



Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

FINAL REPORT

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2025 Load Impact Evaluation for California Non-Residential Critical Peak Pricing Rates (PG&E, SCE, and SDG&E)



Prepared for PG&E, SCE, and SDG&E
By Demand Side Analytics, LLC
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ABSTRACT

This study quantifies the load impacts of the Critical Peak Pricing (CPP) event days for PG&E, SCE, and SDG&E for PY2025, over and above any daily load impacts driven by the customers' time-of-use (TOU) rate pricing. CPP rates charge increased prices during peak hours on event days in exchange for lower rates during other summer hours. CPP rates are the default commercial rates for all three utilities.

The study focuses on two primary research questions, separately for each utility: 1) *Ex post*, what were the 2025 demand reductions from 4 to 9 p.m. on event days? 2) *Ex ante*, what is the magnitude of future load reduction by CPP customers under 1-in-2 weather conditions?

Ex post, PG&E's nine events in PY2025 produced an average demand reduction of 7.9 MW from 89,000 customers. SCE's twelve events produced no significant demand reduction from 233,000 customers. SDG&E had no CPP events in PY 2025. Ex ante, CPP customers would be expected to deliver estimated demand reductions of 7.8 MW (PG&E), 2.7 MW (SCE), and 0.8 MW (SDG&E Medium/Large) in 2026, with impacts changing over time with changes in forecasted enrollments.

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1 EXECUTIVE SUMMARY

Critical Peak Pricing (CPP) rates are time-of-use (TOU) rates with increased prices during peak hours on event days. Event days are chosen by the utilities based on forecasted demand conditions, and customers can optionally receive notification of events ahead of time. Customers pay lower rates during other summer hours or receive bill credits in exchange for higher pricing on event days.

PG&E called nine event days, SCE called twelve, and SDG&E did not call any events in 2025. Event day pricing applies to all CPP subgroups, with events covering the TOU peak window from 4 to 9 p.m. All three utilities have high enrollments in CPP rates since they are the default commercial rates for each, with customers able to opt out to another rate at their discretion.

The study focuses on two primary research questions, separately for each utility:

1. *Ex post*, what were the PY2025 demand reductions from 4 to 9 p.m. on event days?
2. *Ex ante*, what is the magnitude of future load reduction by CPP customers under 1-in-2 weather conditions?

While CPP customers likely shift loads daily for TOU pricing on these rates, both the ex post and ex ante estimates reported here only represent the incremental impacts due to the CPP price adders on event days.

Ex post, PG&E's PY2025 event days produced an average hourly demand reduction from 4 to 9 p.m. of 7.9 MW from 89,000 customers. SCE's events produced no significant decrease from 232,000 customers. SDG&E had no events in PY2025 since system conditions did not meet their minimum threshold to trigger a CPP event day.

Table 1-1 summarizes the estimated ex post demand reductions for an average weekday event hour by utility. All impacts are incremental to other DR program impacts and statistical significance is noted for each subgroup. Load impacts (demand reductions) are represented as positive numbers in this report.

Table 1-1: Summary of 2025 Average Weekday Event Ex Post Demand Reductions

IOU	Sites	Load without DR (MW)	Load Reduction (MW)	% Load Reduction	Significant (90% CL)	Significant (95% CL)
PG&E (All Groups)	88,671	660.90	7.91	1.2%	Yes	Yes
SCE (All Groups)	233,334	1165.83	-1.80	-0.2%	No	No

While SCE's customers produced no significant impacts on average for PY 2025, they anticipate approval to move customers that are not benefiting from CPP to other TOU rates for PY 2026. These

“non performers” make up roughly half of SCE’s current participants and lowered SCE’s ex post estimates for PY 2025.

Table 1-2 summarizes forecasted site enrollments by utility. PG&E anticipates declining enrollments due the growth of Community Choice Aggregators (CCAs), which de-enroll sites by default. SCE anticipates a slight growth in enrollments from year to year, as does SDG&E.

Table 1-2: Total Ex Ante Site Enrollments by Utility

Year	PG&E	SCE	SDG&E (Med. & Large)
2025	90,018	233,049	2,234
2026	96,115	257,337	2,148
2027	98,465	260,338	2,177
2028	81,634	263,330	2,221
2029	78,765	266,322	2,266
2030	76,029	269,325	2,315
2031	73,423	272,321	2,376
2032	70,937	272,342	2,444
2033	68,544	272,366	2,521
2034	66,214	272,386	2,610
2035	64,011	272,408	2,719
2036	61,899	272,426	2,825

Table 1-3 summarizes the portfolio-adjusted ex ante demand reduction capability for each IOU. Since no significant impacts were estimated for any CPP dual-enrollment groups in PY2025, these estimates also represent the program-specific demand reductions, which will not be listed separately in this report¹. Reduction capabilities are for the normal 4 to 9 p.m. CPP event window.

Table 1-3: Total Ex Ante Demand Reductions for August Worst Day, System 1-in-2 Weather (MW, Portfolio-Adjusted and Program-Specific)

Year	PG&E	SCE	SDG&E (Med. & Large)
2025	7.6	2.8	0.8
2026	7.8	2.7	0.8
2027	8.0	2.7	0.8

¹ PG&E’s dual-enrolled BIP customers were removed from the analysis per PG&E’s DR portfolio rules. SCE had a small number of BIP and SDP dual enrollments, but these groups had insignificant load reductions.

Year	PG&E	SCE	SDG&E (Med. & Large)
2028	7.2	2.7	0.8
2029	7.0	2.8	0.8
2030	6.9	2.8	0.8
2031	6.7	2.8	0.8
2032	6.6	2.9	0.9
2033	6.4	2.9	0.9
2034	6.3	2.9	0.9
2035	6.2	3.0	0.9
2036	6.1	3.0	0.9

Ex ante estimates were calculated using 2023-2025 ex post estimates, reference loads for 1-in-2 weather years, and the enrollment forecasts. Based on testing, percentage impacts were applied without any variation by weather or event hour, but they imply larger MW reductions when applied to larger reference loads. Changes over time are a function of changes in the utilities' forecasted enrollment levels.

In PY 2026, CPP customers would be expected to deliver demand reductions of 7.8 (PG&E), 2.7 (SCE), and 0.8 (SDG&E) MW in 2026, with impacts changing over time with changes in enrollments. Notably, PG&E's impacts are expected to decline significantly in future years with the expansion of CCAs.

2 INTRODUCTION

Critical Peak Pricing (CPP) is a load modifying program delivered as a set of rate modifiers by each of the California Investor-Owned Utilities (IOUs): PG&E, SCE, and SDG&E. CPP prices are attached to commercial time-of-use (TOU) rates, with price adders during the window from 4 to 9 p.m. on event days. Events are called by utilities based on system demand and program goals, and customers can sign up to receive day-ahead or day-of notifications.

CPP rates include price adders when events are called, encouraging load shifting, but not controlling loads directly. CPP customers then pay lower rates during non-CPP hours in the summer. While the Joint Utilities' CPP rates have many common features, their structure and provisions vary by utility.

CPP rates are the default commercial rates at all three IOUs, with customers eligible to opt out by choosing another rate plan at any time. CPP thus has broad participation by defaulting many customers onto the rates, but there is less clarity on customers' awareness of rate features or ability to shift loads.

Overall, CPP is a broad behavioral program that incentivizes load shifting by increasing peak prices by a pre-set amount during events, but the magnitude of impacts in recent years are often 0 to 1%. In general, dynamic rates tend to deliver smaller percentage impacts than programs with direct load control. Commercial electric demand is also relatively inelastic, which may further explain the lack of response to events. General factors that may also contribute to lower responses include:

- Since CPP rates also have TOU components on non-event days, measured impacts must be over and above any normal shifting behavior during peak summer hours.
- Lack of awareness of price adders by customers who are defaulted onto CPP.
- Lack of interest in load shifting by customers who are defaulted onto CPP.
- Insurance provided against charges such as first-year bill protection (all IOUs) or reserving loads from CPP event pricing (SDG&E only).
- Lower discretionary loads during 4 to 9 p.m. event window for commercial customers
- Event notifications may not be received by decision makers with the ability to modify loads
- Difficulty in responding to varying four-tiered rates (three-tiered TOU rates plus CPP adders announced one day ahead)

2.1 CPP RATE FEATURES

2.1.1 RATE PLAN & ENROLLMENT DETAILS BY IOU

All three utilities offer similar CPP rates, but with some features unique to each. Where relevant, differences will be noted in the ex post results.

A summary of the CPP rates offered by each utility is shown in Table 2-1 below:

Table 2-1: Summary of CPP Rate Details by Utility

Utility/ Program	PG&E	SCE	SDG&E
Marketed as	Peak Day Pricing (PDP)	CPP	CPP
Peak Window	4-9 p.m. year round	4-9 p.m. year round	4-9 p.m. year round
CPP Rate Adder	Generally: <ul style="list-style-type: none"> \$0.60 per kWh for sites with < 75 kW, \$0.90 per kWh for sites with > 75 kW 	\$0.80 per kWh	Generally: <ul style="list-style-type: none"> \$1.17 per kWh for sites with < 20 kW \$2.58 per kWh for sites with > 20kW
Incentive	Lower energy rates (per kWh) during other summer peak hours	Lower pricing for non-event hours during summer months	Lower energy rates (per kWh) during other summer peak hours (demand charges vary)
Any loads protected from CPP pricing?	No	No	Yes, via monthly Capacity Reservation subscription (\$ per kW)
Bill Protection	Yes, for first year	Yes, for first year	Yes, for first year

The IOUs offer various CPP rates for different business sizes and rate classes, but they have generally similar enrollment rules:

Table 2-2: CPP Enrollment Rules by Utility

Utility/ Program	PG&E	SCE	SDG&E
Default rate for C&I customers (bundled)?	Yes	Yes	Yes
CCAs included?	No	No	No
Ag. Included?	Yes	Yes	Yes
Customers eligible for AutoDR programs?	Yes	Yes	Yes
Other ineligible categories	Other energy incentives, energy reduction, peak hour or direct bidding programs	Direct Access (DA) customers	Direct Access (DA) customers

2.1.2 EVENT DATES & GUIDELINES BY IOU

The largest difference in the three IOUs' CPP rates is the number and timing of event days, with each IOU calling its own events based on unique criteria. More details on event guidelines for each IOU are listed in Table 2-3 below:

Table 2-3: CPP Event Day Guidelines by Utility

Utility/ Program	PG&E	SCE	SDG&E
Number of Events - PY2025	9	12	0
Min./Max. Possible Events	Min. 9, Max. 15	Min. 12, Max. 12 (up to 15 for grid emergencies)	Max. 18 (no Min.)
Event Triggers	Day ahead with high temps, high demand, or short supply	Forecasted system emergencies or extreme weather conditions, day-ahead prices, or CAISO Energy Emergency Alerts	Day-ahead system load forecast > 4,000 MW (Can also be triggered for high temp.'s, extreme conditions, emergencies)

PG&E called nine event days in 2025, including two “minimum dispatch” events called in order to achieve the minimum 9 CPP event days during what was a relatively mild summer. Note that later in the report, one of these events, which was called at well below-average temperatures for a CPP event, was not included in the PG&E ex ante model since it was not representative of normal event conditions.

SCE called twelve events in 2025, some of which were also called with the aim of achieving this minimum number for the year, sometimes at lower temperatures. Of these twelve events, most were called later in the season, with five in August and five in September. No events were called in June for any IOU.

SDG&E called no events in PY2025, as conditions in the SDG&E system did not meet the minimum criteria for triggering a CPP event.

Event day pricing applies to all CPP subgroups, with events lasting for the TOU peak window from 4 to 9 p.m. Table 2-5 lists the event days in comparison across utilities. The CAISO system peak for 2025 came on Thursday Aug. 21st, with similarly high levels of demand on Aug. 22nd and September 1st – 3rd. The event days for each utility are shown in Table 2-4 below. Individual system demand by event date is shown in the individual IOU sections of this report.

Table 2-4: PY2025 Events by Utility

Date	PG&E	SCE	SDG&E
7/10/2025	✓		
7/11/2025	✓		
7/30/2025		✓	
7/31/2025		✓	
8/1/2025		✓	
8/8/2025	✓	✓	
8/21/2025	✓	✓	
8/22/2025	✓	✓	
8/25/2025		✓	
9/2/2025		✓	
9/3/2025		✓	
9/4/2025	✓		
9/16/2025	✓	✓	
9/17/2025	✓	✓	
9/18/2025		✓	
9/23/2025	✓		
Total	9	12	0

*CAISO peak day is shaded gray

2.2 EVALUATION OVERVIEW

The primary goal of the evaluation is to measure CPP event impacts for each IOU by rate class and by size group—Small (under 20kW), Medium (20kW to below 200 kW) and Large (200 kW and above). This consists of estimating hourly ex post load impacts for PY2025 and ex ante load impacts through 2036.

2.2.1 CPP GROUPS

Table 2-5 summarizes CPP subgroups for the evaluation. These groups do not correspond to specific rate plans, which may have different size cutoffs and vary by IOU. The groups are simply those used for Statewide analyses, following previous evaluations. Note that SDG&E's Small customers (<20 kW demand) are evaluated in a separate study.

SDG&E has previously reported results by rate class (Agricultural vs. Commercial) in separate evaluations of their Small CPP customers – that convention is carried over for Medium and Large customers in this evaluation as well. SCE and PG&E customer groups combine commercial and agricultural rate classes and are simply distinguished by size.

Table 2-5: CPP Groups for Statewide Evaluation by IOU

Size Group	Max Demand	PG&E Eval. Groups	SCE Eval. Groups	SDG&E Eval. Groups
Large	200 kW and above	Large	Large	Large Commercial
				Large Agricultural
Medium	20 to 199.99 kW	Medium	Medium	Medium Commercial
				Medium Agricultural
Small	Below 20 kW	Small	Small	Small Commercial
				Small Agricultural
Residential	n/a	n/a (separate evaluation)	Residential	n/a

2.2.2 KEY RESEARCH QUESTIONS

For clarity, Table 2-6 summarizes the key research questions guiding this evaluation:

Table 2-6: Key Research Questions for PY2025 CPP Evaluation

Research Question	
1	What were the demand reductions due to program operations in 2025 – for each event day and hour?
2	How do load impacts differ for customers in each subgroup (Large, Medium, Small) during PY2025?
3	How do weather and event hour influence the magnitude of demand response?
4	What are the ex ante load reduction capabilities for 1-in-2 weather conditions? And how well do those align with ex post results?
5	What concrete steps or experimental tests can be undertaken to improve program performance?

3 DATA SOURCES AND METHODS

The CPP event day impacts were primarily estimated using differences-in-differences with a matched control group. Site-specific individual regression models were also used in cases where there were too few customers in a segment (customer size and subLAP for PG&E, customer size and climate zone for SCE) and for sites with large or unique loads.

Each IOU supplied data for the evaluation, including hourly meter data, customer characteristics, and weather data. They also supplied program information such as enrollment lists, notification data, and enrollment forecasts for future program years. All CPP customers were included in the analysis except for the Small CPP groups for SCE and PG&E, where samples were drawn due to the large number of customers, and some remaining sites with incomplete data.

The SCE evaluation compares energy use based on customers' net loads, except for several large power generators that were found on CPP rates, in which case delivered loads were employed to improve the modeling. SDG&E ex post estimates also use delivered loads except in the case of large power generators, though no new ex post estimates were generated this year. For PG&E, only delivered loads were used for all sites.

Table 3-1 lists further detail on the evaluation data and ex post methods by IOU:

Table 3-1: Ex Post Evaluation Details by IOU

Utility/ Program	PG&E	SCE	SDG&E (PY 2024 Evaluation)
Analysis Method	Differences-in-Differences with matched control group for nearly all sites Individual customer regressions if too few sites in customer segment or for very large (>200kW), noisy sites	Differences-in-Differences with matched control group for nearly all sites Individual customer regressions if too few sites in customer segment or for very large (>200kW), noisy sites	Differences-in-Differences with matched control group Individual customer regressions if too few sites in customer segment or for very large (>200kW), noisy sites
Loads Analyzed	Delivered loads	Net loads (delivered minus received kWh) for almost all sites Delivered loads only for power generators	Net loads (delivered minus received kWh) for almost all sites Delivered loads only for power generators
Samples drawn?	Yes, for Small group	Yes, for Small group	No
Geographic segmentation	SubLAP, LCA, Climate Zone	SubLAP, LCA, Climate Zone	SubLAP, LCA, Climate Zone

Utility/ Program	PG&E	SCE	SDG&E (PY 2024 Evaluation)
Subgroups	Small, Medium, Large	Small, Medium, Large	Large Ag., Large Comm., Medium Ag., Medium Comm.
Other segmentation ²	Industry, NEM, AutoDR	Industry, NEM, Power generators, Non-performers, AutoDR, SGIP	Industry, NEM, Power generators
Analyze event notifications?	Yes	Yes	Yes

3.1 EX POST METHODOLOGY

3.1.1 CONTROL GROUP SELECTION

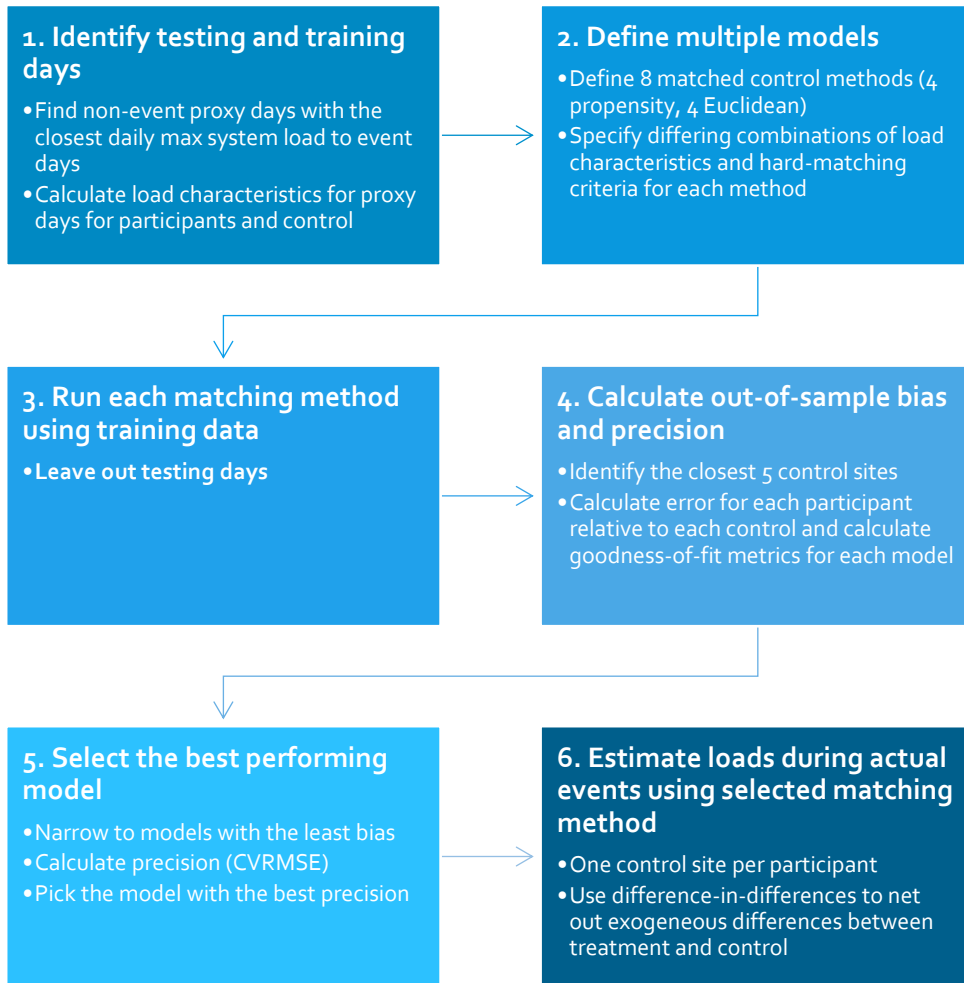
Figure 3-1 summarizes the process used to select matched controls for the difference-in-difference analyses. First, several event-like proxy days were chosen, with similar weather and system conditions to event days. Customers were then matched to non-CPP sites with similar energy-use patterns on the proxy days. More detail on proxy day selection can be found in Appendix B.

Matching methods included different combinations of proxy day load characteristics such as load factor, load shape, and weather sensitivity. Customers were always matched with control candidates in the same geographic area (subLAP for PG&E, climate zone for SCE), net metering status, and size bin. Size bins were constructed using average usage on event-like proxy days. For solar customers, size bins were constructed based on system size.

² Pursuant to the Load Impact Protocol Process Guide (version 6.1, released by the Energy Division on March 5, 2026), "Large loads (e.g. data centers, EV fleet charging station load) should be reported as a distinct load type within ex-ante and ex-post table generators." In PY2025, there were almost 30 customers with loads over 2 MW, and several with loads over 5 MW, enrolled in PG&E's PDP. Judged from the NAICS code, none of these customers appear to be a data center or an EV fleet charging station. SDG&E did not have any customers that met that description either (along with no events and no PY 2025 ex post estimates).

In both the ex post and ex ante impact table generators, there is a customer size indicator, which defines large as 200 kW or above. Hourly load Impacts are available by customer size. Should a different definition for large load be desired, clarification in a future update to the Load Impact Protocol Process Guide would be helpful.

Figure 3-1: Out of Sample Process for Control Group Selection



Matches were evaluated and the process was iterated as necessary until strong matches were achieved for each group. Matching was assessed using bias and goodness-of-fit metrics.

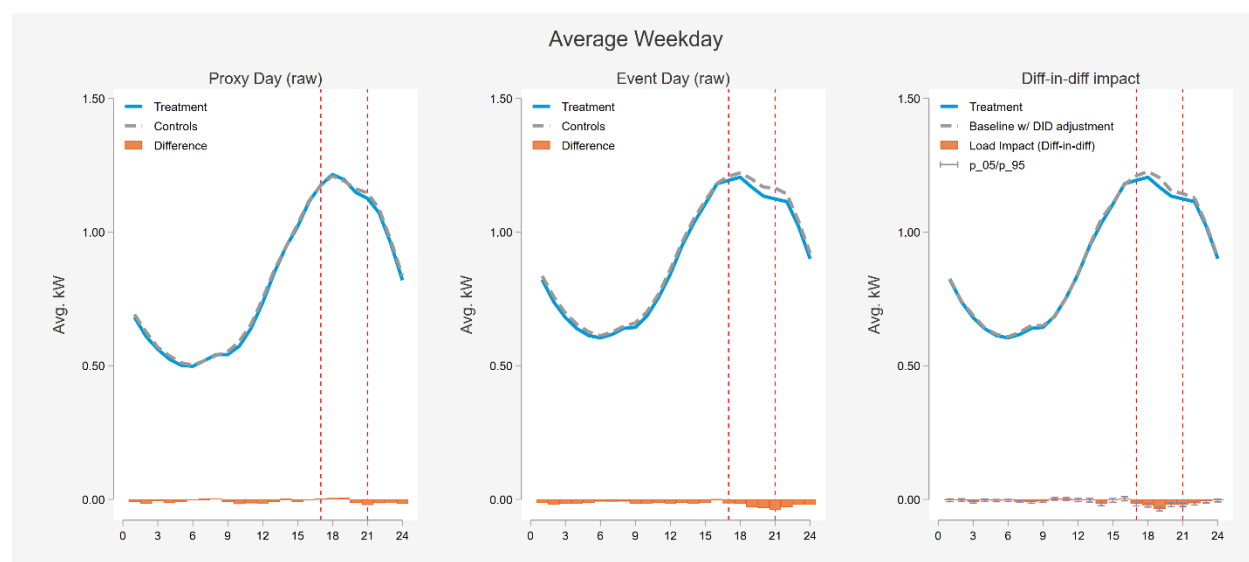
The difference-in-differences approach used the matches collectively as a control group to net out changes in energy usage patterns not due to the CPP events. The individual customer regressions also test for the inclusion of matched control sites as explanatory variables, representing the usage patterns on event days from similar sites. As such, regardless of evaluation methodology, each CPP site was matched to one or more non-CPP sites using a matching tournament where match quality was compared across eight different matching models to identify the best performing model.

3.1.2 DIFFERENCES-IN-DIFFERENCES

Figure 3-2 below demonstrates the mechanics of a difference-in-difference calculation. The data shown is generic and not specific to any group in this evaluation. In the first panel, average observed loads on proxy days are shown for CPP customers and for their matched controls. The difference between these

two is the first “difference” and quantifies underlying differences between CPP customers and their controls not attributable to event participation. Note that this first difference is very small, indicative of a high-quality match and sufficient sample size to neutralize the noise inherent in individual customer loads.

Figure 3-2: Difference-in-Differences Calculation Example



The second panel shows the average observed CPP customer and matched control loads on event days. The gap between these two is the second “difference” which includes both the difference due to event participation and the underlying first difference observable on non-event days.

The third panel shows the average event day loads after netting out the proxy day difference from the event day control load. The result is the difference-in-differences impact, or the change in customers’ usage on event days vs. proxy days, net of any observed differences in the control group on those same days.

For PY 2025, the evaluation applies simple differences-in-differences calculations (differences in group means) in lieu of more complex regression modelling. Regression models attempt to account for partial impacts of various factors on the reference loads, in addition to the observed control group loads. This evaluation simply uses the aggregated control group loads during event hours as the reference load, net of any pre-existing differences between the groups. This allows for greater flexibility during event hours, allowing the control group’s usage to vary in any way necessary, and without extrapolating the reference loads from slope coefficients estimated on non-event days.

The PY 2025 model further omits day-of adjustments for afternoon loads that were used in PY 2023, but does use day-of adjustments for morning loads. These can reduce the noise in estimates, but they may also recalibrate event-day reference loads to include load shifting occurring during earlier hours, biasing the impact estimates. More detail on this modelling decision can be found in Appendix D.

3.1.3 INDIVIDUAL CUSTOMER REGRESSIONS

In cases where a difference-in-differences approach was not possible due to insufficient sample size in the required matching categories or sites with large, noisy loads, site-specific individual customer regression models were used.

For sites requiring individual customer regressions, an out of sample tournament was used to select site specific regression models among 144 possible specifications across 4 parameters:

- Industry profiles, constructed of loads for other similar commercial and industrial customers³
- Local solar irradiance data from nearest weather station
- Number of control sites (up to five matched controls from the matching process above)
- Lags of load data⁴

The industry profiles (based on NAICS codes) and control sites (up to five matches, from the matching process described above) are included as explanatory variables to include the event-day usage patterns of similar sites. A variety of within-subjects lagged loads (1 day, 1 week, 2 weeks) were also included in the model testing.

To implement out of sample testing, the top 50 system load days, excluding event days, were randomly divided into testing and training datasets. Bias and fit metrics were calculated using the testing dataset and the model with the best fit (lowest Root Mean Squared Error) was selected among models with the least bias (Mean Absolute Error⁵). Site-specific load impacts were estimated using the winning model for each site.

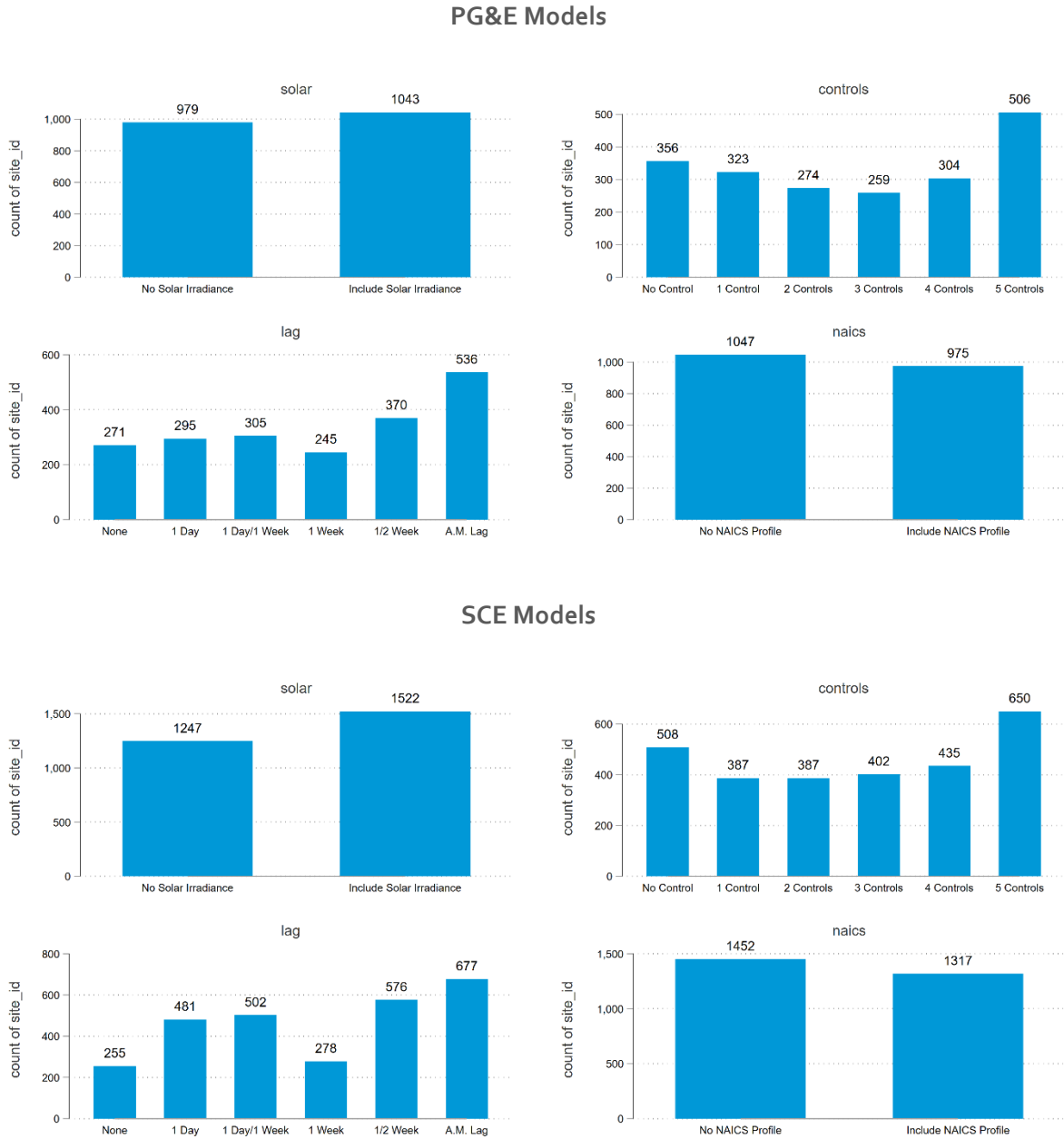
Figure 3-3 shows the different model parameters that were included in the site-specific model tournament and the number of sites for which each parameter was included in the winning model. The wide spread across parameters indicates that it was important to allow for individually-tailored models to be selected for each participating site.

³ Selected from granular load profiles within climate zone and industry segment constructed and maintained by Demand Side Analytics for PG&E, SCE, and SDG&E for the population NMEC settlement validation purposes for the Summer Reliability Program.

⁴ Lags were designed to capture the tendency of large commercial and industrial customers to operate on daily, weekly, or bi-weekly schedules irrespective of weather or time of year. For PY 2025, we also added an early morning lag (avg. kW from 6-10 a.m.) to better estimate loads for sites with on/off patterns or with drastically different loads for entire days.

⁵ MAE was used rather than Mean Average Percent Error (MAPE) to ensure robustness for sites with loads very close to zero, common for sites with solar or other generation.

Figure 3-3: Modeling Parameters Tested and Inclusion in Best Performing Site Specific Models



Further detail on the exact regression specification can be found in Appendix A. In general, a small percentage of this evaluation's estimates were generated by the individual customer regressions.

3.2 EX ANTE METHODOLOGY

A key objective of the DR evaluations is to quantify the relationship between demand reductions, temperature, and hour of the day. The purpose of doing so is to establish the demand reduction capability under 1-in-2 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.

3.2.1 EX ANTE MODEL INPUTS AND SPECIFICATIONS BY IOU

For ex ante projections, we use a top-down enrollment model that includes PY2023 – PY2025 percent impact estimates, system loads, and a CPP enrollment forecast from each IOU. Weather and event-hour impacts were also tested for each IOU, but there were no significant trends in either of these measures on the PY2025 impact estimates, so they were not included. More detail on weather and event hour impacts can be found in each individual IOU section of this report.

Table 3-2 lists details on the ex ante methods by IOU. Methods and data included were largely the same across IOUs, though PG&E has a declining enrollment forecast due to anticipated growth in CCAs, which de-enroll CPP customers by default.

Table 3-2: Ex Ante Analysis Details by IOU

Utility/ Program	PG&E	SCE	SDG&E
Reference loads	PG&E, CAISO 1-in-2 weather year loads	SCE, CAISO 1-in-2 weather year loads	SDG&E, CAISO 1-in-2 weather year loads
PY2025 Ex Post impacts included?	Yes	Yes	No. No events called in PY2025
Historical impact estimates included?	Yes, PY2023 and PY2024	Yes, PY2023 and PY2024	Yes, PY2023 and PY2024
Weather impacts	No, based on testing	No, based on testing	No, based on testing
Different percent impacts by event hour?	No, based on testing	No, based on testing	No, based on testing
Enrollment forecast	11 years (2026-2036), supplied by IOU	11 years (2026-2036), supplied by IOU	11 years (2026-2036), supplied by IOU
Enrollment forecast trend	Declining	Slight increases via defaults	Slight increases via defaults through 2036

3.2.2 PORTFOLIO-ADJUSTED IMPACTS

For ex ante estimates, program-specific and portfolio-adjusted impacts are developed for each IOU and subgroup.⁶ Since customers may be able to participate in more than one energy-saving program, an attribution of savings estimates to separate DR programs is essential. This prevents double-counting savings for planning purposes. Ex post results are properly attributed by calculating the incremental impacts, or the load reduction beyond what was predicted or committed on dually called event hours. Modelling for ex ante is based solely on these incremental impacts.

Across all three IOUs, however, there was little dual-program participation with CPP. The only exception was ELRP – each IOU chose to count CPP impacts before ELRP impacts in their portfolio aggregations, so incremental impacts accounting for dual CPP-ELRP participation are handled in that evaluation. Any impacts for dual CPP-ELRP customers are therefore wholly attributed to CPP in this evaluation.

Among the remaining DR programs with allowable dual participation, only PG&E's and SCE's BIP and SCE's SDP program had dual customers. Of these dual enrollment groups, none produced significant ex post impacts on CPP event days necessitating adjustments for the ex ante modeling⁷. As such, in all cases the portfolio-adjusted impacts reported in this evaluation are equal to the program-specific impacts. Ex ante results will generally be presented as "portfolio-adjusted", since these are the impacts used for planning, but they are equivalent to the program-specific values.

Table 3-3 gives more detail on the dual-program considerations by IOU:

Table 3-3: Eligible Dually Enrolled Programs for Ex Ante Considerations by IOU

IOU	BIP	CBP	Thermostat Programs	ELRP
PG&E	Removed from analysis per PG&E	No dual participants	N/A	Adjustments made in ELRP evaluation
SCE	No significant impacts	No dual participants	SDP dual participants evaluated – no significant impacts	Adjustments made in ELRP evaluation
SDG&E	N/A	No dual participants	N/A	Adjustments made in ELRP evaluation

⁶ The use of the word "program" in the case of CPP means just the rate load impacts alone, not accounting for any interaction with another demand response program – which is referred to as portfolio-adjusted impacts.

⁷ Four PG&E BIP dual enrolled sites were removed from ex post impacts for ex ante portfolio-adjusted modeling but their impacts or effect on reference loads was negligible.

4 PG&E PY2025 IMPACTS

PG&E's CPP rate program, marketed as Peak Day Pricing (PDP) had approximately 89,000 customers enrolled in PY2025. Most customers were enrolled in CPP rates by default, but they can opt out at any time. CPP rates are offered in both commercial and agricultural rate classes. Most, however, are commercial customers, so they are combined for this evaluation into Small, Medium, and Large size distinctions based on their annual peak kW.

PG&E had nine event days in PY2025, largely coinciding with the hottest summer days in PG&E's territory, though summer 2025 temperatures were relatively mild. Event days extended from July through September, and customers were eligible to receive day ahead or day-of event notifications via email, text, or phone.

4.1 PG&E SUMMARY OF RESULTS

Table 4-1 summarizes the estimated ex post demand reductions for the average weekday event for each of PG&E's CPP groups. All impacts are incremental to other DR program impacts, though for PG&E no other programs had significant impacts on the PY2025 estimates. Statistical significance is noted for each subgroup in the last two columns.

PG&E's Large sites had the largest event-hour reductions in percentage terms (1.3%), but these impacts were not statistically significant. PG&E's Medium sites had the greatest aggregate reduction (3.4 MW) and had a slightly smaller load reduction in percentage terms (1.2%). PG&E's Small sites had a similar load reduction for PY2025 in percentage terms (1.2%), but the smallest aggregate reduction (1.8 MW). Both Small and Medium site impacts were significant at the 5% level.

Overall the evaluation found a point estimate of just under 8 MW reduced by PG&E's CPP rate customers during PY2025 event hours. However, this estimate has a broad distribution due to high variance in the Large sites' performance.

Table 4-1: PG&E Ex Post Demand Reductions for an Average Weekday Event

Group	Sites	Load without DR (MW)	Load reduction (MW)	% Reduction	Significant (90% CI)	Significant (95% CI)
Large (200 kW and Above)	1,300	214.02	2.79	1.3%	No	No
Medium (20 to 199.99 kW)	13,033	291.25	3.36	1.2%	Yes	Yes
Small (Below 20 kW)	74,338	145.10	1.76	1.2%	Yes	Yes
Total	88,671	650.37	7.91	1.2%	Yes	Yes

Table 4-2 summarizes PG&E’s forecasted site enrollments through 2036 by group. Many CPP customers have been automatically de-enrolled in recent years as localities have set up Community Choice Aggregations (CCAs), which do not offer CPP rates. PG&E’s team has thus accounted for CPP losses to CCAs in their enrollment forecast, and modeled decreasing enrollments over time in the areas where new CCAs are currently planned.

Table 4-2: PG&E Summary of Ex Ante Site Enrollments

Year	Large	Medium	Small	Total
2025	1,340	13,275	75,403	90,018
2026	1,208	13,967	80,940	96,115
2027	1,234	14,504	82,730	98,468
2028	1,181	12,436	68,016	81,633
2029	1,169	12,070	65,526	78,765
2030	1,157	11,730	63,140	76,027
2031	1,145	11,403	60,875	73,423
2032	1,133	11,111	58,694	70,938
2033	1,121	10,826	56,594	68,541
2034	1,109	10,550	54,553	66,212
2035	1,097	10,299	52,620	64,016
2036	1,085	10,056	50,755	61,896

Table 4-3 summarizes the portfolio-adjusted reductions that PG&E CPP rates can be expected to deliver *ex ante* under August peak conditions in an PG&E 1-in-2 weather year. These impacts were not found to be sensitive to either weather or event hour for PY2025. The estimates are instead a function of the percent impact estimates in this (PY2025) and the previous (Py2023 & PY2024) evaluations. The results reflect reduction capability for a single event across PG&E’s CPP event window (4 to 9 p.m.)

Overall, CPP customers can be expected to deliver an aggregate 7.8 MW per five-hour event next year (2026), with *ex ante* impacts decreasing steadily as enrollments decrease through 2036. Both the Large and Medium groups factor heavily into these projections, accounting for 2.9 and 3.6 MW *ex ante* for 2026. The Small group, with most of the CPP customers, is only anticipated to deliver about 1 MW per year going forward.

Table 4-3: PG&E Ex Ante Demand Reductions for August Worst Day, System 1-in-2 Weather (MW, Portfolio-Adjusted)

Year	Large	Medium	Small	Total
2025	3.3	2.9	1.4	7.6
2026	2.9	3.6	1.4	8.0
2027	3.0	3.7	1.5	8.1
2028	2.9	3.2	1.2	7.3
2029	2.8	3.1	1.2	7.1
2030	2.8	3.0	1.1	7.0
2031	2.8	3.0	1.1	6.8
2032	2.7	2.9	1.1	6.7
2033	2.7	2.8	1.0	6.6
2034	2.7	2.7	1.0	6.4
2035	2.7	2.7	1.0	6.3
2036	2.6	2.6	0.9	6.2

4.2 PG&E EVENT CHARACTERISTICS

Table 4-4 shows the nine CPP event days in PY2025 as well as the PG&E system peak load on each day. All nine events ran from 4 to 9 p.m. and covered all sites on CPP rates. PG&E optionally sends day-ahead notifications to customers to help in load shifting during the increased price periods. These are sent via text, email, or phone based on customers' preferences.

Event days covered a range of summer months, but were focused on days with the highest temperatures and system loads in PG&E territory. All event days were weekdays, and no events were called in June.

PG&E called nine event days in 2025, including two "minimum dispatch" events called in order to achieve the minimum 9 CPP event days during what was a relatively mild summer. One of these events (September 4th), which was called at well below-average temperatures for a CPP event, was not included in the PG&E ex ante model since it was not representative of normal event conditions.

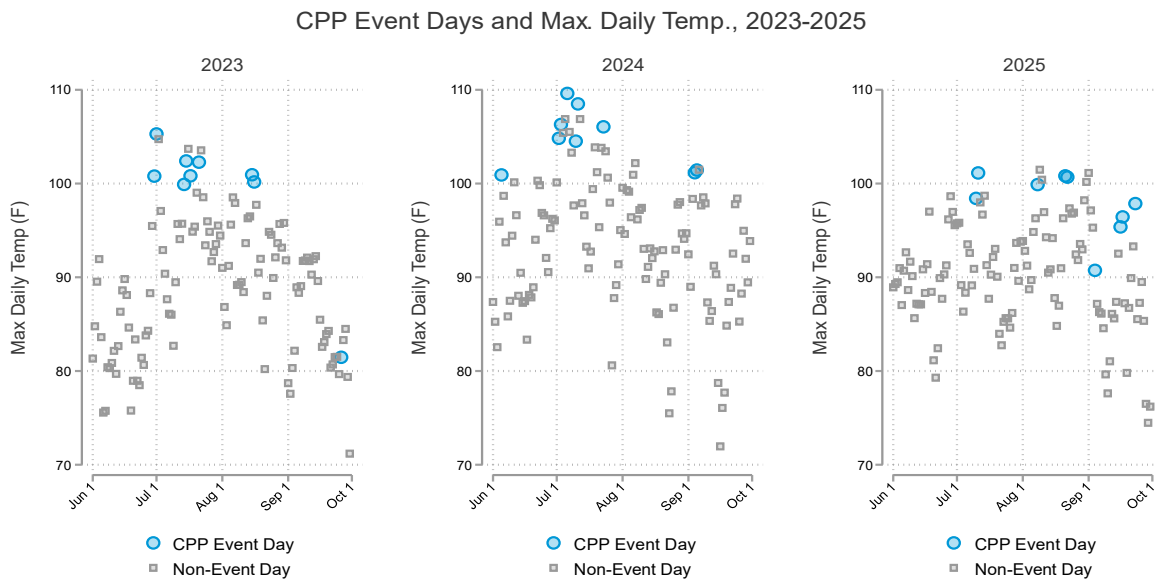
Table 4-4: PG&E CPP Events in 2025

Event date	Day of week	Max PG&E system load (MW)	Event window	All groups
7/10/2025	Thursday	17,527	4 to 9 pm	✓
7/11/2025	Friday	17,840	4 to 9 pm	✓
8/8/2025	Friday	18,246	4 to 9 pm	✓
8/21/2025	Thursday	18,875	4 to 9 pm	✓
8/22/2025	Friday	17,679	4 to 9 pm	✓
9/4/2025	Thursday	15,719	4 to 9 pm	✓
9/16/2025	Tuesday	17,168	4 to 9 pm	✓
9/17/2025	Wednesday	17,305	4 to 9 pm	✓
9/23/2025	Tuesday	18,185	4 to 9 pm	✓

*9/4 and 9/16 events were “minimum dispatch” events that were called to achieve the minimum number of events (9). The 9/4 event (shown in blue) is removed from the ex ante model since it was not representative of normal event conditions for PG&E’s CPP event days.

As shown in Figure 4-1, PG&E’s events came on milder days than those called in previous years. PG&E’s CPP event days are generally among the hottest days of the summer, but temperatures in Summer 2025 were mild relative to previous years, so all events came on days that would have been less extreme in 2023 or 2024.

Figure 4-1: PG&E Event Days and Temperature by Year



All but two of PG&E's events in summer 2025 had statistically significant impacts. All generally had impacts from 0.6% to 2.1% aside from the 9/4 event which was called at much cooler temperatures.

Table 4-5: PY 2025 Impacts by Event Day, All Groups Combined – PG&E

Event date	Total enrolled sites	Avg temp (F, site weighted)	Load reduction (MWh/h)	% Load reduction	Std. error	t-stat	Sig. 90%
7/10/2025	89,430	95.6	3.8	0.6%	3.2	-1.2	No
7/11/2025	89,410	98.1	14.1	2.1%	3.1	-4.5	Yes
8/8/2025	88,812	98.0	10.3	1.6%	3.0	-3.4	Yes
8/21/2025	88,651	96.6	10.0	1.5%	3.2	-3.1	Yes
8/22/2025	88,629	98.2	12.0	1.8%	3.2	-3.8	Yes
9/4/2025	88,394	88.4	-2.4	-0.4%	3.1	0.8	No
9/16/2025	88,260	92.8	7.5	1.2%	3.1	-2.4	Yes
9/17/2025	88,254	93.2	6.1	1.0%	3.2	-1.9	Yes
9/23/2025	88,199	93.9	10.1	1.6%	3.2	-3.1	Yes
Avg Weekday 4-9 pm	88,671	95.0	7.9	1.2%	2.8	-2.8	Yes

4.3 PG&E EX POST LOAD IMPACTS

4.3.1 PG&E SITES IN ANALYSIS

PG&E had almost 89,000 customers on CPP rates in 2025, including both agricultural and commercial customers. Sites were analyzed in groups based on size, as shown in Table 4-6 below. Most sites (roughly 74,000) were in the Small group, with less than 20 kW peak demand. Due to the large number of sites in this group, a random sample was drawn by industry and climate, with just over 40,000 sites included in the actual analysis. All results were then weighted to reflect the full population of Small CPP customers. For example, PG&E CPP had many small office sites in Climate Zone 3 in the Bay Area – only a subset of these were drawn into the random sample, but each small office in the sample carries large weight in the Small group's impact estimates.

Table 4-6 also shows any other difference between the full CPP enrollment counts and the number of sites used for the ex post analysis. "Total Sites" indicates the total number of sites enrolled for at least one PY2025 event. In addition to the sampling for the Small group, several sites were dropped due to incomplete data, outages, or other data issues.

Table 4-6: PG&E PY2025 Site Enrollments by Size (Avg Weekday Event)

Group	Sector	Total sites	Sites in analysis*	Percent
Large	Commercial & Agricultural	1,300	1,275	98%
Medium	Commercial & Agricultural	13,033	12,321	95%
Small	Commercial & Agricultural	74,338	40,235	54%
Total	Commercial & Agricultural	88,671	53,831	61%

*Small group sites in analysis drawn randomly from customer population

4.3.2 PG&E LARGE - IMPACTS BY EVENT

For PY2025, PG&E had an average of 1,300 Large customers across its nine summer events. All enrolled sites were included in the events, with increased prices from 4 to 9 p.m. Table 4-7 summarizes Large sites' load reductions and customer-weighted event temperatures during each event and for the average weekday event. In the tables, the bars show a visual comparison of the reductions that listed to the left of each.

Large sites had estimated impacts between 1 and 2% for most events. Most individual event days did not have statistically significant impacts, however, indicating a high degree of noise in the estimates. The three events that had statistically significant impacts also had the highest estimated impacts, between 2.1% and 3.4%. Overall, weekday events had load reductions of 1.3% on average, and this estimate was not statistically significant.

Table 4-7: Ex Post Impact Estimates by Event - PG&E Large

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Reductions (Ex Post)			Significant (90% CI)	Significant (95% CI)
				Aggregate (MW)	% Reduction	Average Site (kW)		
7/10/2025	4 to 9 pm	96.0	1,315	-1.2	-0.6%	-0.9	No	No
7/11/2025	4 to 9 pm	99.4	1,315	8.0	3.8%	6.1	Yes	Yes
8/8/2025	4 to 9 pm	99.1	1,305	5.4	2.6%	4.1	Yes	Yes
8/21/2025	4 to 9 pm	97.5	1,300	1.7	0.8%	1.3	No	No
8/22/2025	4 to 9 pm	99.6	1,300	6.1	2.9%	4.7	Yes	Yes
9/4/2025	4 to 9 pm	90.5	1,293	-2.7	-1.2%	-2.1	No	No
9/16/2025	4 to 9 pm	94.4	1,288	1.4	0.7%	1.1	No	No
9/17/2025	4 to 9 pm	94.0	1,288	2.9	1.3%	2.3	No	No
9/23/2025	4 to 9 pm	94.6	1,288	3.4	1.6%	2.6	No	No
Avg Weekday 4-9 pm	4 to 9 pm	96.1	1,300	2.8	1.3%	2.1	No	No

Impacts were also estimated for several subsegments of each group and included in the PG&E Ex Post table generators. As many of these were insignificant or inconsistent (e.g. varying impacts by Industry across the Small, Medium, and Large groups), they should be interpreted with caution.

4.3.3 PG&E MEDIUM - IMPACTS BY EVENT

For PY2025, PG&E had an average of 13,033 Medium customers (20 to 199.99 kW max demand) across its nine summer events. All enrolled sites were included in the events, with increased prices from 4 to 9 p.m. Table 4-8 summarizes the load reductions and customer-weighted event temperatures for CPP. In the tables, the bars show a visual comparison of the reductions that are numerically labeled on the left of the bars.

On average, weekday events produced load reductions of 3.4 MW (1.2%) for Medium sites, with the aggregate impact driven in part by the large number of sites in this group. Seven event days had statistically significant load reductions at the 5% level with impact estimates on these days ranging from 0.9 to 1.7%. One event was only significant at the 10% level (9/17) and had a slightly lower impact of 0.8%, and only one event was not statistically significant at either level (9/4).

Table 4-8: Ex Post Impact Estimates by Event - PG&E Medium

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Reductions (Ex Post)			Significant (90% CI)	Significant (95% CI)
				Aggregate (MW)	% Reduction	Average Site (kW)		
7/10/2025	4 to 9 pm	96.0	13,106	3.0	1.0%	0.2	Yes	Yes
7/11/2025	4 to 9 pm	98.8	13,104	3.8	1.3%	0.3	Yes	Yes
8/8/2025	4 to 9 pm	98.7	13,050	3.6	1.2%	0.3	Yes	Yes
8/21/2025	4 to 9 pm	97.1	13,034	4.9	1.6%	0.4	Yes	Yes
8/22/2025	4 to 9 pm	98.9	13,034	3.7	1.2%	0.3	Yes	Yes
9/4/2025	4 to 9 pm	89.2	13,001	0.0	0.0%	0.0	No	No
9/16/2025	4 to 9 pm	93.6	12,991	4.0	1.4%	0.3	Yes	Yes
9/17/2025	4 to 9 pm	93.7	12,993	2.3	0.8%	0.2	Yes	No
9/23/2025	4 to 9 pm	94.3	12,988	5.0	1.8%	0.4	Yes	Yes
Avg Weekday 4-9 pm	4 to 9 pm	95.6	13,033	3.4	1.2%	0.3	Yes	Yes

4.3.4 PG&E SMALL - IMPACTS BY EVENT

PG&E had an average of 74,338 Small CPP customers during PY2025 events. All enrolled sites were included in the events, with increased prices from 4 to 9 p.m. Table 4-9 summarizes the load reductions and customer-weighted event temperatures for Small sites during each event and for the average weekday event. In the tables, the bars show a visual comparison of the reductions that are numerically labeled on the left of the bars.

On average, weekday events produced load reductions of 1.2% (1.8 MW) lower electric demand during event hours. Similar to the Medium group, Small had seven event days with statistically significant load reductions at the 5%, one event was only significant at the 10% level (9/17), and one event that was not statistically significant at either level (9/4). The events that were statistically significant at the 5% level ranged from 1.0% to 2.2%, with most of the impacts being between 1.0% and 1.5%. The event that was only statistically significant at the 10% level had lower impacts than the events that were statistically significant at the 5% level (0.6%), and the event that was not statistically significant as no impacts.

Table 4-9: Ex Post Impact Estimates by Event - PG&E Small

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Reductions (Ex Post)			Significant (90% CI)	Significant (95% CI)
				Aggregate (MW)	% Reduction	Average Site (kW)		
7/10/2025	4 to 9 pm	95.5	75,009	1.9	1.3%	0.0	Yes	Yes
7/11/2025	4 to 9 pm	98.0	74,991	2.3	1.5%	0.0	Yes	Yes
8/8/2025	4 to 9 pm	97.9	74,457	1.4	0.9%	0.0	Yes	Yes
8/21/2025	4 to 9 pm	96.5	74,317	3.4	2.2%	0.0	Yes	Yes
8/22/2025	4 to 9 pm	98.1	74,295	2.1	1.4%	0.0	Yes	Yes
9/4/2025	4 to 9 pm	88.2	74,100	0.2	0.1%	0.0	No	No
9/16/2025	4 to 9 pm	92.6	73,981	2.1	1.5%	0.0	Yes	Yes
9/17/2025	4 to 9 pm	93.1	73,973	0.9	0.6%	0.0	Yes	No
9/23/2025	4 to 9 pm	93.9	73,923	1.8	1.3%	0.0	Yes	Yes
Avg Weekday 4-9 pm	4 to 9 pm	94.9	74,338	1.8	1.2%	0.0	Yes	Yes

4.3.5 PG&E IMPACT BREAKDOWNS BY SUBGROUP

Impacts by Industry

Customers are assigned different industries according to NAICS codes. Agriculture, Mining, and Construction had the highest load reduction both percentagewise (3.8%) and in load size (3.11 MW). Their results were also statistically significant at the 10% level. Institutional/Government and Retail Stores also had statistically significant impacts, saving 1.2% and 0.5% respectively. Schools also had statistically significant impacts, but they were found to use 1.7% more energy during event hours. In previous years, schools also had largely negative impacts. Other industries were not statistically significant, but Wholesale, Transport, and Other Utilities and Manufacturing had fairly high percent impacts, at 1.9% and 1.2% respectively.

Table 4-10: PG&E Ex Post Impact Estimates by Industry

Subcategory	Total enrolled sites	Reference load (MWh/h)	Load w/ DR (MWh/h)	Load reduction (MWh/h)	% Load reduction	Avg temp (F, site weighted)	Std. error	t-stat	Sig 90%
Agriculture, Mining & Construction	6,834	82.89	79.68	3.21	3.9%	95.8	1.4	-2.3	Yes
Institutional/Government	10,971	87.29	86.27	1.01	1.2%	95.3	0.5	-2.2	Yes
Manufacturing	3,209	54.94	54.20	0.74	1.3%	94.7	1.4	-0.5	No
Offices, Hotels, Finance, Services	35,442	204.14	203.45	0.70	0.3%	94.8	0.7	-1.0	No
Other/Unknown	5,345	16.37	16.30	0.07	0.4%	94.6	0.3	-0.2	No
Retail Stores	8,512	81.62	81.18	0.44	0.5%	95.3	0.2	-2.1	Yes
Schools	1,636	25.43	25.69	-0.26	-1.0%	94.7	0.2	1.2	No
Wholesale, Transport, Other Utilities	16,718	96.89	94.88	2.01	2.1%	94.9	1.2	-1.7	Yes

4.4 PG&E EX ANTE LOAD IMPACTS

A key objective of the evaluation is to project, *ex ante*, the load reductions that CPP customers can deliver on future event days. These are intended to reflect performance under normal (1-in-2) peak demand weather conditions for both CAISO and the PG&E system.

In general, ex ante forecasts rely on the estimated ex post impacts for current or recent program years, as well as any relationship between weather and event hour to load reductions. For PY2025, ex ante modeling incorporated PY2023, PY2024, and PY2025 ex post impact estimates, but it did not include any differential impacts based on weather or the event hour.

4.4.1 PG&E Ex ANTE MODEL INPUTS

For PY2025, the key inputs for ex ante impact model are:

- PY2023 ex post impact estimates
- PY2024 ex post impact estimates
- PY2025 ex post impact estimates
- 1-in-2 system weather data for both the CAISO and SCE
- CPP enrollment forecast through 2036

The following factors were also considered, but ultimately were not included in the ex ante model:

- Weather impacts on percent reductions
- Event-hour impacts on percent reductions

Note that while event hour and weather do not impact the percent reductions in the ex ante model, both hotter temperatures and earlier event hours result in larger aggregate impact estimates, since percent reductions are applied to larger reference loads in each case.

PY 2025 Impact Estimates

Ex post impacts estimates by event, hour, and rate class are the primary input for the ex ante model. These are included individually as point estimates for each unique event hour (date x hour combinations) for PY 2025.

Since it was not representative of normal event conditions for PG&E, the September 4th, 2025, event day was removed from the ex ante model. Overall, this increased the 2025 ex post estimates slightly since it had the lowest impact estimate of any event day.

Historical Impact Estimates

PY2023 and PY2024 ex post impacts were included, along with the PY 2025 ex post estimates, in the ex ante model. For PY2025, PG&E's CPP groups had statistically significant impacts on almost all event days. However, the PY2023 and PY2024 percent impacts were included to add more data to the model.

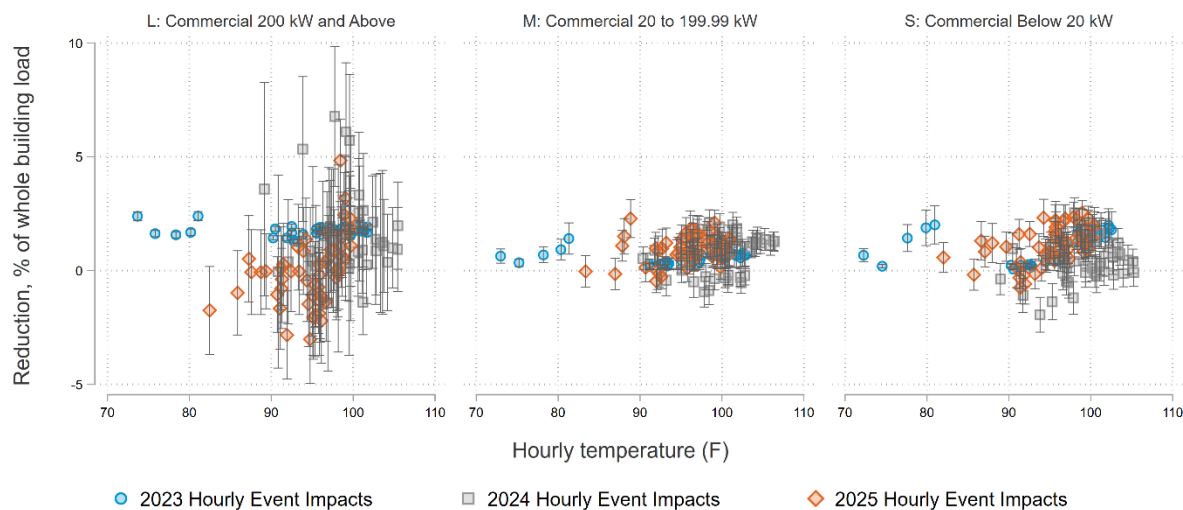
Statewide evaluations through PY 2023 were performed by a different evaluator, with some different decisions made in the ex post modelling, as discussed in the methodology section and in Appendix C. Including the PY2023 impacts can therefore aid in creating greater consistency in the study outputs.

An additional "minimum dispatch" event with well below-average temperatures from 2023 was also removed from PG&E's ex ante model. This was done to treat all years equivalently in the model, and had been done in the past by the previous evaluator per the PG&E program team.

Weather Impacts

Figure 4-2 plots the estimated ex post impacts (in percentage terms) for each event day in 2023-2025 against the average daily temperature (with the average weighted by the number of customers). The points are shown as they would be used in the ex ante modeling.

Figure 4-2: PG&E Hourly Reductions vs. Average Temperatures

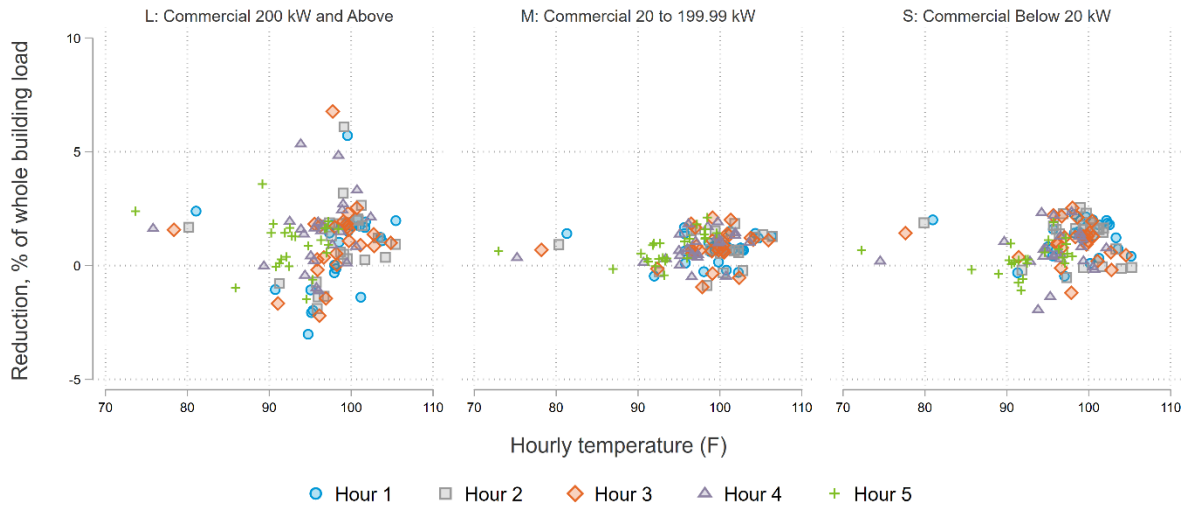


There is no clear trend in the percent impacts as temperature increases along the horizontal axes. Some positive trends can be seen between 90 and 100 degrees in the 2023 estimates for Small and Medium commercial sites only, but these do not extend to lower temperature ranges, nor are they evident in the 2024 or 2025 results to any degree. No weather trends for PG&E were found to be significant in the 2023 or 2024 evaluations and as such were excluded in those evaluations as well. Therefore, ex ante reductions at different temperature levels are assumed to vary only as a function of the reference load.

Event Hour Impacts

Figure 4-3 plots the 2025 ex post impacts separately by event hour. In this figure, level shifts in the impacts along the vertical axis by event hour would imply differential impacts by event hour. There is no clear trend in the graphs showing any series of event hour points higher/lower than the other series. Therefore, ex ante reductions across different event hours are assumed to vary only as a function of the reference load.

Figure 4-3: PG&E Impacts by Event Hour and Temperature



Enrollment Forecast

To derive the aggregate forecast and reference loads, percent impacts per customer are scaled to the site population expected to be enrolled in each planning year. Table 4-11 summarizes the annual enrollment forecast for each subgroup.

Table 4-11: PG&E Participant Enrollment Forecast

Year	Large	Medium	Small	Total
2025	1,340	13,275	75,403	90,018
2026	1,210	13,966	80,939	96,115
2027	1,235	14,502	82,728	98,465
2028	1,181	12,436	68,017	81,634
2029	1,169	12,071	65,525	78,765
2030	1,157	11,730	63,142	76,029
2031	1,145	11,403	60,875	73,423
2032	1,133	11,111	58,693	70,937
2033	1,121	10,827	56,596	68,544
2034	1,109	10,552	54,553	66,214
2035	1,097	10,297	52,617	64,011
2036	1,085	10,058	50,756	61,899

PG&E developed the CPP enrollment forecast that was used to scale the ex ante impacts. PG&E's forecast is very granular, with estimates for each combination of size, subLAP, and industry group.

Overall, PG&E anticipates further expansion of CCAs, which de-enroll CPP customers by default. This drives the large decreases in CPP enrollments through 2036 in the forecast.

4.4.2 PG&E – EX ANTE LOAD IMPACTS

Table 4-12 summarizes the portfolio-adjusted ex ante demand reduction capability of all of PG&E's CPP customers under different planning conditions.

Impact estimates represent customers' estimated demand reductions available from 4 to 9 p.m. under August worst day conditions for a 1-in-2 weather year. Since the ex post analysis showed no clear trends in percent load reductions relative to weather patterns or event hour, the ex ante impacts are assumed to vary only as a function of the reference loads.

PG&E's enrollment forecast includes granular forecasts by industry and subLAP, which accounts for the variance in future enrollments from year to year. In particular, CPP enrollment among agricultural sites, which had smaller ex post impact estimates in this evaluation, is predicted to grow. Enrollment in other industries is generally predicted to decline. Thus, the combined ex ante impacts decrease from 7.2-7.7 MW in 2026 from 5.9 to 6.2 MW in 2036.

Table 4-12: PG&E Combined Ex-Ante Impacts for 1-in-2 August Worst Day (MW)⁸

Weather Type	Year	Sites	CAISO		PG&E	
			Program	Portfolio Adj	Program	Portfolio Adj
1-in-2	2025	90,018	7.17	7.22	7.62	7.67
1-in-2	2026	96,115	7.50	7.54	7.96	8.00
1-in-2	2027	98,468	7.67	7.71	8.14	8.19
1-in-2	2028	81,633	6.92	6.96	7.31	7.35
1-in-2	2029	78,765	6.76	6.81	7.14	7.19
1-in-2	2030	76,027	6.62	6.66	6.99	7.03
1-in-2	2031	73,423	6.47	6.52	6.84	6.88
1-in-2	2032	70,938	6.34	6.38	6.69	6.74
1-in-2	2033	68,541	6.21	6.25	6.55	6.60
1-in-2	2034	66,212	6.08	6.12	6.42	6.46
1-in-2	2035	64,016	5.96	6.00	6.29	6.33
1-in-2	2036	61,896	5.85	5.89	6.18	6.22

⁸ Impacts are both portfolio-adjusted and program-specific impacts since no dual-enrollment groups had significant impacts. Any differences are rounding errors in the aggregations.

4.4.3 PG&E LARGE - EX ANTE LOAD IMPACTS

Table 4-13 summarizes the portfolio-adjusted ex ante demand reduction capability of PG&E's Large CPP customers under different planning conditions.

Impact estimates represent customers' estimated demand reductions available from 4 to 9 p.m. under August worst day conditions for a 1-in-2 weather year. Since the ex post analysis showed no clear trends in percent load reductions relative to weather patterns or event hour, the ex ante impacts are assumed to vary only as a function of the reference loads.

PG&E's enrollment forecast includes granular forecasts by industry and subLAP, which accounts for the variance in future enrollments from year to year. In particular, CPP enrollment among agricultural sites, which had smaller ex post impact estimates in this evaluation, is predicted to grow. Enrollment in other industries is generally predicted to decline. Thus, the combined ex ante impacts decrease from 2.8-2.9 MW in 2026 from 2.6 to 2.7 MW in 2036.

Table 4-13: PG&E Large Ex-Ante Impacts for 1-in-2 August Worst Day (MW)⁹

Weather Type	Year	Sites	CAISO		PG&E	
			Program	Portfolio Adj	Program	Portfolio Adj
1-in-2	2025	1,340	3.18	3.23	3.29	3.35
1-in-2	2026	1,210	2.82	2.86	2.91	2.95
1-in-2	2027	1,235	2.87	2.91	2.96	3.01
1-in-2	2028	1,181	2.77	2.81	2.86	2.90
1-in-2	2029	1,169	2.74	2.79	2.83	2.88
1-in-2	2030	1,157	2.72	2.76	2.80	2.85
1-in-2	2031	1,145	2.69	2.73	2.78	2.82
1-in-2	2032	1,133	2.66	2.71	2.75	2.79
1-in-2	2033	1,121	2.64	2.68	2.72	2.77
1-in-2	2034	1,109	2.61	2.65	2.69	2.74
1-in-2	2035	1,097	2.58	2.63	2.66	2.71
1-in-2	2036	1,085	2.56	2.60	2.64	2.68

4.4.4 PG&E MEDIUM - EX ANTE LOAD IMPACTS

Table 4-14 summarizes the portfolio-adjusted ex ante demand reduction capability of PG&E's Medium CPP customers under different planning conditions.

⁹ Impacts are both portfolio-adjusted and program-specific impacts since no dual-enrollment groups had significant impacts. Any differences are rounding errors in the aggregations.

Impact estimates represent Medium customers' estimated demand reductions available from 4 to 9 p.m. under August worst day conditions for a 1-in-2 weather year. Since the ex post analysis showed no clear trends in percent load reductions relative to weather patterns or event hour, the ex ante impacts are assumed to vary only as a function of the reference loads.

PG&E's enrollment forecast anticipates Medium customers falling by half over the next ten years due to the growth of CCAs, which de-enroll sites by default. This accounts for the decline in impacts from 3.4-3.6 MW in 2026 to 2.5 to 2.6 MW in 2036.

Table 4-14: PG&E Medium Ex-Ante Impacts for 1-in-2 August Worst Day (MW)

Weather Type	Year	Sites	CAISO		PG&E	
			Program	Portfolio Adj	Program	Portfolio Adj
1-in-2	2025	13,275	2.70	2.70	2.91	2.91
1-in-2	2026	13,966	3.37	3.36	3.61	3.61
1-in-2	2027	14,502	3.45	3.45	3.71	3.70
1-in-2	2028	12,436	3.01	3.00	3.21	3.21
1-in-2	2029	12,071	2.92	2.92	3.12	3.12
1-in-2	2030	11,730	2.84	2.84	3.04	3.04
1-in-2	2031	11,403	2.76	2.76	2.95	2.95
1-in-2	2032	11,111	2.69	2.69	2.88	2.88
1-in-2	2033	10,827	2.62	2.62	2.81	2.81
1-in-2	2034	10,552	2.56	2.56	2.73	2.73
1-in-2	2035	10,297	2.49	2.49	2.67	2.67
1-in-2	2036	10,058	2.45	2.45	2.62	2.62

4.4.5 PG&E SMALL - EX ANTE LOAD IMPACTS

Table 4-15 summarizes the portfolio-adjusted ex ante demand reduction capability of PG&E's Small CPP customers under different planning conditions.

Impact estimates represent Small customers' estimated demand reductions available from 4 to 9 p.m. under August worst day conditions for a 1-in-2 weather year. Since the ex post analysis showed no clear trends in percent load reductions relative to weather patterns or event hour, the ex ante impacts are assumed to vary only as a function of the reference loads.

PG&E's enrollment forecast also predicts that Small customers will decrease by half over the next ten years due to CCAs. This accounts for the decline in impacts from 1.3-1.4 MW in 2026 to 0.8 MW by 2036.

Table 4-15: PG&E Small Ex-Ante Impacts for 1-in-2 August Worst Day (MW)

Weather Type	Year	Sites	CAISO		PG&E	
			Program	Portfolio Adj	Program	Portfolio Adj
1-in-2	2025	75,403	1.26	1.26	1.38	1.38
1-in-2	2026	80,939	1.15	1.15	1.26	1.26
1-in-2	2027	82,728	1.20	1.20	1.30	1.30
1-in-2	2028	68,017	1.02	1.02	1.10	1.10
1-in-2	2029	65,525	0.98	0.98	1.06	1.06
1-in-2	2030	63,142	0.94	0.94	1.02	1.02
1-in-2	2031	60,875	0.91	0.91	0.98	0.98
1-in-2	2032	58,693	0.87	0.87	0.95	0.95
1-in-2	2033	56,596	0.84	0.84	0.91	0.91
1-in-2	2034	54,553	0.81	0.81	0.88	0.88
1-in-2	2035	52,617	0.78	0.78	0.85	0.85
1-in-2	2036	50,756	0.75	0.75	0.82	0.82

4.4.6 PG&E COMPARISON OF EX POST & EX ANTE LOAD IMPACTS

For PG&E’s CPP program as a whole, Table 4-16 compares the PY2025 ex ante reference loads and demand reduction to the averages from PY2023 , PY2024 and PY2025 events. Ex ante results are shown for the 4 to 9 p.m. event window and compared to an average PY2023/PY2024/PY2025 weekday.

In the 2023-2025 ex post results, an average CPP site delivered 1.1% in statistically significant load reductions (0.08 kWh per hour) per event from 4 to 9 PM. Ex ante reductions for the 4 to 9 p.m. event window were also 1.1% for both PG&E and CAISO. Note that the ex post counterfactual loads (“Load without DR” in the table) include PY2023, PY2024, and PY2025 loads whereas the ex ante counterfactual loads represent modeled loads for the August worst day only for PY2025 customers.

Table 4-16: PG&E Combined: Comparison of Ex Post and Ex Ante Load Impacts for 2025

Result Type	Day Type	Period	Load without DR (avg site kWh/h)	Load Reduction (avg site kWh/h)	% Reduction	Event Avg Temp (F)
Ex Post	Avg Weekday Event	Event Window	7.71	0.08	1.1%	98.8
Ex Ante (CAISO)	Aug Worst Day, 1-in-2	Resource Adequacy: 4 to 9pm	7.22	0.08	1.1%	92.74
Ex Ante (PG&E)	Aug Worst Day, 1-in-2	Resource Adequacy: 4 to 9pm	7.81	0.08	1.1%	97.10

For PG&E’s Large CPP group, Table 4-17 compares the PY2025 ex ante reference loads and demand reductions to the averages from PY2023 , PY2024 and PY2025 events. Ex ante results are shown for the 4 to 9 p.m. event window and compared to an average PY2023/PY2024/PY2025 weekday.

In the 2023-2025 ex post results, an average Large CPP site delivered 1.6% in statistically significant load reductions (2.78 kWh per hour) per event from 4 to 9 PM. Ex ante reductions for the 4 to 9 p.m. event window were 1.4% and 1.5% for PG&E and CAISO respectively, similar to ex post inputs. Note that the ex post counterfactual loads (“Load without DR” in the table) include both PY2023, PY2024, and PY2025 loads whereas the ex ante counterfactual loads represent modeled loads for the August worst day only for PY2025 customers. The PG&E and CAISO weather ex ante predictions are slightly different because ex ante reference increase for hotter temperatures. Percent impacts are similar across the two ex ante weather specifications, however, because no weather trend was established for impacts.

Table 4-17: PG&E Large: Comparison of Ex Post and Ex Ante Load Impacts for 2025

Result Type	Day Type	Period	Load without DR (avg site kWh/h)	Load Reduction (avg site kWh/h)	% Reduction	Event Avg Temp (F)
Ex Post	Avg Weekday Event	Event Window: 4 to 9pm	173.75	2.78	1.6%	98.5
Ex Ante (CAISO)	Aug Worst Day, 1-in-2	Resource Adequacy: 4 to 9pm	165.76	2.41	1.5%	94.2
Ex Ante (PG&E)	Aug Worst Day, 1-in-2	Resource Adequacy: 4 to 9pm	172.23	2.50	1.4%	98.0

For PG&E’s Medium CPP group, Table 4-18 compares the PY2025 ex ante reference loads and demand reductions to the averages from PY2023 , PY2024 and PY2025 events, with insignificant ex post estimates set to zero for planning purposes. These are the ex post estimates used as inputs in the ex ante forecast. Ex ante results are shown for the 4 to 9 p.m. event window and compared to an average PY2023/PY2024/PY2025 weekday.

In the 2023-2025 ex post results, an average Medium CPP site delivered 1.0% in statistically significant load reductions (0.2 kWh per hour) per event in the 4 to 9 p.m. window. Ex ante reductions for the 4 to 9 p.m. event window were slightly lower at 0.9%.

Table 4-18: PG&E Medium Comparison of Ex Post and Ex Ante Load Impacts for 2025

Result Type	Day Type	Period	Load without DR (avg site kWh/h)	Load Reduction (avg site kWh/h)	% Reduction	Event Avg Temp (F)
Ex Post	Avg Weekday Event	Event Window: 4 to 9pm	23.40	0.23	1.0%	98.7
Ex Ante (CAISO)	Aug Worst Day, 1-in-2	Resource Adequacy: 4 to 9pm	21.86	0.20	0.9%	93.4
Ex Ante (PG&E)	Aug Worst Day, 1-in-2	Resource Adequacy: 4 to 9pm	23.65	0.22	0.9%	97.6

For PG&E's Small CPP group, Table 4-19 compares the PY2025 ex ante reference loads and demand reductions to the averages from PY2023, PY2024 and PY2025 events, with insignificant ex post estimates set to zero for planning purposes. These are the ex post estimates used as inputs in the ex ante forecast. Ex ante results are shown for the 4 to 9 p.m. event window and compared to an average PY2023/PY2024/PY2025 weekday.

In the 2023-2025 ex post results, an average Small CPP site delivered 0.9% in statistically significant load reductions (0.02 kWh per hour) per event. Ex ante reductions for the 4 to 9 p.m. event window were also 0.9%.

Table 4-19: PG&E Small Comparison of Ex Post and Ex Ante Load Impacts for 2025

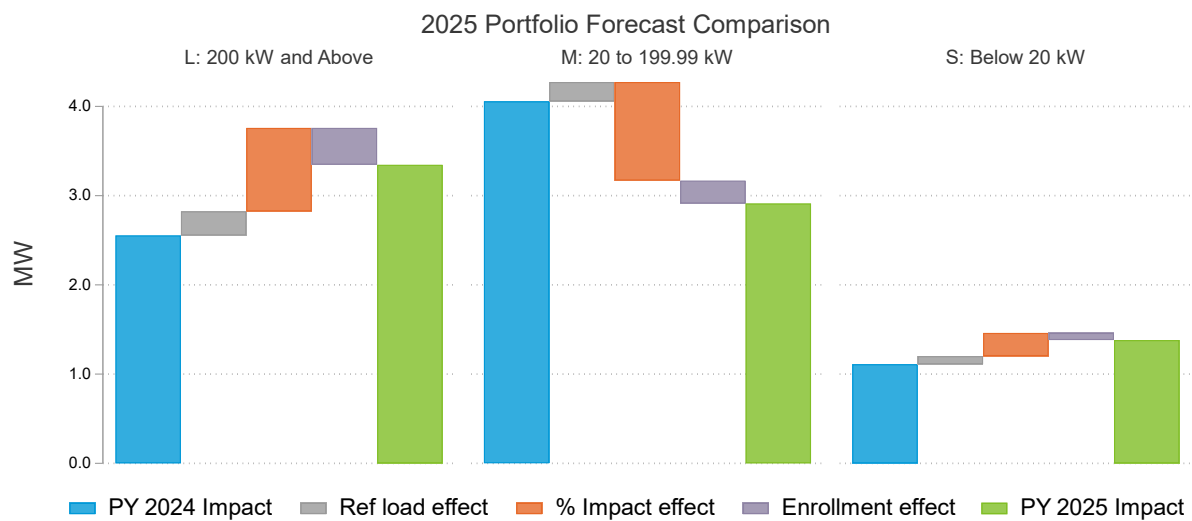
Result Type	Day Type	Period	Load without DR (avg site kWh/h)	Load Reduction (avg site kWh/h)	% Reduction	Event Avg Temp (F)
Ex Post	Avg Weekday Event	Event Window: 4 to 9pm	2.12	0.02	0.9%	97.9
Ex Ante (CAISO)	Aug Worst Day, 1-in-2	Resource Adequacy: 4 to 9pm	1.92	0.02	0.9%	92.6
Ex Ante (PG&E)	Aug Worst Day, 1-in-2	Resource Adequacy: 4 to 9pm	2.10	0.02	0.9%	97.0

4.4.7 PG&E COMPARISON TO 2024 EX ANTE IMPACT ESTIMATES

The ex ante impact estimates in this study are slightly reduced from the PY 2024 evaluation, largely due to decreased impacts from the Medium sites. The following figure gives a breakdown of the difference

in ex ante impact estimates from PY2024 and those generated in in PY2025. The graphs can be interpreted as the individual factors (changes in reference load, percent impacts, or enrollments) that explain the change in the estimated ex ante MW impacts in PY2024 (in blue) and PY2025 (in green).

Figure 4-4: Waterfall Analysis of 2024-2025 PG&E Ex Ante Impacts by Group



The Large group has a higher reference load and higher percent impacts. Decreasing enrollments bring the PY2025 MW results down slightly, but due to the large increase in the percent impacts, the PY2025 impacts are almost a full MW higher than PY2024. The Medium group also had increased reference load, and decreasing enrollments, but the main difference between PY2024 and PY2024 impacts is the significantly lower percent impacts in PY2024, which is what leads to the MW impacts being almost a full MW lower than PY2024. The Small group has seen small changes in the reference load and forecasted enrollments – the increased projection is driven mainly by is the higher percent impacts estimated in PY2025.

4.4.8 PG&E EX ANTE LOAD IMPACT SLICE-OF-DAY TABLE

The following tables show the 2025 ex ante aggregate hourly impacts for all CPP groups for each month under PG&E 1-in-2 monthly worst day conditions. CPP tariffs only allow for dispatch from 4 to 9 p.m. so the Slice-of-Day table shows impacts aligned with the tariffed event window. The estimated reductions are typically larger in the hotter summer months and smaller in the cooler winter months. While the percent impacts underlying these estimates do not vary by weather or event hour, the aggregate impacts reported in the table vary by month and hour based on the reference loads. Separate results by CPP group can be found in the Appendix section PG&E Ex Ante Load Impact Slice-of-Day Tables.

Table 4-20: PG&E Combined Slice of Day Table for Monthly Worst Day (MW, Portfolio-Adjusted)

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	5.33	5.34	5.35	6.75	7.62	8.50	8.52	8.33	8.03	6.90	5.54	5.54
18	5.01	5.02	5.03	6.34	7.15	7.98	8.00	7.81	7.53	6.46	5.19	5.19
19	4.86	4.87	4.88	6.13	6.89	7.71	7.73	7.54	7.26	6.24	5.06	5.06
20	4.83	4.84	4.85	6.01	6.72	7.48	7.50	7.33	7.06	6.12	5.03	5.03
21	4.81	4.82	4.83	5.89	6.55	7.24	7.26	7.09	6.85	5.99	5.01	5.01
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Demand reductions are positive (Blue)

Load increases are negative (Orange)

5 SCE PY 2025 IMPACTS

SCE's CPP rate program had over 230,000 customers in PY2025, most of them in the Small group (less than 20 kW maximum demand). As with the other IOU's, most of these customers were placed on CPP rates by default, but they can opt out and choose a different rate at any time. SCE offers CPP rates in both commercial and agricultural rate classes. Most, however, are commercial customers, so they are combined for this evaluation into the Small, Medium, and Large size distinctions based on their annual peak kW.

SCE has also added some Residential accounts to its Small CPP program as a DR program option; mostly Self-Generation Incentive Program (SGIP) participants. For clarity this group is listed separately as "Residential" throughout this section.

SCE had 12 events in PY2025, each between July and September, with no events in June. To achieve the targeted number of 12 events, SCE often calls CPP events on days with lower temperatures than the other IOUs, so average impacts are not equivalent to those of PG&E and SDG&E.

SCE's CPP rate program is in transition for PY 2025. The program team has identified many non-performing sites that for PY 2026, pending approval, will be moved from CPP rates to a better TOU rate for the customers. These sites make up roughly half of SCE's CPP accounts, and they lowered SCE's ex post estimates for PY 2025.

5.1 SCE SUMMARY OF RESULTS

Table 5-1 summarizes the estimated ex post demand reductions for the average weekday CPP event for each of SCE's CPP subgroups. All impacts are incremental to other DR program impacts, though for SCE no other programs had significant impacts on the PY2025 estimates. Statistical significance is noted for each subgroup in the last two columns.

Overall the evaluation found no significant load impacts from SCE's CPP rate customers during PY2025 event hours. Customers do appear to shift loads for their daily TOU rate pricing, but there were no additional impacts over and above this daily shifting on the 12 CPP event days.

Table 5-1: SCE Ex Post Demand Reductions for an Average Weekday Event

Group	Sites	Load without DR (MW)	Load reduction (MW)	% Reduction	Significant (90% CI)	Significant (95% CI)
Large (200 kW and Above)	1,835	358.16	-0.98	-0.3%	No	No
Medium (20 to 199.99 kW)	21,982	530.12	0.45	0.1%	No	No

Group	Sites	Load without DR (MW)	Load reduction (MW)	% Reduction	Significant (90% CI)	Significant (95% CI)
Small (Below 20 kW)	208,602	277.55	-1.27	-0.5%	Yes	Yes
Residential	915	0.71	0.00	-0.1%	No	No
Total	233,334	1166.54	-1.80	-0.2%	No	No

Table 5-2 summarizes SCE’s forecasted site enrollments over the next ten years by group. These are produced internally by SCE and applied to ex ante estimates in the evaluation. In general, site enrollments are anticipated to increase slowly until 2031 and then level off. Note that 2025 enrollments do not always follow the forecast trend since these were the average number of customers enrolled during PY2025 events.

Table 5-2: SCE Summary of Ex ante Site Enrollments

Year	Large	Medium	Small	Residential	Total
2025	1,827	21,936	208,374	912	233,049
2026	1,847	22,199	231,774	1,517	257,337
2027	1,868	22,458	234,495	1,517	260,338
2028	1,890	22,714	237,209	1,517	263,330
2029	1,906	22,972	239,927	1,517	266,322
2030	1,927	23,234	242,647	1,517	269,325
2031	1,947	23,496	245,361	1,517	272,321
2032	1,968	23,496	245,361	1,517	272,342
2033	1,992	23,496	245,361	1,517	272,366
2034	2,012	23,496	245,361	1,517	272,386
2035	2,034	23,496	245,361	1,517	272,408
2036	2,052	23,496	245,361	1,517	272,426

Table 5-3 summarizes the portfolio-adjusted reductions that SCE CPP rates can be expected to deliver ex ante under August peak conditions in an SCE 1-in-2 weather year. These impacts were not found to be sensitive to either weather or event hour for PY2025. The estimates are instead a function of the percent impacts estimates in this (PY2025) and the previous (Py2023 & 2024) evaluations. The results reflect reduction capability for a single event across SCE’s CPP event window (4 to 9 p.m.).

Overall, Large sites can be expected to deliver an aggregate 2.4 to 2.6 MW per five-hour event in future years. The Medium group, despite large enrollments, is only expected to deliver 0.3 MW. The Small group is predicted to have very little savings in the future (0.02 MW), while the Residential sites are

expected to deliver no savings in future years. Combined, SCE's CPP rate customers would be expected to deliver 2.7 to 3.0 MW per event day from 2026-2036.

Table 5-3: SCE Summary of Ex Ante Demand Reductions, August Worst Day, System 1-in-2 Weather (MW, Portfolio-Adjusted)

Year	Large	Medium	Small	Residential	Total
2025	2.4	0.3	0.0	0.0	2.7
2026	2.3	0.3	0.0	0.0	2.7
2027	2.4	0.3	0.0	0.0	2.7
2028	2.4	0.3	0.0	0.0	2.7
2029	2.4	0.3	0.0	0.0	2.8
2030	2.4	0.3	0.0	0.0	2.8
2031	2.5	0.3	0.0	0.0	2.8
2032	2.5	0.3	0.0	0.0	2.9
2033	2.5	0.3	0.0	0.0	2.9
2034	2.6	0.3	0.0	0.0	2.9
2035	2.6	0.3	0.0	0.0	3.0
2036	2.6	0.3	0.0	0.0	3.0

5.2 SCE EVENT CHARACTERISTICS

Table 5-4 shows the twelve PY2025 CPP event days and the SCE system peak load on each day. All twelve events ran from 4 p.m. to 9 p.m. and covered all sites on CPP rates. SCE optionally sends day-ahead notifications to customers to help with load shifting during the increased price periods. Notification data was not analyzed for differential performance on CPP event days for PY2025.

Event days covered a range of summer months and temperatures. All events were weekdays and none came in June.

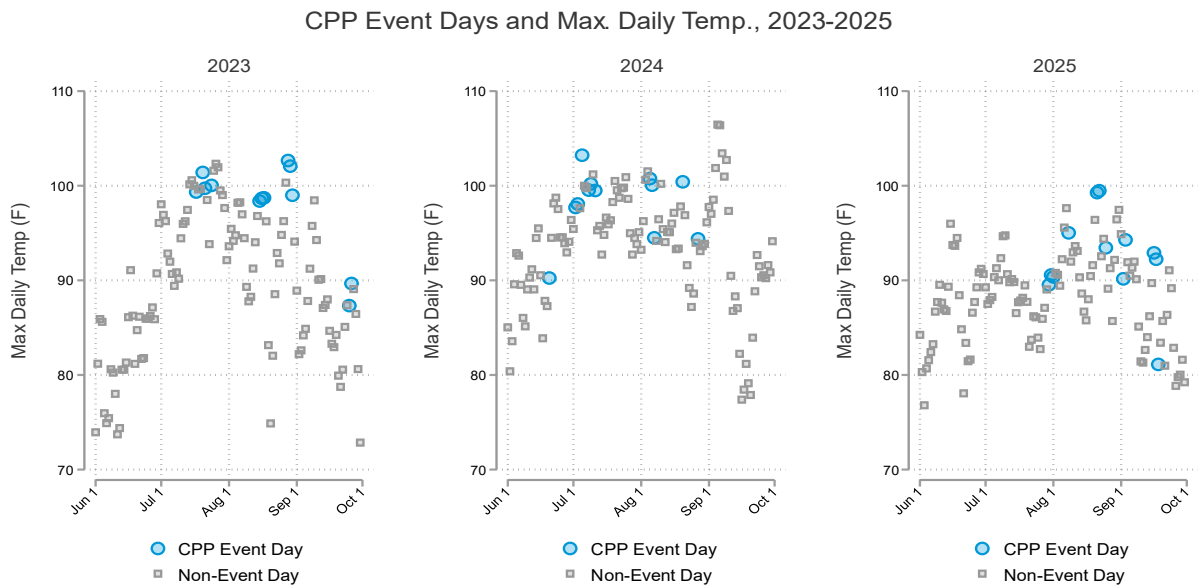
Table 5-4: SCE CPP Event Days for PY2025

Event date	Day of week	Max SCE system load (MW)	Event window	All groups
7/30/2025	Wednesday	17,253	4 to 9 pm	✓
7/31/2025	Thursday	16,745	4 to 9 pm	✓
8/1/2025	Friday	16,824	4 to 9 pm	✓
8/8/2025	Friday	19,854	4 to 9 pm	✓
8/21/2025	Thursday	21,621	4 to 9 pm	✓
8/22/2025	Friday	21,966	4 to 9 pm	✓

Event date	Day of week	Max SCE system load (MW)	Event window	All groups
8/25/2025	Monday	19,750	4 to 9 pm	✓
9/2/2025	Tuesday	20,642	4 to 9 pm	✓
9/3/2025	Wednesday	21,733	4 to 9 pm	✓
9/16/2025	Tuesday	20,815	4 to 9 pm	✓
9/17/2025	Wednesday	20,714	4 to 9 pm	✓
9/18/2025	Thursday	17,709	4 to 9 pm	✓

As shown in Figure 5-1, SCE’s events were generally in line with those called in previous years, with twelve events called across a range of dates. PY2025’s summer was milder than the two previous years, so there are more events called on cooler days than there were in past years. In particular, the last event called for the season (9/18) was a particularly cool day. This event was the third consecutive event called during a warmer week in late September, but clouds and rain throughout the day caused cooler than expected temperatures.

Figure 5-1: SCE Event Days and Temperature by Year



5.3 SCE EX POST LOAD IMPACTS

5.3.1 SCE SITES IN ANALYSIS

SCE had over 230,000 customers on CPP rates in 2025, including both agricultural and commercial customers. Sites were analyzed in subgroups based on size, as shown in Table 5-5 below. Most sites

(roughly 210,000) were in the Small group (less than 20 kW peak demand). Due to the large number of sites in this group, a random sample was drawn by industry and climate, with just over 45,000 sites included in the actual analysis. All results are then weighted to reflect the full population of Small CPP customers. For example, SCE CPP had many small office sites in Climate Zone 8 near Los Angeles – only a subset of these were drawn into the random sample, but each small office in the sample carries large weight in the Small group’s impact estimates.

Table 5-5 also shows any other differences between the full CPP enrollment counts and the number of sites used for the ex post analysis. “Total Sites” indicates the total number of sites enrolled for any PY2025 event. In addition to the sampling for the Small group, several sites were dropped due to incomplete data, outages, or other data issues.

Table 5-5: SCE Participant Populations (Avg Weekday Event)

Group	Sector	Total sites	Sites in analysis*
Large	Commercial & Agricultural	1,835	1,765
Medium	Commercial & Agricultural	21,982	20,171
Small	Commercial & Agricultural	208,602	45,902
Residential	Residential	915	915
Total	Commercial & Agricultural	233,334	68,646

*Small group sites in analysis drawn randomly from customer population

Large electric generators on CPP rates such as solar farms were included in the analysis. However, only the delivered loads were analyzed for these sites. Power generators were determined via NAICS codes as well as other sites with greater than 500 kW daily exports.¹⁰

Impacts were also estimated for several subsegments of each group and included in the SCE Ex Post table generators. As many of these were insignificant or inconsistent, they should be interpreted with caution. Some more noteworthy subsegments are discussed in Section 5.3.6.

SCE’s AutoDR customers were evaluated separately as a CPP subgroup, but this group did not have any significant impacts in 2025.

5.3.2 SCE LARGE – IMPACTS BY EVENT

SCE had just over 1,800 Large CPP customers in PY2025. All enrolled sites were included in the events, with increased prices from 4 to 9 p.m. Table 5-6 summarizes the load reductions and customer-weighted event temperatures for Large sites during each event and for the average weekday event. In

¹⁰ Power generators defined as sites with five-digit NAICS codes of 22111 – Electric Power Generation.

the tables, the bars show a visual comparison of the reductions that are numerically labeled on the left of the bars. Overall, the Large group had no significant load reductions across the 12 PY 2025 events, averaging a statistically insignificant 0.3% load increase per event.

Table 5-6: SCE Large – Ex Post Impact Estimates by Event

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Reductions (Ex Post)			Significant (90% CI)	Significant (95% CI)
				Aggregate (MW)	% Reduction	Average Site (kW)		
7/30/2025	4 to 9 pm	82.5	1,850	2.6	0.7%	1.4	No	No
7/31/2025	4 to 9 pm	82.4	1,846	0.4	0.1%	0.2	No	No
8/1/2025	4 to 9 pm	81.7	1,846	1.9	0.6%	1.0	No	No
8/8/2025	4 to 9 pm	86.4	1,844	3.0	0.9%	1.7	No	No
8/21/2025	4 to 9 pm	90.8	1,839	-5.3	-1.4%	-2.9	Yes	Yes
8/22/2025	4 to 9 pm	89.1	1,840	-1.6	-0.4%	-0.9	No	No
8/25/2025	4 to 9 pm	84.1	1,835	-3.0	-0.8%	-1.6	No	No
9/2/2025	4 to 9 pm	87.7	1,828	-11.7	-3.3%	-6.4	Yes	Yes
9/3/2025	4 to 9 pm	88.2	1,828	-12.1	-3.3%	-6.6	Yes	Yes
9/16/2025	4 to 9 pm	88.4	1,824	-0.7	-0.2%	-0.4	No	No
9/17/2025	4 to 9 pm	79.5	1,824	7.3	2.0%	4.0	Yes	Yes
9/18/2025	4 to 9 pm	76.9	1,824	2.9	0.8%	1.6	No	No
Avg Weekday 4-9 pm	4 to 9 pm	84.8	1,835	-1.0	-0.3%	-0.5	No	No

5.3.3 SCE MEDIUM – IMPACTS BY EVENT

SCE had approximately 22,000 Medium CPP customers in PY2025. All enrolled sites were included in the events, with increased prices from 4 to 9 p.m. Table 5-7 shows the load reductions and customer-weighted event temperatures for Medium sites during each event and for the average weekday event. In the tables, the bars show a visual comparison of the reductions that are numerically labeled on the left of the bars.

Overall, the Medium group had very small load reductions during 2025 events, averaging 0.1% (0.4 MW) load reductions. With the small magnitude of performance relative to variation inherent in the loads, these reductions cannot be distinguished from zero. With varying levels of statistical significance, many individual events had impacts close to zero as well.

Table 5-7: SCE Medium – Ex Post Impact Estimates by Event

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Reductions (Ex Post)			Significant (90% CI)	Significant (95% CI)
				Aggregate (MW)	% Reduction	Average Site (kW)		
7/30/2025	4 to 9 pm	82.1	22,169	4.4	0.9%	0.2	Yes	Yes
7/31/2025	4 to 9 pm	81.9	22,142	2.1	0.4%	0.1	Yes	Yes
8/1/2025	4 to 9 pm	81.2	22,137	-0.1	0.0%	0.0	No	No
8/8/2025	4 to 9 pm	85.9	22,075	2.1	0.4%	0.1	Yes	No
8/21/2025	4 to 9 pm	90.4	22,011	4.4	0.8%	0.2	Yes	Yes
8/22/2025	4 to 9 pm	88.5	22,011	1.6	0.3%	0.1	No	No
8/25/2025	4 to 9 pm	83.6	21,990	-1.3	-0.3%	-0.1	No	No
9/2/2025	4 to 9 pm	87.3	21,921	-5.6	-1.0%	-0.3	Yes	Yes
9/3/2025	4 to 9 pm	87.8	21,908	-2.7	-0.5%	-0.1	Yes	Yes
9/16/2025	4 to 9 pm	88.2	21,816	0.2	0.0%	0.0	No	No
9/17/2025	4 to 9 pm	79.1	21,807	-3.1	-0.6%	-0.1	Yes	Yes
9/18/2025	4 to 9 pm	76.9	21,795	-5.2	-1.1%	-0.2	Yes	Yes
Avg Weekday 4-9 pm	4 to 9 pm	84.4	21,982	0.4	0.1%	0.0	No	No

5.3.4 SCE SMALL – IMPACTS BY EVENT

SCE had almost 210,000 Small CPP customers in PY2025. All enrolled sites were included in the events, with increased prices from 4 to 9 p.m. Table 5-8 summarizes the load reductions and customer-weighted event temperatures for Small sites during each event and for the average weekday event. In the tables, the bars show a visual comparison of the reductions that are numerically labeled on the left of the bars.

Overall, the Small group had no load reductions in 2025, averaging a statistically insignificant 0.5% (1.3 MW per hour) increase electric usage during event hours.

Table 5-8: SCE Small – Ex Post Impact Estimates by Event

Event Date	Event Window	Avg Event Temp (F)	Sites Enrolled	Reductions (Ex Post)			Significant (90% CI)	Significant (95% CI)
				Aggregate (MW)	% Reduction	Average Site (kW)		
7/30/2025	4 to 9 pm	81.6	209,870	-0.4	-0.2%	0.0	No	No
7/31/2025	4 to 9 pm	81.4	209,702	-0.6	-0.2%	0.0	No	No
8/1/2025	4 to 9 pm	80.7	209,607	-1.9	-0.7%	0.0	Yes	No
8/8/2025	4 to 9 pm	85.2	209,158	-2.7	-1.0%	0.0	Yes	Yes
8/21/2025	4 to 9 pm	89.9	208,687	1.0	0.3%	0.0	No	No
8/22/2025	4 to 9 pm	87.9	208,649	-2.3	-0.8%	0.0	Yes	No
8/25/2025	4 to 9 pm	83.1	208,572	1.3	0.5%	0.0	No	No
9/2/2025	4 to 9 pm	86.8	208,107	-1.5	-0.5%	0.0	No	No
9/3/2025	4 to 9 pm	87.4	208,065	-1.7	-0.6%	0.0	No	No
9/16/2025	4 to 9 pm	87.7	207,640	-0.5	-0.2%	0.0	No	No
9/17/2025	4 to 9 pm	78.9	207,590	-3.7	-1.4%	0.0	Yes	Yes
9/18/2025	4 to 9 pm	76.7	207,572	-2.1	-0.9%	0.0	No	No
Avg Weekday 4-9 pm	4 to 9 pm	83.9	208,602	-1.3	-0.5%	0.0	Yes	Yes

5.3.5 SCE RESIDENTIAL AND SGIP CUSTOMERS

SCE had a small amount of Residential customers on CPP rates in PY2025. Approximately half of these residential customers were also participants of the Self-Generation Incentive Program (SGIP), which provides incentives to support existing, new, and emerging distributed energy resources. As part of SGIP, customers are required to participate in a qualifying demand response program. Results for this group are shown below in Table 5-9. Overall the group did not see load reductions on event days. Note also that nearly all the homes in this group have solar generation (as well as many with energy storage), so their net loads are very small.

Table 5-9: SCE Residential CPP Impacts

Group	n	Reference load (MWh/h)	Load w/ DR (MWh/h)	Load reduction (MWh/h)	% Load reduction	Std. error	t-stat	Sig 90%
Non-SGIP	272	0.31	0.31	0.00	-1.1%	0.0	0.2	No
SGIP	643	0.43	0.43	0.00	0.3%	0.0	-0.1	No
Res. (All)	915	0.71	0.71	0.00	-0.1%	0.0	0.0	No

While batteries have the potential for large demand response impacts, the incentives do not appear to be strong enough to induce additional battery dispatch to the grid on event days. It is likely that customers draw from the battery instead of the grid to buy less energy during expensive peak TOU hours, but CPP does not generate incremental impacts.

5.3.6 SCE IMPACT BREAKDOWNS BY SUBSEGMENT

In addition to analyzing the impacts by Small, Medium, and Large, impacts were analyzed by various subgroups. Subgroups analyzed include Performers and Non-performers, Industry, NEM and Power Generators, and customers who receive day ahead notifications. Results for each subgroup are explained below.

SCE Impacts by Performers & Non-Performers

In an effort to improve the CPP rate's performance and customer satisfaction, SCE is currently working to move customers that do not benefit from the rates to other TOU rate plans. For this, SCE has classified customers into two categories: Performers or Non-performers, where Non-performers are customers that have failed to save at least \$20 from CPP pricing (relative to the base TOU rate) in either of the last two program years (PY 2024 and PY 2025).

Approximately half of all customers were classified as Performers and half as Non-performers. The majority of Medium and Large customers were Performers, while there were slightly more Non-performers than Performers in the Small group.

Table 5-10 and Table 5-11 summarize the average event savings of Non-performers and Performers respectively across each of the size categories. Non-performers overall had no significant reductions across any category. Load reductions that are significant for a 90% confidence level in some categories are likely noise in the estimates from year-to-year. In general, this group's impacts are indistinguishable from zero. Note that Residential sites are all classified as "Performers" since they have not been enrolled long enough for the two-year bill impact tests that SCE used to classify the sites.

Performers overall saved 1.1 MW on average event hours. These savings are driven by Medium Commercial customers and Large Agricultural customers. Medium Commercial customers save 0.55 MW on average event hours, which is significant at the 10% level. Large Agricultural customers save slightly more, at 0.65 MW, but these impacts are not statistically significant. As a whole, the Performers' positive impacts were smaller in absolute value than the Non-performers' negative impacts. Their results were also not statistically significant.

Table 5-10: SCE Ex Post Impact Estimates by Group – Non-Performers

CPP Group	Total enrolled sites	Reference load (MWh/h)	Load w/ DR (MWh/h)	Load reduction (MWh/h)	% Load reduction	Avg temp (F, site weighted)	Std. error	t-stat	Sig 90%
200 kW and Above	563	151.45	153.17	-1.72	-1.1%	84.2	0.9	1.9	Yes
20 to 199.99 kW	8,639	303.32	304.04	-0.72	-0.2%	84.5	0.3	2.8	Yes
Below 20 kW	108,494	43.33	43.93	-0.61	-1.4%	83.5	0.4	1.5	No
All groups	117,696	498.10	501.14	-3.04	-0.6%	83.6	1.8	1.7	Yes

Table 5-11: SCE Ex Post Impact Estimates by Group – Performers

PP Group	Total enrolled sites	Reference load (MWh/h)	Load w/ DR (MWh/h)	Load reduction (MWh/h)	% Load reduction	Avg temp (F, site weighted)	Std. error	t-stat	Sig 90%
200 kW and Above	1,273	205.88	205.20	0.68	0.3%	85.1	2.3	-0.3	No
20 to 199.99 kW	13,342	227.01	226.37	0.64	0.3%	84.3	0.4	-1.8	Yes
Below 20 kW	100,108	237.45	237.67	-0.22	-0.1%	84.4	0.5	0.4	No
Residential	915	0.71	0.71	0.00	-0.3%	84.3	0.0	0.1	No
All groups	115,634	671.04	669.94	1.10	0.2%	84.4	3.9	-0.3	No

SCE Impacts by Industry

Customers are assigned different industries groups according to NAICS codes. The vast majority of customers on CPP were Offices, Hotels, Finances, or Services, but this group did not deliver any positive

load impacts for PY 2025. Schools and Retail Stores also generally have no CPP impacts. Similar to previous years, Agriculture, Mining, and Construction, Institutional/Government, and Wholesale and Transport customers delivered the most estimated savings, though their impacts were very noisy and statistically insignificant. Manufacturing sites, which often deliver among the largest impacts, had a much lower point estimate in PY 2025.

Table 5-12: SCE Ex Post Impact Estimates by Industry

Subcategory	Total enrolled sites	Reference load (MWh/h)	Load w/ DR (MWh/h)	Load reduction (MWh/h)	% Load reduction	Avg temp.	Std. error	t-stat	Sig 90%
Agriculture, Mining & Construction	8,787	37.00	35.45	1.55	4.2%	87.1	1.5	-1.1	No
Institutional/Govt.	17,742	132.86	131.72	1.14	0.9%	84.1	0.9	-1.3	No
Manufacturing	8,447	127.22	127.10	0.12	0.1%	83.3	1.2	-0.1	No
Offices, Hotels, Finance, Services	103,332	400.18	402.84	-2.66	-0.7%	84.0	1.3	2.0	Yes
Retail Stores	15,355	127.09	127.42	-0.32	-0.3%	84.1	0.5	0.6	No
Schools	2,889	40.27	40.75	-0.47	-1.2%	83.7	0.3	1.5	No
Wholesale, Transp., Other Utilities	19,407	141.27	140.55	0.72	0.5%	85.0	2.4	-0.3	No

SCE Impacts for NEM and Power Generators

NEM customers did not have different impacts from Non-NEM customers in PY2025. Although Power Generators provided some impacts in PY2025, they did not have any statistically significant results in PY2025. However, their point estimate is much larger than Non-Power Generators (5.7% vs -0.2%). It is also important to note that only delivered loads are evaluated for Power Generators, as their net loads are extremely large (in absolute value), which can make them challenging to model.

Table 5-13: SCE Impacts by NEM and Power Generators

Category	Total enrolled sites	Reference load (MWh/h)	Load w/ DR (MWh/h)	Load reduction (MWh/h)	% Load reduction	Avg temp (F, site weighted)	Sig. 90%
Non-NEM Status	227,761	1109.74	1111.30	-1.56	-0.1%	83.9	No
NEM Status	5,472	57.07	57.28	-0.21	-0.4%	87.4	No
Non-Power Generators	233,145	1160.72	1162.87	-2.15	-0.2%	84.0	No
Power Generators	189	5.86	5.52	0.33	5.7%	92.4	No

SCE Impacts of Notifications

Customers are eligible to receive day-ahead notifications for CPP events. Customers who opt in are notified a day in advance by email, text, or phone call. Table 5-14 summarizes the impact estimates for customers who were and were not notified. Overall, notifications may have helped impacts slightly. Customers who were notified tend to have higher impacts than customers who were not, but the impacts are not statistically significant.

Table 5-14: SCE Ex Post Impacts Estimates by Notification

Category	Sub-category	Total enrolled sites	Reference load (MWh/h)	Load w/ DR (MWh/h)	Load reduction (MWh/h)	% Load reduction	Avg temp (F, site weighted)	Sig. 90%
All groups	N	138,457	625.94	628.06	-2.12	-0.3%	84.2	No
All groups	Y	94,723	540.56	540.25	0.30	0.1%	83.6	No
200 kW and Above	N	937	184.78	186.34	-1.56	-0.8%	84.9	No
200 kW and Above	Y	898	173.54	172.96	0.58	0.3%	84.7	No

5.4 SCE EX ANTE LOAD IMPACTS

A key objective of the evaluation is to project, *ex ante*, the load reductions that CPP customers can deliver on future event days. These are intended to reflect performance under normal (1-in-2) peak demand weather conditions for both CAISO and the SCE system.

In general, ex ante forecasts rely on the estimated ex post impacts for current or recent program years, as well as any relationship between weather and event hour to load reductions. For PY2025, ex ante modeling incorporated PY2023, PY2024 and PY2025 ex post impact estimates, but it did not include any differential impacts based on weather or the event hour.

5.4.1 SCE EX ANTE MODEL INPUTS

For PY2025, the key inputs for ex ante impact model are:

- PY2023 ex post impact estimates
- PY2024 ex post impact estimates
- PY2025 ex post impact estimates
- 1-in-2 system weather data for both the CAISO and SCE
- CPP enrollment forecast through 2036

The following factors were also considered, but ultimately were not included in the ex ante model:

- Weather impacts on percent reductions
- Event-hour impacts on percent reductions

Note that while event hour and weather do not impact the percent reductions in the ex ante model, both hotter temperatures and earlier event hours result in larger aggregate impact estimates, since percent reductions are applied to larger reference loads in each case.

SCE PY 2025 Impact Estimates

Ex post impact estimates by event, hour, and rate class are the primary inputs for the ex ante model. These are included individually as point estimates for each unique event hour (date x hour combinations) for PY 2025.

SCE Historical Impact Estimates

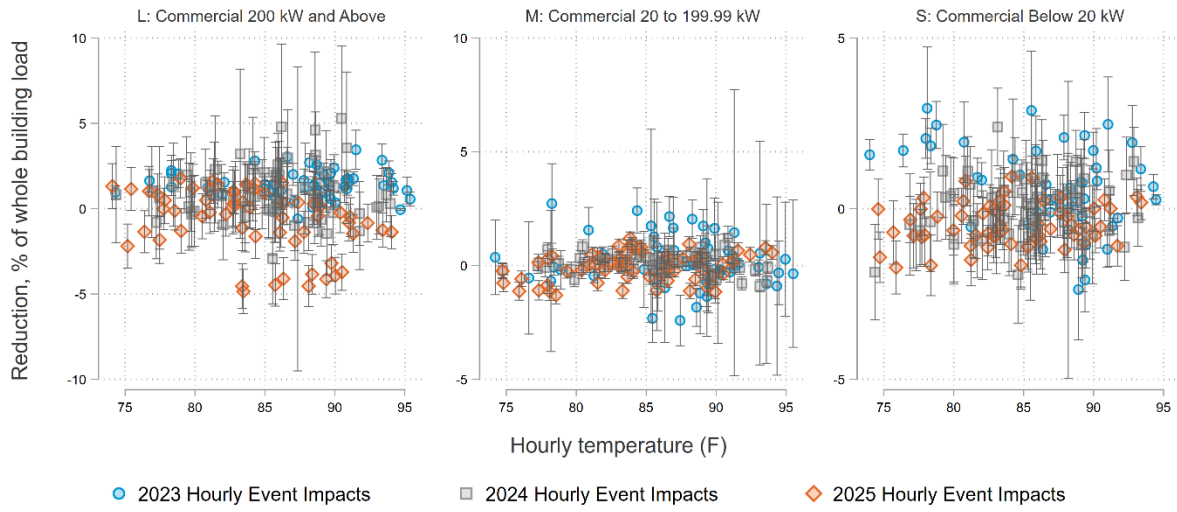
PY2023 and PY2024 ex post impacts were included, along with the current year ex post estimates, in the ex ante model. For PY2025, SCE's CPP groups had statistically insignificant impacts on most event days. This could imply that CPP truly has little impact on these sites, or that there is a great deal of noise in the 2025 outcomes as various businesses chose their loads for reasons besides CPP pricing. As such, the PY2023 and PY2024 percent impacts were included to add more data points to the model. Since the 2023 and 2024 estimates provided a large number of additional data points, we did not include impact estimates from PY2022 in the ex ante modelling.

Statewide evaluations in previous years have also been performed by a different evaluator, with some different decisions made in the ex post modelling, as discussed in the methodology section and in Appendix C. Including the PY2023 and PY2024 impacts can therefore aid in creating greater consistency in the study outputs.

SCE Weather Impacts

Figure 5-2 plots the estimated ex post impacts (in percentage terms) for each event day in 2023-2025 against the average daily temperature (with the average weighted by the number of customers). The points are shown as they would be used in the ex ante modeling.

Figure 5-2: SCE Hourly Reductions vs. Average Temperatures

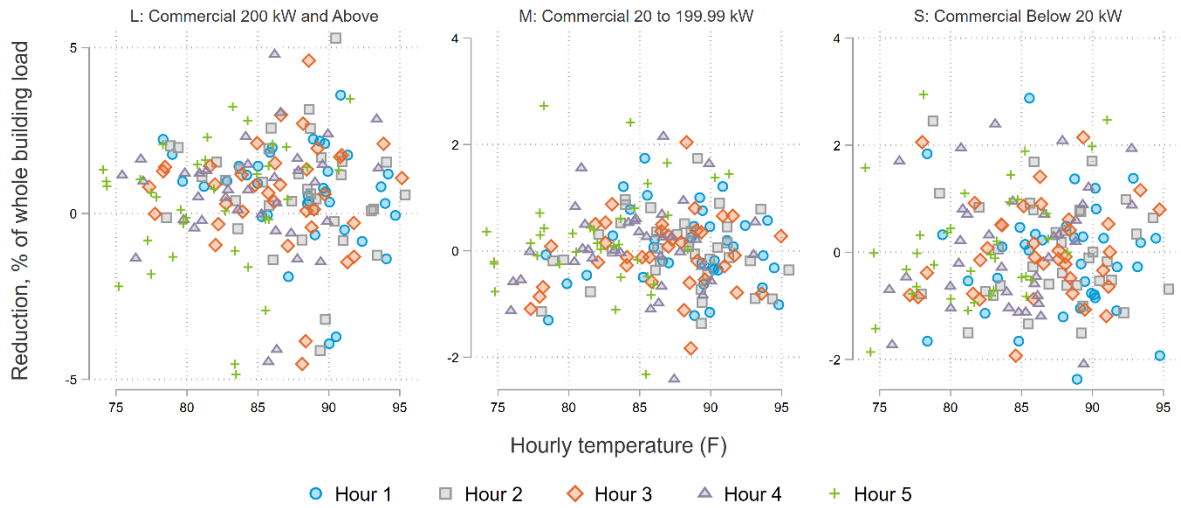


There is no clear trend in the percent impacts as temperature increases along the horizontal axes. In some previous years, a negative temperature gradient (higher impacts for event days with lower temperatures) has been applied to SCE's Small group, but this trend is not evident in the 2025 results, nor was it observed in the other two groups or in the other two IOUs more generally. Therefore, ex ante reductions at different temperature levels are assumed to vary only as a function of the reference load.

SCE Event Hour Impacts

Figure 5-3 plots the 2025 ex post impacts separately by event hour. In this figure, level shifts in the impacts along the vertical axis by event hour would imply differential impacts by event hour. There is no clear trend in the graphs showing any series of event hour points higher/lower than the other series. Therefore, ex ante reductions across different event hours are assumed to vary only as a function of the reference load.

Figure 5-3: SCE Impacts by Event Hour and Temperature



SCE Enrollment Forecast

To derive the aggregate forecast and reference loads, percent impacts per customer are scaled to the site population expected to be enrolled in each planning year. Table 5-15 summarizes the annual enrollment forecast for each subgroup through 2036.

Table 5-15: SCE Participant Enrollment Forecast

Year	Large	Medium	Small	Residential	Total
2025	1,827	21,936	208,374	912	233,049
2026	1,847	22,199	231,774	1,517	257,337
2027	1,868	22,458	234,495	1,517	260,338
2028	1,890	22,714	237,209	1,517	263,330
2029	1,906	22,972	239,927	1,517	266,322
2030	1,927	23,234	242,647	1,517	269,325
2031	1,947	23,496	245,361	1,517	272,321
2032	1,968	23,496	245,361	1,517	272,342
2033	1,992	23,496	245,361	1,517	272,366
2034	2,012	23,496	245,361	1,517	272,386
2035	2,034	23,496	245,361	1,517	272,408
2036	2,052	23,496	245,361	1,517	272,426

SCE developed the CPP enrollment forecast that was used to scale the ex ante impacts. After accounting for some de-enrollments in late 2025, the forecasts anticipate moderate growth in CPP participation through 2030, with no growth beyond that point in the Medium or Small groups. This is

based on the expected growth of all accounts by category, while accounting for the percentage that generally stay on the default CPP rates and do not opt out.

5.4.2 SCE LARGE – EX ANTE LOAD IMPACTS

Table 5-16 summarizes the portfolio-adjusted ex ante demand reduction capability of SCE’s Large CPP customers under different planning conditions. Since no significant impacts were estimated for any Large CPP dual-enrollment groups in PY2025, these estimates also represent the program-specific demand reductions, which will not be listed separately in this report.

Impact estimates represent Large customers’ estimated demand reductions available from 4 to 9 p.m. under August monthly peaking conditions for a 1-in-2 weather year. Since the ex post analysis showed no clear trends in percent load reductions relative to weather patterns or event hour, the ex ante impacts are assumed to vary only as a function of the reference loads.

SCE’s enrollment forecast anticipates slight growth in Large CPP customers year-over-year through 2036. Aggregate ex ante impacts for the Large group thus follow a similar trend, increasing slightly until 2036. Thus, the combined ex ante impacts increase slightly from roughly 2.4 MW in 2025 to 2.6 MW by 2036.

Table 5-16: SCE Large Ex Ante Impacts for 1-in-2 August Worst Day (MW)

Weather Type	Year	Sites	CAISO		SCE	
			Program	Portfolio-Adj.	Program	Portfolio-Adj.
1-in-2	2025	1,827	2.41	2.41	2.45	2.45
1-in-2	2026	1,847	2.30	2.30	2.33	2.33
1-in-2	2027	1,868	2.33	2.33	2.36	2.36
1-in-2	2028	1,890	2.35	2.35	2.39	2.39
1-in-2	2029	1,906	2.38	2.38	2.42	2.42
1-in-2	2030	1,927	2.41	2.41	2.44	2.44
1-in-2	2031	1,947	2.43	2.43	2.47	2.47
1-in-2	2032	1,968	2.46	2.46	2.50	2.50
1-in-2	2033	1,992	2.49	2.49	2.53	2.53
1-in-2	2034	2,012	2.51	2.51	2.55	2.55
1-in-2	2035	2,034	2.56	2.56	2.60	2.60
1-in-2	2036	2,052	2.58	2.58	2.62	2.62

5.4.3 SCE MEDIUM – EX ANTE LOAD IMPACTS

Table 5-17 summarizes the portfolio-adjusted ex ante demand reduction capability of SCE’s Medium CPP customers under different planning conditions. Since no significant impacts were estimated for

any Medium CPP dual-enrollment groups in PY2025, these estimates also represent the program-specific demand reductions, which will not be listed separately in this report.

Impact estimates represent Medium customers' estimated demand reductions available from 4 to 9 p.m. under August monthly peaking conditions for a 1-in-2 weather year. Since the ex post analysis showed no clear trends in percent load reductions relative to weather patterns or event hour, the ex ante impacts are assumed to vary only as a function of the reference loads.

SCE's enrollment forecast anticipates slight growth in Medium CPP customers year-over-year through 2031, at which point enrollments level off through 2036. Aggregate ex ante impacts for the Medium group thus follow a similar trend, increasing slightly through 2031, then remaining constant through 2036. This accounts for the slight increase in impacts from 0.32 to 0.33 MW in 2025 to 0.34 to 0.35 MW in 2036.

Table 5-17: SCE Medium Ex Ante Impacts for 1-in-2 August Worst Day (MW)

Weather Type	Year	Sites	CAISO		SCE	
			Program	Portfolio Adj	Program	Portfolio Adj
1-in-2	2025	21,936	0.33	0.33	0.33	0.33
1-in-2	2026	22,199	0.32	0.32	0.33	0.33
1-in-2	2027	22,458	0.32	0.32	0.33	0.33
1-in-2	2028	22,714	0.33	0.33	0.33	0.33
1-in-2	2029	22,972	0.33	0.33	0.34	0.34
1-in-2	2030	23,234	0.33	0.33	0.34	0.34
1-in-2	2031	23,496	0.34	0.34	0.35	0.35
1-in-2	2032	23,496	0.34	0.34	0.35	0.35
1-in-2	2033	23,496	0.34	0.34	0.35	0.35
1-in-2	2034	23,496	0.34	0.34	0.35	0.35
1-in-2	2035	23,496	0.34	0.34	0.35	0.35
1-in-2	2036	23,496	0.34	0.34	0.35	0.35

5.4.4 SCE SMALL – EX ANTE LOAD IMPACTS

Table 5-18 summarizes the portfolio-adjusted ex ante demand reduction capability of SCE's Small CPP customers under different planning conditions. Since no significant impacts were estimated for any Small CPP dual-enrollment groups in PY2025, these estimates also represent the program-specific demand reductions, which will not be listed separately in this report.

Impact estimates represent Small customers' estimated demand reductions available from 4 to 9 p.m. under August monthly peaking conditions for a 1-in-2 weather year. Since the ex post analysis showed

no clear trends in percent load reductions relative to weather patterns or event hour, the ex ante impacts are assumed to vary only as a function of the reference loads.

SCE's enrollment forecast anticipates slight growth in Small CPP customers year-over-year through 2031, at which point enrollments level off through 2036. Aggregate ex ante impacts for the Small group are largely flat. The increased enrollments are not enough to drive impacts up in a significant way, and they remain at 0.02 MW per event hour. Note that this group's enrollments would likely drop by over 50% with Non-Performers removed, though impacts would likely stay the same since the performing sites would remain on the rates.

Table 5-18: SCE Small Ex Ante Impacts for 1-in-2 August Worst Day (MW)

Weather Type	Year	Sites	CAISO		SCE	
			Program	Portfolio Adj	Program	Portfolio Adj
1-in-2	2025	208,374	0.02	0.02	0.02	0.02
1-in-2	2026	231,774	0.02	0.02	0.02	0.02
1-in-2	2027	234,495	0.02	0.02	0.02	0.02
1-in-2	2028	237,209	0.02	0.02	0.02	0.02
1-in-2	2029	239,927	0.02	0.02	0.02	0.02
1-in-2	2030	242,647	0.02	0.02	0.02	0.02
1-in-2	2031	245,361	0.02	0.02	0.02	0.02
1-in-2	2032	245,361	0.02	0.02	0.02	0.02
1-in-2	2033	245,361	0.02	0.02	0.02	0.02
1-in-2	2034	245,361	0.02	0.02	0.02	0.02
1-in-2	2035	245,361	0.02	0.02	0.02	0.02
1-in-2	2036	245,361	0.02	0.02	0.02	0.02

5.4.5 SCE COMPARISON OF EX POST & EX ANTE LOAD IMPACTS

For SCE's Large CPP group, Table 5-19 compares the PY2025 ex ante reference loads and demand reductions to the averages from PY2023, PY2024, and PY2025 events, with insignificant ex post estimates set to zero for planning purposes. These are the ex post estimates used as inputs in the ex ante forecast. Ex ante results are shown for the 4 to 9 p.m. event window and compared to an average PY2023/PY2024/PY2025 weekday.

In the 2023-2025 ex post results, an average Large CPP site delivered 0.5% in load reductions (1.03 kWh per hour) per event. Ex ante reductions for the 4 to 9 p.m. event window were roughly the same, at 0.6%. The SCE and CAISO weather ex ante predictions differ slightly since ex ante reference loads increase for hotter temperatures. Percent impacts are equal across the two ex ante weather specifications, however, because no weather trend was established for impacts.

Table 5-19: SCE Large Comparison of Ex Post and Ex Ante Load Impacts for 2025

Result Type	Day Type	Period	Load without DR (avg site kWh/h)	Load Reduction (avg site kWh/h)	% Reduction	Event Avg Temp (F)
Ex Post (2023-2025)	Avg Weekday Event	Event Window: 4 to 9pm	214.77	1.03	0.5%	85.6
Ex Ante (CAISO)	Aug Worst Day, 1-in-2	Resource Adequacy: 4 to 9pm	217.41	1.25	0.6%	87.61
Ex Ante (SCE)	Aug Worst Day, 1-in-2	Resource Adequacy: 4 to 9pm	221.36	1.27	0.6%	89.9

For SCE’s Medium CPP group, Table 5-20 compares the PY2025 ex ante reference loads and demand reductions to the averages from PY2023, PY2024 and PY2025 events, with insignificant ex post estimates set to zero for planning purposes. These are the ex post estimates used as inputs in the ex ante forecast. Ex ante results are shown for the 4 to 9 p.m. event window and compared to an average PY2023/PY2024/PY2025 weekday.

In the 2023-2025 ex post results, an average Medium CPP site delivered 0.1% in statistically significant load reductions (0.01 kWh per hour) per event. Ex ante reductions for the 4 to 9 p.m. event window were 0.1% as well.

Table 5-20: SCE Medium Comparison of Ex Post and Ex Ante Load Impacts for 2025

Result Type	Day Type	Period	Load without DR (avg site kWh/h)	Load Reduction (avg site kWh/h)	% Reduction	Event Avg Temp (F)
Ex Post (2023-2025)	Avg Weekday Event	Event Window: 4 to 9pm	24.71	0.01	0.1%	85.8
Ex Ante (CAISO)	Aug Worst Day, 1-in-2	Resource Adequacy: 4 to 9pm	25.76	0.01	0.1%	87.3
Ex Ante (SCE)	Aug Worst Day, 1-in-2	Resource Adequacy: 4 to 9pm	26.50	0.01	0.1%	89.7

For SCE’s Small CPP group, Table 5-21 compares the PY2025 ex ante reference loads and demand reductions to the averages from PY2023, PY2024 and PY2025 events, with insignificant ex post estimates set to zero for planning purposes. These are the ex post estimates used as inputs in the ex

ante forecast. Ex ante results are shown for the 4 p.m. to 9 p.m. event window and compared to an average PY2023/PY2024/PY2025 weekday.

In the 2023-2025 ex post results, an average Small CPP site delivered 0.0% in statistically significant load reductions (0.0 kWh per hour) per event. Ex ante reductions for the 4 to 9 p.m. event window were also 0.0%.

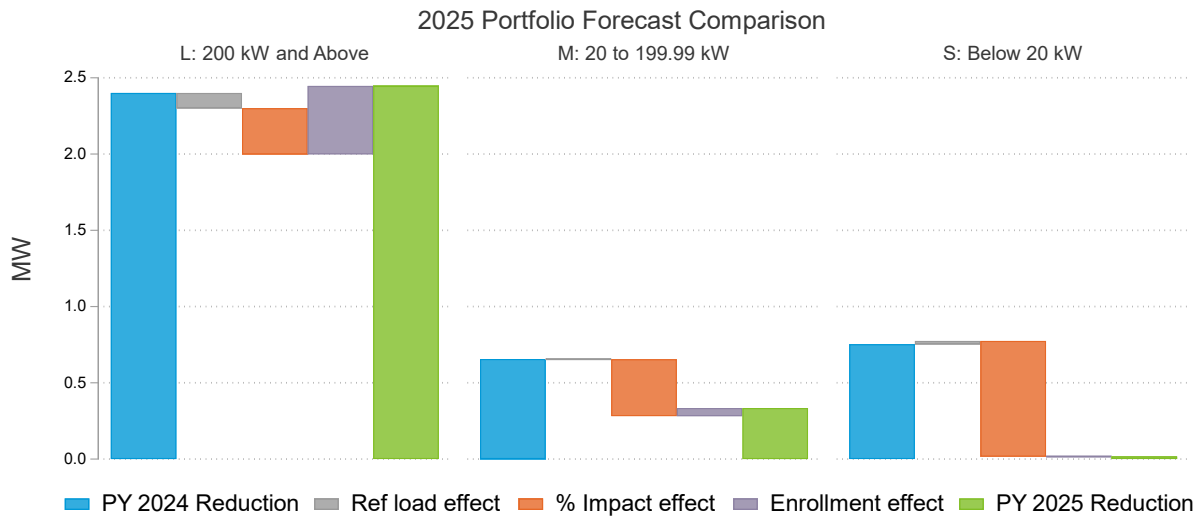
Table 5-21: SCE Small Comparison of Ex Post and Ex Ante Load Impacts for 2025

Result Type	Day Type	Period	Load without DR (avg site kWh/h)	Load Reduction (avg site kWh/h)	% Reduction	Event Avg Temp (F)
Ex Post (2023-2025)	Avg Weekday Event	Event Window: 4 to 9pm	1.35	0.02	0.0%	85.4
Ex Ante (CAISO)	Aug Worst Day, 1-in-2	Resource Adequacy: 4 to 9pm	1.43	0.02	0.0%	86.8
Ex Ante (SCE)	Aug Worst Day, 1-in-2	Resource Adequacy: 4 to 9pm	1.48	0.02	0.0%	89.1

5.4.6 SCE COMPARISON TO 2024 EX ANTE IMPACT ESTIMATES

The ex ante impact estimates in this study are significantly reduced from the previous evaluation, largely due to decreased impacts from the Small sites. The following figure gives a breakdown of the difference in ex ante impact estimates from PY2024 and those generated in in PY2025. The graphs can be interpreted as the individual factors (changes in reference load, percent impacts, or enrollments) that explain the change in the estimated ex ante MW impacts in PY2024 (in blue) and PY2025 (in green).

Figure 5-4: Waterfall Analysis of 2024-2025 SCE Ex Ante Impacts by Group



The Large group's reference load, impact effect, and enrollment effect are similar to 2024, leading to PY2025 reductions to be similar to the PY2024 results. The Medium group is fairly similar in terms of the reference load effect and the enrollment effect, with lower impact estimates leading to lower ex ante impacts. The Small group saw significant changes in the estimated percent impacts, though this group was forecast to provide less than 1 MW in PY 2024.

5.4.7 SCE EX ANTE LOAD IMPACT SLICE-OF-DAY TABLE

Table 5-22 shows SCE's 2025 ex ante aggregate hourly impacts for each month under SCE 1-in-2 monthly peaking conditions (combined across all groups). CPP tariffs only allow for dispatch from 4 p.m. to 9 p.m.

Table 5-22: SCE PY 2025 Slice of Day Table for System 1-in-2 Worst Day (MW, Portfolio-Adjusted)

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	2.25	2.21	2.22	2.65	2.64	2.91	2.96	2.98	3.02	2.83	2.59	2.18
18	2.15	2.14	2.14	2.53	2.52	2.76	2.81	2.82	2.86	2.69	2.48	2.10
19	2.08	2.07	2.07	2.40	2.39	2.58	2.62	2.62	2.64	2.51	2.34	2.04
20	2.03	2.04	2.04	2.33	2.32	2.50	2.54	2.54	2.57	2.43	2.28	2.00
21	2.01	2.02	2.02	2.26	2.26	2.42	2.45	2.45	2.46	2.34	2.21	1.99
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Demand reductions are positive (Blue)

Load increases are negative (Orange)

6 SDG&E PY2025 IMPACTS

SDG&E's Large and Medium CPP customers were evaluated for this study, while the Small CPP customers are included in separate load impact analysis. The Large and Medium groups are further broken down by rate class (Agricultural and Commercial). In total these groups make up over 2,200 CPP customers, with most customers falling in the Medium Commercial (2,032) and Large Commercial (236) groups.

SDG&E had no events in PY2025, so no ex post impacts will be reported.

6.1 SDG&E SUMMARY OF IMPACTS

Table 6-1 summarizes the portfolio-adjusted, reductions that SDG&E's Medium and Large customers can be expected to deliver *ex ante* under August worst day conditions in an SDG&E 1-in-2 weather year. These impacts were not found to be sensitive to either weather or event hour for PY2024. Since there were no events in PY 2025, we held these assumptions constant from PY2024. The estimates are instead a function of the percent impacts estimates in the two previous (PY2023, PY2024) evaluations. The results reflect reduction capability for a single event across SDG&E's CPP event window (4 to 9 p.m.).

Overall, Large Commercial sites can be expected to deliver an aggregate 0.6 to 0.7 MW per event hour in future years. Medium Commercial sites are expected to provide an additional 0.2 MW,

. Combined, SDG&E's Medium and Large CPP customers are expected to deliver 0.8 to 0.9 MW per event hour from 2026-2035.

Table 6-1: SDG&E Summary of Ex Ante Demand Reductions, August 1-in-2 Worst Day (MW, Portfolio-Adjusted)

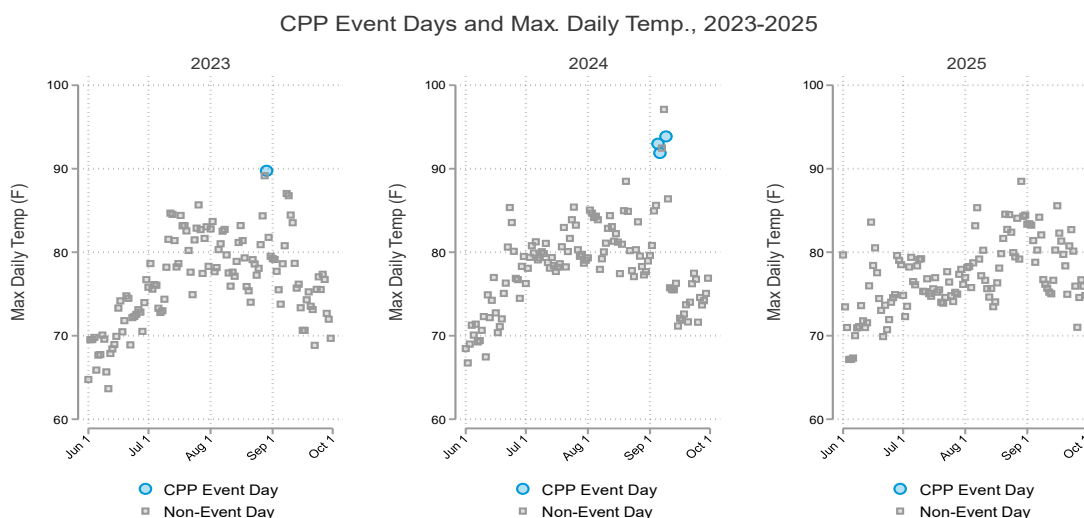
Year	Large Agriculture	Medium Agriculture	Large Commercial	Medium Commercial	Total
2025			0.6	0.2	0.8
2026			0.6	0.2	0.8
2027			0.6	0.2	0.8
2028			0.6	0.2	0.8
2029			0.6	0.2	0.8
2030			0.6	0.2	0.8
2031			0.6	0.2	0.8
2032			0.7	0.2	0.9
2033			0.7	0.2	0.8
2034			0.7	0.2	0.9
2035			0.7	0.2	0.9

6.2 SDG&E EVENT CHARACTERISTICS

SDG&E CPP event days are generally called under extreme weather conditions by design.¹¹ However, no day in PY 2025 reached these extreme conditions so no events were called.

As shown in Figure 6-1, the summer of PY2025 was milder than previous years. In PY2024, all three events came on three consecutive weekdays (with a weekend in between) during a September heat wave. Similarly, in PY2023, the only event was also called on the hottest days of the season. No day in PY2025 reached the temperatures that were seen during the PY2024 or PY2023 events. SDG&E also allows for events to be triggered in response to high forecasted temperatures, on request from CAISO, or other emergencies, but these did not occur in PY 2025.

Figure 6-1: SDG&E Event Days and Temperature by Year



6.3 SDG&E EX POST IMPACT ESTIMATES IN RECENT EVALUATIONS

While no additional ex post impact estimates were calculated in this evaluation, Table 6-2 lists impacts by group in the most recent program years (2022-2024). Impacts vary greatly from year to year, possibly because the smaller number of events and small populations size lead to high variance. There

¹¹ A CPP Event may be triggered if the day-ahead system load forecast for the potential event day is greater than 4,000 MW. Events may also be triggered in response to high forecasted temperatures, extreme conditions, and emergencies. Whenever the California Independent System Operator has issued an alert or warning notice, the California Independent System Operator shall be entitled to request that the utility, at its discretion, call a program event pursuant to this Schedule

five events in PY2022, one event in PY2023, and three events in PY2024. Neither of the PY 2024 estimates were statistically significant, so they are essentially zero.

Table 6-2: Ex Post Impact Estimates in Recent Evaluations

Group	2022	2023	2024
Medium	-1.1%	1.7%	-2.3%
Large	0.3%	4.9%	-2.3%

Many of SDG&E's CPP customers also pay a monthly subscription for capacity reservations, which shield all or part of their loads from CPP event pricing. Previous evaluations found that customers in the Large Commercial, Medium Commercial, and Medium Agriculture groups reserved large shares of their loads and thus had some insurance against price increases on event days.¹²

6.4 SDG&E EX POST LOAD IMPACTS

6.4.1 SDG&E SITES IN ANALYSIS

SDG&E had over 2,200 Large and Medium customers on CPP rates in 2025, including both agricultural and commercial customers. Sites were analyzed in subgroups based on size, as shown in Table 6-3 below. The vast majority of these sites are Medium Commercial.

Table 6-3: SDG&E Site Enrollments by Size

Group	Sector	Total sites	Sites in analysis*
Ag: Large	Agricultural		
Ag: Medium	Agricultural		
Comm: Large	Commercial	236	233
Comm: Medium	Commercial	2,032	2,012

Large electric generators on CPP rates such as solar farms were included in previous ex post analyses. However, only the delivered loads were analyzed for these sites. Power generators were determined

¹² Customers have the option to select a capacity level (in kW) that is reserved from the CPPD Event Day Adder applicable during a CPP Event. Usage during a CPP Event that is protected under the customer's capacity reservation is billed the corresponding energy charges for the time period but not the CPP Event Day Adder. All usage during a CPP Event that is not protected under the customer's capacity reservation is billed at the CPP Event Day Adder and the corresponding energy charges for the time period.

either via NAICS codes for electric generation or load data that showed greater than 500 kW exports during daytime hours.¹³

6.5 SDG&E EX ANTE LOAD IMPACTS⁶⁻⁴

A key objective of the evaluation is to project, *ex ante*, the load reductions that CPP customers can deliver on future event days. These are intended to reflect performance under normal (1-in-2) worst day demand weather conditions for both CAISO and the SDG&E system.

In general, *ex ante* forecasts rely on the estimated *ex post* impacts for current or recent program years, as well as any relationship between weather and event hour to load reductions. For PY2025, *ex ante* modeling incorporated both PY2023 and PY2024 *ex post* impact estimates, but it did not include any differential impacts based on weather or the event hour. Since no events were called in PY2025, there were no *ex post* impacts to include in the model. The included *ex post* impact estimates for both PY2023 and PY2024 are hourly impacts (in percentage terms) by group and event day

6.5.1 SDG&E EX ANTE MODEL INPUTS

For PY2025, the key inputs for *ex ante* impact model are:

- PY2023 *ex post* impact estimates (percent impacts)
- PY2024 *ex post* impact estimates (percent impacts)
- 1-in-2 system weather data for both CAISO and SDG&E
- CPP enrollment forecast through 2035

The following factors were also considered, but ultimately were not included in the *ex ante* model:

- Weather impacts on percent reductions
- Event-hour impacts on percent reductions

Note that while event hour and weather do not impact the percent reductions in the *ex ante* model, both hotter temperatures and earlier event hours result in larger aggregate impact estimates, since percent reductions are applied to larger reference loads in each case.

PY 2025 Impact Estimates

There were no events called in PY2025, so no impact estimates were included.

¹³ Power generators defined as sites with five-digit NAICS codes of 22111 – Electric Power Generation

Historical Impact Estimates

PY2023 and PY2024 ex post impacts were included in the ex ante model. Since there were no impact estimates available for PY2025, the use of historical data was necessary to produce ex ante estimates. As such, the PY2023 and PY2024 percent impacts were included to add more data to the model.

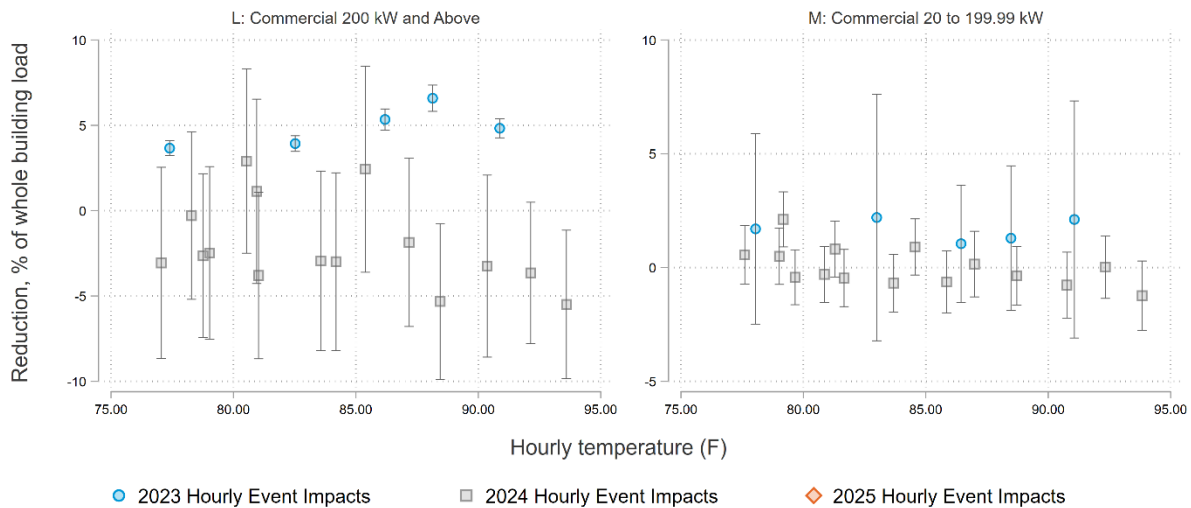
Impact estimates from PY2022 were not included since the number of customers has changed dramatically since that year: current CPP enrollments are less than 50% of what they were in the summer of 2022. These large decreases (due to the CCA expansion) likely affected not only the number of customers but also the composition of the customer pool. As such, the 2022 results would be less applicable to the customer populations that SDG&E can expect going forward.

Statewide evaluations in previous years have also been performed by a different evaluator, with some different decisions made in the ex post modelling, as discussed in the methodology section and in Appendix C. Including the PY2023 and PY2024 impacts can therefore aid in creating greater consistency in the study outputs.

Weather Impacts

Figure 6-2 plots the estimated ex post impacts (in percentage terms) for each event day in 2023-2024 against the average daily temperature (with the average weighted by the number of customers). The points are shown as they would be used in the ex ante modeling.

Figure 6-2: SDG&E Medium & Large Hourly Reductions vs. Average Temperatures

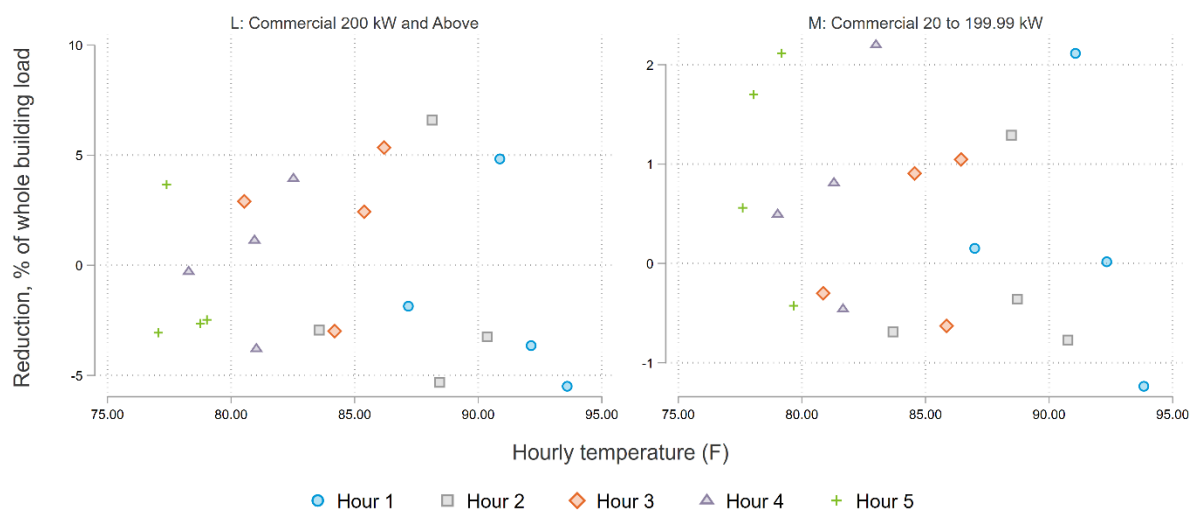


Focusing on the significant impacts (plotted away from zero), there is no clear trend in the percent impacts as temperature increases along the horizontal axes. Therefore, ex ante reductions at different temperature levels are assumed to vary only as a function of the reference load.

Event Hour Impacts

Figure 6-3 plots the 2024 ex post impacts separately by event hour. In this figure, level shifts in the impacts along the vertical axis by event hour would imply differential impacts by event hour. There is no clear trend in the graphs showing any series of event hour points higher/lower than the other series. Therefore, ex ante reductions across different event hours are assumed to vary only as a function of the reference load.

Figure 6-3: SDG&E Medium & Large Impacts by Event Hour and Temperature



Enrollment Forecast

To derive the aggregate forecast and reference loads, percent impacts per customer are scaled to the site population expected to be enrolled in each planning year. Table 6-5 summarizes the annual enrollments forecast for each subgroup through 2035.

Table 6-5: Participant Enrollment Forecast

Year	Ag: Large	Ag: Medium	Comm: Large	Comm: Medium
2025			203	2,011
2026			197	1,930
2027			198	1,958
2028			202	1,998
2029			205	2,040
2030			209	2,085
2031			213	2,142
2032			221	2,202

Year	Ag: Large	Ag: Medium	Comm: Large	Comm: Medium
2033			227	2,273
2034			236	2,352
2035			246	2,448

SDG&E developed the CPP enrollment forecast that was used to scale the ex ante impacts. After accounting for some de-enrollments in late 2025, the forecasts anticipate moderate growth in CPP participation through 2035. This is based on the expected growth of all accounts by category, while accounting for the percentage that generally stay on the default CPP rates and do not opt out.

6.5.2 SDG&E LARGE – EX ANTE LOAD IMPACTS

Table 6-6 summarizes the portfolio-adjusted ex ante demand reduction capability of SDG&E's Large Commercial CPP customers under different planning conditions. Since no impacts were estimated for Large Commercial CPP dual-enrollment groups in PY2025, these estimates also represent the program-specific demand reductions, which will not be listed separately in this report.

Impact estimates represent Large Commercial customers' estimated load reductions available from 4 to 9 p.m. under August worst day conditions for a 1-in-2 weather year. Since the ex post analysis in PY2024 showed no clear trends in percent load reductions relative to weather patterns or event hour, the ex ante impacts are assumed to vary only as a function of the reference loads.

SDG&E's enrollment forecast anticipates slight growth in Large Commercial CPP customers year-over-year through 2035. Aggregate ex ante impacts for the Large Commercial group thus follow a similar trend, increasing slightly through 2035.

The Large Commercial CPP group is expected to deliver about 0.6 MW peak savings during a 1-in-2 event day in 2026, with this figure increasing to 0.7 MW over time due to increases in enrollments.

Table 6-6: SDG&E Large Commercial Ex Ante Impacts for 1-in-2 August Worst Day (MW, Portfolio-Adjusted)

Weather Type	Year	Sites	CAISO		SDG&E	
			Program	Portfolio Adj	Program	Portfolio Adj
1-in-2	2025	203	0.60	0.60	0.61	0.61
1-in-2	2026	197	0.58	0.58	0.59	0.59
1-in-2	2027	198	0.58	0.58	0.59	0.59
1-in-2	2028	202	0.59	0.59	0.60	0.60
1-in-2	2029	205	0.60	0.60	0.61	0.61
1-in-2	2030	209	0.62	0.62	0.63	0.63
1-in-2	2031	213	0.63	0.63	0.64	0.64
1-in-2	2032	221	0.65	0.65	0.67	0.67
1-in-2	2033	227	0.67	0.67	0.68	0.68
1-in-2	2034	236	0.70	0.70	0.71	0.71
1-in-2	2035	246	0.72	0.72	0.74	0.74

Table 6-7 summarizes the portfolio-adjusted ex ante demand reduction capability of SDG&E's Large Agricultural CPP customers. These estimates also represent the program-specific demand reductions. Impact estimates represent Large Agricultural customers estimated load reductions available from 4 to 9 p.m. under August worst day conditions for a 1-in-2 weather year.

SDG&E's enrollment forecast anticipates slight growth in Large Agricultural CPP customers year-over-year through 2035.

Table 6-7: SDG&E Large Agriculture Ex Ante Impacts for 1-in-2 August Worst Day (MW, Portfolio-Adjusted)

Weather Type	Year	Sites	CAISO		SDG&E	
			Program	Portfolio Adj	Program	Portfolio Adj
1-in-2	2025					
1-in-2	2026					
1-in-2	2027					
1-in-2	2028					
1-in-2	2029					
1-in-2	2030					
1-in-2	2031					
1-in-2	2032					
1-in-2	2033					
1-in-2	2034	16	0.0	0.0	0.0	0.0
1-in-2	2035	18	0.0	0.0	0.0	0.0

6.5.3 SDG&E MEDIUM EX ANTE LOAD IMPACTS

Table 6-8 summarizes the portfolio-adjusted ex ante demand reduction capability of SDG&E's Medium Commercial CPP customers under different planning conditions. Since no impacts were estimated for any Medium Commercial CPP dual-enrollment groups in PY2025, these estimates also represent the program-specific demand reductions, which will not be listed separately in this report.

Impact estimates represent Medium Commercial customers' estimated load reductions available from 4 to 9 p.m. under August worst day conditions for a 1-in-2 weather year. Since the ex post analysis showed no clear trends in percent load reductions relative to weather patterns or event hour in PY2024, the ex ante impacts are assumed to vary only as a function of the reference loads.

SDG&E's enrollment forecast anticipates slight growth in Medium Commercial CPP customers year-over-year through 2035. This is based on the expected growth of all accounts by category, while accounting for the percentage that generally stay on the default CPP rates and do not opt out.

The Medium Commercial CPP group is expected to deliver about 0.2 MW peak savings during a 1-in-2 event day in 2026, with this figure increasing to 0.25 MW over time due to increases in enrollments.

Table 6-8: SDG&E Medium Commercial Ex Ante Impacts for 1-in-2 August Worst Day (MW, Portfolio-Adjusted)

Weather Type	Year	Sites	CAISO		SDG&E	
			Program	Portfolio Adj	Program	Portfolio Adj
1-in-2	2025	2,011	0.20	0.20	0.20	0.20
1-in-2	2026	1,930	0.19	0.19	0.19	0.19
1-in-2	2027	1,958	0.19	0.19	0.20	0.20
1-in-2	2028	1,998	0.20	0.20	0.20	0.20
1-in-2	2029	2,040	0.20	0.20	0.20	0.20
1-in-2	2030	2,085	0.20	0.20	0.21	0.21
1-in-2	2031	2,142	0.21	0.21	0.22	0.22
1-in-2	2032	2,202	0.22	0.22	0.22	0.22
1-in-2	2033	2,273	0.22	0.22	0.23	0.23
1-in-2	2034	2,352	0.23	0.23	0.24	0.24
1-in-2	2035	2,448	0.24	0.24	0.25	0.25

Table 6-9 summarizes the portfolio-adjusted ex ante demand reduction capability of SDG&E's Medium Agricultural CPP customers. These estimates also represent the program-specific demand reductions. Impact estimates represent Medium Agricultural customers estimated load reductions available from 4 to 9 p.m. under August worst day conditions for a 1-in-2 weather year.

SDG&E's enrollment forecast anticipates slight growth in Medium Agricultural CPP customers year-over-year through 2035.

Table 6-9: SDG&E Medium Agriculture Ex Ante Impacts for 1-in-2 August Worst Day (MW, Portfolio-Adjusted)

Weather Type	Year	Sites	CAISO		SDG&E	
			Program	Portfolio Adj	Program	Portfolio Adj
1-in-2	2025					
1-in-2	2026					
1-in-2	2027					
1-in-2	2028					
1-in-2	2029					
1-in-2	2030					
1-in-2	2031					
1-in-2	2032					
1-in-2	2033					
1-in-2	2034					
1-in-2	2035					

6.5.4 SDG&E COMPARISON OF EX POST & EX ANTE LOAD IMPACTS

For SDG&E's Large CPP group, Table 6-10 compares the PY2025 ex ante reference loads and demand reductions to the averages from PY2023 and PY2024 events. These are the ex post estimates used as inputs in the ex ante forecast. Note that all event-hour ex post impact estimates are included in the model regardless of statistical significance—these are the best estimates of the impacts we have, and removing or zeroing out point estimates will tend to bias the overall ex post average. Ex ante results are shown for the 4 to 9 p.m. event window and compared to an average PY2023/PY2024 weekday.

In the 2023-2024 ex post results, an average Large CPP site delivered 1.2% in statistically significant load reductions (3.54 kWh per hour) per event. Ex ante reductions for the 4 to 9 p.m. event window were also 1.2%. Differences in ex ante and ex post counterfactual loads ("Load without DR" in the table) are largely explained by the change in the enrollment population from PY2025 ex post enrollment as compared to PY2024 ex ante. Specifically, though there were more customers in PY2024, a few very large PY2024 customers did not participate in PY2025. The SDG&E and CAISO weather ex ante predictions are slightly different because ex ante reference loads increase for hotter temperatures. Percent impacts are equal across the two ex ante weather specifications, however, because no weather trend was established for impacts.

Table 6-10: SDG&E Large Comparison of Ex Post and Ex Ante Load Impacts for 2025

Result Type	Day Type	Period	Load without DR (avg site kWh/h)	Load Reduction (avg site kWh/h)	% Reduction	Event Avg Temp (F)
Ex Post	Avg. Weekday Event	4 to 9 p.m.	302.12	3.54	1.2%	84.3
Ex Ante (CAISO)	Aug. Worst Day, 1-in-2	4 to 9 p.m.	223.69	2.76	1.2%	82.4
Ex Ante (SDG&E)	Aug. Worst Day, 1-in-2	4 to 9 p.m.	227.40	2.80	1.2%	84.7

For SDG&E's Medium CPP group, Table 6-11 compares the PY2025 ex ante reference loads and demand reductions to the averages from PY2023 and PY2024 events, with insignificant ex post estimates set to zero for planning purposes. These are the ex post estimates used as inputs in the ex ante forecast. Ex ante results are shown for the 4 to 9 p.m. event window and compared to an average PY2023/PY2024 weekday.

In the 2023-2024 ex post results, an average Medium CPP site delivered 0.4% in statistically significant load reductions (0.1 kWh per hour) per event. Ex ante reductions for the 4 to 9 p.m. event window were also 0.4%.

Table 6-11: SDG&E Medium Comparison of Ex Post and Ex Ante Load Impacts for 2025

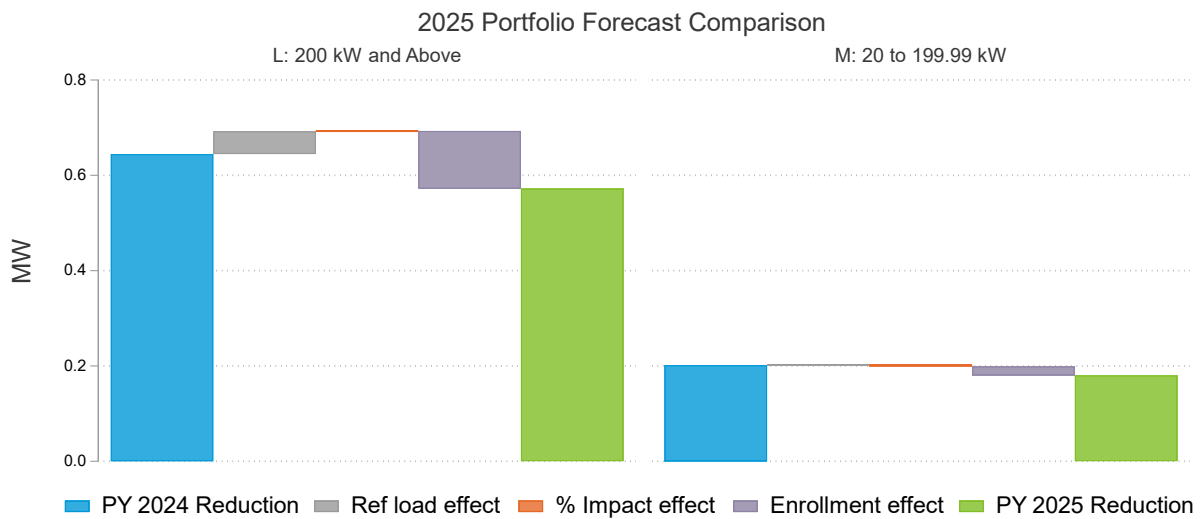
Result Type	Day Type	Period	Load without DR (avg site kWh/h)	Load Reduction (avg site kWh/h)	% Reduction	Event Avg Temp (F)
Ex Post	Avg. Weekday Event	4 to 9 p.m.	27.94	0.10	0.4%	84.6
Ex Ante (CAISO)	Aug. Worst Day, 1-in-2	4 to 9 p.m.	26.05	0.10	0.4%	82.1
Ex Ante (SDG&E)	Aug. Worst Day, 1-in-2	4 to 9 p.m.	26.64	0.10	0.4%	84.0

6.5.5 SDG&E COMPARISON TO 2024 EX ANTE IMPACT ESTIMATES

The ex ante impact estimates in this study are very similar to the PY 2024 estimates, with only slight reductions due to lower enrollments. The following figure gives a breakdown of the difference in ex

ante impact estimates from PY2024 and those generated in in PY2025. The graphs can be interpreted as the individual factors (changes in reference load, percent impacts, or enrollments) that explain the change in the estimated ex ante MW impacts in PY2024 (in blue) and PY2025 (in green).

Figure 6-4: Waterfall Analysis of 2024-2025 SDG&E Ex Ante Impacts by Group



Since there were no new impact estimates in PY2025, all the change from PY2024 to PY2025 can be attributed to the reference load effect and the enrollment effect. The Large group has slightly higher reference loads than in PY2024, but the reduced enrollment causes the PY2025 reductions to be slightly less than the previous year. The Medium group follows a similar pattern, with the decrease in ex ante MW impacts driven by reduced enrollment.

6.5.6 SDG&E EX ANTE LOAD IMPACT SLICE-OF-DAY TABLES

The following tables show the 2024 ex ante aggregate hourly impacts by CPP group for each month under SDG&E 1-in-2 monthly worst day conditions. CPP tariffs only allow for dispatch from 4 to 9 p.m. so the Slice-of-Day table shows impacts aligned with the tariffed event window. The estimated reductions are typically larger in the hotter summer months and smaller in the cooler winter months. While the percent impacts underlying these estimates do not vary by weather or event hour, the aggregate impacts reported in the table vary by month and hour based on the reference loads.

Table 6-12: SDG&E Large PY 2025 Slice of Day Table for Monthly Worst Day (MW, Portfolio-Adjusted)

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	0.46	0.46	0.47	0.56	0.56	0.58	0.64	0.66	0.69	0.63	0.56	0.46
18	0.45	0.45	0.45	0.52	0.52	0.54	0.59	0.62	0.65	0.58	0.53	0.45
19	0.43	0.43	0.43	0.49	0.50	0.51	0.55	0.58	0.60	0.55	0.50	0.43
20	0.40	0.41	0.41	0.45	0.46	0.47	0.50	0.51	0.52	0.49	0.46	0.40
21	0.38	0.39	0.39	0.42	0.42	0.44	0.46	0.48	0.49	0.45	0.42	0.38
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Demand reductions are positive (Blue)

Load increases are negative (Orange)

Table 6-13: SDG&E Medium PY 2025 Slice of Day Table for Monthly Worst Day (MW, Portfolio-Adjusted)

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	0.12	0.12	0.13	0.17	0.17	0.18	0.21	0.22	0.24	0.21	0.18	0.13
18	0.12	0.12	0.12	0.16	0.15	0.16	0.19	0.20	0.21	0.19	0.16	0.12
19	0.11	0.11	0.11	0.14	0.14	0.15	0.17	0.17	0.19	0.16	0.15	0.12
20	0.11	0.11	0.11	0.13	0.13	0.14	0.16	0.16	0.17	0.15	0.14	0.12
21	0.10	0.10	0.11	0.12	0.12	0.13	0.14	0.14	0.15	0.14	0.13	0.11
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Demand reductions are positive (Blue)

Load increases are negative (Orange)

7 RECOMMENDATIONS

Overall, in PY 2025 CPP rates delivered small demand reductions, generally in the range of 0 to 1% across IOUs and groups. Reasons for the general lack of response are not directly tested in this evaluation. However, some factors that may contribute to lower responses, independent of any IOU programming, include:

- Since CPP rates also have TOU components on non-event days, measured impacts must be over-and-above any normal shifting behavior during peak summer hours
- Some customers have insurance provided against charges such as first-year bill protection (all IOUs) or reserving loads from CPP event pricing (SDG&E only)
- Event notifications may not be received by decision makers with the ability to modify loads
- Lower discretionary loads during 4 to 9 p.m. event window for commercial customers
- Customers that are defaulted onto CPP may have a lack of interest in load shifting/reduction
- Customers that are defaulted onto CPP may lack awareness of price adders.
- Customers may have difficulty in responding to varying four-tiered rates (three-tier TOU rates plus CPP adders announced one day ahead)

The recommendations below present options to improve reductions or better understand customer barriers to producing greater demand reductions. Note that the recommendations below may not be currently funded and may not be within each IOU's control. Costs and feasibility would also need to be considered alongside each utility's other research and rate design priorities.

7.1 CPP RECOMMENDATIONS – PG&E

- Survey customers to identify or understand barriers to shifting on event days. Topics to consider may include awareness, flexibility of loads business conditions, cost of shifting loads, etc.
- Analyze the reasons for declining enrollments, aside from CCA expansions. This could include characterizing the types of customers remaining on CPP rates vs. average commercial customers or customers in other DR programs.
- PG&E account managers receive PDP billing reports annually—these can be discussed with customers, with opportunities to educate on load shifting, gain feedback on events, notifications, etc. and/or encourage customers that aren't benefiting from CPP to de-enroll.
- Smaller accounts could receive PDP reports including billed amounts, education on load shifting, and the most recent PY's event dates as well as an opportunity to update contact information and the preferred contact person for event notifications.

7.2 CPP RECOMMENDATIONS – SCE

- Move Non-performers to other TOU rates, per SCE’s current plans (where Non-Performers are defined as sites with 2 consecutive years of non-performance, measured by bill impacts)
- Survey customers to identify or understand barriers to shifting on event days. Topics to consider may include awareness, flexibility of loads, business conditions, cost of shifting loads, etc.
- Notifications may have led to better impacts for PY 2025, but the impacts were not clear. Evaluating the delivery and receipt of notifications, as well as updating relevant contact information for the sites could be helpful. If necessary, these efforts could be targeted at large Agriculture, Government, Manufacturing, and Wholesale sites which historically have the greatest ability to respond to event days.
- Move Residential SGIP customers to a DR program that better incentivizes battery dispatch.
- Number of events: This is likely a decision in rate design, but customers seem to react to the 12 events in the same way they do for the other ~70 summer weekdays, possibly since the events occur very frequently.

7.3 CPP RECOMMENDATIONS – SDG&E

- Test events: Given that no events were called for PY 2025, future evaluations may benefit from at least one annual data point in the form of a test event. This could also ensure smooth event dispatches later in the season.
- Test notifications: SDGE’s PY 2024 impacts were reduced due to an issue with notifications for at least one high-performing site. The extent of the issue, as well as the readiness of the system for days with extreme system loads, would be better understood by testing the notifications ahead of time.
- Enrollments: PY 2025 again saw a slight decline in enrollments, though we are not aware of any plans for further CCA expansions. Assessing enrollment patterns as well as the types of customers that are enrolling/unenrolling in CPP rates could be helpful for the program team as well as evaluators.
- Explore moving some of the accounts with high CPP charges (i.e. those that are not benefiting from the rate) to other TOU rates.

APPENDIX

A. PG&E AND SCE EX ANTE SLICE OF DAY TABLES BY GROUP

PG&E Ex ANTE LOAD IMPACT SLICE-OF-DAY TABLES

The following tables show the 2025 ex ante aggregate hourly impacts by CPP group for each month under PG&E 1-in-2 monthly peaking conditions. CPP tariffs only allow for dispatch from 4 p.m. to 9 p.m. so the Slice-of-Day table shows impacts aligned with the tariffed event window. The estimated reductions are typically larger in the hotter summer months and smaller in the cooler winter months. While the percent impacts underlying these estimates do not vary by weather or event hour, the aggregate impacts reported in the table vary by month and hour based on the reference loads.

Table o-1: PG&E Large PY 2025 Slice of Day Table for System 1-in-2 Worst Day (MW, Portfolio-Adjusted)

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	2.43	2.44	2.45	2.92	3.16	3.37	3.36	3.30	3.21	2.93	2.59	2.59
18	2.37	2.38	2.39	2.84	3.07	3.28	3.27	3.21	3.12	2.85	2.52	2.52
19	2.39	2.40	2.40	2.87	3.10	3.35	3.34	3.27	3.17	2.87	2.54	2.54
20	2.43	2.44	2.45	2.92	3.14	3.40	3.39	3.32	3.22	2.92	2.59	2.59
21	2.42	2.43	2.44	2.92	3.17	3.44	3.44	3.36	3.25	2.92	2.58	2.58
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Demand reductions are positive (Blue)

Load increases are negative (Orange)

Table o-2: PG&E Medium PY 2025 Slice of Day Table for System 1-in-2 Worst Day (MW, Portfolio-Adjusted)

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	1.96	1.96	1.97	2.52	2.90	3.31	3.33	3.26	3.14	2.63	2.02	2.02
18	1.81	1.81	1.81	2.35	2.72	3.11	3.13	3.06	2.94	2.45	1.86	1.86
19	1.73	1.73	1.73	2.23	2.58	2.94	2.96	2.90	2.78	2.32	1.78	1.78
20	1.70	1.70	1.70	2.15	2.47	2.80	2.82	2.76	2.66	2.24	1.74	1.74
21	1.67	1.67	1.67	2.06	2.33	2.61	2.63	2.58	2.50	2.15	1.72	1.72
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Demand reductions are positive (Blue)

Load increases are negative (Orange)

Table o-3: PG&E Small PY 2025 Slice of Day Table for System 1-in-2 Worst Day (MW, Portfolio-Adjusted)

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	0.92	0.92	0.92	1.28	1.53	1.79	1.79	1.73	1.64	1.30	0.90	0.90
18	0.81	0.81	0.81	1.12	1.33	1.55	1.56	1.50	1.43	1.14	0.80	0.80
19	0.73	0.73	0.73	1.00	1.19	1.38	1.38	1.34	1.27	1.02	0.72	0.72
20	0.69	0.69	0.69	0.92	1.08	1.25	1.25	1.22	1.16	0.94	0.68	0.68
21	0.70	0.70	0.70	0.88	1.01	1.15	1.15	1.12	1.07	0.89	0.69	0.69
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Demand reductions are positive (Blue)

Load increases are negative (Orange)

SCE EX ANTE LOAD IMPACT SLICE-OF-DAY TABLES

The following tables show the 2025 ex ante aggregate hourly impacts by CPP group for each month under SCE 1-in-2 monthly peaking conditions. CPP tariffs only allow for dispatch from 4 p.m. to 9 p.m. so the Slice-of-Day table shows impacts aligned with the tariffed event window. The estimated reductions are typically larger in the hotter summer months and smaller in the cooler winter months. While the percent impacts underlying these estimates do not vary by weather or event hour, the aggregate impacts reported in the table vary by month and hour based on the reference loads.

Table o-4: SCE Large PY 2025 Slice of Day Table for System 1-in-2 Worst Day (MW, Portfolio-Adjusted)

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	2.00	1.99	1.99	2.32	2.31	2.51	2.55	2.55	2.58	2.45	2.28	1.96
18	1.92	1.92	1.92	2.22	2.21	2.39	2.43	2.43	2.46	2.33	2.18	1.89
19	1.86	1.86	1.86	2.11	2.10	2.23	2.26	2.26	2.28	2.19	2.06	1.83
20	1.83	1.83	1.83	2.05	2.04	2.18	2.21	2.21	2.23	2.13	2.01	1.80
21	1.81	1.81	1.81	2.00	2.00	2.12	2.15	2.14	2.15	2.06	1.96	1.78
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Demand reductions are positive (Blue)

Load increases are negative (Orange)

Table o-5: SCE Medium PY 2025 Slice of Day Table for System 1-in-2 Worst Day (MW, Portfolio-Adjusted)

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	0.23	0.23	0.23	0.32	0.32	0.37	0.38	0.39	0.40	0.36	0.31	0.23
18	0.22	0.22	0.22	0.29	0.29	0.34	0.35	0.35	0.36	0.32	0.28	0.21
19	0.20	0.20	0.20	0.27	0.27	0.31	0.31	0.32	0.32	0.29	0.26	0.20
20	0.19	0.19	0.19	0.25	0.25	0.28	0.29	0.29	0.29	0.27	0.24	0.19
21	0.19	0.19	0.19	0.23	0.23	0.26	0.26	0.27	0.27	0.25	0.22	0.18
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Demand reductions are positive (Blue)

Load increases are negative (Orange)

Table o-6: SCE Small PY 2025 Slice of Day Table for System 1-in-2 Worst Day (MW, Portfolio-Adjusted)

Hour Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01
18	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01
19	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.01	0.01	0.01	0.01
20	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
21	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Demand reductions are positive (Blue)

Load increases are negative (Orange)

B. INDIVIDUAL SITE REGRESSIONS WITH SYNTHETIC CONTROLS

Individual site regressions were used as a supplementary method for estimating load impacts for PY 2025 impacts for CPP customers. The approach is implemented on hourly site loads. It relies on control sites that did not experience the intervention (up to five matched to each CPP site), lagged customer site usage, an industry usage profile, solar irradiance, plus weather and time characteristics, to estimate the counterfactual. The model estimates a counterfactual load using weather and these various synthetic controls and predictors. A separate model is estimated for each hour of day and all modeling excludes event days. Reductions are the difference between the observed CPP site and predicted counterfactual loads. With a regression model with synthetic controls, one should observe:

- Very similar energy use patterns for CPP site and counterfactual loads when the intervention is not in place.
- A change in demand patterns for customers who are subject to time varying prices, but no similar change for the counterfactual load.
- The timing of the change should coincide with the introduction of intervention.

The use of individually specified site specific regression models allows for incorporation of a subset of possible parameters that best predict out of sample loads for each site and does not rely on finding a

single ideal match. The model equation including the full set up possible parameters is presented below in Equation A-1 and Table A-o-7. In practice the model used for each site included a varying subset of these parameters. A separate model was estimated for each hour of the day.

Equation A-1: Ex Post Regression Model for Non-Residential CPP

$$kW_t = a + \sum_{n=1}^{max} b \cdot kW_{0n,t} + \sum_{n=1}^{max} c_n \cdot kW_{1t-n} + \sum_{n=1}^{max} d_n \cdot month_n + \sum_{n=1}^{max} e_n \cdot dow_n + f \cdot solar_t + g \cdot industry_t + \sum_{n=1}^{max} h_{n,t} \cdot spline_{n,t} + \delta_t + \varepsilon_{i,t}$$

Where:

Table A-o-7: Ex Post Regression Elements for Non-Residential CPP

kW_t	Is the site usage for each time period.
kW_{0t}	Is the synthetic control usage for up to 5 matched controls for each time period. The specific number of controls used varied by site. These synthetic controls were selected based on Euclidean distance matching (the winning matching method in a tournament of 8 methods). They did not experience the treatment.
kW_{1t-n}	Is the lagged customer site usage and could be one of: no lags, 1 day, 1 week, 2 weeks, 1 day and 1 week, 1 and 2 weeks, and a same day AM lag. The specific lags used varied by site.
a	Is the model intercept.
b	Coefficients for the synthetic control loads. The specific number of controls used varied by site and ranged from 0 to 5.
c	Coefficients for the customer site usage lags. The specific lags used varied by site.
d	Coefficients for each month.
e	Coefficients for each day of week.
f	Coefficient for solar irradiance for each time period. Inclusion of this parameter varied by site.
g	Coefficient for industry load profile: normalized hourly loads (scaled from 0 to 1) for control sites in the same industry as the customer site. Industry grouping developed using NAICS code and customer names indicative of industry activity. Inclusion of this parameter varied by site.
h	Coefficients for weather sensitivity of loads, based on a 2 knot spline of 24 hour moving average of temperature, averaged across CPP sites for each time period.
δ_t	Represents time effects for each time period. This accounts for observed and unobserved factors that vary by time but affect all customers equally.
$\varepsilon_{i,t}$	Represents the error term for each individual customer and time period.

Most sites did not require individual site regressions, as a comparable control group was available to estimate event-day counterfactuals. Among sites that did require the individual regressions, loads were often variable or the sites were located in areas with few similar businesses. The tables below report the bias and fit metrics for the models used by utility and group. Mean absolute percent error (MAPE) indicates the percent difference between predicted values and actual kWh on non-event days in summer 2025. The average percent bias is the mean of the percent errors – without taking an absolute value, this becomes the mean of both positive and negative values, with strong models calibrated to achieve a bias close to zero.

Table A-o-8: Bias and Fit Measures for Individual Customer Regressions – PG&E

Group	Sites in Sample	Sites w/ Indiv. Regressions	Avg. kW	Mean Absolute Percent Error (MAPE)	Avg. Percent Bias
Large Agricultural	607	607	89.1	0.009	-0.001
Medium Agricultural	216	92	8.0	0.024	-0.012
Small Agricultural	649	152	1.1	0.014	-0.014
Large Commercial	695	695	217.6	0.002	-0.002
Medium Commercial	12,114	226	24.3	0.002	-0.002
Small Commercial	39,596	266	2.1	0.006	-0.006

Table A-o-9: Bias and Fit Measures for Individual Customer Regressions – SCE

Group	Sites in Sample	Sites w/ Indiv. Regressions	Avg. kW	Mean Absolute Percent Error (MAPE)	Avg. Percent Bias
Large Agricultural	207	207	139.3	0.001	0.000
Large Commercial	1,565	939	242.6	0.001	0.000
Medium Commercial	21,334	91	24.2	0.000	0.000
Small Commercial	45,906	116	-4.9	0.053	-0.053

C. PROXY DAY SELECTION

For the differences-in-differences estimates, customers are compared both over time (event days vs. non-event days) and with a pool of similar, non-CPP customers (the matched control group). Proxy days, the non-event days used for comparison, are selected to be as similar as possible to actual event days. In general, these are often the hottest non-holiday weekdays of the summer (e.g. for SDG&E and PG&E, which call CPP events on days with extreme weather).

Proxy days are selected by matching customers pre-event loads on event days (through 2 p.m.) to loads for the same hours on non-event days. Matches are tested and selected as the group that minimizes bias between the event day and non-event day loads.

A t-test can show the likelihood that two data series are in fact different from each other. For proxy day selection, better matches should produce results with a higher probability that the two series are not different from each other.

The following tables report the p-values from t-tests of the hypothesis that pre-event hour loads on event days and proxy days are the same. Values are generally greater than 0.05, corresponding to the 95% confidence level, and frequently very close to one, meaning the hypothesis of similar loads cannot be rejected at the 95% confidence level and the series are in fact very similar.

Table A-o-10: PG&E Proxy and Event Day Matching: p-Values from t-Tests

Event Date	Medium Ag.	Small Ag.	Medium Comm.	Small Comm.
07-10	0.870	0.968	0.957	0.964
07-11	0.592	0.906	0.879	0.897
08-08	0.772	0.917	0.997	0.998
08-21	0.000	0.232	0.536	0.585
08-22	0.000	0.063	0.316	0.385
09-04	0.237	0.713	0.862	0.879

Table A-o-11: SCE Proxy and Event Day Matching: p-Values from t-Tests

Event Date	Large Comm.	Medium Comm.	Small Comm.
07-30	0.943	0.982	0.985
07-31	0.977	0.994	0.995
08-01	0.909	0.966	0.972
08-08	0.903	0.956	0.964
08-21	0.749	0.876	0.896
08-22	0.799	0.886	0.903
08-25	0.859	0.930	0.941
09-02	0.799	0.905	0.921
09-03	0.478	0.759	0.798
09-16	0.889	0.953	0.961
09-17	0.803	0.913	0.928
09-18	0.797	0.924	0.938

Some smaller values are found in PG&E's agricultural groups, which had fewer customers. At certain levels, the PG&E t-tests in fact imply the hypothesis of similar loads can be rejected (e.g. August 21st and 22nd have significant differences at the 5% level).

Figure A-o-1 and Figure A-o2 shows proxy day and event day loads for CPP customers by IOU, focusing on the Medium Commercial group (which has a large number of customers at each IOU).

Figure A-o-1: PG&E Event and Proxy Day Loads for CPP Customers

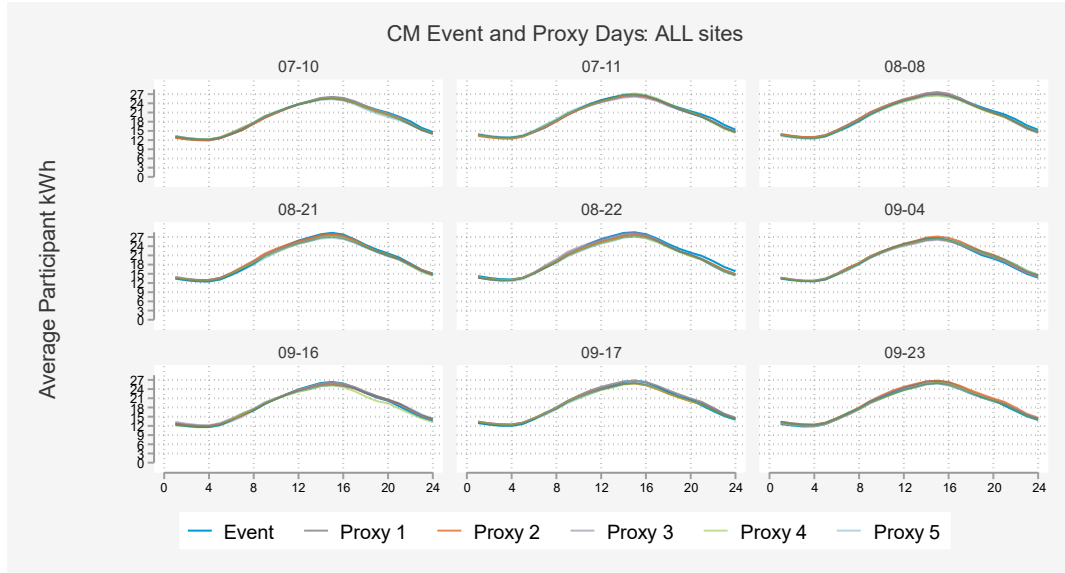
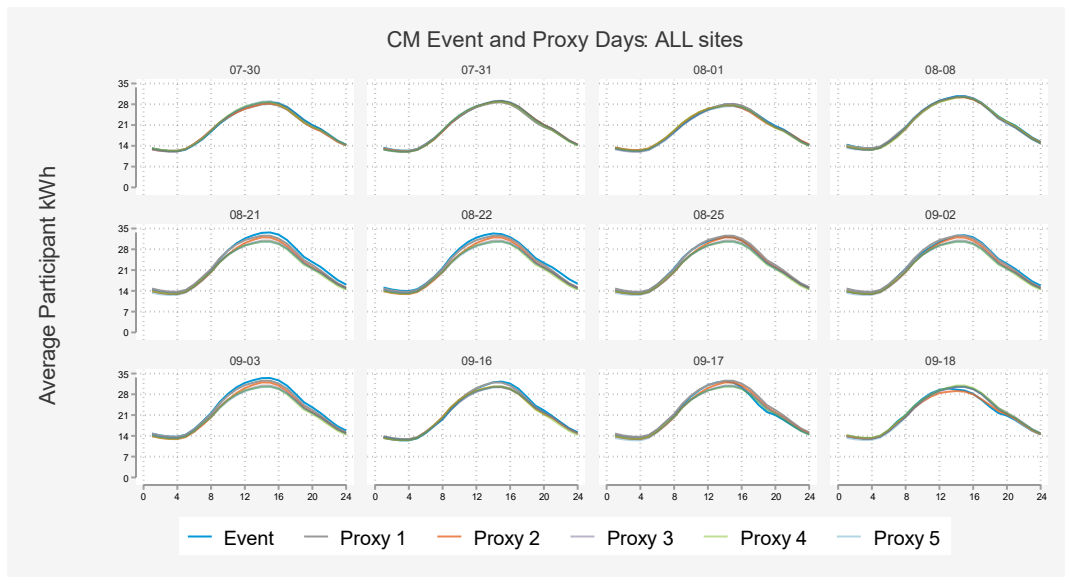


Figure A-o-2: SCE Event and Proxy Day Loads for CPP Customers



Even if very closely matching proxy days cannot be found, differences-in-differences can still be the best estimation method for a DR evaluation. In such cases, dissimilarities between event days and proxy days may simply mean that the event days are very different from other summer days. Differences-in-differences then would still allow for comparison to a control group on these very hot days, with the control group serving as a proxy for the types of loads seen on those extreme days.

Regression modeling would instead require a very precise model to extrapolate each site's usage on an extremely hot day, based only on their behavior on other, milder days. The small impacts observed for

CPP groups (0-1%) make this type of prediction with regression modeling even more difficult. For this reason, differences-in-differences were still used wherever possible.

D. DIFFERENCES-IN-DIFFERENCES MODEL FOR PY 2025

A methodological change from the 2023 evaluations included simpler modeling for greater flexibility. Specifically, to tightly predict event-day loads, previous evaluations employed regression models that included same-day loads in the morning and afternoon leading up to the event start. This type of modelling tends to reduce noise in the estimates, since the event-day loads are able to describe a great deal of the variation in loads observed in the data.

However, including same-day loads, especially in the afternoon leading up to the events, makes the assumption that CPP impacts can occur only during the event window itself. This is a strong assumption for a behavioral program in which customers can receive day-ahead notice of events. If day-of adjustments are included in the model, then reference loads (estimated loads without any DR intervention) may instead contain a part of the event impacts.

For all PY 2025 estimates, day-of adjustments were not made to the loads. The drawback to this approach, however, is that it is more difficult to generate the precise reference loads needed to detect impacts of 0-1%. Including day-of adjustments leads to much greater precision (smaller standard errors), but it is unclear if this is false precision.

Since both approaches may have value in projecting future impacts, the PY 2025 ex ante models include a blend of the PY 2023 and PY 2024 ex post impact estimates.

As noted in the ex post methodology section, beginning in PY 2025 we did include a morning lag term for some of the individual customer regressions. These are the average kWh value from 6 to 10 a.m. on the given day, and only apply to sites that 1) were estimated using the individual customer regressions (generally very large sites or sites with few matched controls) and 2) had this term included in their best regression model based on testing (about 20% of sites with ICRs).