives: to estimate the demand reductions that were delivered in 2025 and to quantify the magnitude of incremental demand reductions during peaking conditions for use in planning.

Time of use rates are considered a passive form of load management. They encourage customers to shift their use from higher-priced periods to lower-cost periods but do not directly control the charging behavior of customers or vehicles. A feature that distinguished event-based resources such as DR programs, from non-event-based resources such as TOU rates, is the ability to dispatch the resource. The primary intervention – a dispatch or price signal – is introduced on some days and not on others, making it possible to observe energy use patterns with and without demand reductions. This, in turn, enables us to assess whether the outcome – electricity use – rises or falls with the presence or absence of demand response dispatch instructions. The exception is TOU rates, which are discussed in more detail below.

The evaluation includes three main interventions¹:

- **Electric Vehicle Time of Use rates.** As explained in the Executive Summary above, SDG&E has two primary residential EV-TOU_{WH} rates, the whole-home rates EV-TOU-2 and EV-TOU-5, and a small number of sub-meter homes on an EV-TOU rate that are not included in this evaluation. As of January 1, 2024, customers without an EV² were eligible to enroll on EV-TOU-5. SDG&E has a separate, more recent, pricing plan, TOU-ELEC, for customers who own an electric vehicle, energy storage, and/or an electric heat pump water heater. All of the rates include a peak period from 4-9 PM, super off-peak rates from 12-6 AM, and off-peak rates in all other hours. The main differences between the whole premise rates are in the super off-peak rates, the monthly billing fee, and rates during holidays and weekends. Overall, the EV-TOU-5 rate has a lower super off-peak price, a higher monthly fixed charge, and the same rates for weekdays and weekends. On the other hand, the TOU-ELEC rate has the lowest price difference between the off-peak and super off-peak periods among the three rates. Nearly all new enrollments are on the EV-TOU-5 rate.

¹ TOU-ELEC customers are included in the ex-post analysis but excluded from the ex-ante analysis, due to their small number and the lack of precision in their impacts used for forecasting. A separate report will be issued, focusing specifically on TOU-ELEC.

² It has always been the case that customers self-report EV ownership when they enroll, so it is possible that customers without EVs could be enrolled on these rates prior to January 1 2024. In our analysis, those customers will be matched to, and compared with, other customers that are unlikely to own EVs.

The remainder of this section provides context and additional detail about the EV-TOU-5, EV-TOU-2, and TOU-ELEC rates. It details the key research questions, summarizes 2025 grid conditions, and discusses the whole home electric vehicle TOU rates and historical participation.

2.1 RESEARCH QUESTIONS

While each program/rate at each utility has unique characteristics, the core research questions are similar:

- What were the demand reductions due to electric vehicle time of use rates?
- How do load impacts differ for different types of customers?
- How does weather influence the magnitude of demand response, if at all?
- How does price influence the magnitude of demand response?
- What is the ex-ante load reduction capability for 1-in-2 and 1-in-10 weather conditions? And how well do these reductions align with ex-post results and prior ex-ante forecasts?
- What concrete steps can be undertaken to improve program performance?

2.2 KEY FACTS ABOUT ELECTRIC VEHICLES IN SDG&E

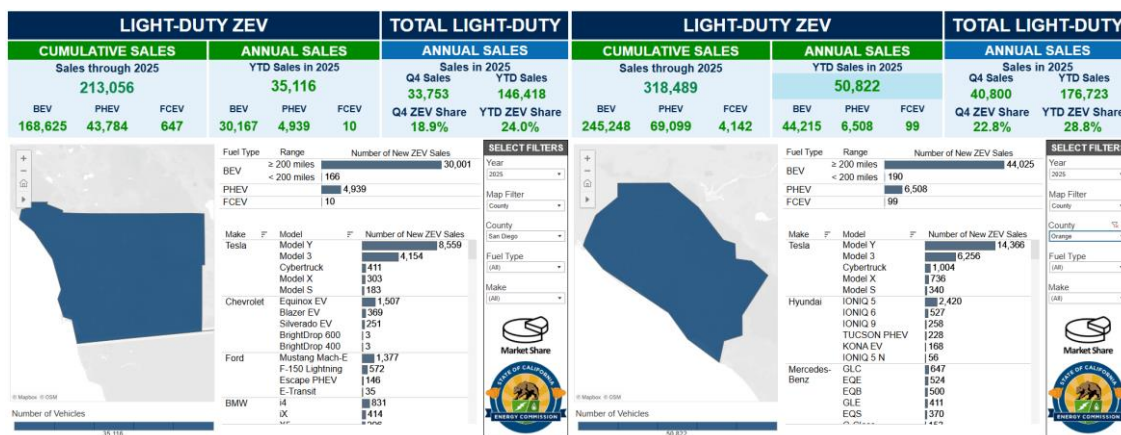
Electric vehicles have the potential to transform the electric grid fundamentally. As the residential electric vehicle market grows, it will impact all aspects of the electric grid. Therefore, in addition to the load impacts achieved by the electric vehicle programs, it is also essential to understand the population and distribution of electric vehicles in SDG&E's service territory.

As of December 2024, over 2.9M³ vehicles were registered with the California DMV in SDG&E's service territory, which includes all of San Diego County and portions of South Orange County. Over 170,000 electric vehicles and 47,000 plug-in hybrid electric vehicles (PHEV) were registered in SDG&E territory. While the share of electric vehicles is small, the market share of electric vehicles grew exponentially until 2023, and stagnated in 2024, as shown in Figure 2. In 2025, the market share fell slightly. Focusing on San Diego County (Figure 1, left panel), 24% of new vehicle sold were either full electric vehicles or plug-in hybrid vehicles, slightly lower than 2024. The historical market share penetration data has matured enough that vehicle share adoption can be estimated using historical data, as shown in Figure 2. This estimation of future market share relies on simple methods and historical data. Recent macroeconomic factors, and potential changes in state and federal policy, present a significant headwind to EV adoption. Higher interest rates tend to affect EVs more than other vehicles because they have a high up front cost and lower operational cost. Tax credits for EVs passed under the Inflation Reduction Act of 2022 (IRA) and vehicle emissions standards that benefit EVs have been weakened.

³ Source: California Energy Commission (2024). Data last updated January 31, 2025. Retrieved February 15, 2025.

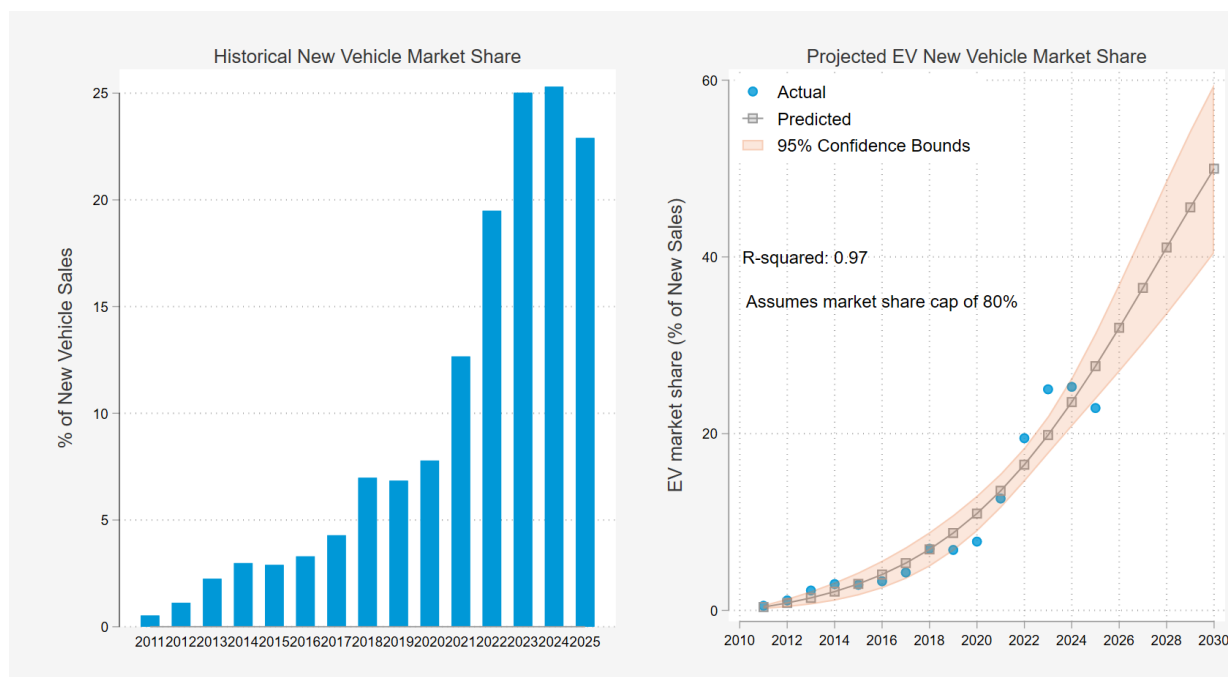
These changes have begun to be reflected in sales, as demonstrated in the fall in market share in 2025. Appendix A provides an analysis and forecast of EV market share in a scenario without tax credits.

Figure 1: Electric Vehicle Population in SDG&E Territory (2025)



Source: California Energy Commission (2025). New ZEV Sales in California. Data last updated December 31, 2025. Retrieved February 4, 2026, from <https://www.energy.ca.gov/zevstats>

Figure 2: Electric Vehicle Market Share of New Vehicle Sales in California



Data source: California Energy Commission (2025). New ZEV Sales in California. Retrieved February 4, 2026, from <https://www.energy.ca.gov/zevstats> Graphs and market share projection produced by DSA.

2.3 2025 GRID CONDITIONS

SDG&E delivers electricity to 3.7 million people in San Diego and southern Orange counties. It has 1.5 million residential and business accounts, a service area that spans 4,100 square miles, and a peak demand of over 4,000 MW⁴. SDG&E is responsible for ensuring that electricity supply remains reliable by projecting future demand and reinforcing the transmission and distribution network so that sufficient capacity is available to meet local needs as they grow over time. SDG&E is part of the California Independent System Operator (CAISO) electricity market.

The electric grid is unique in that supply and demand must be balanced nearly instantaneously because an imbalance can lead to cascading outages and compromise the reliability of the entire grid. The California System Operator has the critical role of balancing supply and demand, thus ensuring grid reliability. Historically, the electric grid infrastructure has been sized to meet the aggregate demand of end-users when it is forecasted to be at its highest—peak demand. With the introduction of large amounts of solar and wind power, the focus of planning has shifted to ensure enough flexible resources are in place to meet the demand that cannot be met by solar and wind alone – known as net loads.

Meeting peak demand requires procuring enough supply capacity to meet peak demand and maintaining sufficient operating reserves to absorb system shocks such as unscheduled generator outages, transmission outages, and large unforeseen swings in demand or supply. However, peak demand conditions occur infrequently – one or two times every ten years or so – and thus, planning for a small number of extreme conditions drives a significant share of infrastructure costs. An alternative to building additional peaking power plants is to reduce coincident demand by injecting power within the distribution grid (e.g., battery storage) or by reducing or shifting demand. The EV-TOU_{WH} prices encourage customers to shift usage to lower-priced hours when the electric grid is not peaking.

Figure 3 shows the hourly load pattern for the ten highest load days for SDG&E, CAISO, and CAISO net loads. SDG&E load peaked at 4,022 MW, CAISO load peaked at 43,921 MW, and CAISO net loads peaked at 40,129 MW. Figure 4 shows the concentration of demand visualized with a normalized load duration curve. A load duration curve is a way to visualize "peakiness" or utilization of a system. It simply ranks each hour of the year based on demand from highest to lowest. The need for generation capacity resources is highly concentrated. If targeted precisely, shaving loads on the top 1% of hours at SDG&E would lead to a 16% reduction (585 MW) in generation capacity needs at SDG&E. Likewise, a small number of hours drives peak planning and infrastructure costs for the California system. Shaving CAISO net loads on the top 1% of hours would lead to a 17% reduction (~5,927 MW) in need for generation capacity. Figure 5 shows the hourly electricity market prices for the SDG&E area from May to September 2025. The high price periods coincided with times when CAISO net loads were highest.

⁴ SDG&E system load peaked at 4,022 MW on Tuesday September 2 at 6:45 PM.

Figure 3: SDG&E and CAISO Top Ten Peak Load Days (Oct 2024-Sep 2025)

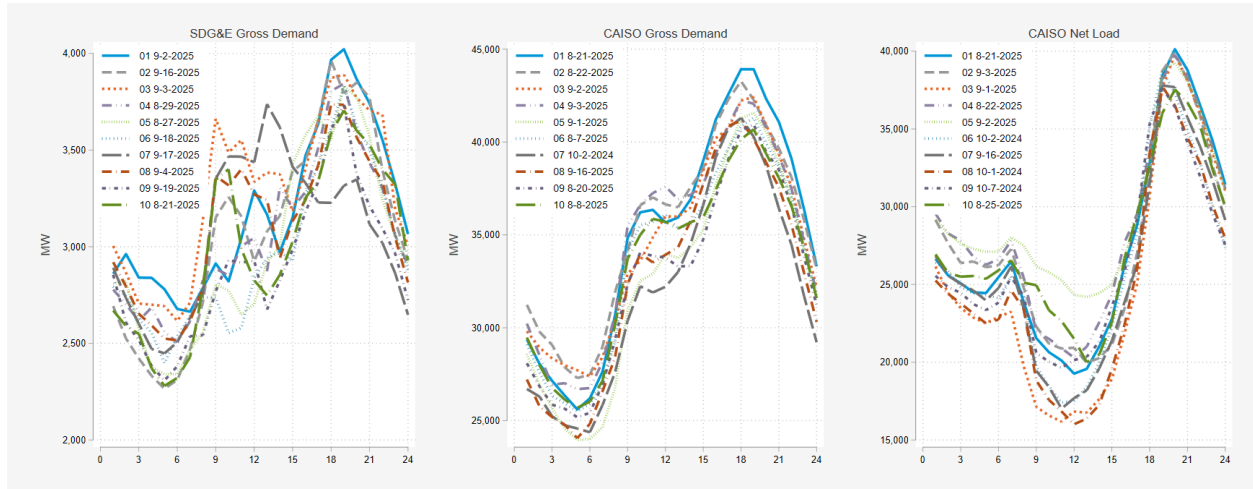


Figure 4: Normalized Load Duration Curves for Top 5% of Hours (Oct 2024-Sep 2025)

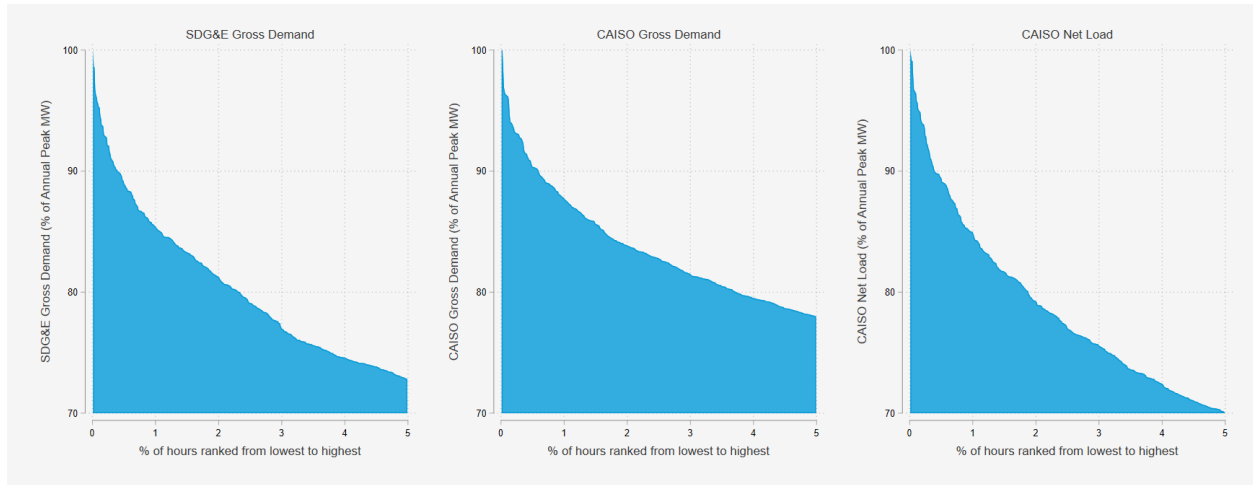
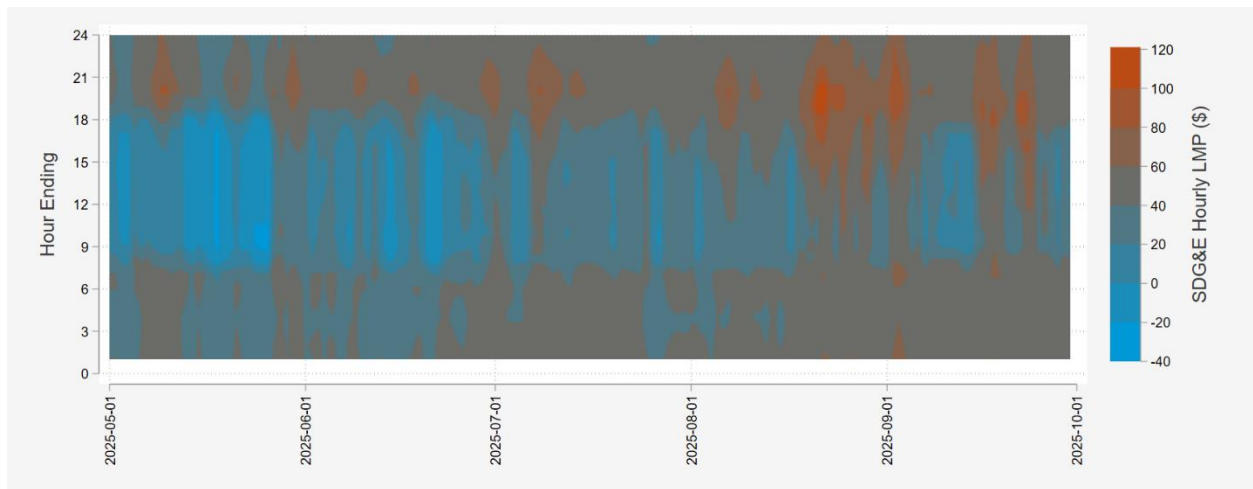


Figure 5: SDG&E Summer 2025 Hourly Electricity Market Prices



3 METHODOLOGY

This section first presents an overview of general issues in program evaluation. We then discuss the specific methodology we use in this analysis to estimate load impacts for EV-TOU_{WH} rates. The primary challenge of impact evaluation is the need to accurately detect changes in energy consumption while systematically eliminating plausible alternative explanations for those changes, including random chance. Did the price signal cause a behavior change resulting in a load shift? Or can the differences be explained by other factors? To estimate changes in load, it is necessary to estimate what load would have been in the absence of the rate change – this is called the counterfactual or reference load. At a fundamental level, the ability to measure load changes accurately depends on four key components:

- **The effect or signal size** – The effect size is most easily understood as the percent change. It is easier to detect large changes than it is to detect small ones.
- **Inherent data volatility or background noise** – The more volatile the load, the more difficult it is to detect small changes. Energy use patterns of homes with air conditioners tend to be more predictable than industrial load patterns.
- **The ability to filter out noise or control for volatility** – At a fundamental level, statistical models, baseline techniques, and control groups – no matter how simple or complex – are tools to filter out noise (or explain variation) and allow the effect or impact to be more easily detected.
- **Sample/population size** – For most of the programs in question, sample sizes are not relevant because we plan to analyze data for the full population of participants either using AMI data or thermostat runtime. Sample size considerations aside, it is easier to precisely estimate average impacts for a large population than for a small population because individual customer behavior patterns smooth out and offset across large populations.

3.1 EV-TOU RATE METHODOLOGY

We estimate EV-TOU_{WH} rate load impacts by difference-in-differences with a matched control group. To avoid confounding the effect of the rate with changes in load due to a newly registered EV, the analysis sample is a subsample of the population that we restrict to customers that did not acquire an EV in the analysis window. Furthermore, to estimate monthly load impacts that are not subject to composition effects, we require that the analysis sample have a full year of pre- and post-treatment data. We provide more detail below.

Like other TOU rates, once a customer is on an EV-TOU_{WH} rate, the EV-TOU_{WH} rate is in place every day, and it is no longer possible to observe their behavior absent new rates. Thus, estimating effects ideally requires a control group. Furthermore, to estimate monthly load reductions that are not subject to composition effects, we require a year of pre-treatment and post-treatment data for both the EV-TOU_{WH} and control groups. The pre-treatment data is useful for assessing if energy consumption changed and allows the use of more powerful statistical techniques such as difference-in-difference models. When neither group is on EV-TOU_{WH} rates, the energy use patterns should be nearly identical. If the EV-TOU_{WH} rates lead to changes in energy use, we should observe a change in consumption for

customers who went on the EV-TOU_{WH} rate but no similar change for the control group. In addition, the timing of the change should coincide with the adoption of EV-TOU_{WH} rates.

Ex-Post Evaluation Approach

Key issues that influenced the ex-post evaluation approach are:

- **Identifying an appropriate control pool.** The primary challenge in evaluating electric vehicle programs is finding appropriate control customers. The appropriate control pool is customers who have electric vehicles but have not signed onto the EV-TOU_{WH} rate. However, SDG&E only has conclusive data about EV ownership for homes that sign onto TOU rates for electric vehicles. DSA used AMI data to develop electric vehicle propensity estimates and identify sites with electric vehicles that were not on TOU rates for electric vehicles. In developing the propensity models, we intentionally avoided variables that focus on hourly load patterns and overall consumption since both are influenced by the TOU rates for electric vehicles. Instead, the markers to identify electric vehicles were focused on max demand values on temperate days when air conditioning loads were not present.
- **Electric vehicle adoption often coincides with enrollment in the TOU rate and solar or battery storage adoption.** When multiple changes occur at once, it is more difficult to isolate the effect of the TOU rates. It is necessary to eliminate from the analysis both participants and control candidates that purchased their electric vehicle or had solar or battery installation near the time they enrolled on the EV-TOU_{WH} rate. SDG&E provided access to their interconnection data, allowing us to remove sites with changes in solar or battery status over the analysis period.
- **Rolling enrollments versus first-year patterns.** Customers adopt and sign on to electric vehicle rates at different points in time. The pattern can create imbalanced time series and lead to spurious effects. We must estimate monthly load impacts, which requires observing load in the same calendar month pre- and post-enrollment. If we did not require a year of pre- and post-treatment data for all customers, the specific customers underlying each monthly load impacts estimate would differ across months. Thus, the primary analysis is based on sites with a full year before and after customers transitioned to the electric vehicle TOU rates.⁵

The above factors were taken into consideration in selecting our evaluation approach, which is summarized in Table 2.

Table 2: EV-TOU Ex-Post Evaluation Approach Summary

Methodology Component	Description
1. Population or sample analyzed	The evaluation focused only on incremental sites that enrolled between October 1, 2023 and September 30, 2024 thereby reaching their full first year of savings on

⁵ The analysis sample for 2025 was pulled at the premise-account level, to ensure that we examine data for a premise for the same individual and do not pick up spurious effects due to movers.

Methodology Component	Description
	October 1, 2025. The estimation sample included sites with a full year of data before and after EV-TOU _{WH} rate adoption. It excluded sites who had a change in electric vehicle, solar, or battery status that coincided with the study period. The estimation sample included approximately 13% of the total incremental enrollments as customers often enroll on TOU rates for electric vehicles shortly after getting their electric vehicle.
2. Data included in the analysis	The analysis included a full year of pre and post EV-TOU _{WH} data. The same data was included for participants and matched control. In all cases, we ensured that both the participant and control had pre and post EV-TOU _{WH} data for the same day of year.
3. Use of control groups	We relied on a control group of customers with electric vehicles but that were not on SDG&E's TOU rates for electric vehicles. The process to find this control group involves two steps. First, we build electric vehicle propensity using AMI data to identify unique load patterns that indicate the presence of electric vehicles (but avoiding variables about load shape and overall consumption). As part of the analysis, we also identified the approximate date the electric vehicle(s) arrived at the household. Once control candidates with electric vehicles had been identified, we matched customers using pre-treatment hourly AMI data. The matching on pre-treatment loads used propensity score matching and Euclidian distance matching and matches were selected only from customers with similar electric vehicle scores. Participants were paired to the matched control site and the control site was assigned the same "treatment date" as the participant.
4. Evaluation Method	Simple difference-in-differences was used to isolate the load impact. The process involved the following steps: <ol style="list-style-type: none"> 1. Aggregate (or average) the data to the relevant time unit of analysis. This was done for both participants and control and for the year before and after the treatment. 2. The difference between the before and after period was calculated for the treatment group. 3. The difference between the before and after period was calculated for the control group. 4. The difference observed in the control group was netted out of the participant difference to produce the difference-in-differences.
5. Model selection	The approach relies more heavily on selecting a comparable matched control group than the model specification. We conducted a tournament to identify the model that performed best (least percent bias and relative RMSE) at identifying the control pool.
6. Segmentation of impact results	The results were segmented by: <ul style="list-style-type: none"> ■ Rate ■ Region in SDG&E territory (based on 3-digit zip code) ■ Solar status ■ Low income

EX-ANTE EVALUATION APPROACH

A key objective of evaluations is to quantify the relationship between changes in load, temperature, and hour-of-the-day. The purpose of doing so is to establish the load-shift capability under 1-in-2 and 1-in-10 weather conditions for planning purposes and, increasingly, for operations. When possible, we rely on the historical event performance to forecast ex-ante impacts for future years for different operating conditions.

At a fundamental level, the process of estimating ex-ante impacts is simple:

1. Decide on an adequate segmentation to reflect how the customer mix evolves over time.
2. Estimate the relationship between reference loads and weather.
3. Use the models to predict reference loads for different weather conditions (e.g., 1-in-2 and 1-in-10 weather year conditions).
4. Estimate the relationship between weather and impacts.
5. Predict load impacts for different weather conditions.
6. Combine the reference loads (#4) and impacts (#5) to produce per-customer impacts.
7. Multiply per-customer impacts by the enrollment forecast.

The process can be used to develop ex-ante estimates of demand reduction as a function of different temperatures and day types. It can be used to develop estimates for 1-in-2 and 1-in-10 weather year planning conditions, and it can be used to develop time-temperature matrices useful for estimating reduction capability for operations or a wider range of planning conditions.

Table 3: EV-TOU Ex-Ante Evaluation Approach Summary

Methodology Component	Demand Side Analytics Approach
1. Years of historical data	Data from the year prior to the adoption of EV-TOU _{WH} rates for each customer was used to develop reference loads. The load reductions for a full year of EV-TOU _{WH} participation were used to model ex-ante load impacts.
2. Process for producing ex-ante impacts	<p>The key steps were:</p> <ul style="list-style-type: none"> ▪ Segment customers by rate type (EV-TOU-5 and EV-TOU-2) and solar status. ▪ Estimate the relationship between reference loads and weather on a per household basis. ▪ Use the models to predict reference loads for 1-in-2 and 1-in-10 weather year conditions. ▪ Estimate the relationship between EV-TOU_{WH} load impacts and weather. ▪ Predict the reductions for 1-in-2 and 1-in-10 weather year conditions. ▪ Combine per customer reference loads and load impacts with an incremental forecast of enrollment on EV-TOU_{WH} rated developed by SDG&E⁶.
3. Accounting for changes in the participant mix	The ex-ante load impacts account for changes in the participant mix across the two main rate types – EV-TOU-2 and EV-TOU-5 – and rooftop solar status.
4. Producing busbar level impacts	Granular results for distribution planning have been required for the last few years. A key consideration in the approach is that there is more data about customer loads than there is data on the percent reductions delivered during events. To develop ex-ante impacts at the busbar level, we use the load impacts by segment and the current mix of customers at the busbar level to estimate the granular impacts.

⁶ A separate forecast for EV-TOU_{WH} enrollment was produced by DSA, and included in the appendix.

4 ELECTRIC VEHICLE TOU EX-POST RESULTS

This section focuses on the magnitude of demand reductions delivered by incremental EV-TOU_{WH} participants for the time frame from October 1, 2024 to September 30, 2025. SDG&E has three primary whole premise time of use rates for electric vehicles, EV-TOU-2, EV-TOU-5 and TOU-ELEC. These rates encourage customers to shift their use from higher priced periods to lower cost periods, but do not directly control the charging behavior of customers or vehicles.

Overall, SDG&E has signed over 80,000 homes onto electric vehicle TOU rates. For context, SDG&E territory has roughly 170,000 full battery electric vehicles and 47,000 plug-in hybrid vehicles in its territory. Since mid-2018 most electric vehicles have signed onto the EV-TOU-5 rate rather than the EV-TOU-2 rate. The EV-TOU-5 rate has a higher fixed charge and substantially lower super-off-peak rates. When the EV-TOU-5 rate was first introduced, many EV-TOU-2 customers switched onto it. However, by PY2022, the rates were largely stable and the switching between electric vehicle rates was negligible. TOU-ELEC is a rate for customers who own an electric vehicle, energy storage, and/or an electric heat pump water heater, and has the lowest price difference between the off-peak and super off-peak periods among the three rates.

Figure 6: Total Enrollments by EV-TOU Rate type

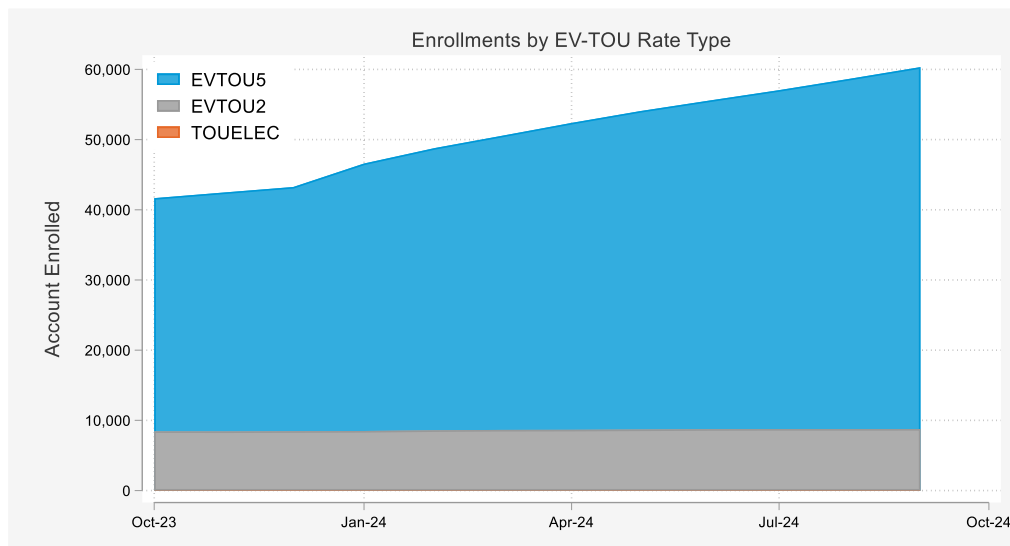
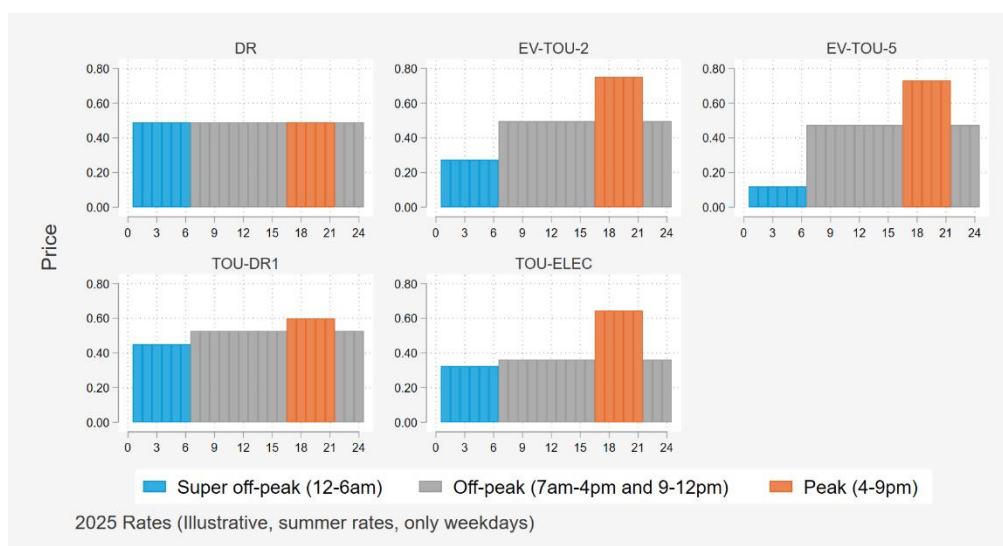


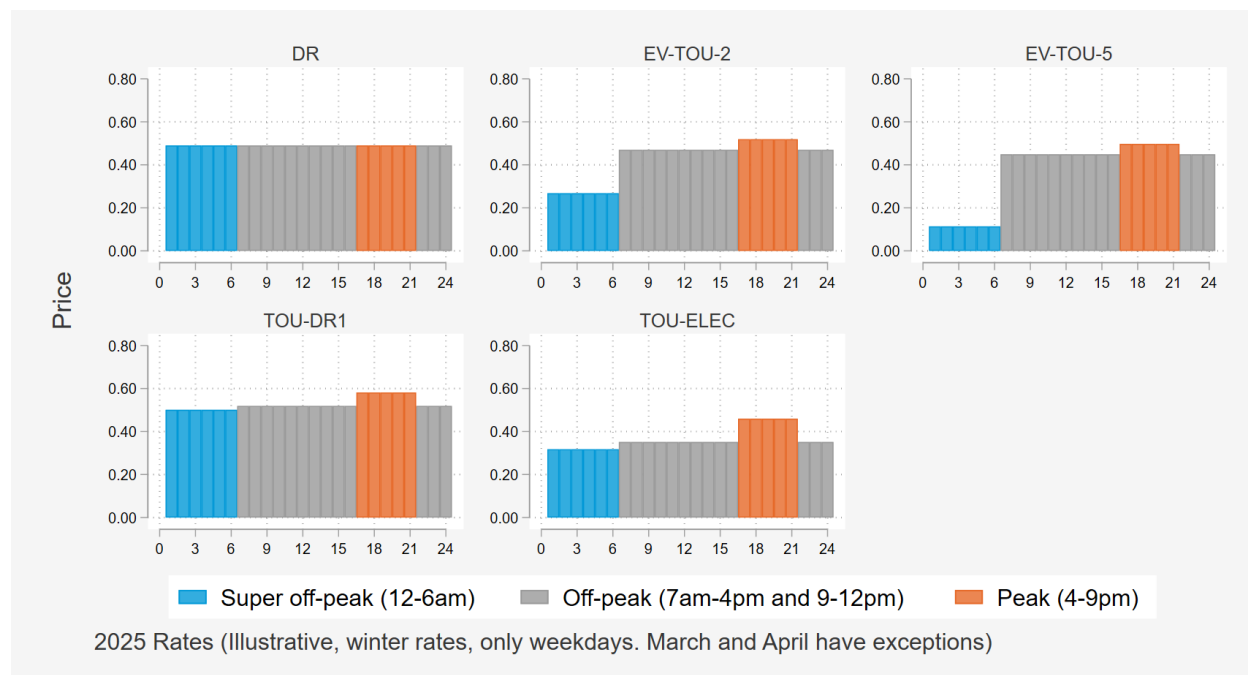
Figure 7: SDG&E Residential Rate Schedules for Summer 2025



Participation in EV-TOU_{WH} rates is voluntary, and customers selected the TOU rates for electric vehicles over the flat domestic rate (DR) and the default TOU rate (TOU-DR1) that applies to roughly 60% of

SDG&E customers. Notably, the EV-TOU-2, EV-TOU-5, and TOU-ELEC rates have higher peak prices (4-9 PM) and lower super-off-peak prices (12-6 AM). Thus, the higher on peak price and lower super off-peak price encourages customers to shift usage more than SDG&E's default time of use rate (TOU-DR1). As Figure 8 shows, the primary difference between summer and winter months is the significantly lower peak price during the winter months.

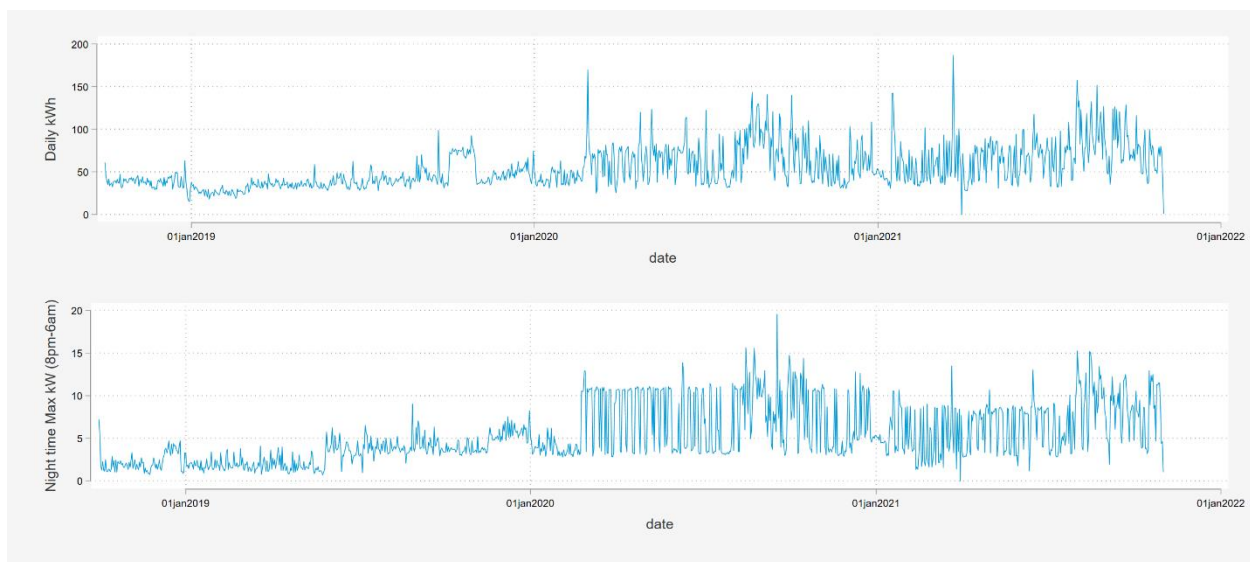
Figure 8: SDG&E Residential Rate Schedules for Winter 2025



4.1 CHARGING PATTERNS BEFORE AND AFTER TOU RATES FOR ELECTRIC VEHICLES

The early adopters of electric vehicles differ from the typical SDG&E customers. They are on average more likely to own solar and battery storage and are less likely to be on California Alternative Rates for Energy (CARE). When an electric vehicle is introduced, it fundamentally changes usage and max demand at a home. Figure 9 illustrates how the introduction of an electric vehicle leads to an increase in daily use, an increase in daily max demand, and increased volatility in energy use. The change is most obvious for customers with an electric vehicle Level 2 charger⁷ and for the maximum demand observed between 8 PM and 6 AM.

Figure 9: Example of How the Introduction of Electric Vehicle Change Household Energy Use



To isolate the effects of TOU we used the AMI data to identify customers with a similar electric vehicle footprint that were not on TOU rates for electric vehicles to serve as controls. In addition, we removed any participants and candidate controls where the change in electric vehicle ownership appeared to coincide with the adoption of TOU rates for electric vehicles. The participants were then matched to customers with similar electric vehicle footprints and a similar whole home load pattern during the time frame when neither participants nor the control candidates were on TOU rates.

Figure 10 show the hourly load patterns for the EV-TOU_{WH} customers and the corresponding controls both before and after the participants enrolled on the rate. The plots reflect the raw data without any

⁷Level 2 charging enables the vehicle to charge at a higher rate, between 3.3 and 19.2 kW an hour depending on the amperage of the equipment, whereas a Level 1 charger cannot charge more than 1.32 kW an hour. It is very difficult to identify a Level 1 charger using hourly interval data as other appliances in the home can use a similar amount of energy as a central air conditioner, or a pool pump, or heat pump.

modeling. When neither group was on TOU rates, the electricity patterns mirrored each other, with small differences in the off-peak period. Once participants go on TOU rates, the electric use patterns diverge. Customers on whole home TOU rates for electric vehicles increased usage between 12-6 AM when prices were lowest, and decreased usage during the higher prices hours. Although the electric vehicle rates differ for the 4-9 PM period, participants reduced usage during both off-peak (6AM-4 PM and 10 PM-12 PM) and peak hours (4-9 PM). Table 4 shows the data underlying Figure 10, and shows the difference-in-difference calculation, which nets out pre-existing observed differences.

Figure 10: Hourly Load Patterns Before and After EV-TOU Rates (May-October)

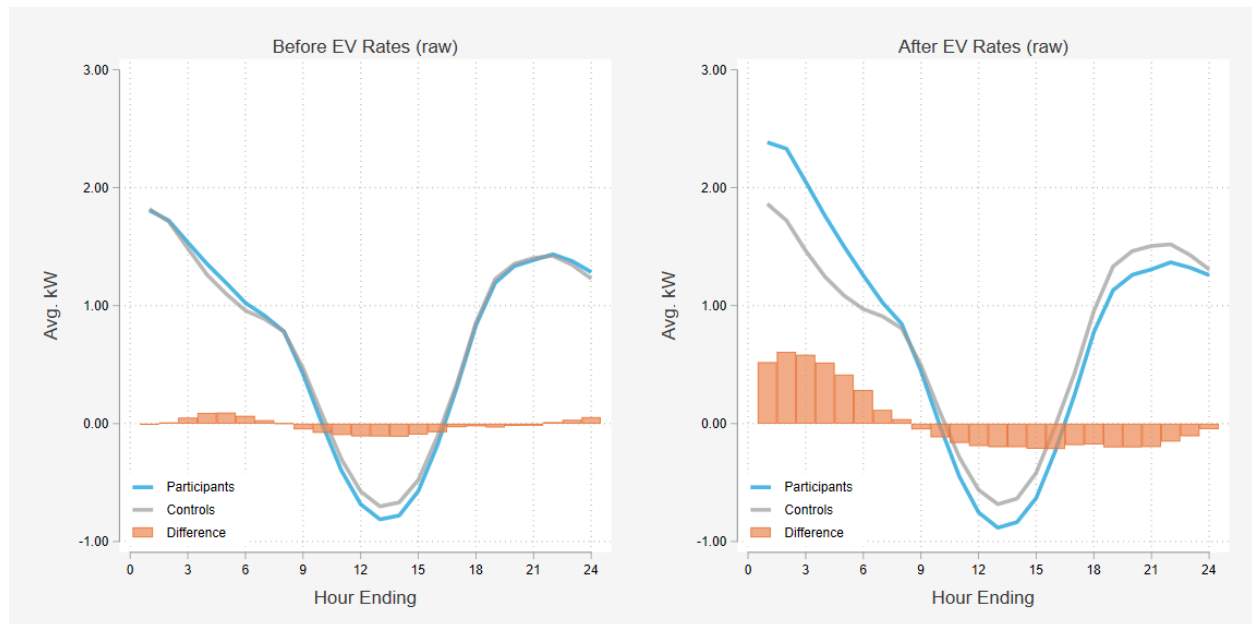


Table 4: First Year Hourly Differences-in-Differences

Hour Start	Treatment (n = 2965)			Control (n=2965)			Difference-in-Differences		
	Before	After	Diff	Before	After	Diff	Diff-in-Diff	Std. Error	t-stat
0:00	1.81	2.38	0.58	1.82	1.86	0.04	0.53	0.027	20.06
1:00	1.72	2.33	0.61	1.71	1.72	0.01	0.60	0.025	23.60
2:00	1.54	2.05	0.51	1.49	1.46	-0.02	0.53	0.021	25.26
3:00	1.35	1.76	0.41	1.26	1.25	-0.02	0.43	0.018	23.84
4:00	1.19	1.50	0.31	1.10	1.08	-0.01	0.32	0.017	19.43
5:00	1.02	1.26	0.23	0.96	0.97	0.01	0.22	0.013	17.09
6:00	0.91	1.03	0.11	0.89	0.91	0.02	0.09	0.009	9.61
7:00	0.78	0.84	0.06	0.78	0.81	0.03	0.04	0.008	4.35
8:00	0.42	0.44	0.03	0.47	0.49	0.03	0.00	0.009	-0.01
9:00	-0.01	-0.02	-0.02	0.07	0.09	0.02	-0.04	0.010	-3.78
10:00	-0.40	-0.45	-0.05	-0.30	-0.29	0.02	-0.07	0.012	-5.56
11:00	-0.68	-0.75	-0.07	-0.58	-0.56	0.01	-0.08	0.013	-6.20
12:00	-0.81	-0.88	-0.07	-0.70	-0.68	0.02	-0.09	0.014	-6.34
13:00	-0.78	-0.83	-0.06	-0.67	-0.64	0.03	-0.09	0.014	-6.27
14:00	-0.57	-0.63	-0.06	-0.48	-0.42	0.06	-0.12	0.013	-8.93
15:00	-0.18	-0.23	-0.05	-0.11	-0.01	0.09	-0.14	0.013	-11.32
16:00	0.31	0.25	-0.06	0.34	0.43	0.09	-0.15	0.012	-12.54
17:00	0.83	0.78	-0.06	0.86	0.96	0.10	-0.16	0.011	-13.73
18:00	1.19	1.13	-0.06	1.23	1.33	0.11	-0.17	0.011	-15.11
19:00	1.34	1.26	-0.07	1.35	1.46	0.11	-0.18	0.011	-16.06
20:00	1.39	1.31	-0.08	1.40	1.51	0.10	-0.18	0.012	-15.26
21:00	1.44	1.37	-0.07	1.42	1.52	0.10	-0.16	0.014	-11.97
22:00	1.38	1.32	-0.06	1.35	1.43	0.08	-0.14	0.015	-9.19
23:00	1.28	1.26	-0.03	1.23	1.31	0.08	-0.10	0.016	-6.62

Figure 11 shows average demand from 4-9 PM for each day for the full year before and after the introduction of the EV-TOU_{WH} rates by day-of-year. The energy use patterns are similar for the treatment and control groups before the official adoption of the TOU rates for electric vehicles, but there are small differences. Those pre-existing differences are removed or netted out in the differences-in-differences technique.

Figure 11: Peak Period (4-9 PM) Daily Differences Before and After TOU Rates for Electric Vehicles

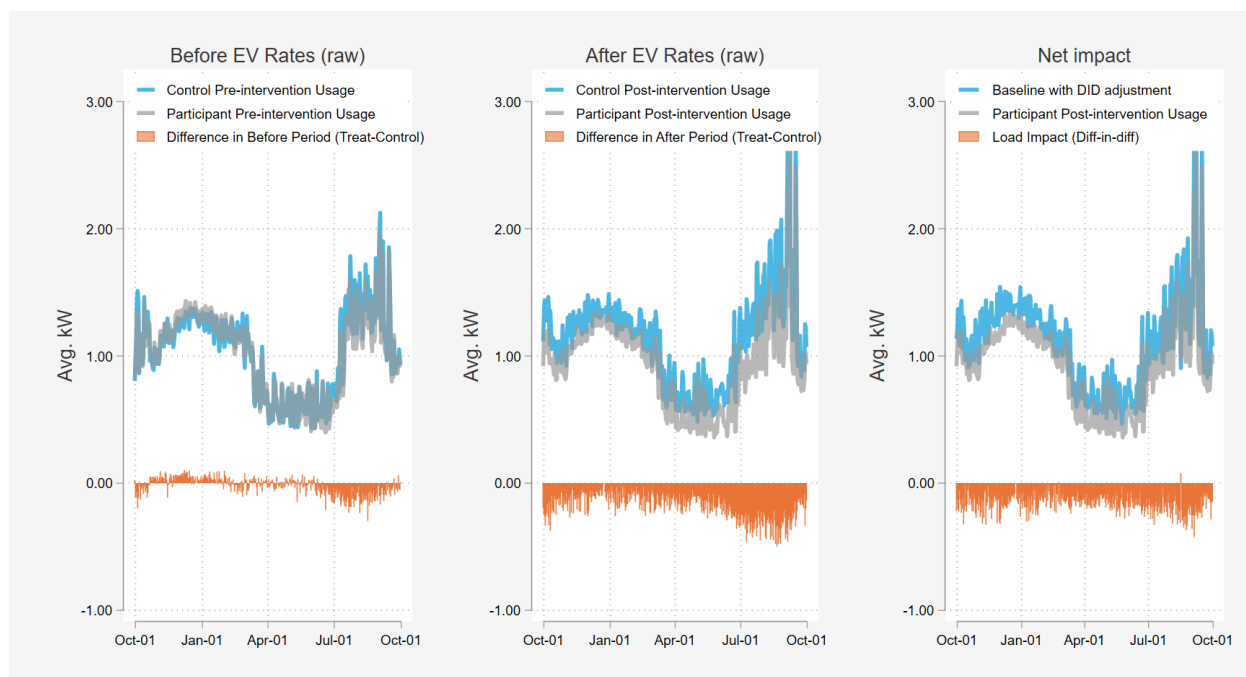
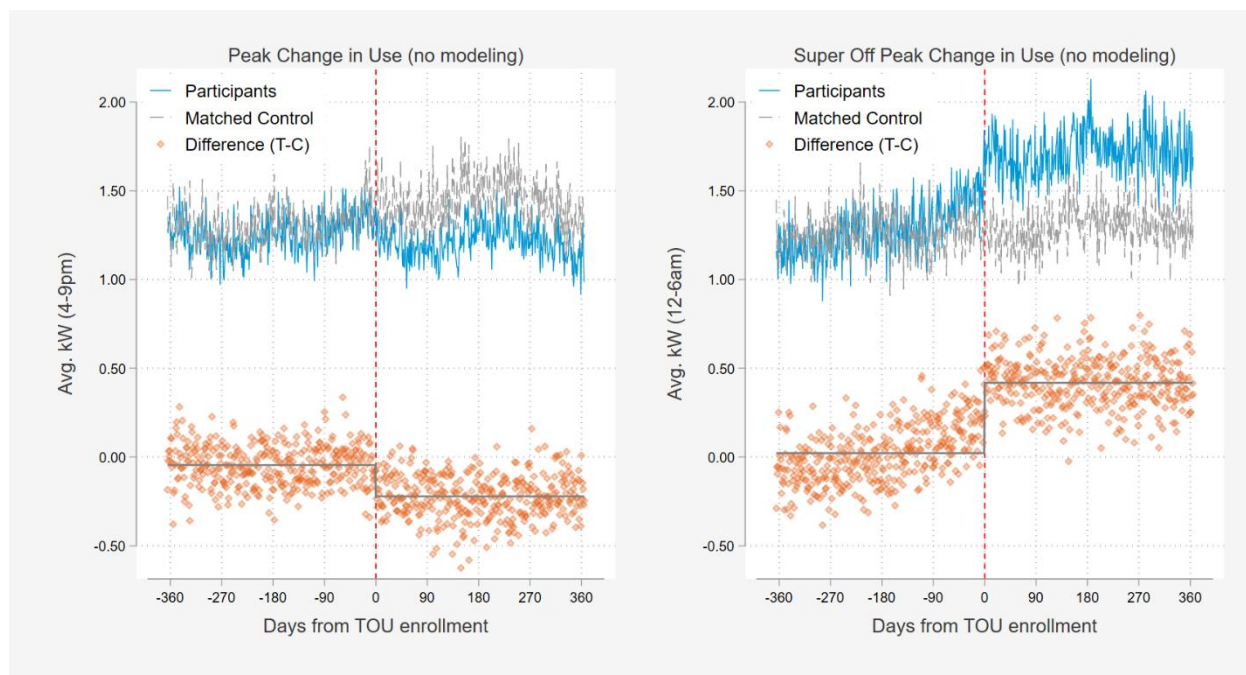


Figure 12 also shows the differences by day of year, but it compares the 365 days immediately before and after enrollment based on the days from enrollment. Thus, it normalizes the time dimensions allowing for direct comparison of sites that enrolled on different dates. As before, the energy use patterns are similar for the treatment and control groups before the official adoption of the whole home TOU rates for electric vehicles, but there are small differences. The change in energy usage for participants roughly coincides with the adoption of the rates and the change in energy usage matches the expected price response. Participants decrease energy use when prices are higher and reduce demand when prices are lower. The shift in behavior does not coincide perfectly because billing periods differ by customer and customers may consider changes over multiple days and weeks in advance of the transition to electric vehicle rates.

Figure 12: Treatment and Control Group Differences by Days from Treatment



4.2 LOAD IMPACTS ON HIGHEST SYSTEM LOAD DAYS

Although EV-TOU_{WH} customers have a daily incentive to shift load away from hours when prices are highest, peak hours, and charge when prices are lowest, it is critical to understand how the rates change load pattern when demand is highest. As noted earlier, many grid infrastructure components are sized to meet the aggregate peak demand levels that occur infrequently. When customers reduce demand coincident with the peaks that drive infrastructure needs – either by injecting power within the distribution grid (e.g., behind-the-meter generation) or by reducing demand – they often help avoid the costs associated with infrastructure expansion. Notably, different parts of the grid can peak at different times. As Figure 3 showed, the SDG&E system peaks on different days than CAISO demand, which, in turn, differs from the days when CAISO net loads are highest.

Figure 13 shows the average hourly demand reduction from EV-TOU_{WH} participants in the 10 days when demand was highest for CAISO, CAISO net loads, and SDG&E. The change in peak and super-off-peak demand is similar for all three.

Table 5 provides additional detail about the load impacts for the top 5, 10, and 20 highest load days for CAISO, CAISO net loads, and SDG&E. For CAISO loads, the reductions were larger in magnitude on the top 5 and 10 highest system load days than on the top 20 highest system load days. Load reductions were similar across SDG&E top days.

Figure 13: Hourly Load Impacts on Top Highest Load Days by System

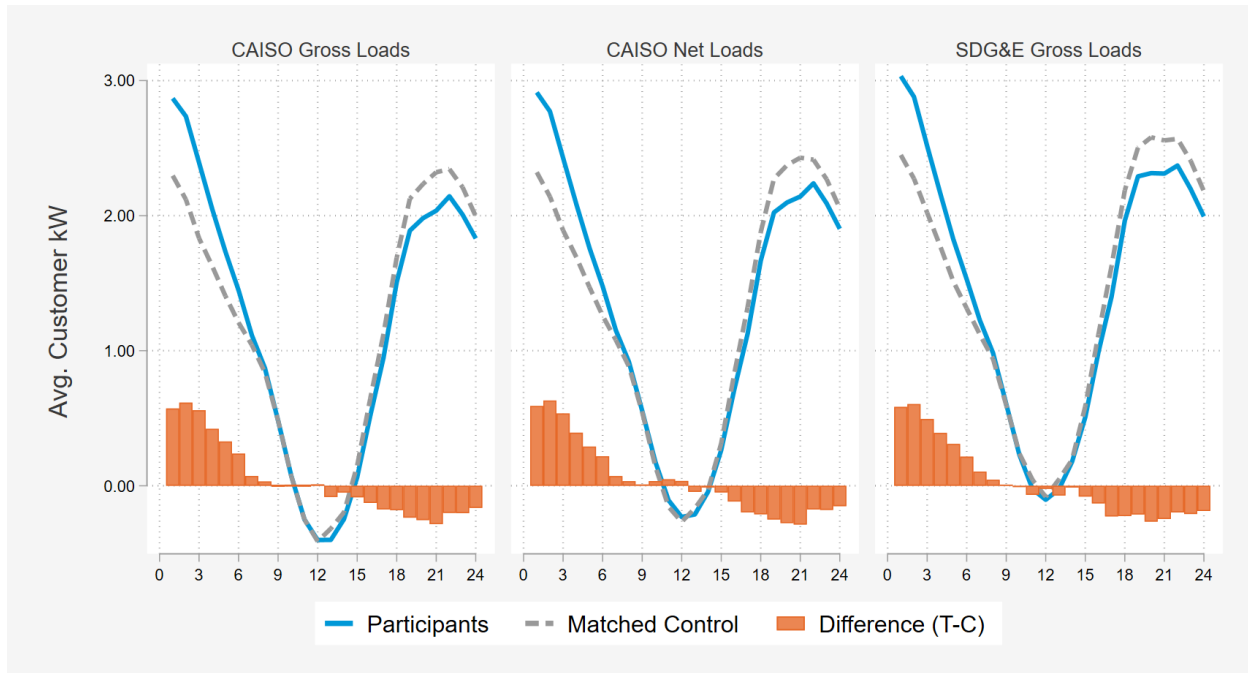


Table 5: Ex-post Demand Reductions on Highest System Load Days (4-9 PM)

System	Month	Sample ^[1]	New Accounts	Total Accounts	Daily avg. temp ^[2]	Avg. Customer (kW)			New Load Impact (MW)	Aggregate Total Load Impact (MW)
						Reference Load	Load Impact	% Change		
CAISO Gross Loads	Top 05 load day(s)	2,965	22,378	80,440	80.2	2.3	-0.26	-11.4%	-5.73	-20.59
	Top 10 load day(s)	2,965	22,378	80,440	77.6	1.9	-0.23	-11.9%	-5.05	-18.17
	Top 20 load day(s)	2,965	22,378	80,440	76.9	1.8	-0.22	-12.2%	-4.88	-17.53
CAISO Net Loads	Top 05 load day(s)	2,965	22,378	80,440	81.5	2.4	-0.23	-9.5%	-5.21	-18.71
	Top 10 load day(s)	2,965	22,378	80,440	78.5	2.1	-0.24	-11.9%	-5.47	-19.66
	Top 20 load day(s)	2,965	22,378	80,440	76.5	1.8	-0.21	-11.7%	-4.73	-17.01
SDG&E Gross Loads	Top 05 load day(s)	2,965	22,378	80,440	83.8	2.6	-0.24	-9.0%	-5.33	-19.17
	Top 10 load day(s)	2,965	22,378	80,440	80.7	2.3	-0.24	-10.3%	-5.26	-18.91
	Top 20 load day(s)	2,965	22,378	80,440	78.6	2.0	-0.24	-12.0%	-5.38	-19.35

[1] Estimating sample is lower than populations because it excludes sites that whose transition to EV TOU_{WH} coincided with the arrival of the electric vehicle or with solar or battery installation.

[2] Participant weighted average temperature. SDG&E maps all customers to eight distinct weather stations.

4.3 LOAD IMPACTS FOR MONTHLY WORST DAY

Figure 14 visualizes the hourly load impacts for the monthly worst day of each month. It shows the actual load for sites on EV-TOU_{WH} and the reference load or counterfactual. The orange bars reflect the change in demand, or load impacts. A positive value indicates an increase in energy use and a negative value indicates a decrease in demand. In general use increased during the 12-6 AM period when prices were lowest and decreased during the peak window of 4-9 PM.

Figure 14: Ex-post Monthly Worst Day (SDG&E) Hourly Load Impacts

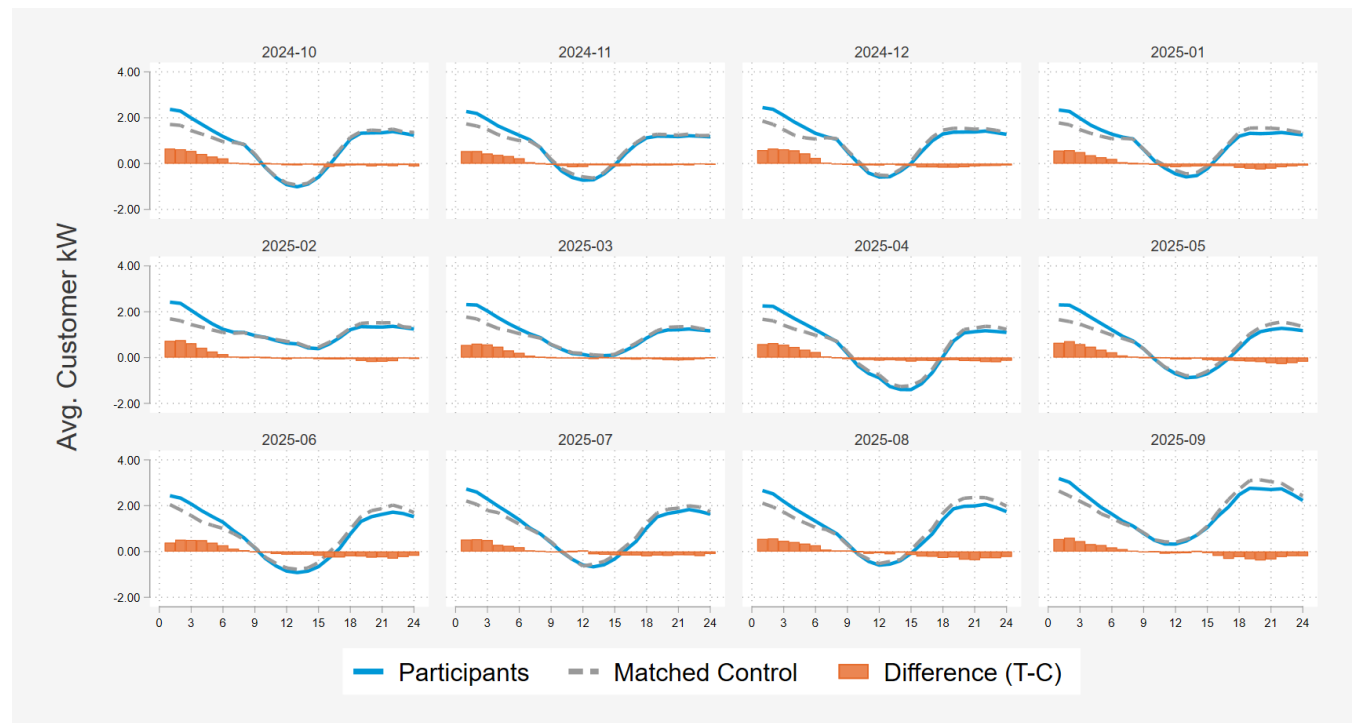


Table 6 summarizes the hourly demand reductions for the worst days in each month. In general, estimating TOU impacts for a single hour is more difficult and noisier than estimating impacts for the average day of each month. Thus, we used the top 3 SDG&E load day for each month and also recommend a degree of caution in reviewing the monthly worst day impacts.

Table 6: Ex-post Monthly Worst Day (SDG&E) Hourly Demand Reductions per Site

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sep	Oct	Nov	Dec
1	-0.56	-0.73	-0.54	-0.58	-0.64	-0.39	-0.52	-0.55	-0.55	-0.66	-0.54	-0.59
2	-0.58	-0.76	-0.60	-0.63	-0.71	-0.52	-0.54	-0.58	-0.60	-0.62	-0.55	-0.66
3	-0.50	-0.62	-0.57	-0.56	-0.58	-0.51	-0.50	-0.47	-0.45	-0.55	-0.44	-0.62
4	-0.36	-0.43	-0.47	-0.46	-0.47	-0.49	-0.29	-0.41	-0.32	-0.42	-0.38	-0.58
5	-0.27	-0.26	-0.31	-0.34	-0.34	-0.38	-0.24	-0.34	-0.28	-0.31	-0.33	-0.44
6	-0.20	-0.15	-0.20	-0.24	-0.23	-0.27	-0.19	-0.27	-0.18	-0.23	-0.23	-0.25
7	-0.06	-0.04	-0.08	-0.05	-0.09	-0.13	-0.05	-0.08	-0.10	-0.04	-0.06	-0.04
8	0.00	-0.01	-0.02	0.02	-0.03	-0.06	-0.02	-0.04	-0.03	0.02	0.01	0.04
9	0.02	-0.03	0.01	0.07	0.01	0.03	0.04	-0.04	0.03	0.06	0.05	0.06
10	0.05	0.00	0.04	0.10	0.01	0.05	0.03	0.01	0.02	0.01	0.10	0.09
11	0.11	0.04	0.04	0.11	0.02	0.11	0.00	0.10	0.09	0.03	0.16	0.07
12	0.16	0.07	0.05	0.13	0.08	0.13	-0.05	0.07	0.08	0.07	0.14	0.08
13	0.13	0.04	0.06	0.11	0.08	0.14	0.12	0.12	0.08	0.07	0.07	0.05
14	0.13	0.04	0.01	0.13	0.05	0.14	0.15	0.05	-0.01	0.04	0.07	0.08
15	0.11	0.06	0.04	0.17	0.10	0.18	0.16	0.15	0.06	0.07	0.12	0.10
16	0.10	0.08	0.07	0.14	0.13	0.26	0.17	0.22	0.19	0.15	0.11	0.17
17	0.11	0.08	0.09	0.15	0.13	0.26	0.17	0.23	0.32	0.11	0.08	0.16
18	0.18	0.06	0.06	0.12	0.16	0.20	0.21	0.28	0.24	0.08	0.09	0.17
19	0.23	0.14	0.08	0.12	0.17	0.22	0.17	0.25	0.33	0.07	0.08	0.17
20	0.25	0.19	0.11	0.15	0.20	0.26	0.19	0.35	0.39	0.12	0.08	0.16
21	0.22	0.19	0.12	0.16	0.25	0.25	0.16	0.37	0.35	0.09	0.06	0.12
22	0.16	0.16	0.11	0.19	0.28	0.31	0.16	0.29	0.24	0.11	0.07	0.11
23	0.12	0.03	0.07	0.20	0.24	0.24	0.19	0.29	0.20	0.06	0.03	0.10
24	0.09	0.06	0.02	0.14	0.18	0.18	0.11	0.23	0.20	0.13	0.06	0.08

Demand Reductions are positive (Blue)

Load increases are negative (Orange)

Table 7 shows the reference loads and load impacts by rate period for the monthly worst day of each month. The demand reductions are generally larger for hotter months. Customers reduced demand by 0.33 kW per site (11.4%) in September 2025, when SDG&E experienced its highest peak demand.

Table 7: Ex-post Monthly Worst Day (SDG&E) Demand Reductions by Rate Period

Rate Period	Month	New Accts	Daily avg. temp ^[1]	Avg. Customers (kW)		Aggregate Incremental (MW)		% Change
				Reference Load	Load Impact	Reference Load	Load Impact	
Peak (4-9 PM)	2024-Oct	62,362	68.9	1.21	0.09	75.53	5.87	-7.8%
	2024-Nov	63,765	59.0	1.18	0.08	75.43	4.86	-6.4%
	2024-Dec	65,315	56.0	1.44	0.16	94.21	10.30	-10.9%
	2025-Jan	67,337	55.0	1.38	0.20	93.15	13.27	-14.2%
	2025-Feb	69,396	54.6	1.36	0.13	94.06	9.26	-9.8%
	2025-Mar	71,258	55.3	1.08	0.09	76.75	6.63	-8.6%
	2025-Apr	73,145	60.9	0.60	0.14	43.99	10.22	-23.2%
	2025-May	74,790	64.3	0.90	0.18	67.00	13.44	-20.1%
	2025-Jun	76,336	74.1	1.31	0.24	100.06	18.17	-18.2%
	2025-Jul	77,767	74.5	1.46	0.18	113.27	14.05	-12.4%
	2025-Aug	79,123	78.0	1.90	0.30	150.08	23.52	-15.7%
	2025-Sep	80,440	84.4	2.86	0.33	229.68	26.26	-11.4%
Off-peak (6AM-4PM and 10PM-12AM)	2024-Oct	62,362	71.0	0.20	0.06	12.61	3.71	-29.4%
	2024-Nov	63,765	63.3	0.30	0.07	19.37	4.60	-23.8%
	2024-Dec	65,315	58.5	0.50	0.07	32.37	4.90	-15.1%
	2025-Jan	67,337	58.4	0.49	0.09	32.77	5.79	-17.7%
	2025-Feb	69,396	55.0	0.91	0.04	63.30	2.75	-4.3%
	2025-Mar	71,258	55.9	0.59	0.03	42.32	2.18	-5.1%
	2025-Apr	73,145	61.2	-0.03	0.11	-2.42	8.17	337.1%
	2025-May	74,790	64.7	0.21	0.08	15.90	6.13	-38.6%
	2025-Jun	76,336	76.1	0.28	0.12	21.42	9.34	-43.6%
	2025-Jul	77,767	75.8	0.46	0.08	35.59	6.01	-16.9%
	2025-Aug	79,123	78.9	0.57	0.10	45.15	8.23	-18.2%
	2025-Sep	80,440	85.5	1.28	0.08	103.10	6.43	-6.2%
Super off-peak (12-6AM)	2024-Oct	62,362	59.5	1.37	-0.46	85.28	-28.98	34.0%
	2024-Nov	63,765	49.7	1.38	-0.41	87.69	-26.17	29.8%
	2024-Dec	65,315	45.8	1.42	-0.52	92.44	-34.12	36.9%
	2025-Jan	67,337	47.2	1.43	-0.41	95.98	-27.85	29.0%
	2025-Feb	69,396	53.6	1.39	-0.49	96.78	-34.09	35.2%
	2025-Mar	71,258	53.0	1.40	-0.45	99.86	-32.08	32.1%
	2025-Apr	73,145	52.1	1.34	-0.47	97.91	-34.29	35.0%
	2025-May	74,790	58.5	1.35	-0.50	101.10	-37.16	36.8%
	2025-Jun	76,336	65.8	1.48	-0.43	113.02	-32.51	28.8%
	2025-Jul	77,767	68.2	1.73	-0.38	134.81	-29.50	21.9%
	2025-Aug	79,123	68.1	1.59	-0.44	125.81	-34.55	27.5%
	2025-Sep	80,440	72.8	2.06	-0.40	165.34	-31.82	19.2%

[1] Participant weighted average temperature. SDG&E maps all customers to eight distinct weather stations.

[2] To reduce noise, the top 3 system load days were included in the analysis for each month

4.4 LOAD IMPACTS FOR MONTHLY AVERAGE DAY

Figure 15 visualizes the hourly load impacts for the monthly average day of each month. It shows the actual load for sites on electric vehicle rates and the reference load or counterfactual. The orange bars reflect the change in demand, or load impacts. A positive value indicates an increase in energy use and a negative value indicates a decrease in demand. In general use increased during the 12-6 AM period when prices were lowest and decreased during the peak window of 4-9 PM.

Table 8 summarizes the hourly demand reductions for the average days of each month.

Table 9 shows the reference loads and load impacts by rate period for the monthly average day of each month. The demand reductions are generally larger for hotter months. Customers reduced demand by 0.19 kW per site (13.1%) in September 2025, when SDG&E experienced its highest peak demand.

Figure 15: Ex-post Monthly Average Day Hourly Load Impacts

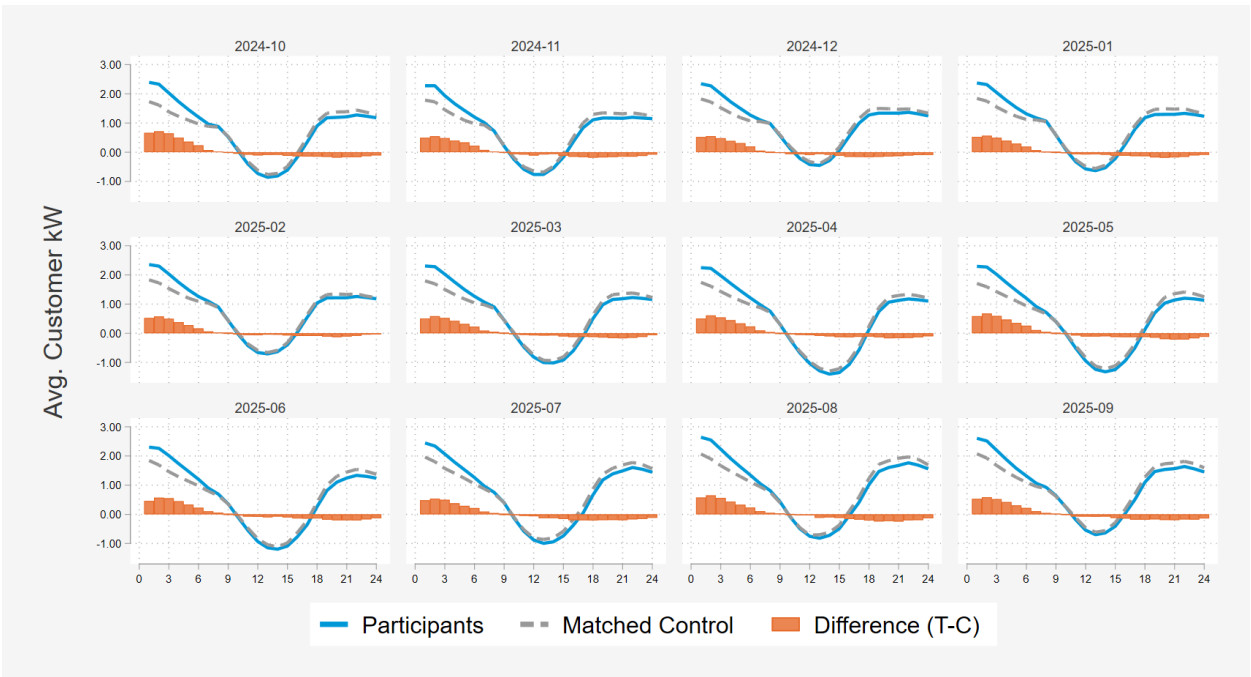


Table 8: Ex-post Monthly Average Day Hourly Demand Reductions per Site

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sep	Oct	Nov	Dec
1	-0.53	-0.52	-0.51	-0.51	-0.59	-0.46	-0.48	-0.58	-0.53	-0.66	-0.50	-0.52
2	-0.57	-0.58	-0.59	-0.61	-0.68	-0.57	-0.54	-0.65	-0.59	-0.72	-0.55	-0.55
3	-0.50	-0.50	-0.52	-0.54	-0.59	-0.55	-0.50	-0.56	-0.52	-0.65	-0.49	-0.48
4	-0.40	-0.38	-0.43	-0.45	-0.47	-0.45	-0.38	-0.44	-0.42	-0.50	-0.40	-0.39
5	-0.30	-0.28	-0.32	-0.34	-0.36	-0.33	-0.29	-0.33	-0.31	-0.36	-0.34	-0.31
6	-0.19	-0.17	-0.23	-0.23	-0.26	-0.22	-0.22	-0.23	-0.22	-0.24	-0.23	-0.20
7	-0.07	-0.06	-0.09	-0.10	-0.11	-0.11	-0.09	-0.11	-0.11	-0.08	-0.08	-0.05
8	-0.02	-0.03	-0.05	-0.04	-0.05	-0.06	-0.05	-0.05	-0.05	-0.02	-0.03	0.00
9	0.00	-0.01	-0.01	0.00	0.00	0.00	0.00	-0.03	-0.02	0.02	0.01	0.03
10	0.04	0.04	0.04	0.04	0.03	0.04	0.03	0.01	0.01	0.05	0.06	0.07
11	0.07	0.06	0.05	0.05	0.08	0.08	0.05	0.04	0.07	0.08	0.08	0.07
12	0.08	0.07	0.07	0.07	0.11	0.09	0.07	0.04	0.08	0.11	0.11	0.10
13	0.07	0.05	0.08	0.09	0.11	0.10	0.13	0.12	0.08	0.09	0.08	0.06
14	0.09	0.05	0.08	0.10	0.10	0.08	0.13	0.11	0.08	0.09	0.06	0.09
15	0.12	0.07	0.11	0.13	0.13	0.11	0.16	0.12	0.12	0.12	0.12	0.12
16	0.12	0.09	0.13	0.14	0.13	0.14	0.20	0.16	0.14	0.14	0.16	0.16
17	0.13	0.09	0.12	0.12	0.13	0.15	0.20	0.18	0.18	0.15	0.17	0.16
18	0.14	0.09	0.13	0.12	0.13	0.14	0.21	0.22	0.18	0.15	0.19	0.17
19	0.18	0.11	0.15	0.14	0.15	0.18	0.20	0.25	0.17	0.16	0.18	0.16
20	0.19	0.13	0.17	0.17	0.20	0.20	0.19	0.23	0.19	0.18	0.16	0.15
21	0.18	0.11	0.17	0.17	0.22	0.20	0.20	0.25	0.20	0.17	0.15	0.13
22	0.16	0.09	0.15	0.16	0.21	0.21	0.17	0.20	0.18	0.17	0.15	0.12
23	0.11	0.05	0.12	0.14	0.17	0.17	0.16	0.20	0.18	0.13	0.13	0.10
24	0.09	0.04	0.07	0.10	0.12	0.14	0.12	0.14	0.14	0.11	0.08	0.09

Demand Reductions are positive (Blue)

Load increases are negative (Orange)

Table 9: Ex-post Monthly Average Day Demand Reductions by Rate Period

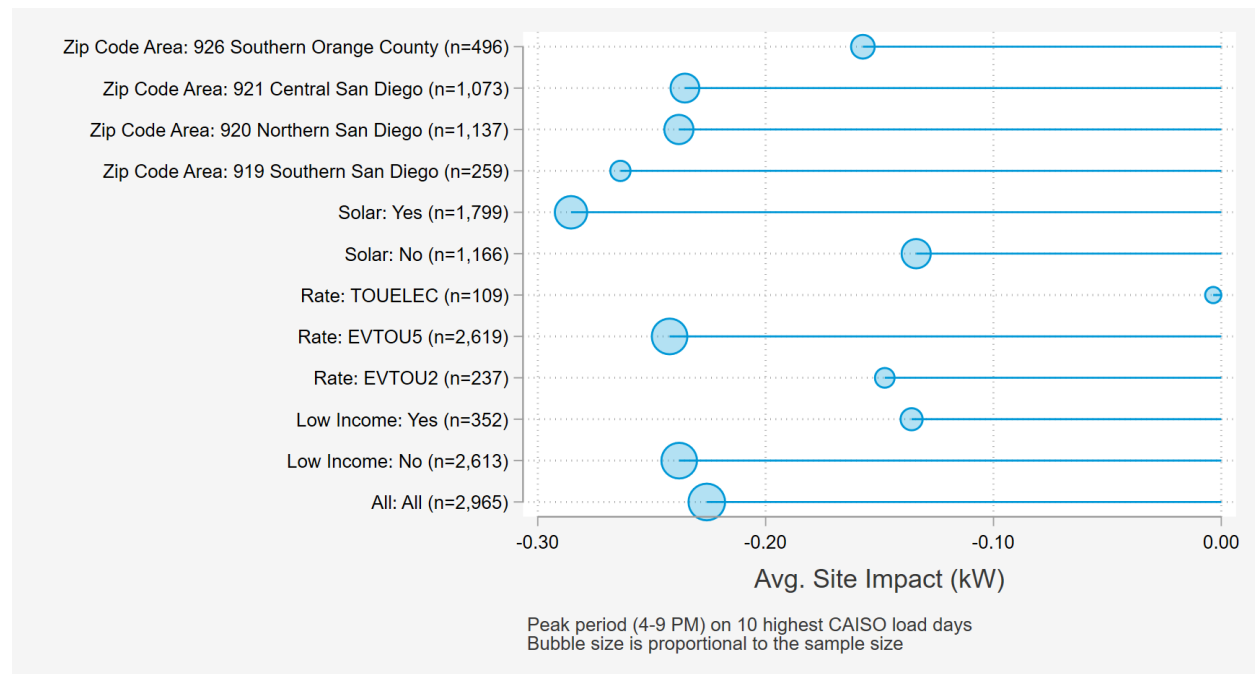
Rate Period	Month	New Accts	Daily avg. temp ^[1]	Avg. Customers (kW)		Aggregate Incremental (MW)		% Change
				Reference Load	Load Impact	Reference Load	Load Impact	
Peak (4-9 PM)	2024-Oct	23,346	66.2	1.13	0.16	26.43	3.82	-14.4%
	2024-Nov	23,192	58.2	1.26	0.17	29.29	3.95	-13.5%
	2024-Dec	23,097	55.2	1.42	0.16	32.69	3.59	-11.0%
	2025-Jan	23,022	54.0	1.34	0.16	30.81	3.76	-12.2%
	2025-Feb	22,994	56.1	1.16	0.11	26.59	2.50	-9.4%
	2025-Mar	22,923	57.0	0.89	0.15	20.45	3.36	-16.4%
	2025-Apr	22,868	59.8	0.64	0.14	14.73	3.29	-22.3%
	2025-May	22,792	62.2	0.67	0.16	15.22	3.76	-24.7%
	2025-Jun	22,707	67.2	0.79	0.18	17.99	4.00	-22.2%
	2025-Jul	22,604	71.5	1.16	0.20	26.17	4.55	-17.4%
	2025-Aug	22,495	73.7	1.46	0.22	32.89	5.05	-15.4%
	2025-Sep	22,378	70.9	1.42	0.19	31.86	4.16	-13.1%
Off-peak (6AM-4PM and 10PM-12AM)	2024-Oct	23,346	67.6	0.27	0.08	6.39	1.84	-28.7%
	2024-Nov	23,192	62.5	0.29	0.07	6.64	1.68	-25.4%
	2024-Dec	23,097	58.6	0.53	0.07	12.29	1.69	-13.8%
	2025-Jan	23,022	57.4	0.43	0.07	9.98	1.53	-15.3%
	2025-Feb	22,994	58.6	0.29	0.04	6.76	0.90	-13.3%
	2025-Mar	22,923	57.9	0.15	0.06	3.40	1.32	-38.9%
	2025-Apr	22,868	60.4	-0.05	0.07	-1.14	1.56	136.4%
	2025-May	22,792	63.3	0.03	0.08	0.66	1.83	-275.4%
	2025-Jun	22,707	68.0	0.08	0.08	1.84	1.73	-94.1%
	2025-Jul	22,604	72.4	0.24	0.08	5.53	1.91	-34.4%
	2025-Aug	22,495	74.6	0.37	0.07	8.41	1.62	-19.3%
	2025-Sep	22,378	72.2	0.46	0.07	10.35	1.58	-15.2%
Super off-peak (12-6AM)	2024-Oct	23,346	58.7	1.34	-0.52	31.23	-12.17	39.0%
	2024-Nov	23,192	49.8	1.38	-0.42	32.10	-9.65	30.1%
	2024-Dec	23,097	48.6	1.45	-0.41	33.38	-9.45	28.3%
	2025-Jan	23,022	46.7	1.48	-0.41	34.06	-9.51	27.9%
	2025-Feb	22,994	50.5	1.46	-0.41	33.53	-9.32	27.8%
	2025-Mar	22,923	51.1	1.42	-0.43	32.63	-9.92	30.4%
	2025-Apr	22,868	52.8	1.36	-0.45	31.05	-10.21	32.9%
	2025-May	22,792	57.8	1.34	-0.49	30.51	-11.17	36.6%
	2025-Jun	22,707	61.7	1.40	-0.43	31.78	-9.80	30.8%
	2025-Jul	22,604	65.1	1.50	-0.40	33.99	-9.08	26.7%
	2025-Aug	22,495	66.6	1.59	-0.46	35.68	-10.46	29.3%
	2025-Sep	22,378	65.0	1.58	-0.43	35.39	-9.64	27.2%

[1] Participant weighted average temperature. SDG&E maps all customers to eight weather stations.

4.5 LOAD IMPACTS BY CUSTOMER TYPE

Figure 16 shows the impacts of key customer segments for the peak period (4-9PM) on the ten highest CAISO system load days. The results across categories should be interpreted as descriptive, not causal, in the sense that if a non-solar customer were to acquire solar it would not be the case that on average their load reduction would double; rather, solar ownership is correlated with other factors that lead to higher load reductions. We caution that results are noisier when the estimating sample size is smaller such as for the EV-TOU-2 rate or TOU-ELEC.

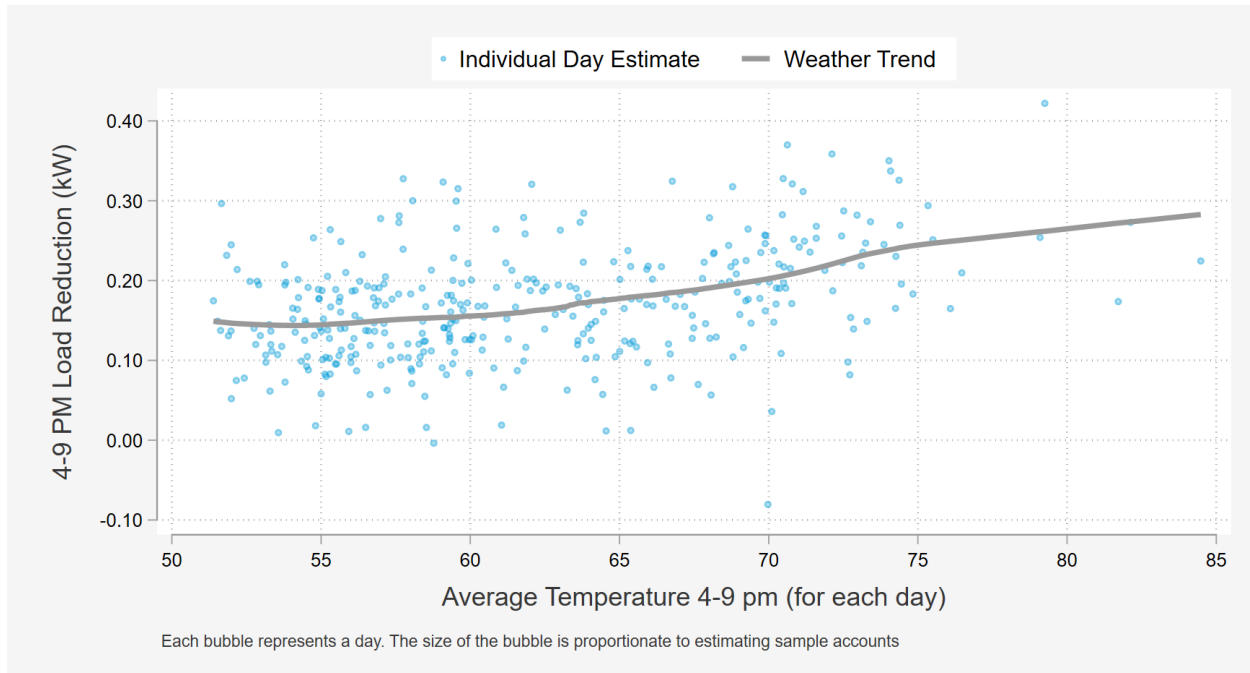
Figure 16: Load Impacts per Site for Key Customer Segments



4.6 WEATHER SENSITIVITY OF LOAD IMPACTS

A key question for residential rates is whether the peak period load impacts are weather sensitive. While the electric vehicle rates are designed to encourage charging during super off-peak hours, the rates apply to the energy used by the whole home. Thus, customers have an incentive not only to modulate their electric vehicle charge but to modify demand for other peak period end uses. As part of the evaluation, we estimated the demand reductions for each day and hour of the year using the differences-in-differences technique. Figure 17 shows the relationship between the daily peak period (4-9) load impacts and weather for days after the transition to whole home TOU rates for electric vehicles. In general, the demand reductions grow larger when temperatures are hotter, and more so at higher temperatures. Customers have an incentive to shift non-EV loads because the rates apply to the whole home, not just the electric vehicle.

Figure 17: Peak Period (4-9 PM) Demand Reduction Weather Sensitivity



4.7 KEY FINDINGS

- This year's EV market share growth has stagnated compared to previous years.
- Most new enrollment is occurring on the EV-TOU-5 rate.
- The number of sites shifting from the EV-TOU-2 to the EV-TOU-5 rate is now negligible.
- There are too few sites on the TOU-ELEC rate to draw reliable conclusions about its impact. Consequently, TOU-ELEC customers were excluded from the ex-ante analysis.
- Customers who enroll on the whole home electric vehicle TOU rate decrease demand when prices are higher usage when the prices are lowest. Moreover, the change in load patterns coincides with the enrollment on whole home TOU rates for electric vehicles.
- Customers deliver slightly larger peak demand reductions on the hotter days.
- In 2025, on top 10 highest CAISO gross, CAISO net, and SDG&E system load days over the study period, customers reduced demand by 0.23 kW, 0.24 kW, and 0.24 kW per home, on average, over the 4-9 PM peak period. This amounted to reduction in demand between 10%-12% of the household load and led to over 18 MW in total demand reductions during those days.

5 ELECTRIC VEHICLE TOU EX-ANTE RESULTS

Ex-ante impacts describe the magnitude of program resources available under planning conditions defined by weather. The ex-ante estimates are developed for both SDG&E and California ISO peak conditions under normal (1-in-2) and extreme (1-in-10) peak planning conditions. We estimated ex-ante impacts based on the relationship between demand reductions and weather using the ex-post performance over the analysis period (October 2024 to September 2025) and factored in projected changes in enrollment.

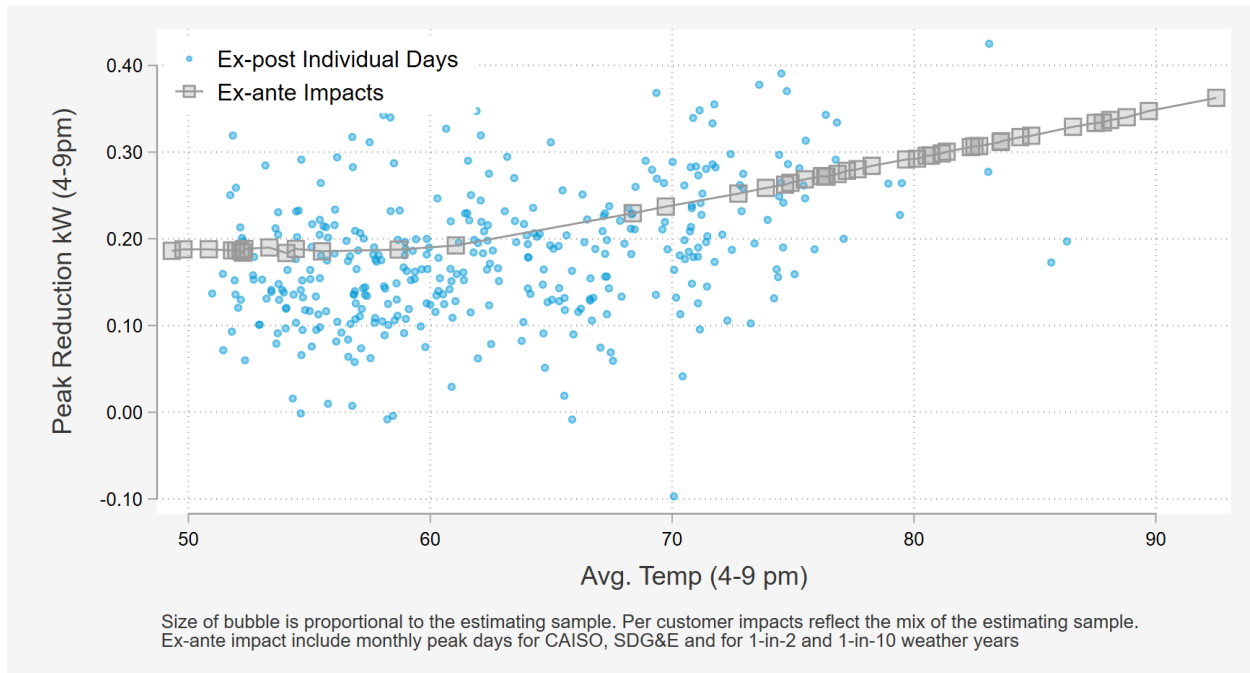
In this analysis, we use the enrollment forecast based on California Energy Commission projections of EV registrations. However, this forecast was projected in January 2025. This forecast was produced before some policy changes and market conditions for the EV market had taken full effect. Because of this, we re-forecasted electric vehicle adoption and enrollment on the electric vehicle TOU rates in a scenario without electric vehicle subsidies or other incentive policies. The methodology for this projection is in Appendix A and the Ex-Ante results for this forecast are in Appendix B.

5.1 DEVELOPMENT OF EX-ANTE IMPACTS

The ex-ante impacts were developed by estimating the relationship between weather and demand reductions for customers for who enrolled over the analysis period, had an electric vehicle for the year before they signed onto the rate, and did not install solar or battery storage (a major non-routine event) in the pre-treatment year or the analysis period.

In total, we estimated the relationship between hourly (8,760 hours per year) demand reductions and weather for 4 distinct segments – defined by the rate type (EV-TOU-2 or EV-TOU-5) and the presence of rooftop solar. The segmentation allows SDG&E to account for changes in the customer mix, namely that most new participants enroll in EV-TOU-5, and share of sites with solar is growing. The hourly (8760) pattern of ex-post reductions was analyzed using a multi-variate regression model to estimate ex-ante impact under planning conditions. A separate model was estimated for each segment and hour of day. The model accounts for the effects day of week, and weather. Figure 18 overlays the per-customer ex-ante impacts for 4-9 PM on top of the ex-post impacts for each individual day over the analysis period.

Figure 18: Ex-ante and Ex-post Per Customer Peak Demand Reductions (4-9 PM)



5.2 OVERALL RESULTS

Figure 19 shows a heat map of the per-customer load reduction by month and hour of day for SDG&E 1-in-2 monthly peak day weather conditions. The results are scaled to reflect the current mix of customers on whole home electric vehicle TOU rates (versus the available estimating sample). Table 10 and Table 11 show the per-customer hourly impacts for each month under CAISO and SDG&E monthly peaking conditions, respectively. The tables are designed to enable the CPUC's Slice-of-Day Resource Adequacy requirements. The estimated reductions are greater on monthly worst days than on average weekdays and reductions are greater in hotter months than in cooler ones. The load reductions also coincide with the hours (4-9 PM) and months (August and September) when reductions are needed most.

Figure 19: Heat map of Per Customer Ex-Ante Demand Reductions by Hour and Month

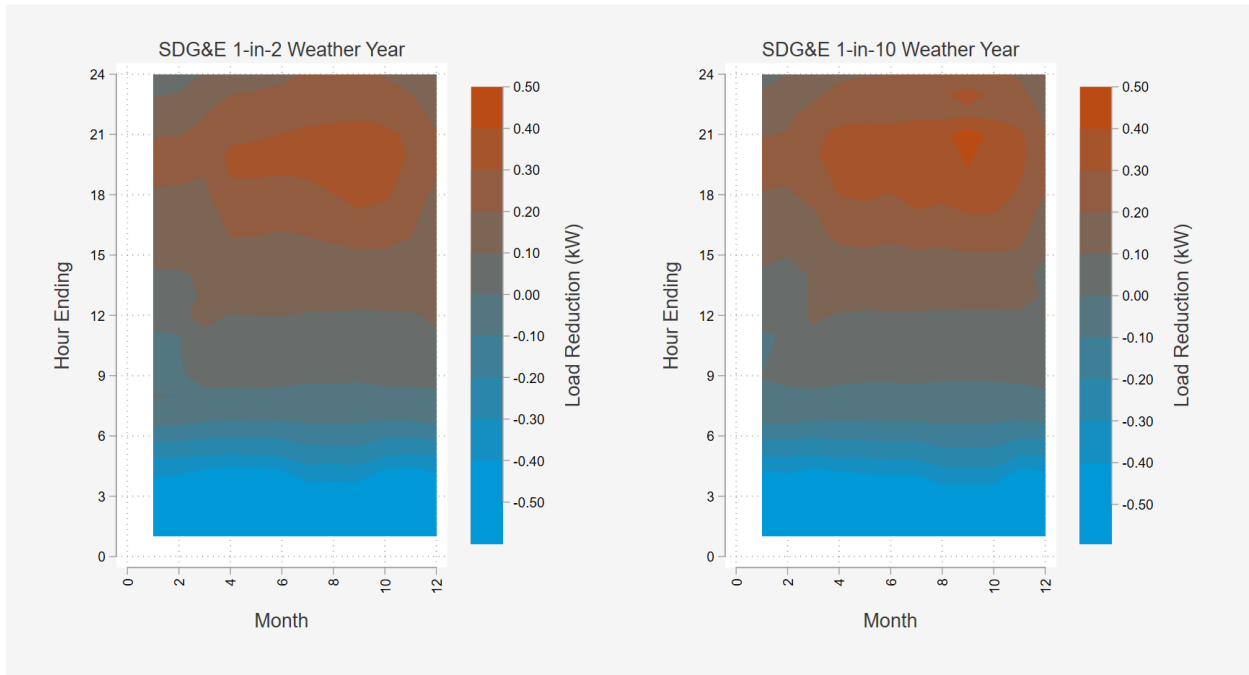


Table 10: Slice of Day Table for CAISO 1-in-2 Weather Year Monthly Worst Day (Per Customer Demand Reductions)

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sep	Oct	Nov	Dec
1	-0.51	-0.51	-0.52	-0.52	-0.52	-0.53	-0.53	-0.53	-0.53	-0.53	-0.52	-0.51
2	-0.56	-0.56	-0.58	-0.60	-0.59	-0.58	-0.57	-0.56	-0.56	-0.58	-0.60	-0.54
3	-0.50	-0.50	-0.54	-0.56	-0.56	-0.54	-0.50	-0.49	-0.49	-0.53	-0.56	-0.47
4	-0.42	-0.43	-0.45	-0.47	-0.46	-0.44	-0.39	-0.38	-0.37	-0.43	-0.47	-0.41
5	-0.30	-0.30	-0.30	-0.31	-0.31	-0.29	-0.27	-0.26	-0.25	-0.29	-0.31	-0.29
6	-0.18	-0.18	-0.18	-0.19	-0.19	-0.18	-0.16	-0.16	-0.16	-0.18	-0.19	-0.17
7	-0.05	-0.05	-0.06	-0.07	-0.07	-0.07	-0.07	-0.07	-0.07	-0.07	-0.07	-0.04
8	-0.01	-0.01	-0.01	-0.02	-0.02	-0.02	-0.03	-0.03	-0.03	-0.02	-0.02	0.00
9	0.00	0.00	0.02	0.03	0.03	0.03	0.02	0.02	0.02	0.03	0.03	-0.01
10	0.01	-0.01	0.03	0.06	0.07	0.06	0.05	0.05	0.05	0.05	0.05	-0.03
11	-0.02	-0.03	0.04	0.08	0.09	0.08	0.08	0.08	0.08	0.08	0.08	-0.07
12	0.03	0.03	0.09	0.10	0.11	0.10	0.10	0.09	0.09	0.08	0.09	0.02
13	-0.03	0.00	0.05	0.13	0.13	0.13	0.14	0.14	0.14	0.15	0.15	-0.04
14	0.00	0.04	0.08	0.13	0.12	0.13	0.13	0.14	0.14	0.14	0.14	0.01
15	0.10	0.11	0.13	0.17	0.16	0.17	0.17	0.18	0.18	0.18	0.18	0.10
16	0.10	0.11	0.13	0.20	0.17	0.20	0.20	0.21	0.22	0.22	0.21	0.10
17	0.15	0.14	0.14	0.22	0.19	0.22	0.23	0.25	0.26	0.27	0.24	0.15
18	0.20	0.19	0.18	0.25	0.22	0.26	0.27	0.29	0.29	0.31	0.26	0.20
19	0.22	0.22	0.21	0.28	0.25	0.29	0.30	0.32	0.33	0.34	0.28	0.23
20	0.23	0.23	0.24	0.31	0.28	0.31	0.33	0.34	0.34	0.35	0.30	0.23
21	0.20	0.20	0.20	0.27	0.25	0.29	0.32	0.34	0.34	0.35	0.28	0.19
22	0.17	0.15	0.18	0.23	0.23	0.24	0.25	0.26	0.26	0.26	0.23	0.15
23	0.12	0.10	0.13	0.20	0.20	0.22	0.25	0.26	0.27	0.26	0.20	0.10
24	0.09	0.07	0.10	0.15	0.16	0.18	0.21	0.21	0.22	0.20	0.16	0.07

Demand Reductions are positive (Blue)

Load increase are negative (Orange)

Table 11: Slice of Day Table for SDG&E 1-in-2 Weather Year Monthly Worst Day (Per Customer Demand Reductions)

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sep	Oct	Nov	Dec
1	-0.51	-0.51	-0.52	-0.52	-0.52	-0.52	-0.53	-0.53	-0.53	-0.52	-0.52	-0.51
2	-0.53	-0.55	-0.58	-0.60	-0.60	-0.59	-0.56	-0.56	-0.56	-0.59	-0.60	-0.56
3	-0.45	-0.48	-0.54	-0.57	-0.56	-0.55	-0.48	-0.49	-0.48	-0.55	-0.57	-0.50
4	-0.39	-0.41	-0.45	-0.47	-0.47	-0.45	-0.36	-0.37	-0.36	-0.45	-0.47	-0.42
5	-0.29	-0.29	-0.30	-0.31	-0.31	-0.30	-0.25	-0.25	-0.25	-0.30	-0.31	-0.30
6	-0.16	-0.17	-0.19	-0.19	-0.19	-0.19	-0.16	-0.16	-0.15	-0.19	-0.19	-0.17
7	-0.04	-0.04	-0.06	-0.07	-0.07	-0.07	-0.07	-0.07	-0.07	-0.07	-0.07	-0.05
8	0.00	0.00	-0.01	-0.02	-0.02	-0.02	-0.03	-0.03	-0.03	-0.02	-0.02	-0.01
9	-0.02	-0.01	0.02	0.03	0.03	0.03	0.02	0.02	0.01	0.03	0.03	0.01
10	-0.03	-0.01	0.06	0.06	0.06	0.06	0.05	0.05	0.04	0.05	0.05	0.06
11	-0.02	0.00	0.09	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.09
12	0.08	0.08	0.12	0.10	0.10	0.10	0.09	0.09	0.08	0.08	0.09	0.12
13	0.07	0.07	0.11	0.14	0.13	0.13	0.14	0.15	0.15	0.15	0.15	0.12
14	0.09	0.09	0.11	0.13	0.13	0.13	0.13	0.14	0.14	0.14	0.14	0.12
15	0.13	0.13	0.15	0.17	0.17	0.17	0.17	0.18	0.19	0.18	0.17	0.15
16	0.13	0.13	0.15	0.20	0.20	0.19	0.20	0.22	0.24	0.23	0.20	0.15
17	0.14	0.14	0.15	0.23	0.23	0.22	0.23	0.26	0.29	0.27	0.23	0.15
18	0.19	0.18	0.18	0.27	0.27	0.26	0.27	0.30	0.33	0.31	0.25	0.18
19	0.22	0.22	0.20	0.31	0.31	0.30	0.31	0.33	0.37	0.34	0.27	0.20
20	0.23	0.23	0.24	0.31	0.32	0.32	0.33	0.35	0.38	0.35	0.29	0.24
21	0.20	0.20	0.21	0.28	0.29	0.30	0.33	0.35	0.38	0.34	0.27	0.20
22	0.15	0.16	0.20	0.23	0.24	0.24	0.26	0.26	0.27	0.25	0.23	0.18
23	0.09	0.10	0.14	0.20	0.21	0.23	0.26	0.27	0.28	0.24	0.20	0.12
24	0.06	0.07	0.11	0.15	0.16	0.18	0.21	0.21	0.23	0.19	0.16	0.09

Demand Reductions are positive (Blue)

Load increase are negative (Orange)

Table 12 shows aggregate ex-ante demand reduction forecasts for an August monthly system worst day. Forecasts are shown under the four weather scenarios identified above. The increase in the demand reductions throughout the forecast years can be explained by the expected growth of electric vehicles and the corresponding growth in whole home electric vehicle TOU rate enrollments. Ex-ante weather conditions are static through the forecast window. There is a small amount of variation in participant-level impacts through the forecast window due to the expected enrollments by rate and solar status. Most future participants are projected to enroll on the EV-TOU-5 rate.

Table 12: Aggregate August Monthly System Worst Day (SDG&E) Demand Reduction Forecast (MW)

Forecast Year	Enrollment Forecast	SDG&E Weather		CAISO Weather	
		1-in-2	1-in-10	1-in-2	1-in-10
2025	105,985	33.8	36.3	32.6	35.0
2026	128,664	41.1	44.2	39.7	42.6
2027	156,905	50.3	53.9	48.5	52.0
2028	190,208	61.1	65.5	58.9	63.1
2029	228,548	73.5	78.7	70.9	75.9
2030	278,306	89.6	96.0	86.4	92.6
2031	331,656	106.8	114.4	103.1	110.4
2032	390,228	125.8	134.7	121.4	130.0
2033	452,325	145.9	156.2	140.8	150.7
2034	521,253	168.2	180.1	162.4	173.8
2035	587,487	189.7	203.0	183.1	195.9

Figure 20 and

Figure 21 show the estimated ex-ante load profiles for sites on whole home electric vehicle TOU rates. Both figures show profiles for the August worst day, and both figures use SDG&E weather conditions rather than CAISO conditions. Figure 20 shows profiles under 1-in-2 weather conditions, and

Figure 21 shows profiles for 1-in-10. Note that the forecast year shown is 2026.

Figure 20: Aggregate Ex-ante Impact for 1-in-2 Weather Conditions, August Worst Day 2026

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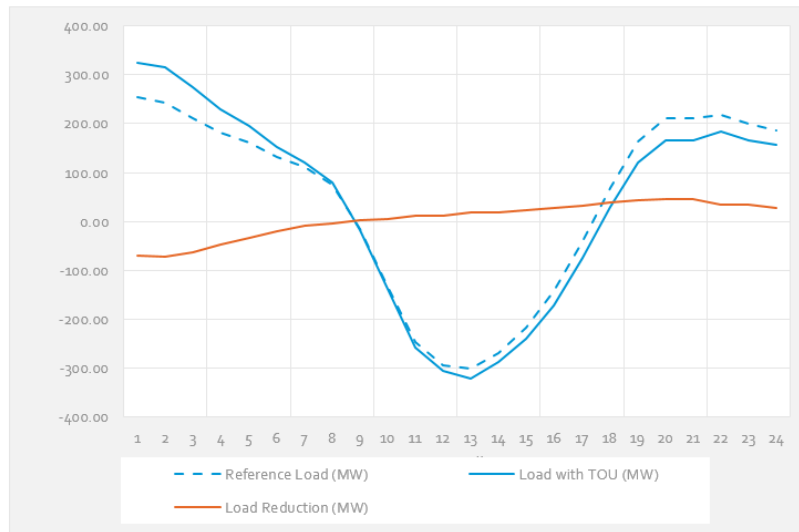


Table 1: Menu options

Type of Result	Aggregate Total
System (CAISO/SDG&E)	SDG&E
Weather Year	1-IN-2
Forecast Year	2026
Category	All
Subcategory	All
Day type	MONTHLY SYSTEM WORST DAY
Month	08 Aug
Hour Ending View	HE (Prevailing Time)

Table 2: Event day information

Total sites	128,664
Daily Max Temp	89.0
Peak Period (4pm-9pm) Impact (MW)	41.13
Peak Period (4pm-9pm) Impact (%)	33.4%



	Hour Ending	Reference Load (MW)	Load with TOU (MW)	Load Reduction (MW)	% Load Reduction	Avg Temp (°F, Site-Weighted)	Uncertainty Adjusted Impact - 5th 95th		Standard Error	T-Statistic
1	1	254.89	323.89	-69.00	-27.1%	72.35	-90.06	-47.94	12.80	-5.39
2	2	241.75	314.50	-72.75	-30.1%	71.45	-93.89	-51.61	12.85	-5.66
3	3	210.74	274.30	-63.56	-30.2%	71.02	-82.99	-44.13	11.81	-5.38
4	4	181.92	230.05	-48.13	-26.5%	70.80	-66.14	-30.12	10.95	-4.40
5	5	161.96	195.00	-33.04	-20.4%	70.66	-49.16	-16.92	9.80	-3.37
6	6	132.12	152.56	-20.44	-15.5%	70.32	-32.91	-7.96	7.58	-2.69
7	7	111.65	120.74	-9.09	-8.1%	70.30	-18.69	0.50	5.83	-1.56
8	8	74.94	78.98	-4.04	-5.4%	70.77	-13.19	5.12	5.56	-0.73
9	9	-14.96	-17.40	2.44	-16.3%	74.28	-7.20	12.08	5.86	0.42
10	10	-132.38	-138.46	6.08	-4.6%	79.00	-5.50	17.66	7.04	0.86
11	11	-246.50	-257.22	10.72	-4.3%	83.82	-2.26	23.70	7.89	1.36
12	12	-294.73	-306.26	11.53	-3.9%	86.84	-2.55	25.60	8.56	1.35
13	13	-301.60	-320.83	19.24	-6.4%	88.60	3.90	34.58	9.33	2.06
14	14	-268.34	-286.34	17.99	-6.7%	88.97	2.16	33.83	9.63	1.87
15	15	-216.43	-239.37	22.94	-10.6%	86.81	6.96	38.92	9.72	2.36
16	16	-142.89	-170.99	28.09	-19.7%	86.83	12.03	44.16	9.77	2.88
17	17	-40.24	-73.34	33.10	-82.3%	86.63	16.93	49.27	9.83	3.37
18	18	69.53	31.07	38.46	55.3%	85.44	22.69	54.24	9.59	4.01
19	19	162.84	119.76	43.08	26.5%	82.94	28.19	57.96	9.05	4.76
20	20	211.11	165.45	45.67	21.6%	80.41	30.58	60.75	9.17	4.98
21	21	212.14	166.78	45.36	21.4%	77.23	30.21	60.51	9.21	4.92
22	22	218.24	184.46	33.77	15.5%	75.33	18.17	49.38	9.49	3.56
23	23	200.57	165.63	34.94	17.4%	74.03	18.67	51.21	9.89	3.53
24	24	185.78	157.83	27.95	15.0%	73.17	11.72	44.19	9.87	2.83
Daily		Reference Load (MW)	Load with TOU (MW)	Load Reduction (MW)	% Change	Avg Temp (°F, Site-Weighted)	Uncertainty Adjusted Impact - Percentiles		Std Err	T-statistic
		MWh	MWh	MWh		F	5th	95th		
Overall		972.10	870.80	101.30	10.4%	78.3	85.84	116.77	9.40	10.78
Peak Hours		615.38	409.72	205.66	33.4%	82.5	190.24	221.09	9.38	21.94

Figure 21: Aggregate Ex-ante Impact for 1-in-10 Weather Conditions, August Worst Day 2026

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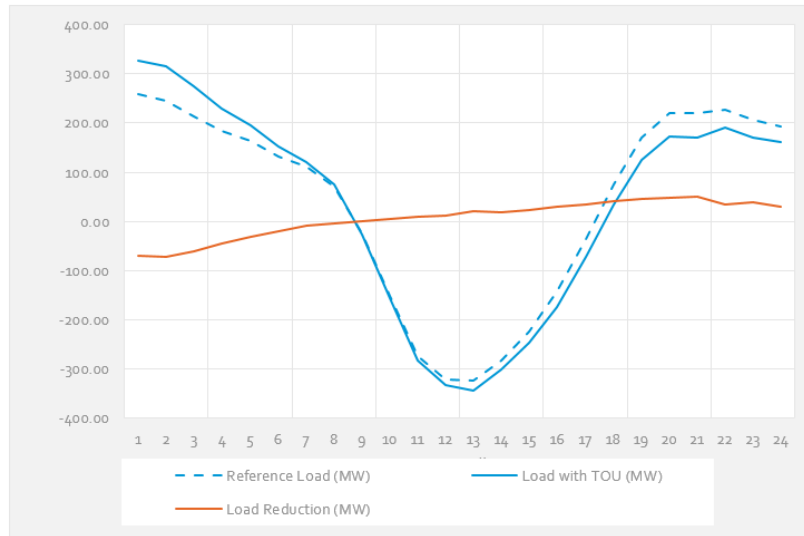


Table 1: Menu options

Type of Result	Aggregate Total
System (CAISO/SDG&E)	SDG&E
Weather Year	1-IN-10
Forecast Year	2026
Category	All
Subcategory	All
Day type	MONTHLY SYSTEM WORST DAY
Month	08 Aug
Hour Ending View	HE (Prevailing Time)

Table 2: Event day information

Total sites	128,664
Daily Max Temp	91.9
Peak Period (4pm-9pm) Impact (MW)	44.17
Peak Period (4pm-9pm) Impact (%)	34.0%



	Hour Ending	Reference Load (MW)	Load with TOU (MW)	Load Reduction (MW)	% Load Reduction	Avg Temp (°F, Site-Weighted)	Uncertainty		Standard Error	T-Statistic
							Adjusted Impact -			
							5th	95th		
1	1	258.14	327.63	-69.48	-26.9%	75.66	-90.54	-48.42	12.80	-5.43
2	2	244.89	316.09	-71.20	-29.1%	74.99	-92.34	-50.06	12.85	-5.54
3	3	212.76	273.39	-60.63	-28.5%	74.09	-80.06	-41.20	11.81	-5.13
4	4	183.14	228.10	-44.96	-24.6%	73.31	-62.98	-26.95	10.95	-4.11
5	5	163.47	194.97	-31.50	-19.3%	72.90	-47.62	-15.37	9.80	-3.21
6	6	132.43	151.76	-19.33	-14.6%	72.78	-31.80	-6.85	7.58	-2.55
7	7	110.76	119.78	-9.02	-8.1%	72.08	-18.62	0.57	5.83	-1.55
8	8	71.42	75.93	-4.52	-6.3%	74.37	-13.67	4.63	5.56	-0.81
9	9	-25.27	-26.89	1.62	-6.4%	78.64	-8.02	11.26	5.86	0.28
10	10	-151.56	-156.58	5.02	-3.3%	83.85	-6.56	16.59	7.04	0.71
11	11	-272.58	-283.20	10.62	-3.9%	88.74	-2.36	23.60	7.89	1.35
12	12	-320.64	-331.40	10.76	-3.4%	90.99	-3.31	24.84	8.56	1.26
13	13	-322.98	-342.87	19.88	-6.2%	91.87	4.54	35.22	9.33	2.13
14	14	-282.09	-300.47	18.38	-6.5%	91.67	2.54	34.21	9.63	1.91
15	15	-222.94	-246.68	23.74	-10.7%	91.04	7.76	39.72	9.72	2.44
16	16	-143.13	-172.81	29.68	-20.7%	91.00	13.61	45.75	9.77	3.04
17	17	-36.75	-72.35	35.60	-96.9%	90.71	19.43	51.77	9.83	3.62
18	18	74.93	33.94	40.98	54.7%	89.29	25.21	56.76	9.59	4.27
19	19	170.80	124.54	46.26	27.1%	87.06	31.37	61.14	9.05	5.11
20	20	220.52	171.96	48.55	22.0%	84.64	33.47	63.63	9.17	5.29
21	21	219.88	170.44	49.44	22.5%	81.25	34.28	64.59	9.21	5.37
22	22	226.64	191.60	35.04	15.5%	79.25	19.44	50.64	9.49	3.69
23	23	207.54	169.19	38.35	18.5%	78.09	22.08	54.62	9.89	3.88
24	24	192.17	161.34	30.83	16.0%	77.36	14.59	47.06	9.87	3.12
	Daily	Reference Load (MW)	Load with TOU (MW)	Load Reduction (MW)	% Change	Avg Temp (°F, Site-Weighted)	Uncertainty Adjusted Impact - Percentiles		Std Err	T-statistic
		MWh	MWh	MWh		F	5th	95th		
	Overall	911.54	777.44	134.10	14.7%	81.9	118.64	149.56	9.40	14.27
	Peak Hours	649.36	428.54	220.83	34.0%	86.6	205.41	236.25	9.38	23.55

5.3 COMPARISON TO PRIOR YEARS

Table 13 shows a comparison of vintage year PY2024 and PY2025 ex-ante impacts for the two different weather scenarios at the participant level. All impacts represent monthly worst day impact estimates, and SDG&E weather conditions are used.

Compared with PY2024, the latest PY2025 EV-TOU-5 and EV-TOU-2 load impacts are higher for the core summer months under both 1-in-2 and 1-in-10 conditions. In the PY2025 evaluation, impacts were higher than in PY24

Table 13: Comparison of Per Participant Ex-Ante Demand Reductions under SDG&E Weather Scenarios (kW)

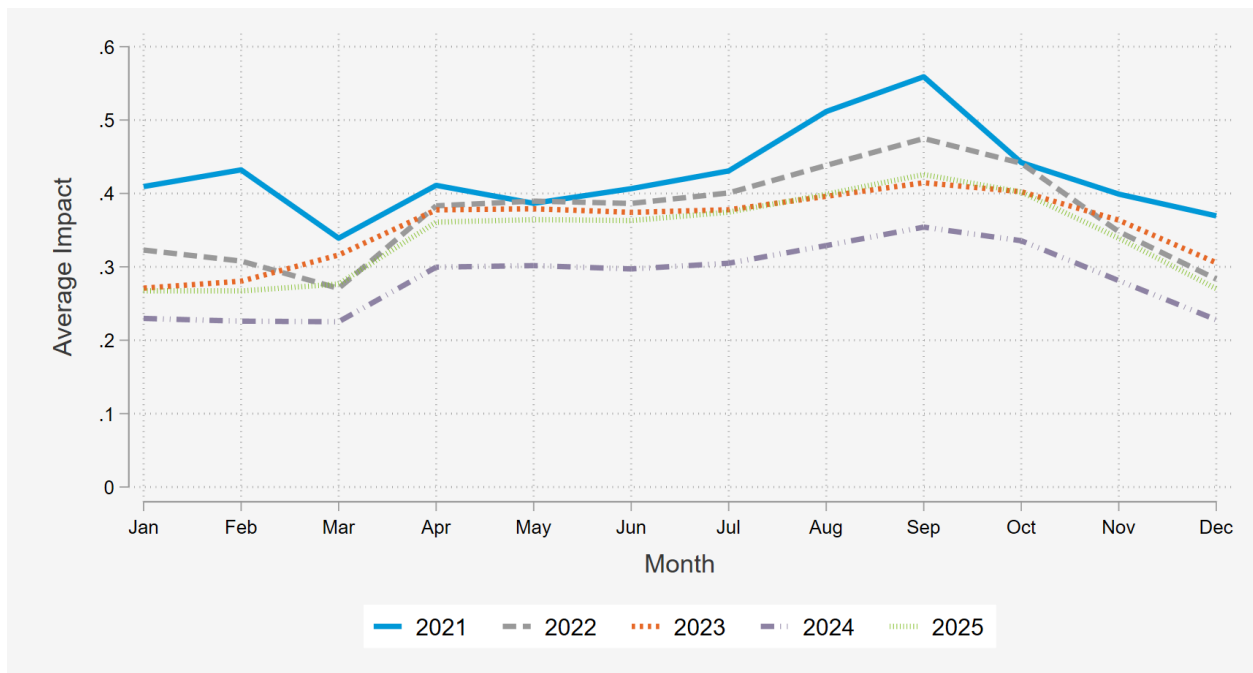
	PY24 Evaluation*				PY25 Evaluation			
	EVTOU ₅		EVTOU ₂		EVTOU ₅		EVTOU ₂	
	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10
May	0.23	0.26	0.18	0.27	0.29	0.34	0.21	0.28
June	0.22	0.25	0.17	0.24	0.29	0.32	0.21	0.26
July	0.23	0.27	0.19	0.31	0.30	0.35	0.23	0.31
August	0.25	0.27	0.25	0.29	0.32	0.35	0.26	0.30
September	0.27	0.29	0.30	0.36	0.35	0.38	0.31	0.36
October	0.26	0.28	0.26	0.31	0.33	0.36	0.27	0.32

*Per Customer impacts for 2025

We also compared the ex-ante results across the five years of available data (2021–2025). Figure 22 presents the average load impact during peak hours (4pm – 9pm) for each month, focusing specifically on EVTOU₅ customers with solar under 1-in-2 weather conditions, reflecting the profile expected for most future participants.

Overall, the 2025 results align closely with historical performance. The notable exception is 2021, which shows substantially higher impacts. This is likely due to the fact that customers had not yet broadly adapted their behavior to time-of-use rates, which are now the default rate statewide, so the shift in usage was more dramatic. Additionally, pandemic-related disruptions in 2021 may have influenced electricity usage patterns. Some of the higher impacts in 2021 could be attributed to an “early adopter” effect, where the most responsive customers enroll early. Even if that is the case, the magnitude and consistency of results in subsequent years suggest that the program is capable of delivering sustained impacts over time.

Figure 22: Average Load Impact during Peak Hours by Month, 2021-2025



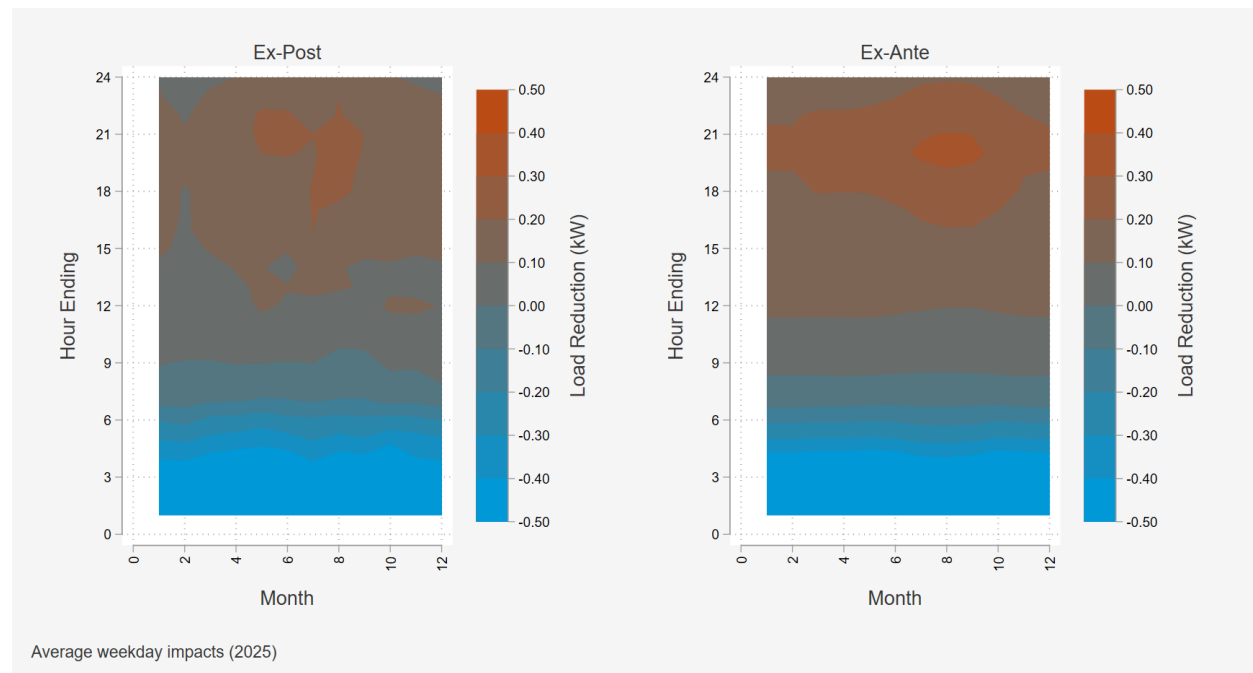
5.4 EX-POST TO EX-ANTE COMPARISON

When comparing ex-post and ex-ante, it is important to keep the distinction between the two estimates in mind. Ex-ante impacts are estimates of the future resources available under standardized planning conditions (defined by weather). Ex-post impacts are estimates of what past impacts were given the weather, conditions, and magnitude of resources available. The ex-ante impacts are based on the ex-post impact and weather trends, as shown earlier in Figure 18.

Figure 23 compares the per site ex-post load impacts to the ex-ante load impacts for the average weekday by month and hour. The ex-post load impacts are very similar in magnitude to the ex-ante impact estimates shown in the table. Both have the highest reductions in the summer, though for ex-post this peak occurs slightly earlier. Ex-ante has higher sustained reductions through all months in peak hours. The differences are due to weather and composition of the samples. The ex-ante standardized weather indicates hotter weather conditions typically occur in August in September, and this is reflected in higher impacts in those months.

The percentage of customers on EV-TOU-2 is 8% in both the ex post analysis sample and the ex ante enrollment forecast. The proportion of solar customers is larger in the ex ante populations: solar make up 60% of ex post analysis accounts and 68% of ex ante enrollment. Note that, because of uncertainty that is introduced when a sample is split into sub-populations, estimating effects on subpopulations and then aggregating can result in different estimates than when effects are estimated on the pooled population.

Figure 23: Comparison of Ex-Post and Ex-Ante Per Customer Demand Reductions under SDG&E peak conditions (2025)



6 RECOMMENDATIONS

Electric vehicles have the potential to transform the electric grid fundamentally. They are a new, incremental, flexible, and critical load. As the residential electric vehicle market grows, it will impact all aspects of the electric grid. The efforts to ensure electric vehicles are a flexible load over the next few years will be vital as the market share increases. There are over 2.9M vehicles in SDG&E territory and the implications of transportation electrification for the electric grid are large. Moreover, electric vehicles are quickly maturing from an early adopter technology to mass adoption. The transformation is most evident for new vehicles, where electric vehicles constitute 24% of the market in San Diego County and 29% of the new vehicle market in Orange County. Thus, it has become increasingly important to provide customers incentives and tools to manage charging to lower bills and reduce use during peak hours.

Key recommendations from the evaluation are:

- **Continue to study the persistence of impacts and cohort effects.** In this evaluation, we studied cohort effects associated with successive years of EV-TOU_{WH} enrollees. We reported those findings above. We also began to study the persistence of impacts for the PY2024 analysis sample. Currently, ex post estimates from incremental sites that recently enrolled are currently applied to all enrolled sites in order to produce ex ante estimates. If effect varies with cohort (for example if the early enrollees were more engaged and provide larger estimates), or if effects change over time for a cohort (for example if reductions grow over time due to learning), then this method yields biased estimates for the full population. The findings of the cohort analysis suggest that ex ante should not be modified this year. We will continue to compare effects for future cohorts. The persistence analysis, when complete, could yield parameters that will be used to scale impacts for ex ante based on duration a customer has been enrolled. That analysis is still underway, and we will report findings next year.
- **Assess whether SDG&E can incorporate California Department of Motor Vehicle (DMV) registration data to identify control sites** – sites with electric vehicles that are not enrolled on EV-TOU-5 or EV-TOU-2. The DMV makes vehicle registration data available for public use but with limitations on how it is used and requirements regarding public notices and data security. While algorithms to identify electric vehicles using AMI data are helpful, vehicle registration data is a better source of information.
- **Consider modifying the building blocks used for ex-ante impacts.** Currently, the ex-ante impacts are based on four types of sites, customers on EV-TOU-5 and EV-TOU-2 with and without solar. Few new sites are enrolling on EV-TOU-2 and most new enrollments are on EV-TOU-5. As a result, the EV-TOU-2 analysis relies on an estimating sample that is small. For future years, we recommend that SDG&E build its ex-ante forecast based on sites on electric vehicle TOU rates with and without solar, eliminating the distinction between EV-TOU-5 and EV-TOU-2. This year, despite the small sample size, EV-TOU-2 effects were reasonable in magnitude and fairly precise, so we did not modify the method.

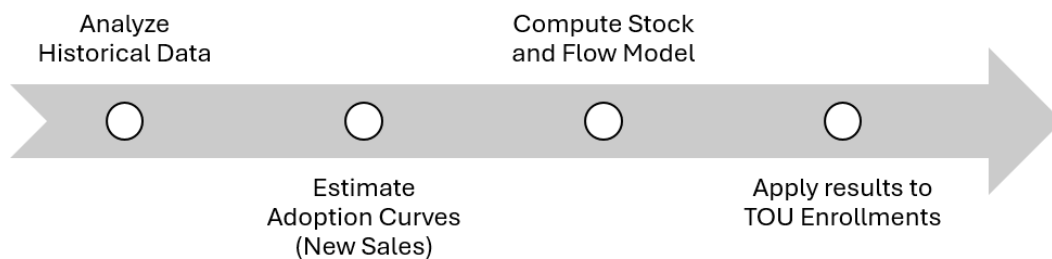
- **Consider a supplemental analysis to examine non-EV owner load impacts.** Residential customers taking service on Schedule NBT are required to utilize EV-TOU-5 as their otherwise applicable schedule (OAS) for electric service. These customers do not require a qualifying motor vehicle to participate on EV-TOU-5. Schedule NBT applies to customers that submitted solar interconnection applications on or after April 15, 2023. A challenge of estimating load impacts for these customers is that their solar adoption coincides with their enrollment on their rate. Under our current methodology, the timing of their enrollment shortly after interconnection will mean these customers are dropped from the analysis. Future evaluations could first identify the number of Schedule NBT customers without EVs enrolling and then consider alternative strategies to estimate their load impacts.

Appendix A ELECTRIC VEHICLE ADOPTION METHODOLOGY + RESULTS

A.1 INTRODUCTION

Due to recent policy and market changes, we re-forecasted the number EV-TOU_{WH} enrollees in the SDG&E territory to use in the Ex-Ante analysis. A key component of that forecast is a forecast of registered electric vehicles (EVs) for the territory. This latest forecast incorporates the vehicle population data through April, 2025⁸ and includes analysis based on recent market changes. This appendix documents the forecast methodology and describes the results through year 2045. Figure 24 provides an overview of the forecast methodology.

Figure 24: Overview of EV Forecast Methodology



⁸ Light-Duty Vehicle Population in California. Downloaded from “<https://www.energy.ca.gov/data-reports/energy-almanac/zero-emission-vehicle-and-infrastructure-statistics-collection/light>” on October 3, 2025.

A.2 HISTORIC EV ADOPTION PATTERNS IN SDG&E TERRITORY

The first step in the EV forecast is cleaning and analyzing vehicle population data for the SDG&E territory. We then compute the share of currently registered vehicles that are electric vehicles for each vehicle model year.

California makes available the vehicle population data for all 29.4 million light duty vehicles in the state, including information about the fuel type (e.g. battery electric, plug-in hybrid, fuel cell, gasoline, diesel, etc.), the make and model year, and zip code. We narrowed the population to vehicles in the SDG&E electric territory by zip code.

April 2025 Cumulative Vehicle Registration

- Battery Electric: 170,874
- PHEVs: 47,540
- Total electric vehicles: 218,414
- Total LDVs: 2,999,694

Year end	New BEVs + PHEVs
2020	11,883
2021	21,628
2022	31,532
2023	57,916
2024	41,419

The main objective of the historical analysis was to understand the total vehicles in the service territory, the rate of entry of new vehicles, and how the EV share (as percent of new vehicles) was changing over time.

Based on the vehicle registration data, there were 2,999,694 light-duty vehicles (LDVs) in the SDG&E territory. Of those, 218,414 were EVs. Among the EVs, 170,874 were battery electric vehicles (BEVs) and 47,540 were PHEVs.

Figure 25 shows light-duty vehicle registrations for each model year in the SDG&E territory by vehicle type. Registrations of model years after 2020 are lower than in prior years and lower than the historical rate of new vehicle entry in SDG&E's service territory.

Changes in the rate of new vehicles by year after 2020 are driven by a mix of pandemic conditions, supply chain shortages, inflation, high interest rates, and other economic factors.

Figure 25: SDG&E Vehicle Stock by Fuel Type and Model Year

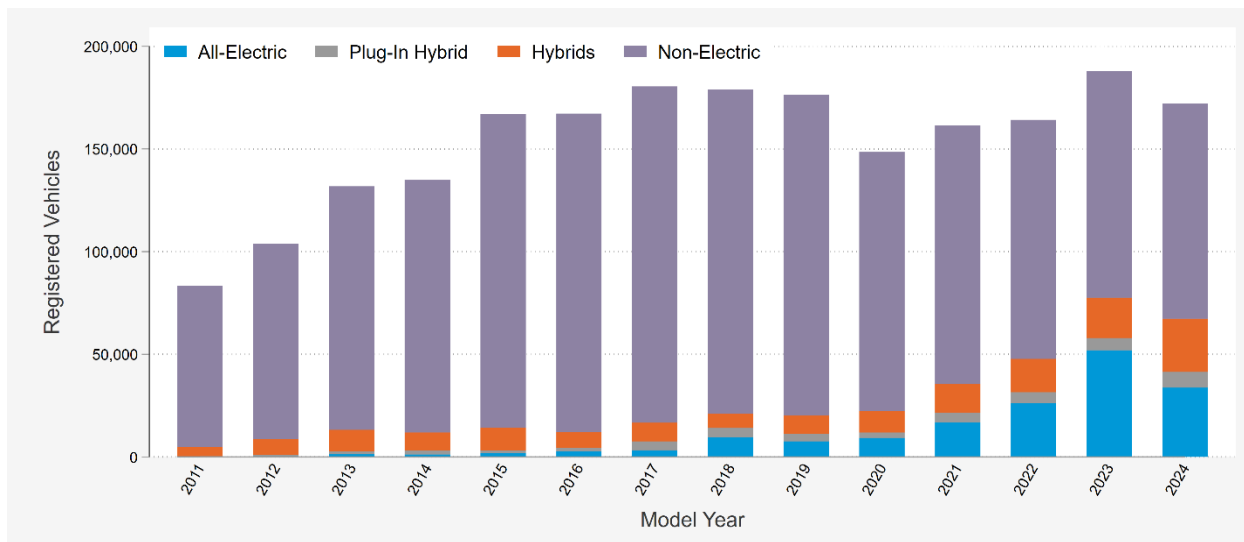


Figure 26 and Table 14 show the share of green vehicles as a percentage of registered vehicles for each model year. We define green vehicles as BEV, PHEV, or hybrid vehicles. In total, green vehicles now make up almost 40% of 2024 model year registrations. Electric vehicles include full battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs). They accounted for 24.1% of 2024 model year registrations.

Importantly, hybrid vehicle sales do not appear to have crowded out electric vehicle sales. Starting in 2016, EV sales start to grow, and the share of hybrids falls, suggesting people who may have bought a hybrid switch to EV as they rise in popularity, and starting in 2018, the EVs surpassed hybrids in new vehicle registrations and continued that trend. Hybrid sales did continue to increase overtime, gaining about 1% per year in new vehicle sales from 2020-2023. 2024 was the only year that deviated from that trend, with new EV sales declining and the share of hybrids rising (jumping from 10.5% in 2023 to 15% in 2024). This may be because of changes in consumer sentiment, rising supply chain or electricity costs, or higher interest rates. Higher interest rates will, in theory, reduce EV sales relative to sales of other vehicles because EVs have a higher upfront purchase price and lower cost per mile.

Figure 26: Green Vehicle Share by Type and Model Year

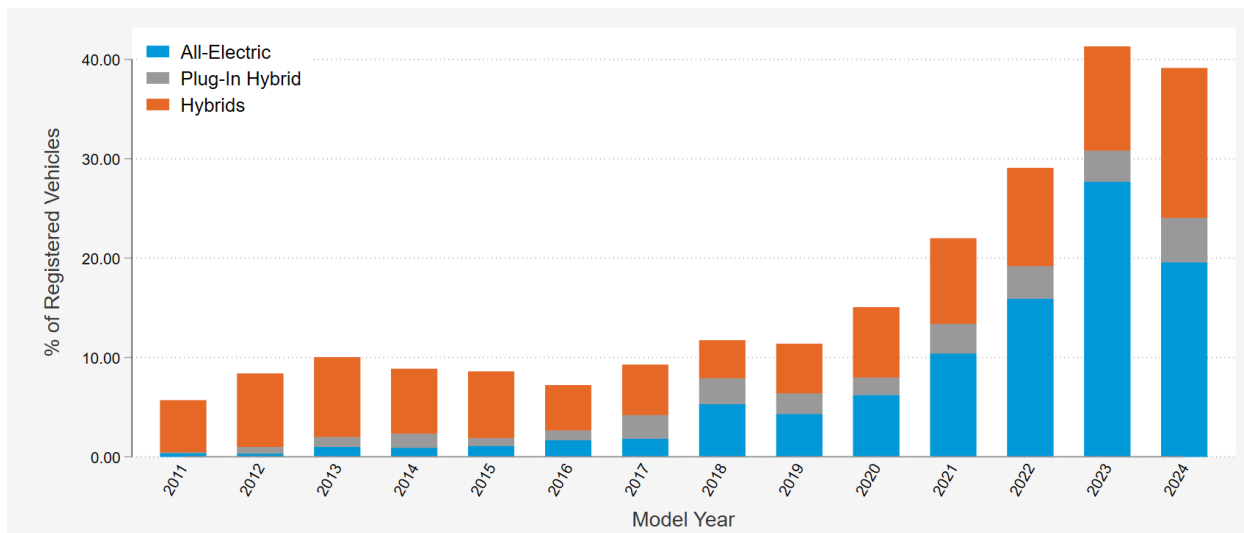


Table 14: SDG&E Electric and Green Vehicle Share by Model Year

Model Year	BEV	PHEV	Hybrid	Green %	Electric %
2010	0.0%	0.0%	2.7%	2.7%	0.0%
2011	0.4%	0.1%	5.2%	5.7%	0.5%
2012	0.3%	0.7%	7.4%	8.4%	1.0%
2013	1.0%	1.0%	8.0%	10.0%	2.0%
2014	0.9%	1.5%	6.5%	8.9%	2.4%
2015	1.1%	0.8%	6.7%	8.6%	1.9%
2016	1.7%	1.0%	4.5%	7.2%	2.7%
2017	1.8%	2.4%	5.1%	9.3%	4.2%
2018	5.3%	2.6%	3.8%	11.7%	7.9%
2019	4.3%	2.1%	5.0%	11.4%	6.4%
2020	6.2%	1.8%	7.0%	15.0%	8.0%
2021	10.4%	3.0%	8.6%	22.0%	13.4%
2022	15.9%	3.3%	9.9%	29.1%	19.2%
2023	27.7%	3.1%	10.5%	41.3%	30.8%
2024	19.6%	4.5%	15.1%	39.1%	24.1%

A.3 PREDICTION OF FUTURE NEW VEHICLE MARKET SHARE

We use the share of currently registered vehicles that are EVs for each historical vehicle model year from 2010 to 2024 to predict the EV share in future model years. We estimate two innovation diffusion curves (Bass diffusion models): one assuming that EVs eventually reach 95% market share, and another assuming EVs reach 75% market share. The models fit adoption curves (S-curves) to actual historical data. Since the inflection point has not been reached, they require a market share cap assumption, and the model finds path that best fits the historical data and the trajectory that meets the market share cap (i.e., the cap is determined but the path and uncertainty is based on the best fit to historical data).

Our “high” forecast is based on the California EV mandate (100% by 2035), but because of political uncertainty, we include the 75% market share as a low scenario, as a naturally occurring outcome due to the historical fast adoption rates in California. Figure 27 shows the results from each diffusion model. The panel on the left shows the 75% market share model, and the panel on the right shows the 95% market share model. Due to recent removal of EV tax credits originally introduced as part of the Inflation Reduction Act, we also run the diffusion model on a scenario with no tax credits, using the adjustment coefficients from Allcott et al. 2024⁹, shown in Figure 28. This model assumes that there were never tax credits, therefore lowering the observed values and the projected ones. Figure 29 compares the tax credit (observed) scenario and the counterfactual, with no tax credits.

Figure 27: EV Market Share Forecast from Bass Diffusion Models

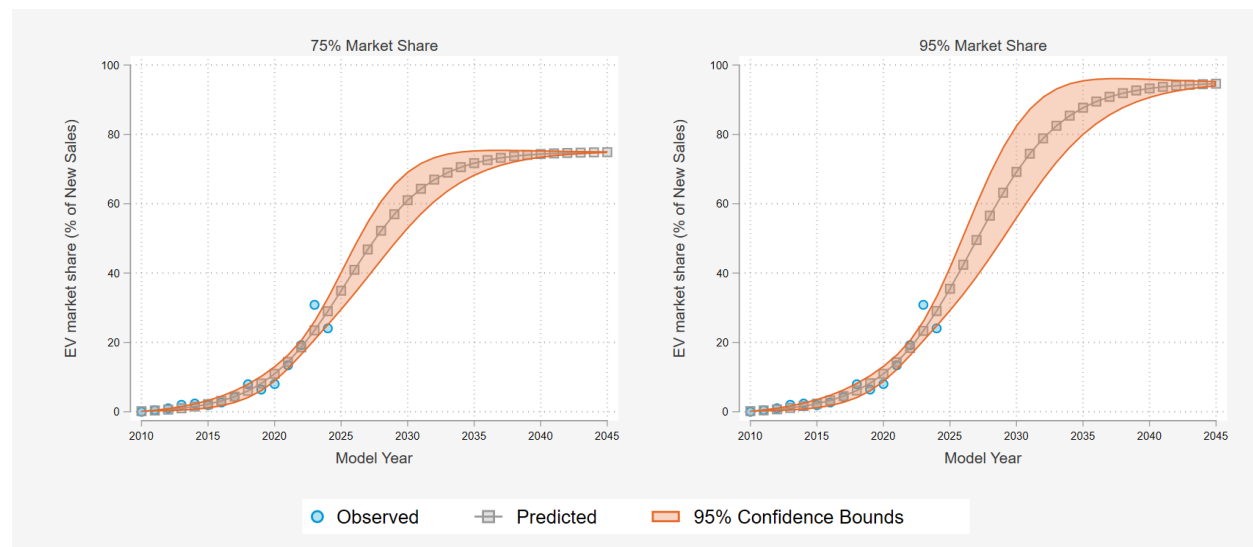


Figure 28: Electric Vehicle Market Share Forecast, No Tax Credit Scenario

⁹ Allcott et al. 2024: The Effects of “Buy American”: Electric Vehicles and the Inflation Reduction Act, <https://haas.berkeley.edu/wp-content/uploads/WP350.pdf>

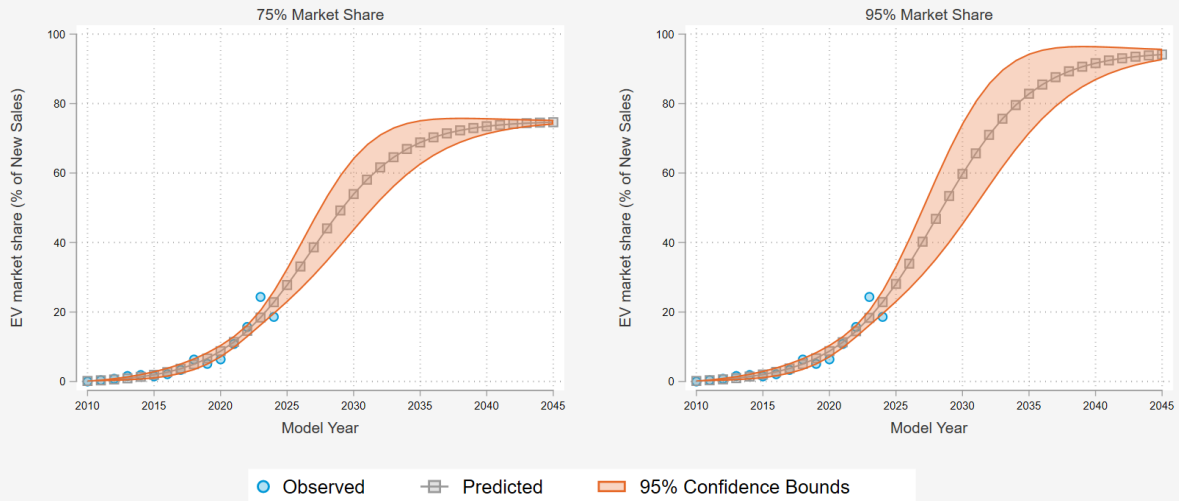
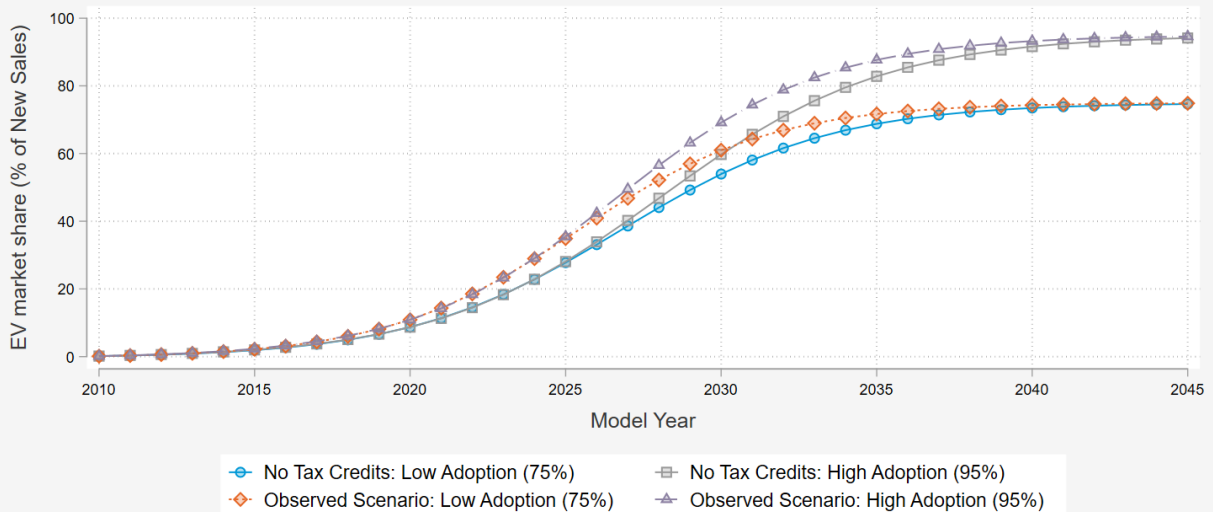


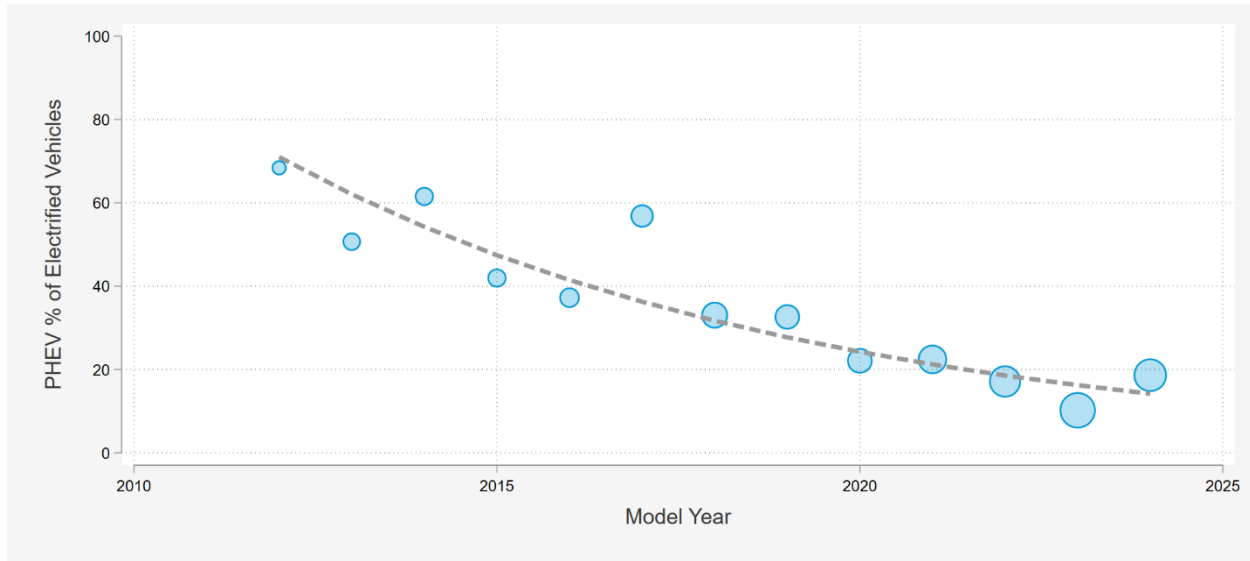
Figure 29: Comparison of EV Market Share in IRA EV Tax Credits Scenario and Counterfactual



The key difference between the tax credit forecast and the counterfactual scenario lies in the timing of market share attainment. With tax credits, the expected market share is reached earlier, followed by a plateau in adoption. Without tax credits, it takes longer to reach the 75% or 95% market share.

The second step in the forecast methodology is predicting PHEV share of EVs in future model years. We estimate the relationship using historical data and predict for future model years. We model natural logarithm of market share as a linear function of the natural logarithm of model year and estimate the relationship by OLS regression. Figure 30 shows the fitted values in grey, and the actual values in blue. The trend is towards PHEV's making up a smaller share of new electric vehicles registrations for newer model years.

Figure 30: PHEVs as a Share of EVs for Historical Model Years



A.4 STOCK AND FLOW MODEL

The stock and flow model uses new vehicle entry, EV market share, and a decay rate to project the stock of future EVs. The decay rate is estimated using the average of the ratio of total vehicles in the previous model year to the total vehicles in the current model year. In our data, the estimated decay rate was 0.95.

To predict the number of model year m EVs in a calendar year y we use the following equation

$$EV_m(y) = E * s_m * r^{(y-m)},$$

where E is the entry rate of total vehicles, s_m is the predicted market share for model year m , and r is the decay rate.

To determine the rate of new entry of vehicles, we used a weighted average of the population each year and the new vehicles to generate a new car to population ratio. We then used population projections to determine the changing rate of new vehicles by year. Since the dataset represented a snapshot of the vehicle population in 2024, decomposed by model year, we applied a decay rate to retrospectively estimate new registrations for prior calendar years. This process was effectively “back-filling” the historical data and adjusting the figures upward to estimate true new registrations in a previous calendar year. The new car to population ratio was 0.0281, and the average rate of new entry for the predicted years (2025-2045) was 183,762. We compute the EV counts for all model years less than or equal to the calendar year of interest. For a calendar year, this yields the predicted number of EVs of each model year that are registered in that calendar year. We can then sum over model years to find, for a calendar year, the number of registered EVs. After a new model year is introduced, its decay over time is visible from one calendar year to the next.

Figure 31 and Figure 32 show the predicted number of registered EVs as output from the stock and flow model for calendar years 2025 through 2045, in the low and high scenarios respectively

Figure 31: Stock and Flow Model Output for Calendar Years 2025 through 2045 - Low Scenario

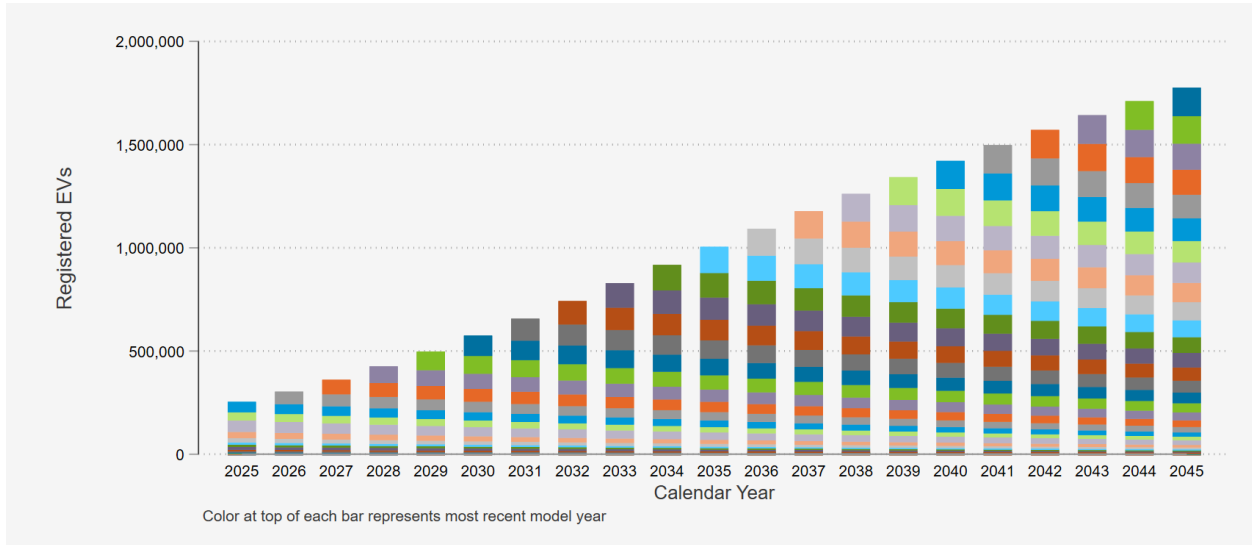
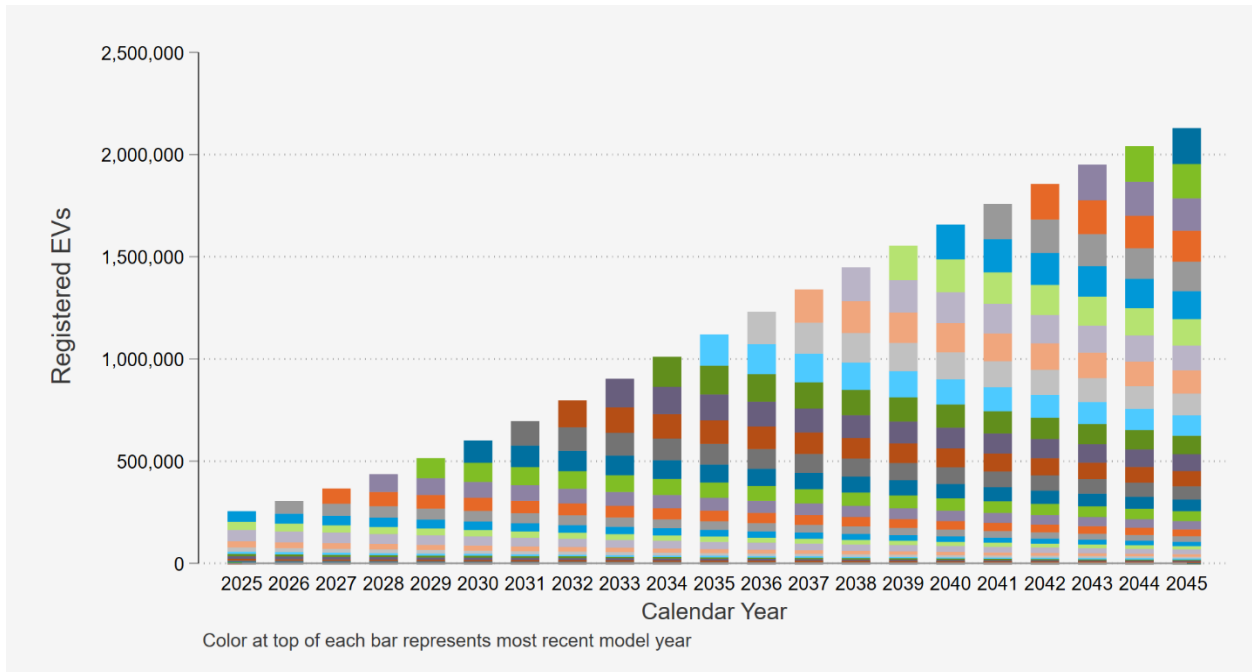


Figure 32: Stock and Flow Model Output for Calendar Years 2025 through 2045 - High Scenario



For PHEVs, the stock and flow model is the same, but we multiply by p_m , which is the share of EVs in model year m that are PHEVs:

$$PHEV_m(y) = E * s_m * p_m * r^{(y-m)}.$$

This equation helps to determine how many of the vehicles bought in the projected years will be BEVs versus PHEVs, which is an important determinant in EV-related electricity rate adoption.

A.5 FORECAST RESULTS

Table 15 shows the electric vehicle forecasts for 2025 to 2045 and provides details about vehicle counts. Uncertainty in these estimates is a result of uncertainty in predictions from the Bass diffusion model that predicts future market share.

Table 15: Light Duty Electric Vehicle Forecast

Year	Total Electrified Vehicles		BEVs only		PHEVs only	
	Low Scenario	High Scenario	Low Scenario	High Scenario	Low Scenario	High Scenario
2025	253,783	254,343	222,245	222,735	31,538	31,608
2026	303,245	305,273	270,270	272,078	32,974	33,195
2027	360,650	365,551	326,335	330,770	34,315	34,781
2028	425,647	435,348	390,206	399,099	35,441	36,249
2029	497,433	514,323	461,187	476,846	36,246	37,477
2030	574,922	601,712	538,257	563,338	36,665	38,374
2031	656,896	696,426	620,230	657,554	36,666	38,872
2032	742,068	797,107	705,816	758,166	36,252	38,941
2033	829,199	902,268	793,736	863,680	35,463	38,588
2034	917,169	1,010,418	882,833	972,592	34,336	37,827
2035	1,005,022	1,120,172	972,083	1,083,459	32,939	36,713
2036	1,091,997	1,230,325	1,060,661	1,195,020	31,336	35,305
2037	1,177,501	1,339,872	1,147,916	1,306,207	29,585	33,665
2038	1,261,084	1,447,990	1,233,338	1,416,132	27,746	31,858
2039	1,342,427	1,554,052	1,316,564	1,524,111	25,864	29,941
2040	1,421,323	1,657,594	1,397,340	1,629,625	23,983	27,969
2041	1,497,635	1,758,281	1,475,503	1,732,298	22,131	25,983
2042	1,571,283	1,855,878	1,550,945	1,831,856	20,338	24,022
2043	1,642,226	1,950,223	1,623,607	1,928,112	18,619	22,111
2044	1,710,459	2,041,225	1,693,471	2,020,952	16,988	20,273
2045	1,775,993	2,128,835	1,760,541	2,110,313	15,452	18,522

A.6 TOU ENROLLMENT FORECASTING

Projecting the electric vehicle population in SDG&E enabled us to estimate future enrollment rates in the EV-TOU_{WH} Rate program. SDG&E's EV-TOU_{WH} rates are voluntary Time of Use rate programs designed to offer electric bill saving for EV drivers, while also promoting charging during periods when the grid historically experiences lower demand and has excess capacity. Several whole home EV-TOU rates have been introduced over time; this analysis focuses on EV-TOU-2 and EV-TOU-5. EV-TOU-2 was introduced in 2016 and was the predominant whole home EV-TOU rate at that time, until EV-TOU-5 was launched in 2018 and has accounted for the vast majority of enrollments since. For simplicity, the two rates together will be referred to as EV-TOU_{WH} throughout the remainder of this analysis.

To forecast TOU enrollment, we assume that some share of the base of registered EVs enrolled when the rate was introduced, and that thereafter, incremental annual EV-TOU_{WH} enrollment is directly tied

to new annual EV registrations. We first used historical EV and whole home TOU enrollment data and took a weighted ratio of the yearly enrollment to new EV registrations between 2020 and 2023. Although these years were affected by the COVID-19 pandemic and related supply chain disruptions that led to reduced car sales, we believe that because it is a ratio-based metric, it remains representative of real-world trends. TOU enrollment data from 2018 and 2019 was not used because the EV-TOU-5 rate was introduced mid-2018, and a large share of enrollees in that period will be legacy EV owners rather than owners of newly registered vehicles. Additionally, there were a number of customers that switched from EV-TOU-2 to EV-TOU-5 when EV-TOU-5 was introduced, so we took the weighted ratio for both rates after the introduction of the second. We focused exclusively on BEV registrations, excluding PHEVs, since BEV owners are more likely to benefit from TOU rates and therefore more inclined to enroll in the EV-TOU_{WH} program.¹⁰ The weighted average ratio of TOU enrollments to EV registrations from 2020 to 2024 was 0.299 for EV-TOU-5 and 0.026 for EV-TOU-2 (significantly lower enrollment). These rates were applied to projected annual EV registrations from 2025 through 2045 to estimate future EV-TOU_{WH} enrollments.

As was done in the SDG&E enrollment forecast (discussed below), we split the EV-TOU-5 enrollment into NEM and non-NEM participants, with non-NEM participants opting in at a lower rate. Residents with rooftop solar are required to be on the “Solar Billing Plan” (also known as NEM 3.0) which gives them the EV-TOU-5 rate, and SDG&E predicts that these customers will make up roughly 62% of the total EV-TOU-5 enrollments. For EV-TOU-2, we assumed that all new enrollees would be NEM participants. Historical data indicates that non-NEM customers began transitioning off the EV-TOU-2 rate following the introduction of EV-TOU-5, presumably switching to the newer rate. These unenrollments were substantial during the initial years of EV-TOU-5 but have since stabilized, supporting the assumption that the remaining EV-TOU-2 enrollment base is relatively steady.

Figure 33 illustrates the forecasted annual EV-TOU-5 enrollments from 2025 to 2045, and Figure 34 demonstrates them cumulatively, including the registrations before 2025. Figure 35 and Figure 36 do the same for EV-TOU-2. Following an inflection point in 2036, the enrollment rate begins to decline, mirroring the projected slowdown in new EV sales. Table 16 and Table 17 present the incremental and cumulative EV-TOU-5 and EV-TOU-2 enrollments by year, beginning in 2025.

¹⁰ We cannot estimate separate enrollment ratios for BEV and PHEV owners because we do not observe the vehicle type of existing EV-TOU_{WH} enrollees.

Figure 33: EV-TOU-5 Annual Enrollment Forecast Comparison by NEM Status and Market Share Scenario

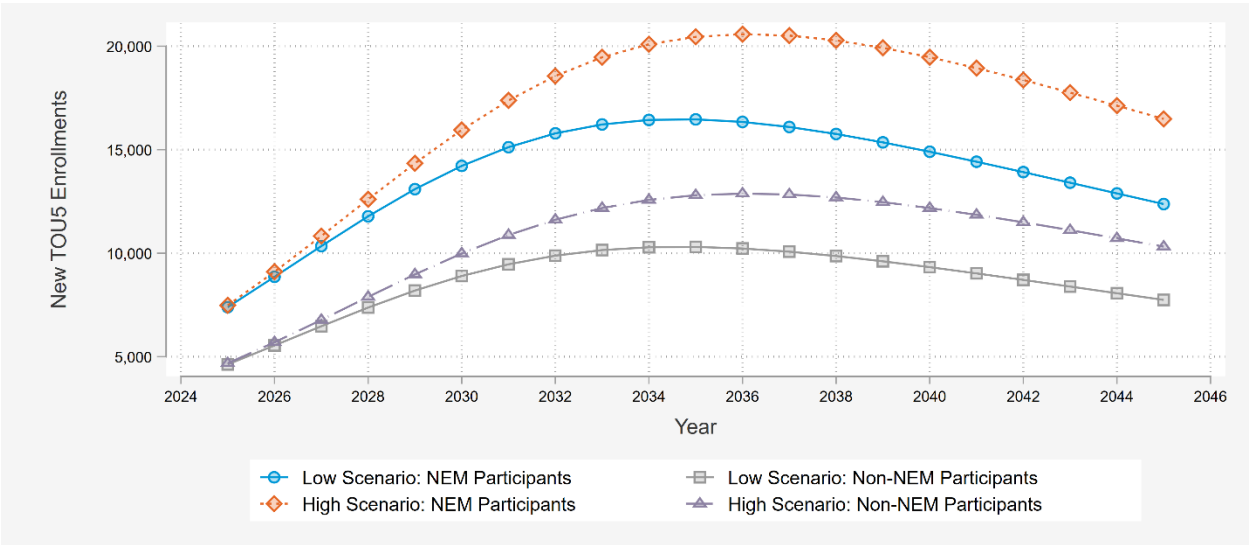


Figure 34: EV-TOU-5 Cumulative Enrollment Forecast Comparison by NEM Status and Market Share Scenario

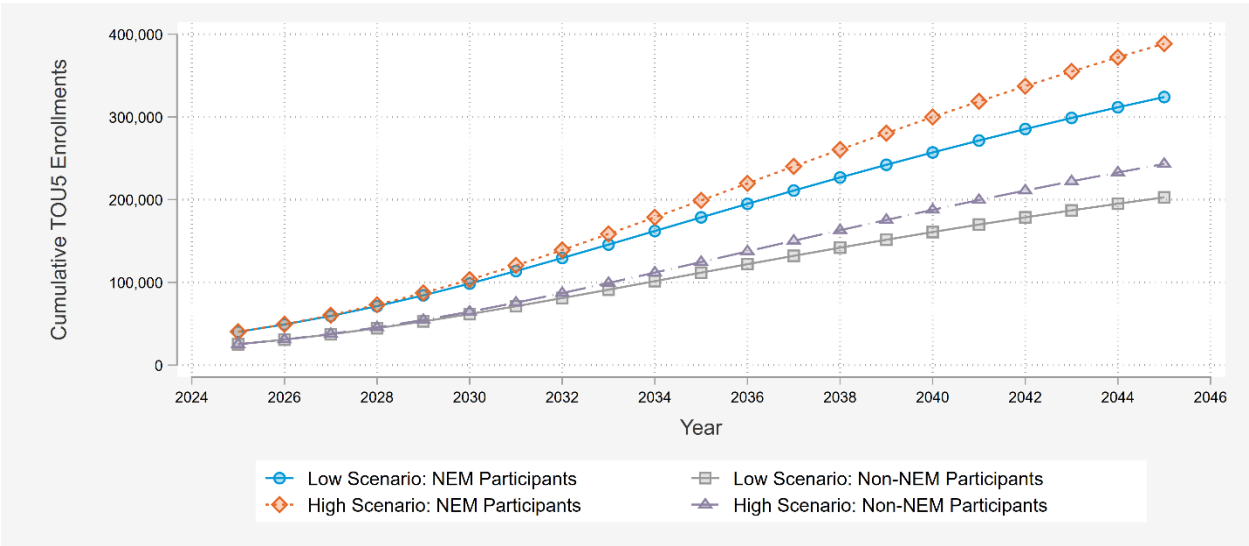


Figure 35: EV-TOU-2 Annual Enrollment Forecast Comparison by NEM Status and Market Share Scenario

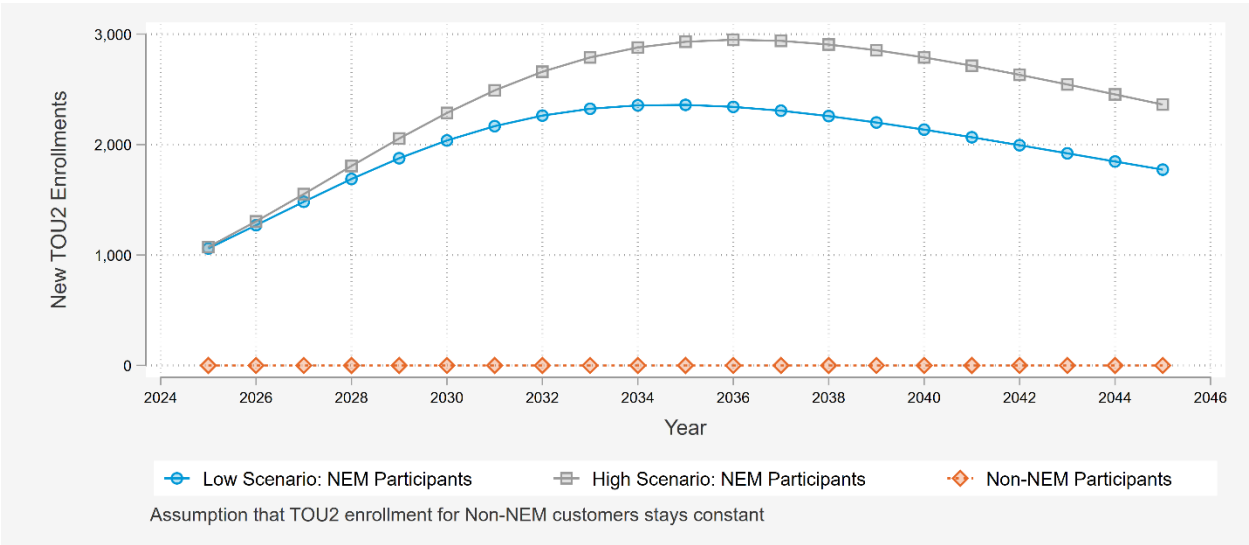


Figure 36: EV-TOU-2 Cumulative Enrollment Forecast Comparison by NEM Status and Market Share Scenario

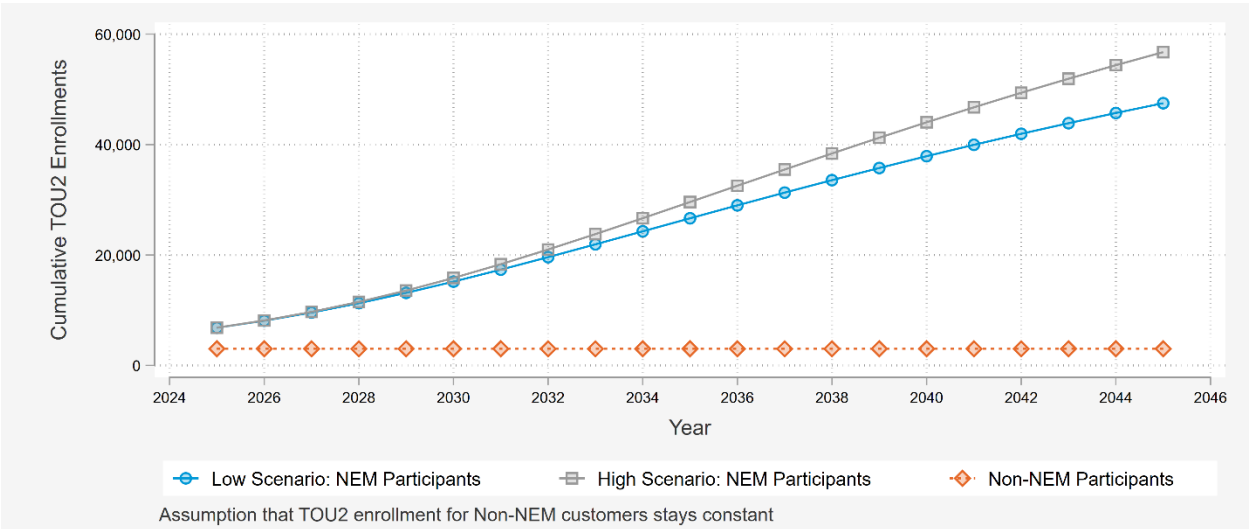


Table 16: EV-TOU-5 Annual Registrations by NEM Status and Market Share Scenario

Year	Low EV Penetration Scenario				High EV Penetration Scenario			
	NEM Customers	Non-NEM Customers	Total Enrollment	Cumulative Enrollment	NEM- Customers	Non-NEM Customers	Total Enrollment	Cumulative Enrollment
2025	7,394	4,627	12,021	65,425	7,484	4,684	12,168	65,572
2026	8,860	5,545	14,405	79,831	9,103	5,697	14,800	80,373
2027	10,343	6,473	16,817	96,647	10,828	6,777	17,605	97,977
2028	11,783	7,375	19,158	115,805	12,606	7,889	20,495	118,473
2029	13,095	8,196	21,291	137,096	14,344	8,977	23,320	141,793
2030	14,219	8,899	23,117	160,213	15,957	9,986	25,943	167,736
2031	15,123	9,465	24,588	184,801	17,382	10,878	28,260	195,997
2032	15,790	9,882	25,671	210,473	18,562	11,617	30,179	226,175
2033	16,220	10,151	26,372	236,845	19,466	12,183	31,649	257,824
2034	16,437	10,287	26,725	263,569	20,093	12,575	32,668	290,492
2035	16,466	10,305	26,771	290,340	20,454	12,801	33,255	323,747
2036	16,342	10,227	26,569	316,909	20,582	12,881	33,463	357,210
2037	16,098	10,075	26,172	343,081	20,513	12,838	33,351	390,561
2038	15,759	9,863	25,622	368,703	20,280	12,692	32,972	423,533
2039	15,354	9,609	24,964	393,667	19,921	12,467	32,388	455,921
2040	14,902	9,327	24,229	417,896	19,466	12,183	31,649	487,570
2041	14,420	9,025	23,445	441,341	18,942	11,855	30,797	518,367
2042	13,918	8,711	22,629	463,970	18,367	11,495	29,862	548,229
2043	13,405	8,390	21,795	485,765	17,758	11,114	28,872	577,101
2044	12,889	8,067	20,956	506,721	17,128	10,719	27,847	604,949
2045	12,374	7,744	20,118	526,838	16,486	10,318	26,804	631,753

Table 17: EV-TOU-2 Annual Registrations by NEM Status and Market Share Scenario

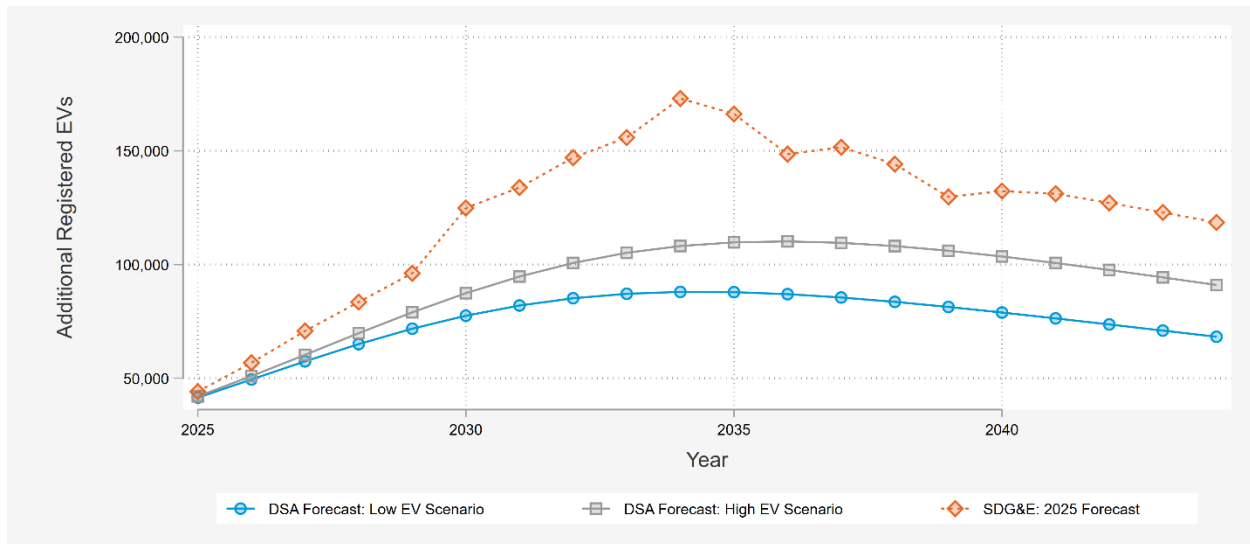
Year	Low EV Penetration Scenario			High EV Penetration Scenario		
	NEM Customers	Non-NEM Customers	Cumulative Enrollment	NEM Customers	Non-NEM Customers	Cumulative Enrollment
2025	1,059	0	9,851	1,072	0	9,864
2026	1,270	0	11,121	1,304	0	11,169
2027	1,482	0	12,603	1,552	0	12,721
2028	1,689	0	14,292	1,806	0	14,527
2029	1,876	0	16,168	2,055	0	16,582
2030	2,037	0	18,206	2,287	0	18,869
2031	2,167	0	20,373	2,491	0	21,359
2032	2,263	0	22,635	2,660	0	24,019
2033	2,324	0	24,960	2,789	0	26,809
2034	2,355	0	27,315	2,879	0	29,688
2035	2,359	0	29,674	2,931	0	32,619
2036	2,342	0	32,016	2,949	0	35,568
2037	2,307	0	34,323	2,939	0	38,507
2038	2,258	0	36,581	2,906	0	41,413
2039	2,200	0	38,781	2,855	0	44,268
2040	2,135	0	40,917	2,789	0	47,057
2041	2,066	0	42,983	2,714	0	49,772
2042	1,994	0	44,977	2,632	0	52,404
2043	1,921	0	46,898	2,545	0	54,948
2044	1,847	0	48,745	2,454	0	57,403
2045	1,773	0	50,518	2,362	0	59,765

A.7 COMPARISON WITH SDG&E 2025 FORECASTING

In 2025, SDG&E released a forecast of EV penetration within its service territory, along with projected whole home TOU enrollments. The market for electric vehicles is currently facing several headwinds including the removal of federal tax credits, higher interest rates, and rising electricity prices. We therefore have conducted an independent analysis considering the most recent EV sales data and adjusting for a “no-tax credits” scenario going forward. The following section presents a comparison between the two forecasts.

SDG&E’s annual EV sales projections were consistently higher than those of DSA, with year-over-year differences ranging from approximately 5,800 to nearly 65,000 vehicles, even when compared to DSA’s “high” scenario. While both forecasts exhibit a similar overall trajectory, peaking around 2035 and gradually declining thereafter, SDG&E’s forecast shows a sharper peak occurring slightly earlier. Figure 37 illustrates the comparison between the two forecasts.

Figure 37: Comparison between SDG&E and DSA's Annual New EV Forecasts



We also compared our EV-TOU-5 and EV-TOU-2 enrollment projections to those from SDG&E. Consistently, SDG&E's forecast was higher than DSA's in every year. This trend reflects the broader divergence in EV sales projections, suggesting that both forecasts apply a similar EV-to-enrollment ratio. However, DSA's projections are more conservative for the majority of TOU enrollments (those on the EV-TOU-5 rate), accounting for recent market developments such as policy shifts. DSA projects slightly higher numbers for EV-TOU-2 enrollments, as the SDG&E forecast predicts almost only about 100 enrollees per year. Figure 38 and Figure 39 illustrate the differences between the two whole home TOU enrollment forecasts for EV-TOU-5 and EV-TOU-2 respectively.

Figure 38: Comparison between SDG&E and DSA's Annual EV-TOU-5 Enrollment Forecasts

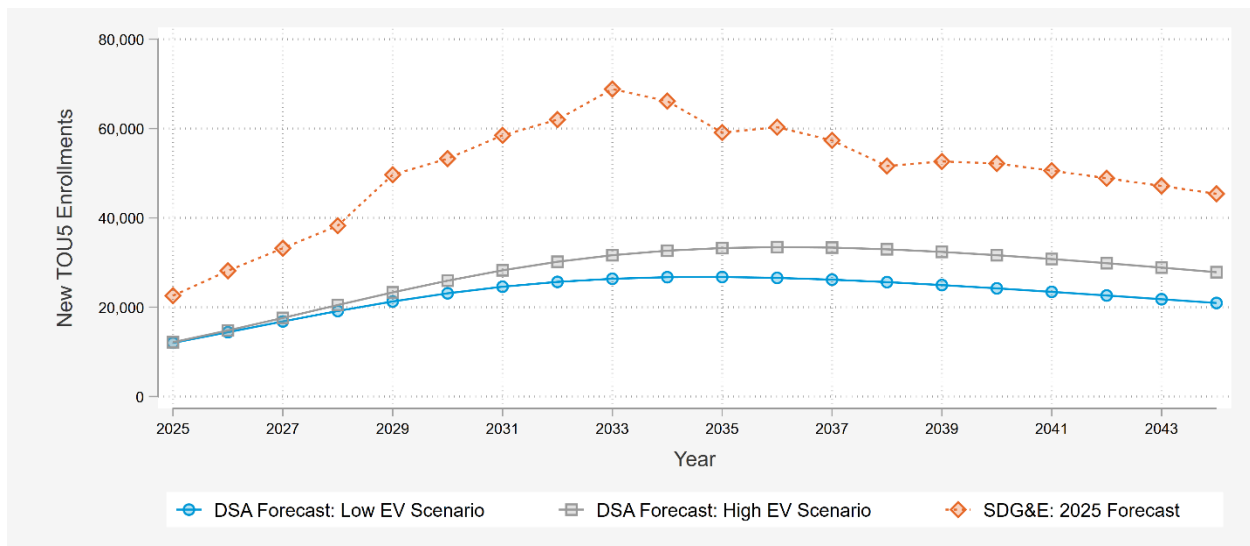
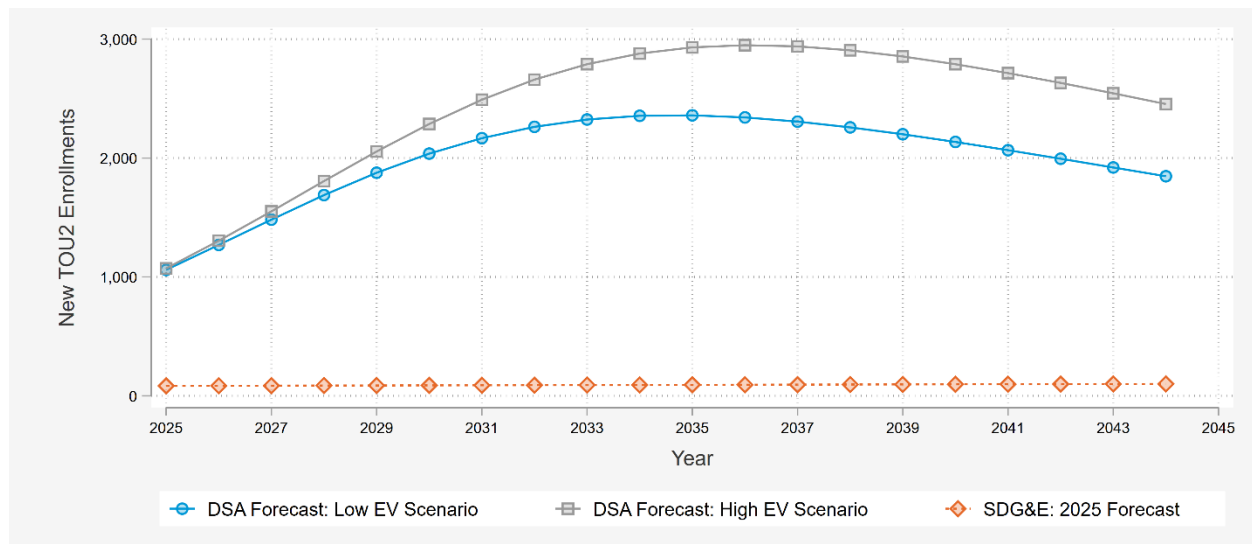


Figure 39: Comparison between SDG&E and DSA's Annual EV-TOU-2 Enrollment Forecasts



Appendix B ELECTRIC VEHICLE TOU EX-ANTE RESULTS: DSA FORECAST

Ex-ante impacts describe the magnitude of program resources available under planning conditions defined by weather. The ex-ante estimates are developed for both SDG&E and California ISO peak conditions under normal (1-in-2) and extreme (1-in-10) peak planning conditions. We estimated ex-ante impacts based on the relationship between demand reductions and weather using the ex-post performance over the analysis period (October 2024 to September 2025) and factored in projected changes in enrollment.

In the main text, we use the enrollment forecast provided San Diego Gas & Electric. However, this forecast was projected in January 2025, before some policy changes and market conditions for the EV market had taken full effect. Because of this, DSA re-forecasted electric vehicle adoption and enrollment on the whole home electric vehicle TOU rates in a scenario without electric vehicle subsidies or other incentive policies. The methodology for this projection is in Appendix A, and the results and comparison with the SDG&E forecast are here.

Appendix A compares the two forecasting approaches, presenting both a “low” and “high” DSA scenario based on expected EV adoption rates. Given recent policy and market trends, this analysis relies on the “low” DSA scenario, which assumes EVs reach a 75% market share in California by 2045.

Overall, the DSA forecast is substantially lower than the SDG&E forecast, roughly half as large, when considering all customers together. One exception is the EV-TOU-2 customer group: because the SDG&E forecast projects very limited EV-TOU-2 adoption (fewer than 100 customers per year), the DSA estimate is higher for that segment. However, once EV-TOU-5 customers are included, the SDG&E forecast becomes significantly larger. As a result, the total aggregated load reduction is lower under the DSA forecast.

Per-customer impacts are broadly similar across the two forecasts, but differences in the distribution of EV-TOU_{WH} types and solar versus non-solar customers lead to slight variations in the per-customer results.

B.1 OVERALL RESULTS

Figure 40 shows a comparison heat map of the per-customer load reduction by month and hour of day for SDG&E 1-in-2 monthly peak day weather conditions for both forecasts. The results are scaled to reflect the current mix of customers on whole home electric vehicle TOU rates (versus the available estimating sample). The results are very similar, but the SDG&E forecast does have more sustained per-customer reductions across longer periods of time (peak reduction over multiple months).

Table 18 and Table 19 show the per-customer hourly impacts for the DSA forecast each month under CAISO and SDG&E monthly peaking conditions, respectively. The tables are designed to enable the CPUC's Slice-of-Day Resource Adequacy requirements. The estimated reductions are greater on monthly worst days than on average weekdays and reductions are greater in hotter months than in cooler ones. The load reductions also coincide with the hours (4-9 PM) and months (August and September) when reductions are needed most.

Figure 40: Heat map Comparison of Per Customer Ex-Ante Demand Reductions by Hour and Month

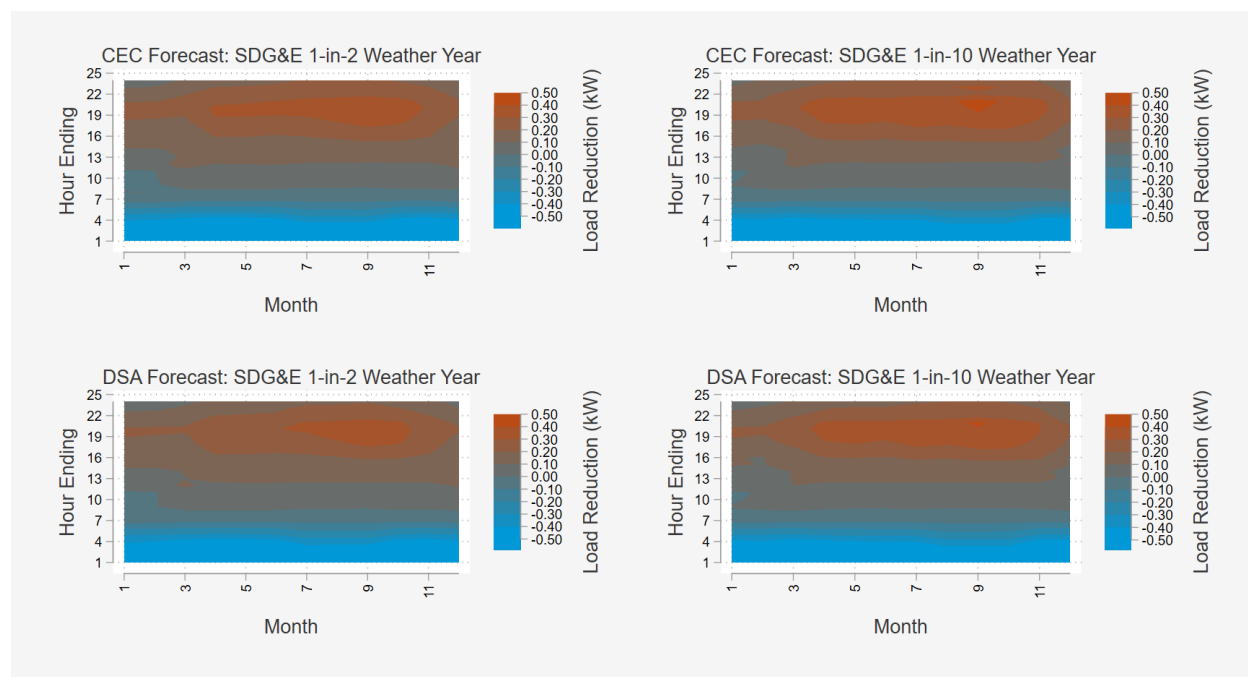


Table 18: Slice of Day Table for CAISO 1-in-2 Weather Year Monthly Worst Day (Per Customer Demand Reductions)

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sep	Oct	Nov	Dec
1	-0.51	-0.51	-0.51	-0.51	-0.51	-0.51	-0.51	-0.51	-0.51	-0.51	-0.51	-0.51
2	-0.54	-0.54	-0.57	-0.59	-0.58	-0.56	-0.54	-0.53	-0.53	-0.56	-0.59	-0.53
3	-0.49	-0.49	-0.52	-0.54	-0.54	-0.52	-0.48	-0.46	-0.46	-0.51	-0.55	-0.47
4	-0.42	-0.42	-0.44	-0.46	-0.45	-0.43	-0.38	-0.36	-0.35	-0.42	-0.46	-0.40
5	-0.30	-0.30	-0.30	-0.31	-0.30	-0.29	-0.26	-0.25	-0.25	-0.28	-0.31	-0.29
6	-0.19	-0.19	-0.19	-0.20	-0.20	-0.19	-0.16	-0.16	-0.16	-0.18	-0.20	-0.18
7	-0.06	-0.06	-0.07	-0.08	-0.08	-0.08	-0.07	-0.07	-0.07	-0.08	-0.08	-0.05
8	-0.01	-0.01	-0.01	-0.02	-0.02	-0.02	-0.03	-0.03	-0.03	-0.03	-0.02	0.00
9	0.01	0.00	0.02	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02	-0.01
10	0.00	-0.01	0.03	0.06	0.06	0.05	0.05	0.05	0.05	0.04	0.05	-0.03
11	-0.02	-0.03	0.03	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	-0.06
12	0.04	0.04	0.08	0.09	0.10	0.09	0.09	0.08	0.08	0.07	0.08	0.02
13	-0.04	-0.01	0.04	0.12	0.11	0.12	0.12	0.13	0.13	0.13	0.13	-0.04
14	0.00	0.04	0.07	0.12	0.11	0.12	0.12	0.12	0.12	0.13	0.12	0.01
15	0.09	0.10	0.11	0.15	0.14	0.15	0.15	0.16	0.16	0.16	0.16	0.09
16	0.09	0.10	0.11	0.18	0.15	0.17	0.18	0.19	0.19	0.20	0.19	0.09
17	0.14	0.13	0.13	0.21	0.18	0.21	0.22	0.24	0.25	0.26	0.23	0.14
18	0.18	0.18	0.17	0.24	0.21	0.25	0.25	0.28	0.28	0.29	0.25	0.18
19	0.20	0.20	0.19	0.27	0.23	0.27	0.28	0.30	0.31	0.33	0.26	0.21
20	0.21	0.21	0.21	0.28	0.25	0.29	0.30	0.32	0.32	0.33	0.28	0.21
21	0.18	0.18	0.18	0.25	0.22	0.26	0.30	0.31	0.32	0.33	0.25	0.18
22	0.15	0.13	0.16	0.20	0.20	0.21	0.22	0.23	0.23	0.23	0.20	0.13
23	0.10	0.08	0.11	0.16	0.16	0.18	0.21	0.22	0.24	0.22	0.16	0.08
24	0.07	0.05	0.08	0.12	0.12	0.14	0.17	0.17	0.18	0.17	0.12	0.05

Demand Reductions are positive (Blue)

Load increase are negative (Orange)

Table 19: Slice of Day Table for SDG&E 1-in-2 Weather Year Monthly Worst Day (Per Customer Demand Reductions)

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sep	Oct	Nov	Dec
1	-0.51	-0.51	-0.51	-0.51	-0.51	-0.51	-0.51	-0.51	-0.51	-0.51	-0.51	-0.51
2	-0.52	-0.54	-0.57	-0.58	-0.58	-0.57	-0.52	-0.53	-0.52	-0.57	-0.59	-0.55
3	-0.45	-0.47	-0.52	-0.55	-0.54	-0.53	-0.45	-0.46	-0.46	-0.53	-0.55	-0.49
4	-0.39	-0.40	-0.44	-0.46	-0.46	-0.43	-0.35	-0.36	-0.35	-0.44	-0.46	-0.41
5	-0.29	-0.29	-0.30	-0.31	-0.31	-0.29	-0.24	-0.25	-0.24	-0.30	-0.31	-0.30
6	-0.18	-0.18	-0.19	-0.20	-0.20	-0.19	-0.16	-0.16	-0.16	-0.19	-0.20	-0.19
7	-0.05	-0.05	-0.07	-0.08	-0.07	-0.08	-0.07	-0.07	-0.07	-0.08	-0.08	-0.06
8	0.00	0.00	-0.01	-0.02	-0.02	-0.02	-0.03	-0.03	-0.03	-0.02	-0.02	-0.01
9	-0.01	0.00	0.02	0.03	0.03	0.03	0.02	0.02	0.01	0.02	0.02	0.01
10	-0.03	-0.01	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.05	0.05
11	-0.02	-0.01	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
12	0.07	0.08	0.11	0.08	0.09	0.09	0.08	0.08	0.07	0.07	0.08	0.11
13	0.06	0.06	0.10	0.12	0.12	0.12	0.12	0.13	0.14	0.13	0.13	0.10
14	0.08	0.08	0.10	0.12	0.12	0.12	0.12	0.13	0.13	0.13	0.13	0.10
15	0.12	0.12	0.13	0.15	0.15	0.15	0.15	0.16	0.17	0.16	0.15	0.13
16	0.11	0.11	0.13	0.18	0.18	0.17	0.18	0.19	0.21	0.21	0.18	0.13
17	0.13	0.12	0.14	0.22	0.22	0.21	0.22	0.25	0.28	0.26	0.22	0.14
18	0.17	0.17	0.17	0.26	0.26	0.25	0.26	0.29	0.32	0.30	0.24	0.16
19	0.20	0.20	0.18	0.29	0.29	0.28	0.29	0.32	0.35	0.33	0.25	0.18
20	0.21	0.21	0.22	0.29	0.30	0.30	0.31	0.33	0.35	0.33	0.27	0.21
21	0.18	0.18	0.18	0.26	0.26	0.28	0.31	0.33	0.35	0.32	0.24	0.18
22	0.13	0.14	0.17	0.20	0.21	0.21	0.23	0.23	0.24	0.22	0.20	0.16
23	0.08	0.09	0.11	0.16	0.17	0.19	0.22	0.23	0.24	0.21	0.17	0.10
24	0.05	0.05	0.08	0.12	0.13	0.14	0.18	0.18	0.19	0.15	0.13	0.07

Demand Reductions are positive (Blue)

Load increase are negative (Orange)

Table 20 shows aggregate ex-ante demand reduction forecasts for an August monthly system worst day. Forecasts are shown under the four weather scenarios identified above. The increase in the demand reductions throughout the forecast years can be explained by the expected growth of electric vehicles and the corresponding growth in whole home electric vehicle TOU rate enrollments. Ex-ante weather conditions are static through the forecast window. There is a small amount of variation in participant-level impacts through the forecast window due to the expected enrollments by rate and solar status. Most future participants are projected to enroll on the EV-TOU-5 rate.

Error! Reference source not found. and Figure 41 show the comparison between the aggregate August monthly system worst day for the DSA and SDG&E forecast. As mentioned above, the SDG&E forecast is roughly double that of the DSA one due to the differing enrollment forecasts.

Table 20: Aggregate August Monthly System Worst Day (SDG&E) Demand Reduction Forecast (MW)

Forecast Year	Enrollment Forecast	SDG&E Weather		CAISO Weather	
		1-in-2	1-in-10	1-in-2	1-in-10
2025	105,985	33.8	36.3	32.6	35.0
2026	128,664	41.1	44.2	39.7	42.6
2027	156,905	50.3	53.9	48.5	52.0
2028	190,208	61.1	65.5	58.9	63.1
2029	228,548	73.5	78.7	70.9	75.9
2030	278,306	89.6	96.0	86.4	92.6
2031	331,656	106.8	114.4	103.1	110.4
2032	390,228	125.8	134.7	121.4	130.0
2033	452,325	145.9	156.2	140.8	150.7
2034	521,253	168.2	180.1	162.4	173.8
2035	587,487	189.7	203.0	183.1	195.9

Table 21: SDG&E and DSA Comparison - Aggregate August Monthly System Worst Day (SDG&E) Demand Reduction Forecast (MW)

Forecast Year	Enrollment Forecast		SDG&E Weather				CAISO Weather			
	DSA	SDG&E	DSA	SDG&E	DSA	SDG&E	DSA	SDG&E	DSA	SDG&E
			1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10	1-in-2	1-in-10
2025	70,919	105,985	21.4	33.8	23.1	36.3	20.5	32.6	22.2	35.0
2026	85,730	128,664	25.9	41.1	28.0	44.2	24.9	39.7	26.9	42.6
2027	103,155	156,905	31.3	50.3	33.8	53.9	30.1	48.5	32.5	52.0
2028	123,153	190,208	37.5	61.1	40.5	65.5	36.0	58.9	38.9	63.1
2029	145,544	228,548	44.4	73.5	47.9	78.7	42.7	70.9	46.0	75.9
2030	170,038	278,306	51.9	89.6	56.1	96.0	49.9	86.4	53.8	92.6
2031	196,261	331,656	60.0	106.8	64.8	114.4	57.7	103.1	62.2	110.4
2032	223,801	390,228	68.5	125.8	73.9	134.7	65.8	121.4	71.0	130.0
2033	252,244	452,325	77.2	145.9	83.4	156.2	74.3	140.8	80.1	150.7
2034	281,194	521,253	86.1	168.2	93.0	180.1	82.9	162.4	89.3	173.8
2035	310,308	587,487	95.1	189.7	102.7	203.0	91.5	183.1	98.6	195.9

Figure 41: SDG&E and DSA Comparison - Aggregate August Monthly System Worst Day (SDG&E) Demand Reduction Forecast (MW)

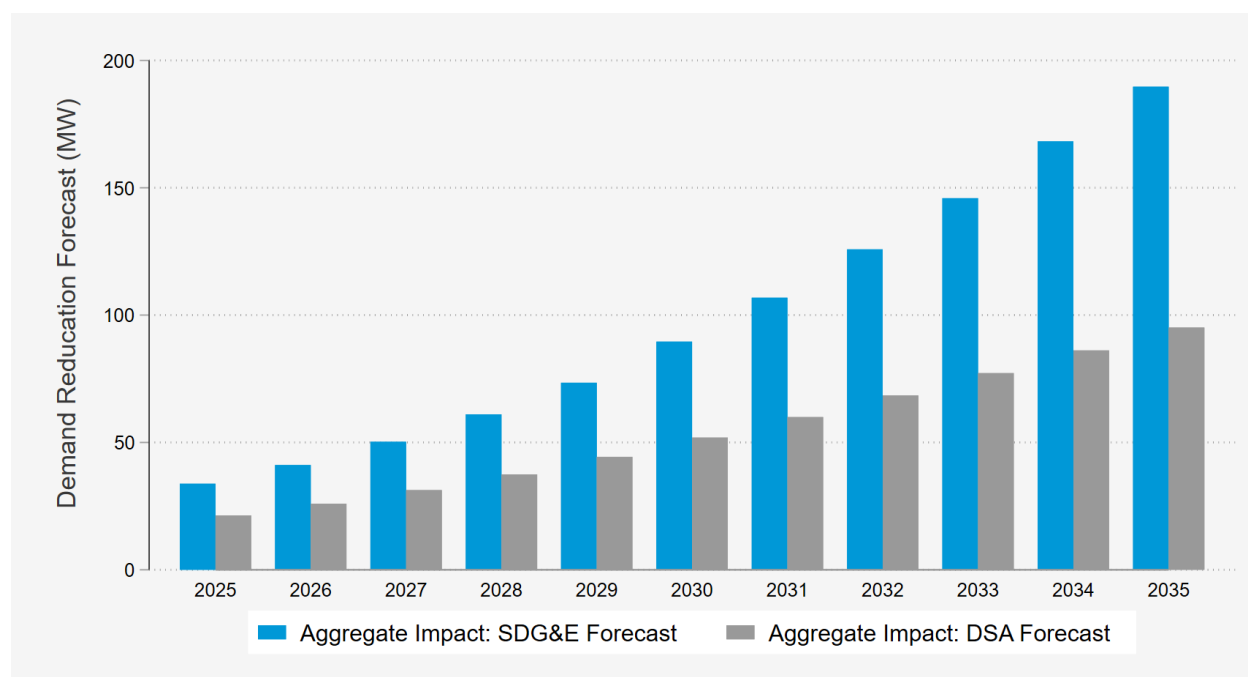


Figure 42 and Figure 43 show the DSA forecast estimated ex-ante load profiles for sites on electric vehicle TOU rates. Both figures show profiles for the August worst day, and both figures use SDG&E weather conditions rather than CAISO conditions. Figure 42 shows profiles under 1-in-2 weather conditions, and Figure 43 shows profiles for 1-in-10. Note that the forecast year shown is 2026.

Figure 42: Aggregate Ex-ante Impact for 1-in-2 Weather Conditions, August Worst Day 2026

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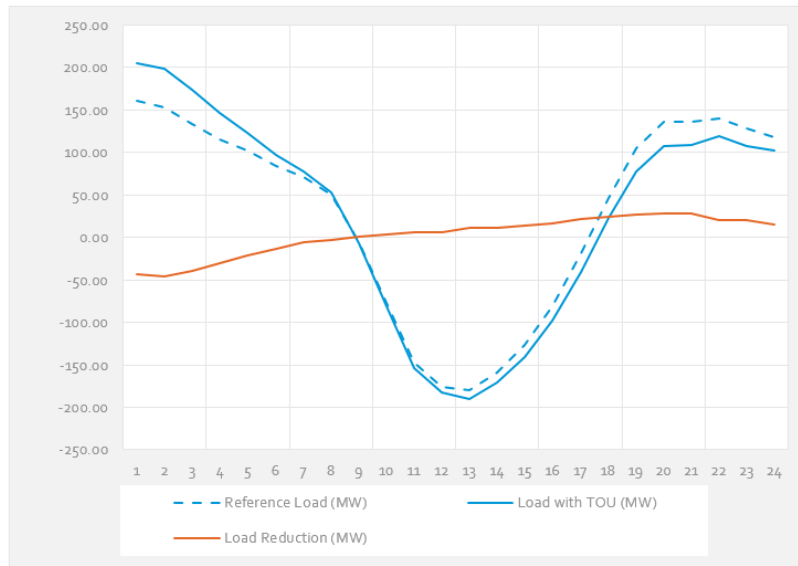


Table 1: Menu options

Type of Result	Aggregate Total
System (CAISO/SDG&E)	SDG&E
Weather Year	1-IN-2
Forecast Year	2026
Category	All
Subcategory	All
Day type	MONTHLY SYSTEM WORST DAY
Month	08 Aug
Hour Ending View	HE (Prevailing Time)

Table 2: Event day information

Total sites	85,730
Daily Max Temp	88.8
Peak Period (4pm-9pm) Impact (MW)	25.92
Peak Period (4pm-9pm) Impact (%)	31.9%



	Hour Ending	Reference Load (MW)	Load with TOU (MW)	Load Reduction (MW)	% Load Reduction	Avg Temp (°F, Site-Weighted)	Uncertainty		Standard Error	T-Statistic
							Adjusted Impact -			
							5th	95th		
1	1	161.43	205.27	-43.84	-27.2%	72.34	-57.88	-29.81	8.53	-5.14
2	2	153.44	198.85	-45.41	-29.6%	71.45	-59.49	-31.32	8.56	-5.30
3	3	133.84	173.66	-39.82	-29.8%	71.01	-52.77	-26.87	7.87	-5.06
4	4	115.55	146.25	-30.70	-26.6%	70.79	-42.70	-18.69	7.30	-4.21
5	5	102.16	123.45	-21.29	-20.8%	70.65	-32.03	-10.55	6.53	-3.26
6	6	83.82	97.38	-13.57	-16.2%	70.32	-21.88	-5.25	5.05	-2.68
7	7	71.59	77.67	-6.09	-8.5%	70.29	-12.48	0.31	3.89	-1.57
8	8	50.07	52.63	-2.56	-5.1%	70.75	-8.66	3.54	3.71	-0.69
9	9	-4.96	-6.38	1.42	-28.7%	74.23	-5.00	7.85	3.91	0.36
10	10	-77.00	-80.73	3.73	-4.8%	78.94	-3.99	11.44	4.69	0.79
11	11	-146.99	-153.56	6.57	-4.5%	83.73	-2.08	15.22	5.26	1.25
12	12	-176.25	-182.86	6.61	-3.8%	86.71	-2.77	15.99	5.70	1.16
13	13	-179.23	-190.51	11.29	-6.3%	88.47	1.07	21.51	6.21	1.82
14	14	-159.21	-170.17	10.96	-6.9%	88.83	0.41	21.51	6.42	1.71
15	15	-126.94	-140.40	13.46	-10.6%	86.70	2.81	24.11	6.47	2.08
16	16	-81.37	-98.06	16.69	-20.5%	86.72	5.99	27.40	6.51	2.56
17	17	-18.90	-40.18	21.28	-112.6%	86.51	10.51	32.06	6.55	3.25
18	18	47.12	22.49	24.63	52.3%	85.33	14.12	35.14	6.39	3.86
19	19	105.19	78.04	27.15	25.8%	82.85	17.23	37.07	6.03	4.50
20	20	135.98	107.50	28.47	20.9%	80.34	18.43	38.52	6.11	4.66
21	21	136.59	108.51	28.08	20.6%	77.18	17.98	38.17	6.14	4.57
22	22	139.65	119.66	19.99	14.3%	75.30	9.60	30.39	6.32	3.16
23	23	128.00	108.06	19.94	15.6%	74.00	9.10	30.78	6.59	3.03
24	24	117.96	102.53	15.42	13.1%	73.16	4.60	26.24	6.58	2.34
		Refload	Obsload			Temp	0.05	0.95	SE	
	Daily	Reference Load (MW)	Load with TOU (MW)	Load Reduction (MW)	% Change	Avg Temp (°F, Site-Weighted)	Uncertainty Adjusted Impact - Percentiles		Std Err	T-statistic
		MWh	MWh	MWh		F	5th	95th		
	Overall	711.52	659.09	52.43	7.4%	78.2	42.13	62.74	6.26	8.37
	Peak Hours	405.98	276.36	129.62	31.9%	82.4	119.34	139.89	6.25	20.75

Figure 43: Aggregate Ex-ante Impact for 1-in-10 Weather Conditions, August Worst Day 2026

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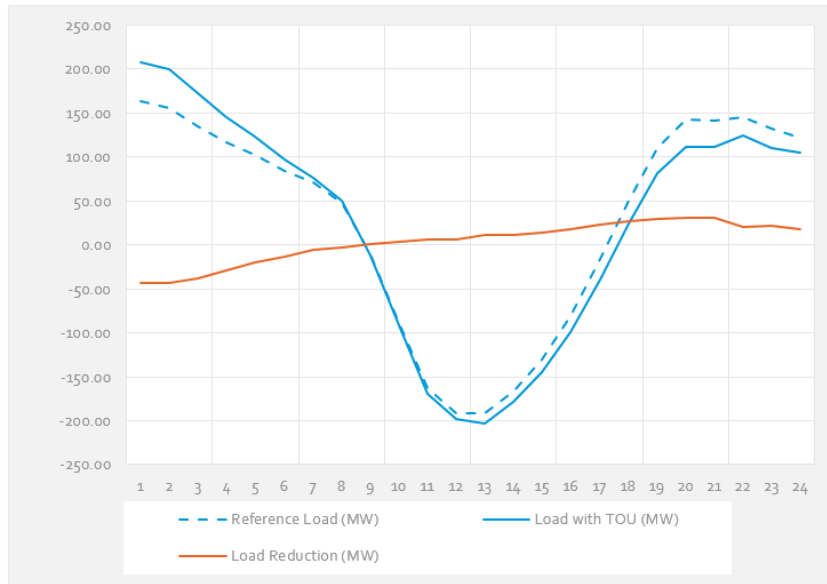


Table 1: Menu options

Type of Result	Aggregate Total
System (CAISO/SDG&E)	SDG&E
Weather Year	1-IN-10
Forecast Year	2026
Category	All
Subcategory	All
Day type	MONTHLY SYSTEM WORST DAY
Month	08 Aug
Hour Ending View	HE (Prevailing Time)

Table 2: Event day information

Total sites	85,730
Daily Max Temp	91.8
Peak Period (4pm-9pm) Impact (MW)	28.03
Peak Period (4pm-9pm) Impact (%)	32.7%



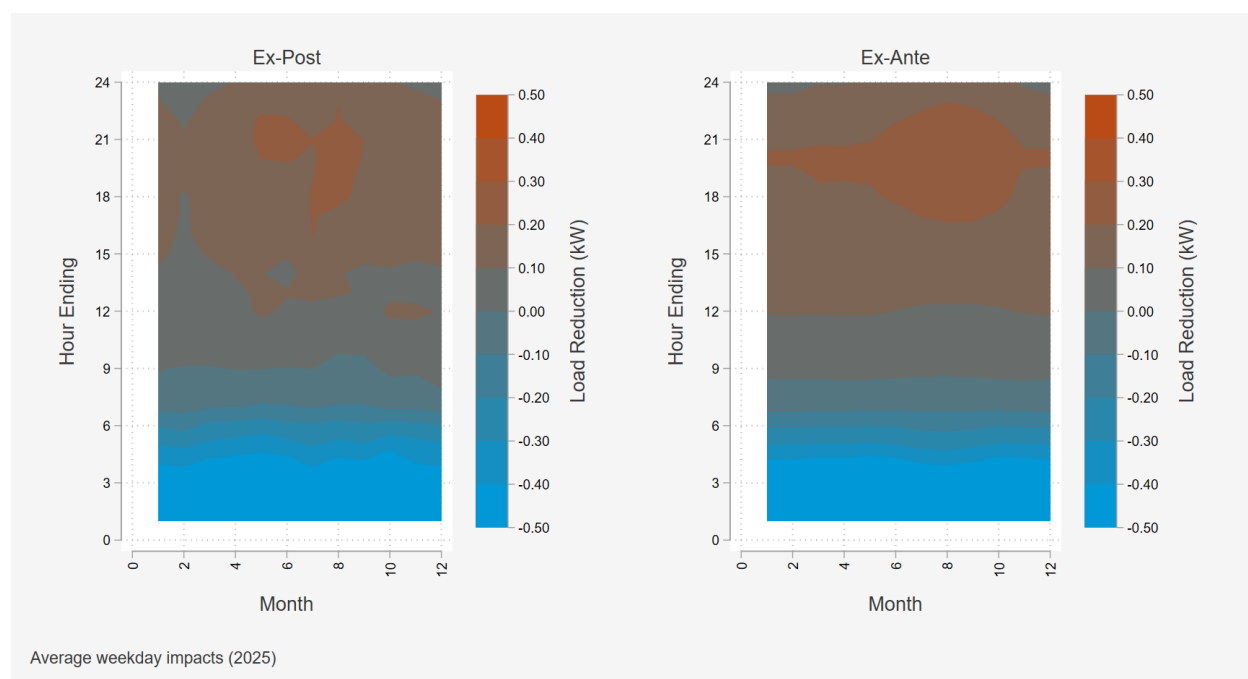
	Hour Ending	Reference Load (MW)	Load with TOU (MW)	Load Reduction (MW)	% Load Reduction	Avg Temp (°F, Site-Weighted)	Uncertainty Adjusted Impact - Percentiles		Standard Error	T-Statistic
							5th	95th		
1	1	164.05	207.88	-43.83	-26.7%	75.64	-57.86	-29.80	8.53	-5.14
2	2	156.00	199.83	-43.83	-28.1%	74.98	-57.92	-29.75	8.56	-5.12
3	3	135.51	173.12	-37.61	-27.8%	74.08	-50.56	-24.66	7.87	-4.78
4	4	116.57	145.03	-28.46	-24.4%	73.31	-40.46	-16.46	7.30	-3.90
5	5	103.06	123.18	-20.13	-19.5%	72.91	-30.87	-9.38	6.53	-3.08
6	6	84.07	96.80	-12.73	-15.1%	72.78	-21.05	-4.42	5.05	-2.52
7	7	70.89	76.89	-6.00	-8.5%	72.10	-12.39	0.40	3.89	-1.54
8	8	47.89	50.72	-2.83	-5.9%	74.36	-8.93	3.27	3.71	-0.76
9	9	-11.26	-12.25	0.99	-8.8%	78.61	-5.44	7.41	3.91	0.25
10	10	-88.75	-91.92	3.17	-3.6%	83.80	-4.54	10.88	4.69	0.68
11	11	-162.92	-169.52	6.60	-4.1%	88.70	-2.05	15.25	5.26	1.26
12	12	-192.02	-198.13	6.11	-3.2%	90.93	-3.27	15.48	5.70	1.07
13	13	-192.07	-203.73	11.66	-6.1%	91.79	1.44	21.88	6.21	1.88
14	14	-167.41	-178.62	11.22	-6.7%	91.58	0.66	21.77	6.42	1.75
15	15	-130.57	-144.51	13.94	-10.7%	90.96	3.29	24.58	6.47	2.15
16	16	-80.99	-98.71	17.72	-21.9%	90.93	7.02	28.43	6.51	2.72
17	17	-16.28	-39.31	23.03	-141.5%	90.65	12.26	33.81	6.55	3.52
18	18	50.59	24.21	26.38	52.1%	89.23	15.87	36.89	6.39	4.13
19	19	110.47	81.13	29.33	26.6%	87.01	19.41	39.25	6.03	4.86
20	20	142.37	111.86	30.51	21.4%	84.60	20.46	40.56	6.11	4.99
21	21	141.94	111.04	30.90	21.8%	81.23	20.80	41.00	6.14	5.03
22	22	145.30	124.34	20.96	14.4%	79.24	10.57	31.36	6.32	3.32
23	23	132.58	110.44	22.13	16.7%	78.09	11.29	32.97	6.59	3.36
24	24	122.10	104.84	17.26	14.1%	77.36	6.44	28.08	6.58	2.62
		Reflow	Obsload			Temp	0.05	0.95	SE	
Daily		Reference Load (MW)	Load with TOU (MW)	Load Reduction (MW)	% Change	Avg Temp (°F, Site-Weighted)	Uncertainty Adjusted Impact - Percentiles		Std Err	T-statistic
		MWh	MWh	MWh		F	5th	95th		
Overall		681.10	604.61	76.49	11.2%	81.9	66.19	86.79	6.26	12.21
Peak Hours		429.09	288.93	140.16	32.7%	86.5	129.88	150.43	6.25	22.44

B.2 EX-POST TO EX-ANTE COMPARISON

When comparing ex-post and ex-ante, it is important to keep the distinction between the two estimates in mind. Ex-ante impacts are estimates of the future resources available under standardized planning conditions (defined by weather). Ex-post impacts are estimates of what past impacts were given the weather, conditions, and magnitude of resources available. The ex-ante impacts are based on the ex-post impact and weather trends, as shown earlier in Figure 18.

Figure 44 compares the per site ex-post load impacts to the ex-ante load impacts for the average weekday by month and hour. The ex-post load impacts are very similar in magnitude to the ex-ante impact estimates shown in the table. Both have the highest reductions in the summer, though for ex-post this peak occurs slightly earlier. Ex-ante has higher sustained reductions through all months in peak hours. The differences are due to weather and composition of the samples. The ex-ante standardized weather indicates hotter weather conditions typically occur in August in September, and this is reflected in higher impacts in those months.

Figure 44: Comparison of Ex-Post and Ex-Ante Per Customer Demand Reductions under SDG&E peak conditions (2025)



Appendix C HISTORICAL COHORT IMPACTS

To assess the program's efficacy over time, we compared ex-ante results across five years of available data (2021–2025), examining whether impact has shifted as the program has matured. The comparison covers solar and non-solar customers enrolled in EV-TOU-5 across weather years; EV-TOU-2 was excluded given that the majority of future enrollments are projected to be EV-TOU-5. Overall, impacts are consistent across years, particularly for the solar group. Supporting figures for each grouping and weather year are included in this appendix.

Figure 45: Average Load Impact during Peak Hours by Month, EV-TOU-5 + Solar 1-in-2 Weather Conditions

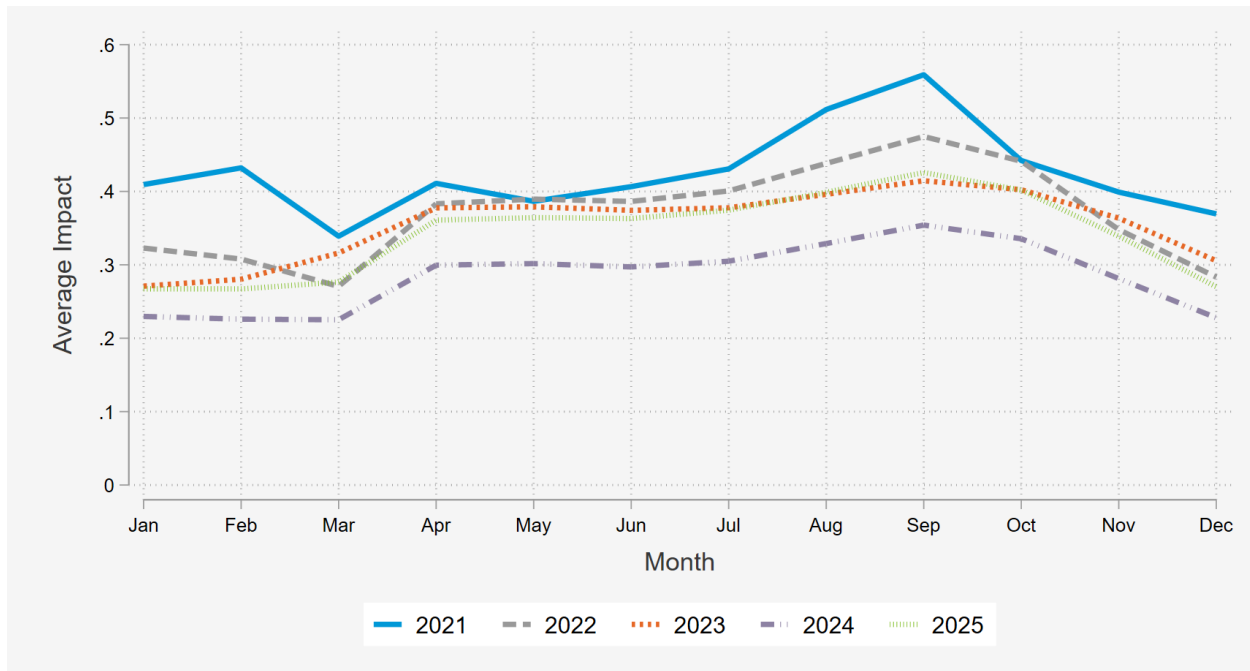


Figure 46: Average Load Impact during Peak Hours by Month, EV-TOU-5 + Solar 1-in-10 Weather Conditions

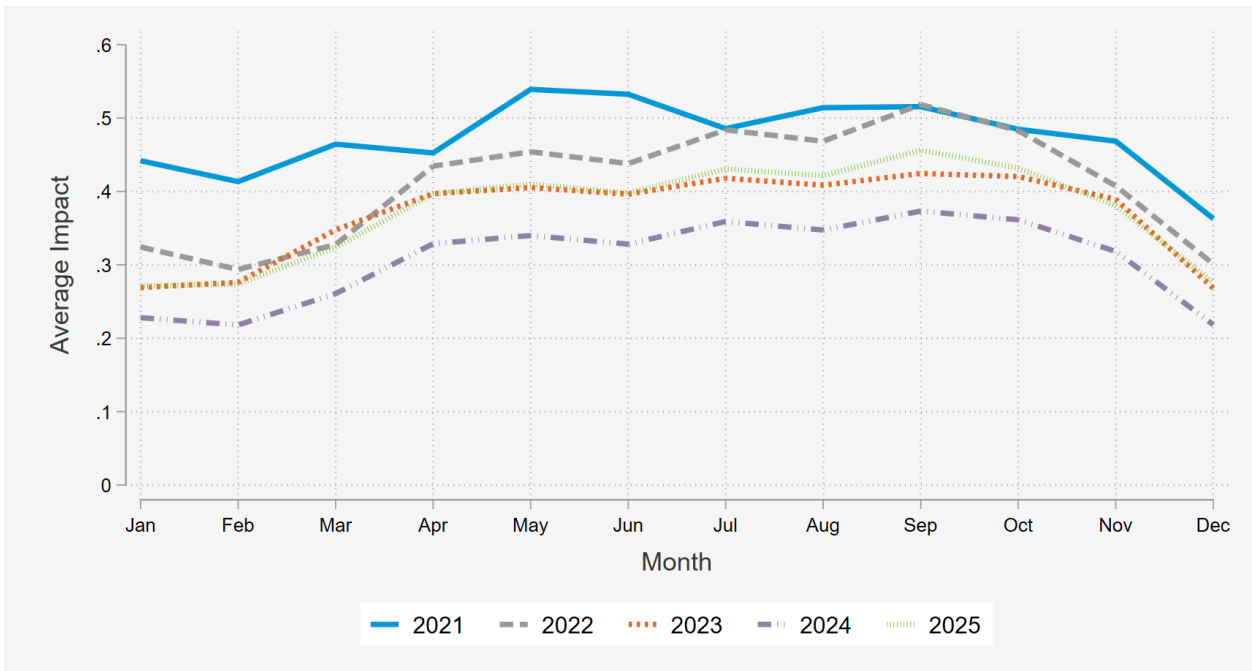


Figure 47: Average Load Impact during Peak Hours by Month, EV-TOU-5 + No Solar 1-in-2 Weather Conditions

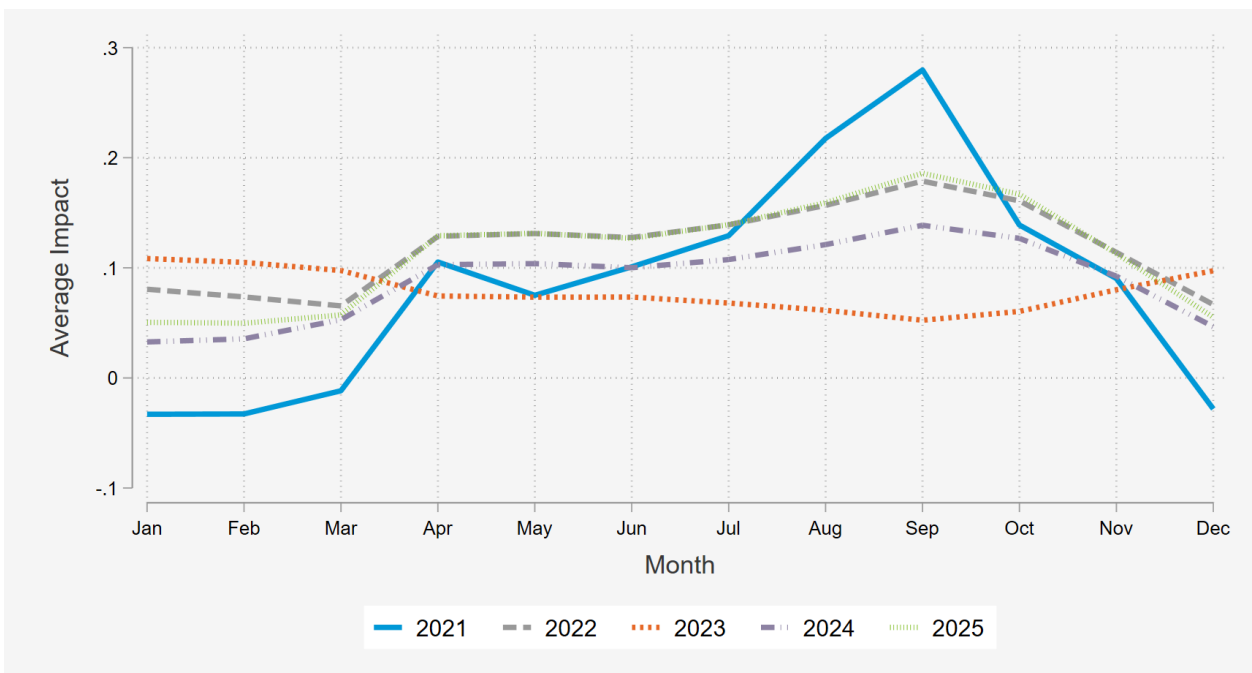


Figure 48: Average Load Impact during Peak Hours by Month, EV-TOU-5 + No Solar 1-in-10 Weather Conditions

