Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

REPORT

PY2024 SCE Smart Energy Program Load Impact Evaluation

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Confidential information is redacted and denoted with black highlighting: [redacted]

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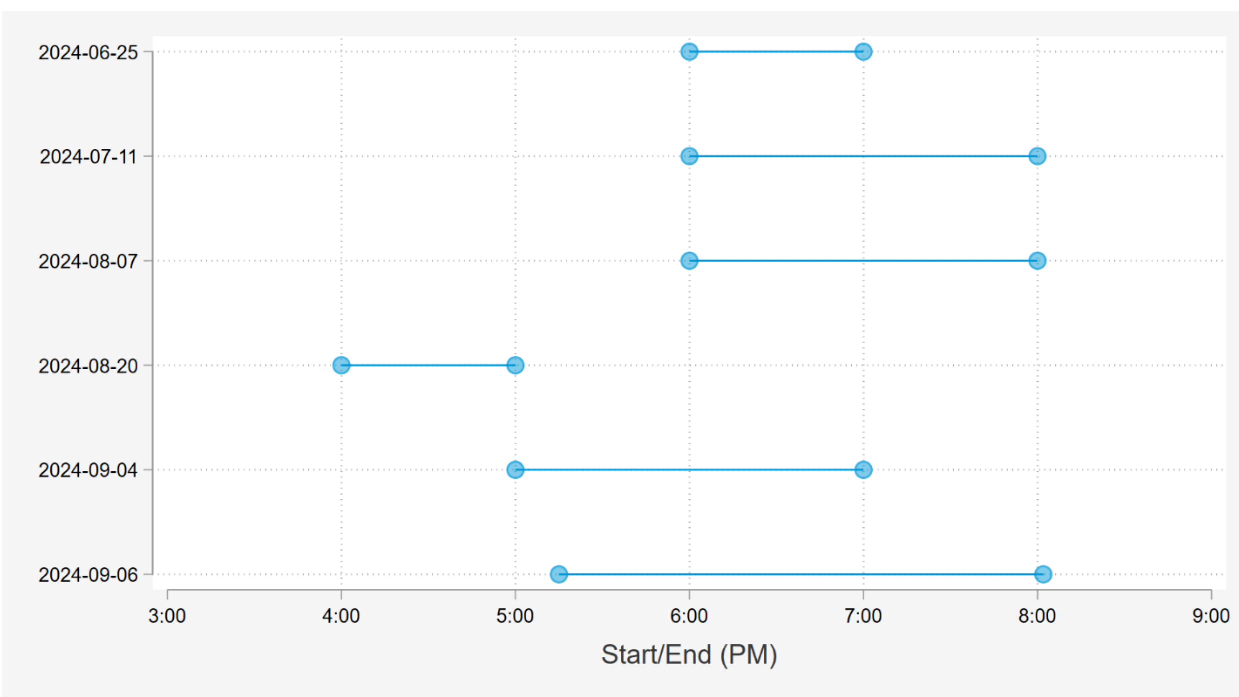
1 EXECUTIVE SUMMARY

This report documents the evaluation year 2024 load impact evaluation of Southern California Edison's (SCE) Smart Energy Program (SEP). SEP is a residential demand response (DR) program that utilizes Wi-Fi connected smart thermostats to reduce air conditioning load in participating households during peak hours. SCE retained Demand Side Analytics (DSA) to conduct the SEP load impact evaluation for PY2024. The primary objectives of this report are to:

- Document the findings of an ex-post (after the fact) load impact study for PY2024 events.
- Provide ex-ante (forward looking) estimates of SEP's demand reduction capability over the next eleven years (2025 to 2035) under various weather conditions.

When SCE initiates SEP events, the two participating DR thermostat vendors adjust cooling set points upward by as much as four degrees (F) to limit air conditioning usage and reduce electric demand. SCE can call SEP events for emergency (reliability) reasons, economic purposes, or as part of measurement and evaluation. The evaluation year for 2024 goes from October 2023 to September 2024. Evaluation years end in September to ensure load impacts are available in time for filing the following spring. SCE dispatched SEP on six days during PY2024 between June and September. Of the 6 events, five were the result of self-scheduling in the day-ahead market or energy price triggers and one (09/06) was dispatched for reliability purposes. All but one were called territory wide. The event dispatched on September 6th was supposed to be rolled out to all participants within the Mira Loma A-Bank but encountered dispatch issues leading to only a subset of customers from one of the program vendors being dispatched within the A-Bank area. Figure 1 shows the six events along with the start and end time. All times in this report are displayed in Pacific Daylight time.

Figure 1: SEP PY2024 Event Start and End Times (Pacific Daylight)



SEP events are typically called in the late afternoon in alignment with the Resource Adequacy (RA) window which spans from 4- 9 PM. In 2019, SCE integrated SEP into the CAISO wholesale energy market where it is offered as a dispatchable resource based on energy prices. As a result of integrating into the CAISO market, 2019-2024 events have been called later in the day compared to previous years when the program was dispatched based on other triggers, such as the gross peak demand forecast.

SEP enrollments continued to grow through the summer of 2024, growing by more than 7,000 participants during the offseason. This growth in enrollment was in line with the ex-ante enrollment forecast from the previous year's analysis. The substantial growth in SEP program enrollments can be attributed to larger and more focused marketing efforts.

1.1 SUMMARY OF EX-POST LOAD IMPACTS

There were six distinct SEP events in PY2024 between June and September 2024. SEP events may be dispatched at the B-bank substation level[1], Sub-Load Aggregation Point (SubLAP) or called for the entire SCE territory. In PY2024 all events but one were dispatched territory wide. The September 6th emergency event was a partial dispatch of the Mira Loma A-Bank area. Each territory wide event started and ended between the hours of 4pm and 8pm. DSA utilized a matched control group with regression analysis to estimate the impacts of each event across the full participant group and a variety of segments. Table 1 shows the event details and average hourly impacts for all PY2024 events and the "Average Event Day" profile. DSA defines an "Average Event Day" for PY2024 as the weighted average of the two territory-wide events that began at 6pm and ended at 8pm (two-hour duration). Savings estimates presented in Table 1 show the average hourly impacts. It is important to note that events with longer durations will have lower average hourly impacts because of this tapering trend, thus lowering the event's average hourly impact with each additional hour of dispatch.

The hottest territory wide event took place on 9/4/2024. The two-hour event on that day had an average per customer hourly reduction of 0.97 kW and an average aggregate hourly savings of 78.3 MW during the full event hours. Impacts on the peak day, compared to the average event day were significantly higher.

The event on September 6th was intended exclusively for customers in the Mira Loma A-Bank area, where 3,094 SEP customers were eligible for dispatch. However, due to an error when dispatching the event, only 436 customers were actually dispatched.

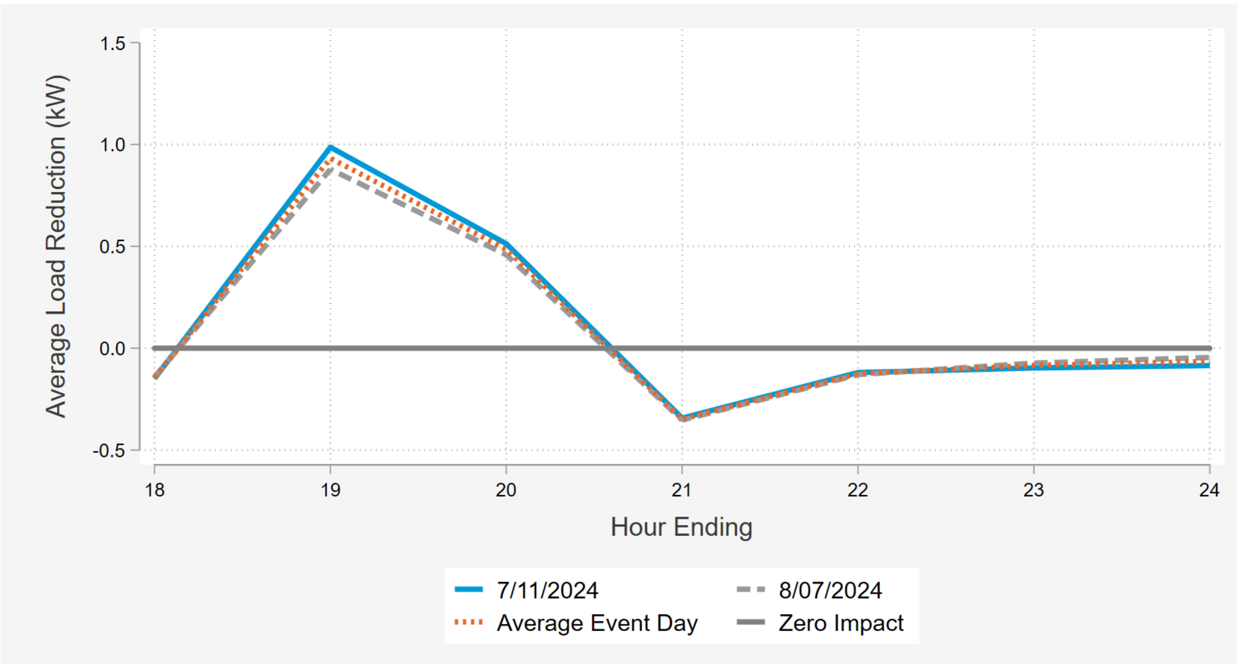
[1] D.23-12-005, pg.68

Table 1: 2024 Ex-post Event Impacts

Event Date	Start Time	End Time	Participants	Average Event Temp	Daily Max Temp	Average Full Hour Impact (kW Reduction)	Average Aggregate Full Hour Impact (MW Reduction)	Pre-Cooling
6/25/2024	6:00 PM	7:00 PM	77,321	82.9	85.8	0.88	67.8	Yes
7/11/2024	6:00 PM	8:00 PM	77,876	86.9	90.6	0.75	58.4	Yes
8/7/2024	6:00 PM	8:00 PM	79,647	81.6	86.1	0.67	53.3	Yes
8/20/2024	4:00 PM	5:00 PM	80,205	94.4	94.4	1.25	99.9	Yes
9/4/2024	5:00 PM	7:00 PM	80,528	95.5	96.2	0.97	78.3	Yes
9/6/2024	5:15 PM	8:02 PM	436	95.8	104.8	0.86	0.4	No
Average Event Day	6:00 PM	8:00 PM	78,771	84.3	88.1	0.71	55.8	Yes

Figure 2 shows program load impacts from the "Average Event Day" along with its contributing dates. The event window temperature during the "Average Event Day" was 84.3 °F over the two event hours. While outdoor temperature affects SEP load impacts, the most important predictor of hourly load impact is event hour, or whether a given hour is the first, second, etc. hour of dispatch. The first hour of the "Average Event Day" provides a reduction of approximately 0.93 kW per household, while the second hour had a reduction of 0.49 kW per household. One of the SEP vendors deployed pre-cooling on each of the event days included in the "Average Event Day", as well as each other event day except for the emergency event day on September 6th. The pre-cooling of homes leads to larger load impacts during the event at the expense of load increases in hour leading up to each non-emergency event.

Figure 2: Hourly Load Reductions for 2024 Average Event Day



1.2 SUMMARY OF EX-ANTE LOAD IMPACTS

SCE and CAISO can call SEP reliability events anytime during the year. SEP economic events are restricted to non-holiday weekdays from 11am to 9pm. In the ex-ante impacts, SEP events are assumed to span the Resource Adequacy (RA) window. The definition of the RA window varies by month, beginning at 5pm and lasting until 10pm in March, April, and May, while beginning at 4pm and lasting until 9pm in all other months. The varying RA window is meant to represent the time of day which is most likely to require dispatchable resources throughout each month of the year. We see decaying impacts in each hour of the five hours of the RA window just as is typically demonstrated in the ex-post evaluation. Figure 3 illustrates this trend for monthly system worst days using SCE and CAISO 1-in-2 weather conditions. Although SEP is *available* year-round, it is a weather sensitive program with little or no impact when air conditioning is not being used. Using 1-in-2 weather for monthly system worst days, we estimate non-zero SEP capability in March through November for both SCE and CAISO weather conditions. CAISO 1-in-2 conditions show a significant dip capability between April and May. This is due to lower forecasted temperatures for the May system worst day than the April system worst day in the CAISO 1-in-2 weather scenario.

Figure 3: Average Customer Ex-Ante Impacts on 2025 Monthly System Worst Days: 1-in-2 Conditions

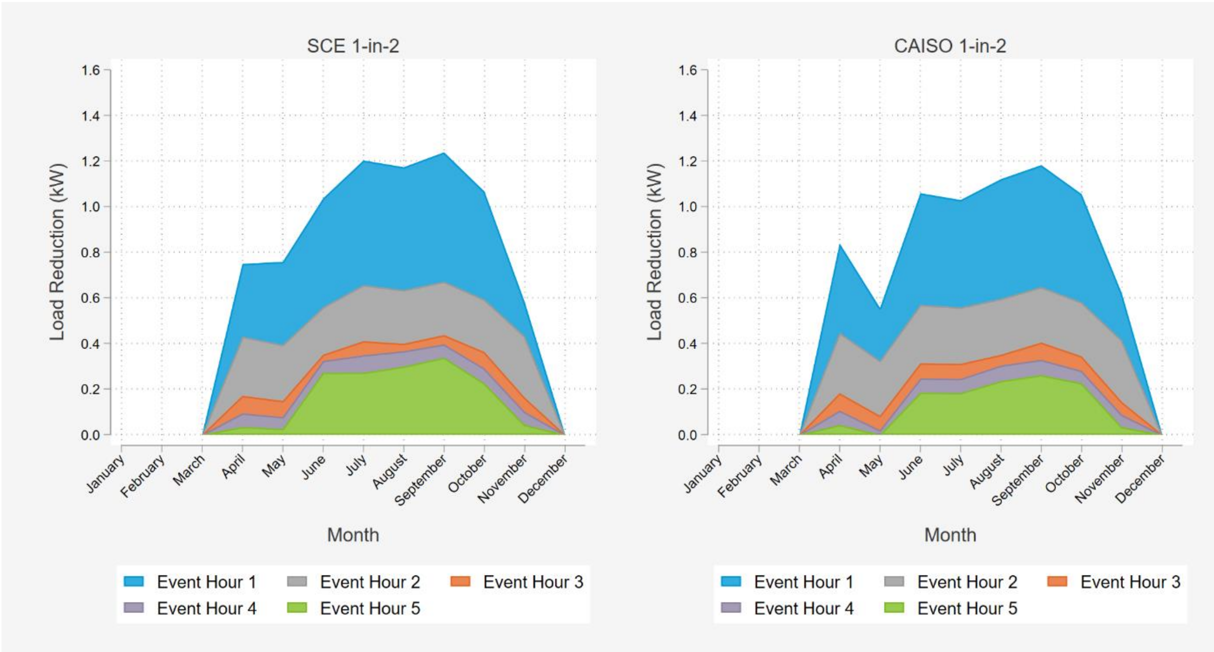
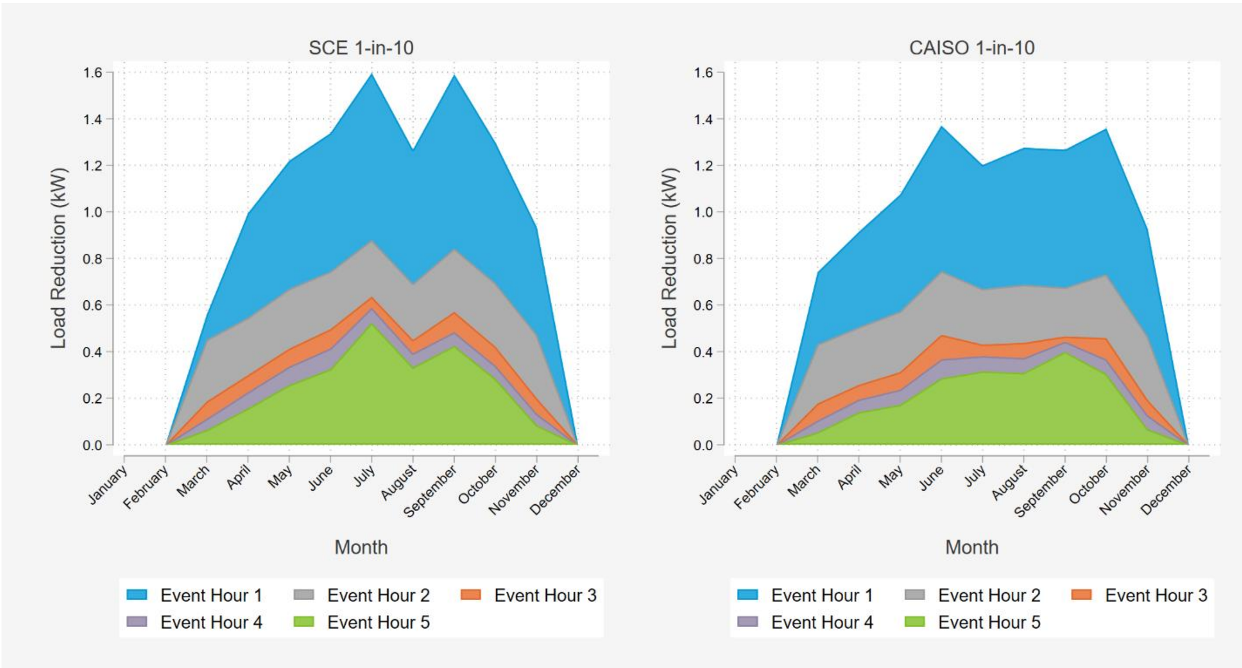


Figure 4 shows the same set of results for 1-in-10 weather conditions, which are hotter than 1-in-2 conditions. The SCE 1-in-10 condition impacts have two peaks over the summer months, July and September. This is due to higher forecasted temperatures in those months. The participant weighted maximum daily temperature for an August worst day in SCE 1-in-10 conditions is 99.4 °F, while July and September are 104.4 and 104.5 °F respectively.

Figure 4: Average Customer Ex-Ante Impacts on 2025 Monthly System Worst Days: 1-in-10 Conditions



The estimated average load impact per customer on a September system worst day using SCE 1-in-10 weather is 1.59 kW during the first hour of dispatch, up 0.07 kW from the PY2023 ex-ante forecast. For comparison, the weighted average maximum daily temperature for a September system worst day using CAISO 1-in-10 weather is 99.0°F and the estimated load impact is 1.27 kW during the first hour of dispatch.

Table 2 shows the SEP aggregate ex-ante load impacts for a September Monthly Worst Day in 2025. SCE's current enrollment forecast projects enrollment to reach 87,774 customers by that time. The estimated load impact of SEP in 2025 ranges from 103.7 MW to 139.6 MW during hour ending 17. Estimated impacts decline across the RA window and range from 22.9 MW to 37.3 MW in hour ending 21. Average impacts for the five-hour RA window range from 49.5 MW to 68.7 MW.

Table 2: SEP Aggregate Ex-Ante Impacts (MW) During RA Window: 2025 September Monthly Worst Day

Hour Ending	SCE 1-in-2	CAISO 1-in-2	SCE 1-in-10	CAISO 1-in-10
17	108.7	103.7	139.6	111.2
18	58.9	56.9	74.0	59.3
19	38.3	35.4	50.1	40.8
20	34.8	28.8	42.5	38.9
21	29.7	22.9	37.3	35.1
RA Window	**54.1**	**49.5**	**68.7**	**57.1**

SCE forecasts that SEP enrollments will near 135,069 households by 2035. Actual enrollment in PY2024 was high and overall exceeded expectations based on the PY2023 enrollment forecast. Using the SCE enrollment forecast and the ex-ante average customer impacts, we estimate an average aggregate load impact across the five RA window hours of 83.4 MW for SCE 1-in-2 weather conditions on a September monthly worst day and 106.0 MW for SCE 1-in-10 conditions on a September monthly worst day in 2035. Using CAISO peaking conditions, we estimate an average aggregate impact of 76.4 MW for 1-in-2 conditions and 88.0 MW for 1-in-10 conditions on a September monthly worst day.

1.3 KEY FINDINGS AND RECOMMENDATIONS

Based on the PY2024 ex-post and ex-ante evaluations, DSA highlights the following considerations for program design and future load impact evaluations.

- SEP program enrollment increased by approximately 7,000 customers in the offseason between PY2023 and PY2024 and a further 3,000 customers during the PY2024 season. This growth trend is similar to the growth seen in the previous year. Continued marketing efforts played a large part in the healthy enrollments this year as well as previous years. The increase is in line with predictions made by the SEP program team in PY2023. Precise enrollment projections increase the accuracy of aggregate ex-ante forecasts as the enrollment forecasts play a large role in predicting future program capabilities.

- The most important predictor of SEP load impact is not time of day or weather, but the position of an hour within an event. Impacts are largest during the first event hour and decline sharply in each subsequent hour. Consequently, shorter events show larger average load impacts than longer events. Over the past several years, the SEP program has tended to call shorter events leading to higher average full hour impacts. While shorter events are likely preferred by customers, calling only short duration events poses a challenge with estimating ex-ante impacts. In PY2024 ex-ante, 2021-2024 event impacts were used for predicting future program impacts. Over that duration of time only a single event was called with four full hours and no events with five hours. This lack of data on how program participants perform over long events means that predicting program performance over a hypothetical five hour event requires using performance from other event hours to predict hours four and five of control. DSA recommends a focus on calling longer events and, if possible, during hotter outdoor temperatures to ensure that ex-ante predictions of program impacts are as accurate as possible.

- [redacted]

- In PY2024 homes with two thermostats showed approximately 37% larger load reductions during events than homes with a single thermostat. Those with three or more thermostats had impacts about 17% higher than those with two program thermostats. These incremental increases in the estimated program impacts based on the number of thermostats enrolled are similar to those seen in previous years. Currently customer bill credits do not consider the number of thermostats controlled.

- ✓ SCE may want to consider larger bill credits for homes with multiple program thermostats. This number may be scaled with the number of thermostats that the customer brings to the program.

- In PY2024, the event that took place on September 6th was a localized emergency event that was intended for all participants in the Mira Loma A-Bank area. However, only 436 out of intended 3,094 participants were dispatched due to an error in dispatch by SCE's Grid Control Center. While this event had small aggregate impacts due to the smaller number of customers dispatched, the localized load relief provided to the distribution system on that day was valuable. In future program years, DSA recommends testing these granular geographic dispatch levels to ensure that in future emergency conditions the correct groups of participants can be reliably dispatched. The ability to dispatch program participants at granular geographic levels means that SEP has the potential to play an important part in distribution system reliability in the future.

- PY2024 was a relatively mild summer with no event conditions reaching the level of a 1-in-2 weather year. For ex-ante forecasts relying on a single year's data, particularly a mild year, could lead to inaccurately estimating program performance under extreme weather conditions. Incorporating multiple years of historic event results is essential for building robust estimates of future program performance.

- The PY2024 ex-ante forecasts of impacts are generally higher than the PY2023 per-participant impacts for the same ex-ante weather conditions. We attribute this change to two key factors:

  - ✓ SEP program staff removed customers who opt out or don't perform. This means that, over time, only customers who perform well during events are left in the program, increasing the average per customer impacts from events.

  - ✓ [redacted]

2 PROGRAM DESCRIPTION

SCE's Smart Energy Program is a technology-enabled program in which residential customers with a qualified smart thermostat are provided a monthly bill credit in exchange for allowing their smart thermostat provider to temporarily adjust their temperature set point or limit their air conditioning runtime. During SEP events, thermostat providers can adjust cooling set points upward by as much as four degrees (F) or impose a cycling strategy to limit air conditioning usage during peak hours. Limiting air conditioning usage lowers electric demand in participating households. SCE can call multiple events on a single day, but the total number of hours triggered cannot exceed six hours in a given day. The six-hour limit was approved by the California Public Utilities Commission (CPUC) and can only be used for emergency purposes.[2] Economic events are still limited to no more than four hours in a day. Dual enrollment in Critical Peak Pricing (CPP) dispatchable pricing tariffs or other Demand Response programs, such as the Summer Discount Plan (SDP) program, is prohibited.

SEP has evolved considerably from its predecessor program, Save Power Day (SPD). SEP now relies exclusively on direct load control of central air conditioning systems through Wi-Fi connected smart thermostats. Participants receive a courtesy notification through their smart thermostat service provider prior to event dispatch but are not expected to take any action in response to the event signal.

SCE provides eligible new SEP participants with a one-time $75 bill credit for enrolling and a daily bill credit of $0.3275 per day provided annually during the summer from June 1 through September 30 for remaining in the program. SCE can call events year-round, though customers only receive bill credits for June through September participation. SEP events can be dispatched, or triggered, for multiple reasons.

A. CAISO emergency conditions;
B. At the discretion of SCE's grid control center for load relief in SCE service territory;
C. In response to high wholesale energy prices (e.g., economic dispatch);
D. For program measurement and evaluation or system contingencies.

SEP economic dispatch (trigger C) is limited to the first 40 hours of dispatch per year. Once 40 hours of SEP events have been triggered in a calendar year for any of the dispatch reasons noted above (A – D), SCE will not trigger any SEP events under trigger C. Additionally, Trigger C can only be activated on non-holiday weekdays from 11am to 9pm. SEP dispatch for triggers A, B, and D can be activated at any time, including weekends and holidays. No more than 180 hours of SEP events can be called in a calendar year for all dispatch triggers combined.

[2] D.21-12-015, Attachment 1, pg.6

In PY2024, SEP economic dispatches were self-scheduled in the day-ahead market by SCE. SEP events were dispatched on a total of six days between June 2024 and September 2024. Table 3 lists the event dates and dispatch reason. The CAISO system peak day for 2024 is highlighted in green.

Table 3: PY2024 SEP Event Days and Dispatch Reason

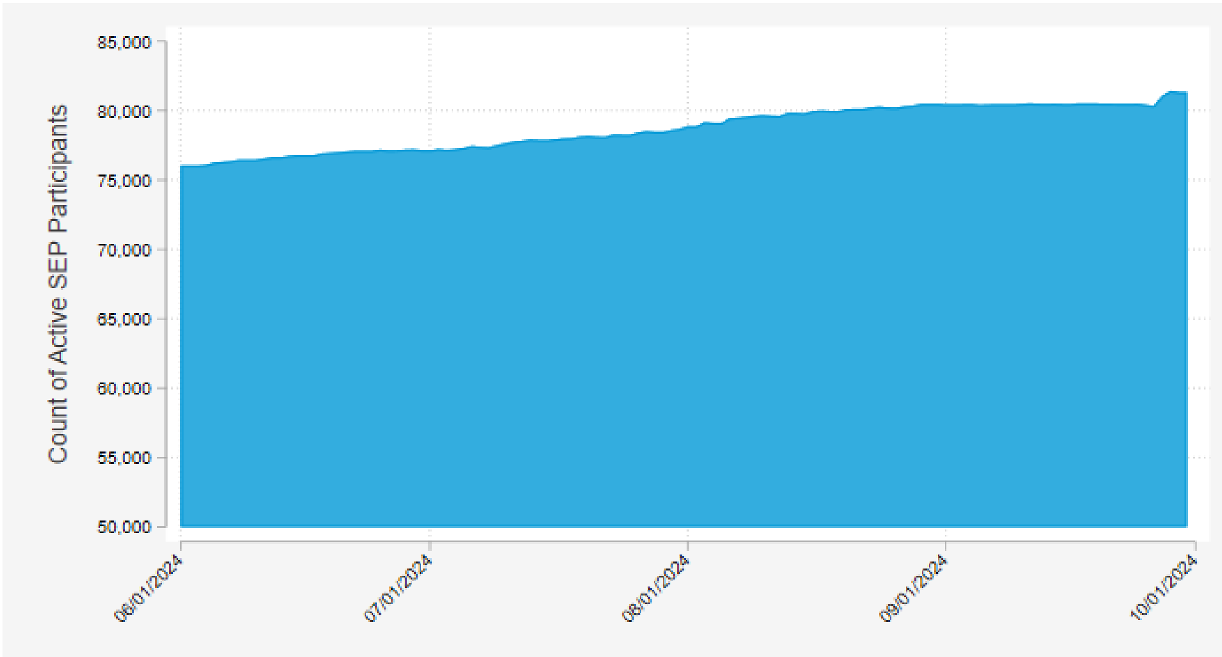
Date	Dispatch Trigger	SubLAPs Dispatched
6/25/2024	Self-Scheduled DAM	Territory Wide
7/11/2024	Self-Scheduled DAM	Territory Wide
8/7/2024	Self-Scheduled DAM	Territory Wide
8/20/2024	Self-Scheduled DAM	Territory Wide
9/4/2024	Self-Scheduled DAM	Territory Wide
9/6/2024	Distribution Emergency	Partial Dispatch of SCEC

There were 80,528 active participants in SEP as of the last scheduled territory wide event of the season on 9/4/2024. This is a substantial increase over the end of summer count from 2023 (70,003). The growth between the two years can largely be attributed to continued marketing efforts to reach broader audiences through targeted marketing channels[3].

Figure 5 shows the number of enrolled households over the summer 2024 DR season. Historically, enrollments have been highest during the summer months when bill credits are available, and SCE's marketing efforts are most active. There was steady and continued growth in enrollment over the summer that outpaced attrition. In past years, attrition in enrollment was typically associated with move outs or customers disenrolling because of heat waves that included many DR events. When a customer's comfort is impacted multiple days in quick succession, they are much more likely to leave the program. Early September of 2024 saw a heat wave, but program enrollment held steady during that time. SEP also conducts compliance reviews and may remove customers whose thermostat is offline, consistently opting out of events or not meeting the minimum energy usage requirement. In past years, these compliance reviews have made up a substantial amount of the customers leaving the program.

[3] D.21-12.-015, Attachment 1, p.6

Figure 5: Summer 2024 Enrollment Trend



The highest program enrollment across all territory wide events in PY2024 was 80,528. Table 4 shows the distribution of customers across various segmentation variables of interest.

- The LCA variable indicates the Local Capacity Area. About 83% of SEP participants are located in the LA Basin LCA.
- SEP participants enrolled in the low income rates (CARE or FERA programs) are indicated by the 'Low Income' segment.
- Approximately 36% of SEP participants have net energy metering (NEM) of rooftop solar arrays. The NEM percentage is up by 3% compared to PY2023, when only 33% of SEP customers had net energy metering.
- The 'Size' variable is based on customer's 2024 average net load on non-event weekdays during the Resource Adequacy window of 4pm to 9pm. Participants were binned based on whether they were above or below the median RA window average demand, which is 2.11 kW.
- The SubLAP variable segments participants by sub-load aggregation point.
- The 'Tariff' variable indicates whether the participant was on a flat volumetric rate (e.g. Domestic Service Plan) or a time-varying rate during summer 2024. Dynamic rate customers make up 66% of the SEP customer base in PY2024. SCE defaults customers to a dynamic rate in most parts of its service territory so they now make up the majority of the population. We consider tiered rates based on consumption flat because they do not vary by time of day.
- The 'Thermostats' variable indicates the number of smart thermostats a participant enrolls in SEP. Approximately 84% of participants have just a single smart thermostat enrolled in the program.
- [redacted]

- Zone is another geographic segmentation variable. The 'Remainder of System' segment are outside of the area impacted by the 2013 decommissioning of the San Onofre Nuclear Generating Station in 2013. SEP enrollments in the South Orange County and South of Lugo regions have increased since 2018, while the number of active participants in the Remainder of System region have decreased.

Table 4: Summary of SEP Enrollment by Customer Segment

Segmentation Variable	Segment Description	Participants	Percentage
All Customers		80,528	100%
LCA	Big Creek/Ventura	11,287	14%
	LA Basin	66,852	83%
	Outside LA Basin	2,389	3%
Low Income	CARE	19,373	24%
	Non-CARE	61,155	76%
NEM	NEM Customer	28,655	36%
	Non-NEM Customer	51,873	64%
Size	Above Median (2.11 kW)	40,367	50%
	Below Median (2.11 kW)	40,161	50%
SubLAP	SCEC	35,512	44%
	SCEN	9,109	11%
	SCEW	31,341	39%
	SCHD	2,332	3%
	SCLD	57	0%
	SCNW	2,178	3%
Tariff	Dynamic	53,121	66%
	Flat	27,407	34%
Thermostats	1 Thermostat	68,025	84%
	2 Thermostats	10,832	13%
	3+ Thermostats	1,672	2%
[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]
Zone	Remainder of System	39,209	49%
	South Orange County	13,489	17%
	South of Lugo	27,841	35%

The SEP participant population is located across SCE service territory and experiences a wide range of weather conditions. At the conclusion of the PY2024 event season, there were active participants in nine of the sixteen CEC[4] climate zones. For both the ex-post and ex-ante analysis we map each participant to one of 23 SCE-maintained weather stations. Table 5 presents the number of SEP participants mapped to each weather station along with the three year average number of cooling degree days (CDD) and heating degree days (HDD) using the period October 1, 2021 to September 30, 2024.

CDD and HDD were each calculated using a base of 60°F. We calculate CDD separately for each day using the difference of average daily temperature and 60, but the value is capped at zero. As an example, an 80-degree day has a CDD of 20, which is the difference of 80°F and 60°F. A cooler day, at 45°F, would have a CDD of zero, because the value is capped at zero, and an HDD60 value of 15. Higher values of CDD indicate greater needs for cooling, while higher values of HDD indicate greater needs for heating.

$$CDD60 = \max\,(0, average\ daily\ temperature - 60)$$

$$HDD60 = \max\,(0{,}60 - average\ daily\ temperature)$$

The daily CDD and HDD values are summed across the three-year period, then divided by three to give an average yearly value. SEP has relatively few participants in areas with mild summer weather that requires limited air conditioning.

[4] California Energy Commission

Table 5: SEP Enrollments by Weather Station with Yearly Average CDD60 and HDD60

Weather Station	SEP Enrollments	CDD60	HDD60
173	19,849	2,072	416
121	14,215	2,518	1,193
122	11,113	3,022	694
172	4,585	2,721	387
51	4,536	1,569	545
112	4,035	3,295	1,392
171	3,607	2,353	723
111	3,584	1,889	428
132	3,187	5,855	342
181	3,132	2,410	975
194	1,900	3,085	1,823
161	1,894	1,374	392
193	1,771	1,334	1,022
123	1,540	3,279	1,701
131	451	1,019	858
195	435	1,120	3,577
191	367	3,300	1,770
113	352	4,322	1,531
151	307	829	911
192	127	3,958	1,445
141	66	2,626	2,708
182	55	5,776	483
101	30	601	5,481

3 EVALUATION METHODOLOGY

3.1 EX-POST METHODS

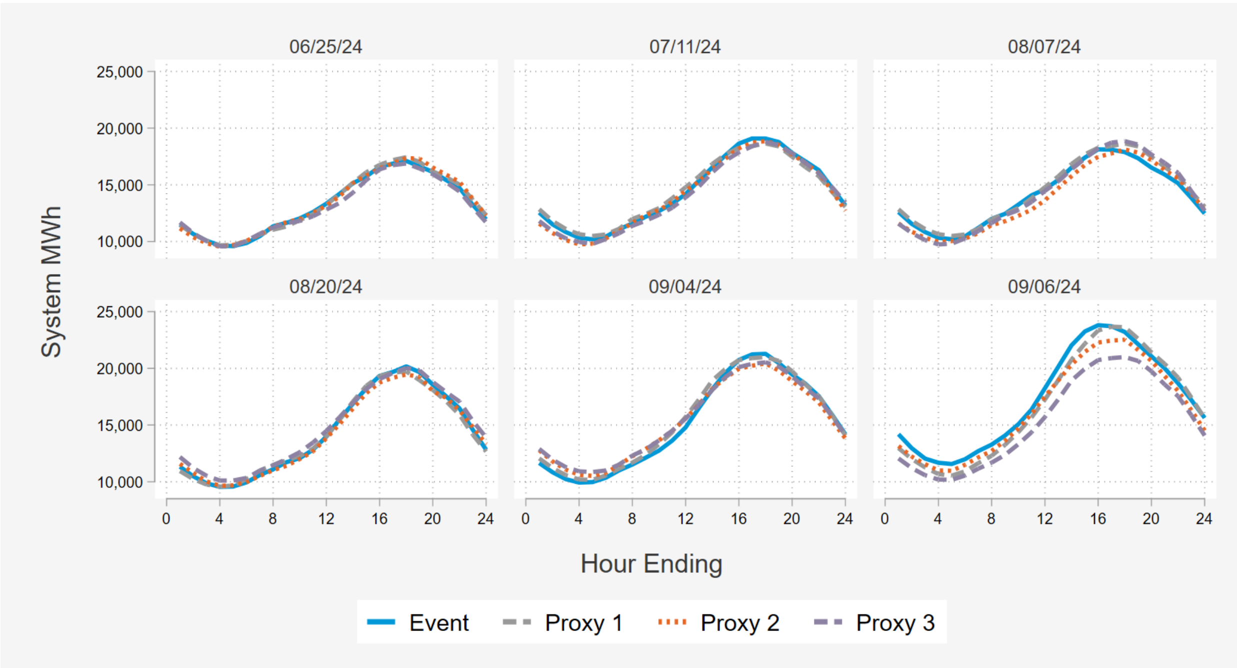
Overview of Evaluation Method Selected

DSA utilized a matched control group and panel regression analysis for the 2024 SEP load impact evaluation. We select the matched control group customers from a stratified random sample, which ensures that high usage and/or unique participants are still likely to find an appropriate match. We select the control group using load patterns on non-event proxy days, geographic location, and other customer characteristics (e.g., net metering status) to develop propensity scores within each stratum. For each participant, we identify the nearest neighbor based on propensity scores. The regression analysis incorporates a difference-in-differences model where the small differences between the participant and matched control group on proxy days are netted out of the differences observed on event days. We estimate ex-post load impacts across all customers as well as at a segment level for a variety of categories including SubLAP, size, tariff rate, and more.

Proxy Day Selection

DSA used Euclidean distance matching on system loads to select a set of proxy days for each SEP event. We choose proxy days from a set of days with similar characteristics to each event day in PY2024. All PY2024 events occurred from June to September 2024. All these events also happened on a non-holiday weekday, which means that they were able to be matched with any non-event non-holiday weekdays from summer 2024. For every event date, we select the three most similar SCE system load days based on their available matches. A proxy day can be chosen multiple times for different events, but an event day cannot be used as a proxy day for another event. Figure 6 shows each event date with its three selected matches. Days that are generally warm but not extreme tend to have very similar and predictable load shapes to each other, so proxy day matches in 2024 were generally good. The only exception was the emergency event called on September 6th. It was the SCE system peak day for 2024 meaning that all available proxy days had less extreme loads. The chosen proxy days still provide a reasonable approximation of the event day load shape.

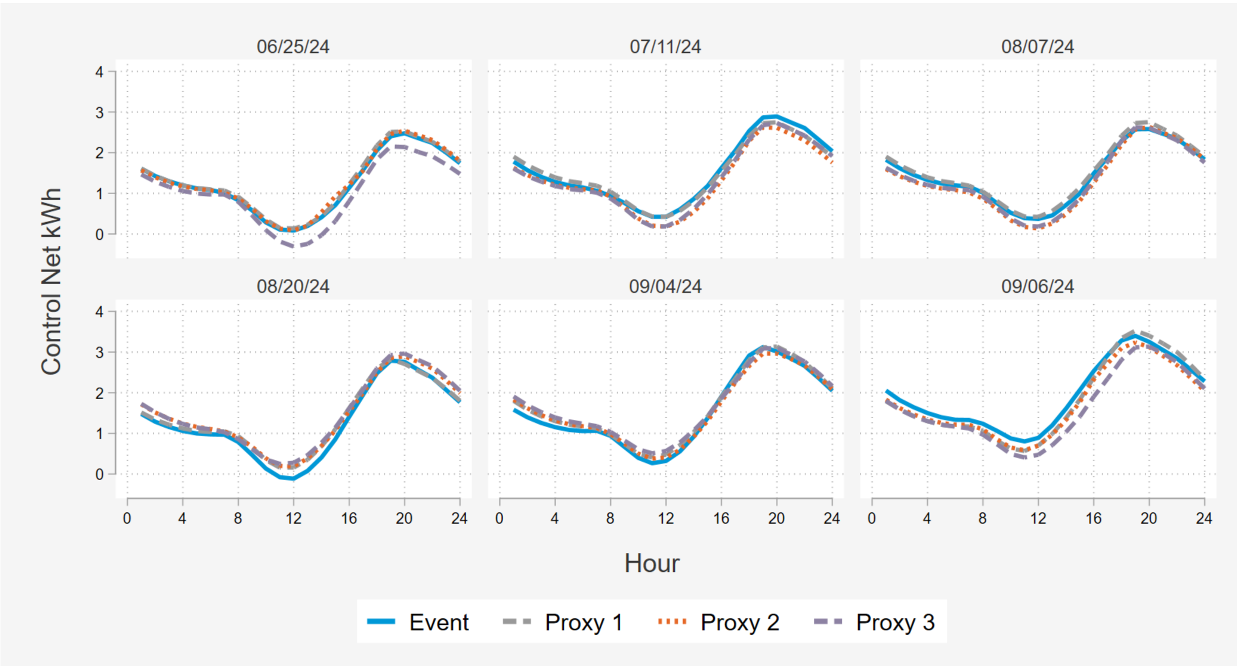
Figure 6: Event and Proxy Day System Load



While we use SCE system load to select the proxy days, the control customers come from a sample of non-participant SCE customers. These customers, or the "pool" of potential control customers, should be representative of all SCE customers, but must also cover the range characteristics of the participant customers.

Figure 7 shows the selected proxy days and event days, as seen in Figure 6, but for the average customer in the control pool. The proxy day loads line up well with the event day loads during event hours for the pool of non-participant homes from which the matched control group was ultimately selected.

Figure 7: Event Day and Proxy Day Loads for Matching Pool



PARTICIPANT MATCHING

Using the SEP participant and non-participant load data on the full set of proxy days, we select a match for each participant with propensity score matching. Prior to matching, DSA excludes Rule 24[5] customers and those who participate in other demand response programs, except for ELRP from the eligible control pool. In 2022, SCE defaulted high usage and low-income customers who were not participating in another Demand Response program to the Emergency Load Reduction Program (ELRP). This means that the customers who participate in SEP that fall into those categories would have been defaulted to ELRP as well if they were not in SEP. To properly understand the counterfactual for those customers, we allow them to be matched with ELRP control customers since that is the most realistic counterfactual we can find. Propensity score matching (PSM) is a method that uses probit modeling to predict the propensity score, which is the likelihood of a customer participating in SEP. We first categorize households based on several characteristics:

- **Net Metering**: indicates the household has rooftop solar.
- **Climate zone**: geographic areas defined by their climate type. For better matching in PY2024, zones 5, 6, and 8 were matched in a single pool.
- **Rate bins**: defines whether a customer is on a dynamic rate (e.g., Time-of-use) or a flat rate

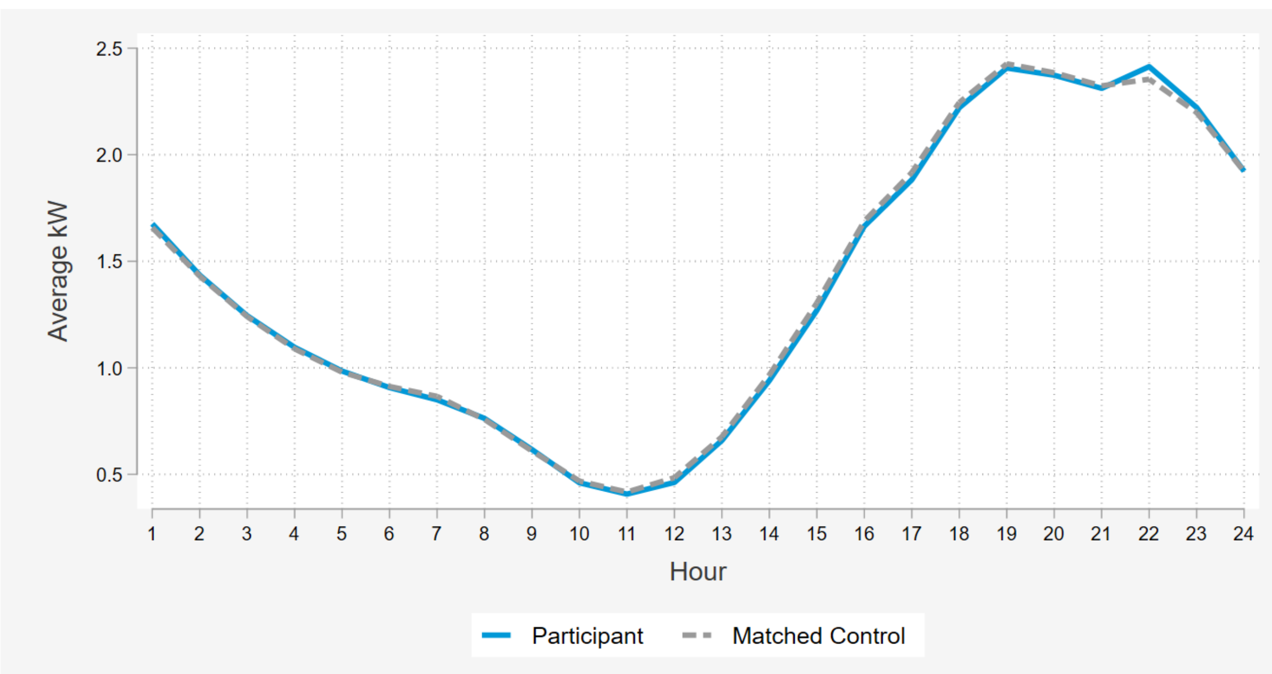
[5] Rule 24 customers are enrolled in other third party Demand Response programs. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M037/K189/37189001.pdf

- **Size bins**: splits customers into four bins based on the size of their average energy usage from 4pm-9pm

Within each of these segmentations, all applicable participant and control homes are grouped and then undergo PSM for a set of matching model specifications. We select the best PSM model based on lowest bias and best fit using out of sample testing on proxy days not used to develop the matches. For this analysis, the chosen model included variables for kWh during 4pm to 9pm RA window, eight three-hour bins of kWh to capture usage during the entire day, a load shape variable to describe load distribution throughout the day, and others.

Matches are selected with replacement, ensuring every participant is matched to the best possible non-participant. If there are no controls within a specified range of a given participant, that participant will not have a matched control. For the summer 2024 analysis, 2,034 participants are not matched: this is about 1.5% of participants. Some customers may not find matches due to missing interval data on event and proxy days or usage values that are not comparable with any of the potential matches. Matches are assigned pseudo characteristics, where each match takes on the characteristics of its participant household. For controls matched multiple times, the load will be represented multiple times in the regression analysis, but the characteristics will vary based on each unique participant. Figure 8 compares the average hourly kW by treatment and control group on all proxy days. The hourly difference-in-differences regression analysis is used to estimate load impacts and capture any remaining statistical difference between the treatment and control groups. The slight difference in the treatment and control groups during each hour on proxy days gets subtracted from the difference in the two groups on the event days. This allows us to estimate the true effect of the event.

Figure 8: Average Hourly kW on Proxy Days



Ex-post Model

DSA used a difference-in-differences (DiD) panel regression model to estimate the hourly load impacts for SEP. With minor differences between the treatment and matched control group, the DiD approach will net out any unobserved differences from the two groups and the resulting coefficient will indicate the event impact. To capture the best results for each event, DSA individually regressed each event with its three proxy days. Every hour is separately regressed to avoid any heteroscedastic errors. Equation 1 shows the model specification and Table 6 describes the components.

Equation 1: Ex-post Regression

$$kW_{ih} = \beta_{0h} + \beta_{1h} * date + \beta_{2h} * treat_i * eventDay + \beta_{3h} * same\ day\ adj_i + v_{ih} + \varepsilon_{ih}$$

Table 6: Regression Description

Model Term	Description
kW_{ih}	Net electrical demand in kW for customer i, in hour h
β_{0h}	Mean demand for all customers on proxy days in hour h
β_{1h}	Regression coefficient for the date variable for hour h. Captures date-specific departures from the mean
date	Set of four indicator variables for event day and three proxy days
β_{2h}	Regression coefficient of interest
$treat_i$	Indicator variable for the SEP participant group
$eventDay$	Indicator variable for the SEP event day
$treat_i * eventDay$	Interaction term equal to 1 for treated customers on the event day and 0 otherwise
β_{3h}	Regression coefficient for the same day adjustment for individual i
$same\ day\ adj_i$	Average demand of customer i in event start hour-2 and event start hour -3
v_{ih}	Customer fixed effects variable for customer i in hour h
ε_{ih}	Error term

Equation 1 shows the regression implemented for every event and every hour of the day. The dependent variable, kW_{ih} is the net electrical demand in kW for a given hour and premise. The independent variable date is a set of indicator variables differentiating the four dates used in each event regression, one for the event day and three for the proxy days. The variable of interest in this model is the interaction term between treatment and event. The β_{2h} term captures the coefficient on this interaction and represents the average impact of the SEP event. The v_{ih} term captures the customer fixed effects and the error term captures any remaining unobserved differences. The same day adjustment variable is the average demand from a two-hour window ending an hour before the start of any event that improves the fit of the model. For example, if the event of interest starts at 6pm, the same day adjustment term is the average demand of customer i from 3pm to 5pm.

For each event day, this regression estimates per customer impacts which are then expanded to the aggregate impacts based on the number of participants dispatched for each event. We estimate a pooled regression model for all participants as well as each subcategory separately. Table 4 lists each subcategory and the associated number participants.

3.2 EX-ANTE METHODS

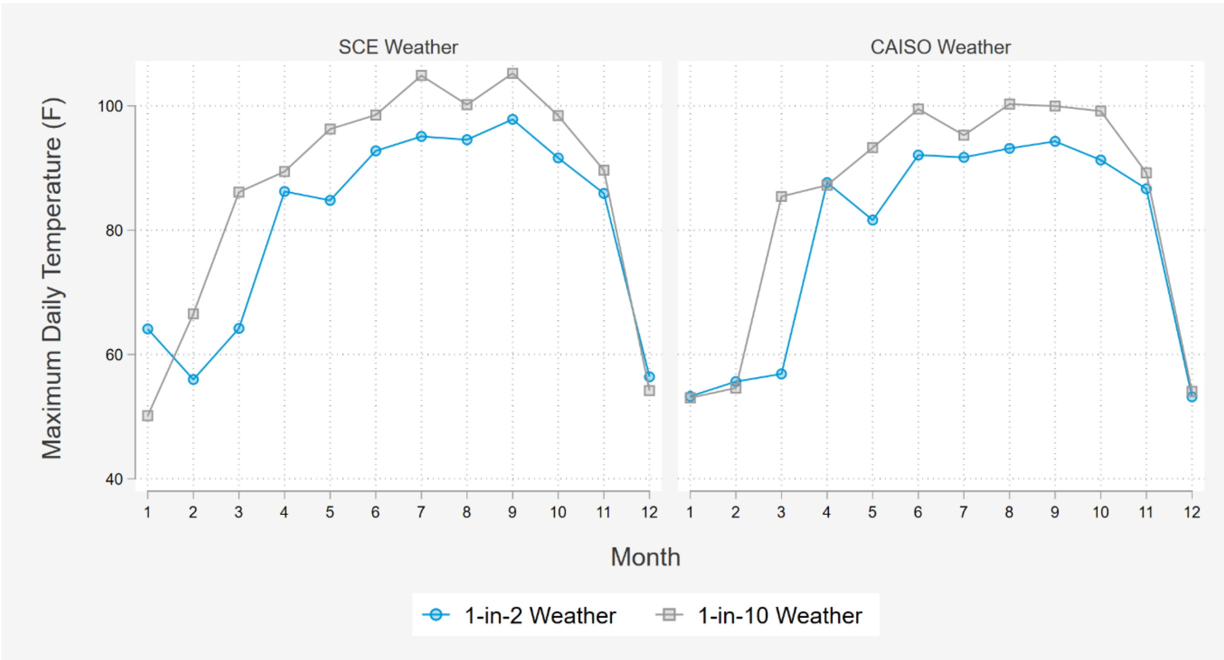
A key objective of DR evaluations is to quantify the expected load relief a program can deliver under different planning conditions. The weather conditions used for ex-ante load impact estimates are generally extreme to reflect conditions when the grid is constrained due to high demand. For SEP, we produce a forecast of load impacts for multiple sets of weather conditions.

- 1-in-2 weather reflects the expected peaking conditions for a normal year.
- 1-in-10 weather reflects peaking conditions that would be observed in an extreme year.
- Monthly system worst day for each month of the year. The ex-ante forecast also includes 'Typical Event Day' conditions, which are assumed to occur in August.
- SCE forecast and a CAISO forecast. Both forecasts have 1-in-2 and 1-in-10 weather for all weather stations.

Figure 9 compares the maximum daily temperature for the monthly system worst days using the 1-in-2 and 1-in-10 weather for the SCE and CAISO forecasts. We weight the forecasts across weather stations using the number of active SEP participants at the conclusion of PY2024 shown in Table 5. We hold these weights constant over the forecast horizon. There are notable differences in the SCE and CAISO forecasts. For example, the SCE forecast predicts a weighted average temperature 5°F higher than the CAISO forecast for a monthly system worst day in September on a 1-in-10 weather year. For a weather sensitive program like SEP, this means the ex-ante load reduction capability of SEP is greater using the SCE forecast for a September system worst day.

The PY2024 ex-ante weather forecasts project a higher monthly maximum temperature for April than May in the 1-in-2 weather scenarios. This is due to the fact that these forecasts are done using historic data and, in the current dataset, April is the more extreme month.

Figure 9: Monthly System Worst Day Comparison by Forecast

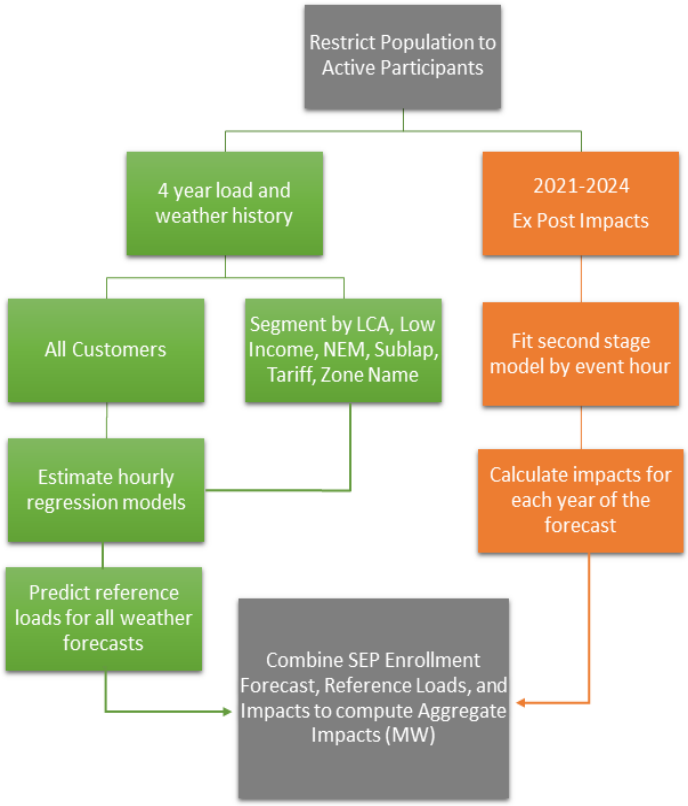


During PY2024, SEP dispatched events at different times of day: the duration of events last either one or two full hours, with partial hours on one of the event days. Ex-ante estimation requires a single event profile to be selected. The ex-ante event profile was selected to mirror the CAISO RA window, which begins at 4pm and ends at 9pm for all months of the year except March, April, and May when the window is from 5pm to 10pm. There were no events in 2024 that matched this profile, with all of the planned events being 2 hours or less. Larger dispatch windows were more common in the past. This shows the value of including events from prior years in our model. Although, there was only one four hour event and no five-hour events from 2021-2024 so we assume the impacts during the final two hours of the RA window will reflect the expected impacts during the third hour of an SEP event dispatch. In practice, the predicted impacts of the fourth and fifth hour will differ from those of the third hour due to differences in expected outdoor temperature, and are likely to be of lesser magnitude than the ones predicted by the ex-ante model.

Overview of Evaluation Method Selected

Figure 10 outlines the SEP ex-ante estimation methodology. On the left (green), it shows the steps to model reference loads (what average customer loads would be without SEP), and on the right (orange), it lists the steps to estimate SEP load impacts. The ex-ante segmentation is similar to the ex-post segmentation but excludes the "size," "thermostats," and "vendor" segments. Active participant shares are calculated by LCA, Low Income (CARE/FERA Status), NEM, SubLAP, Tariff, and Zone Name, with the assumption that these ratios remain constant as enrollment grows. Territory-wide events from 2021–2024—weighted more heavily for recent events—are used to estimate the second-stage model (see Ex-ante Impacts Model Section). Finally, reference loads, average per-customer impacts, and the enrollment forecast are combined to produce the aggregate savings.

Figure 10: Ex-ante Estimation Process Diagram



EX-ANTE REFERENCE LOAD MODEL

DSA selected the reference load model by analyzing model fit statistics at the "All Customers" level. Upon determining the final model, we applied the model specification to the subcategories of the LCA, Low Income (CARE Status), NEM, SubLAP, Tariff, and Zone Name categories. The specific modeling steps taken were:

- Merge hourly load data and hourly weather data for all active SEP participants for January 2021 through September 2024.
- Drop any SEP event days.
- Drop dates when customers experienced outages.
- Restrict the data set to non-holiday weekdays.
- Structure all data in Pacific Prevailing Time. This produces reference load estimates for March and November that reflect a mix of daylight savings and standard time. This is appropriate because monthly averages include a mix of the two conventions and the worst day could fall before or after the time change.
- Estimate the regression model shown in Equation 2.

Equation 2: Reference Load Regression Model Specification

$$Net\ kW_i = \beta_0 + \beta_1 * CDD65 + \beta_2 * bins\_60 + \beta_3 * bins\_65 + \beta_4 * bins\_70 + \beta_5 * bins\_75 + \beta_{6-10} * DayOfWeek + \varepsilon_i$$

Table 7 defines each of the terms listed in Equation 2. The model terms and base temperatures for degree day and degree hour terms were selected based on model fit statistics (adjusted R-squared, root mean square error) and the statistical significance of model parameters (standard error and t-statistic).

Table 7: Reference Load Regression Model Specification

Model Term	Description
Net kW_i	Average net electrical demand in kW during interval i
β_0	The model intercept
CDD65	Cooling degree days base 65°F
β_1	Regression coefficient for the CDD65 term
bins_60, bins_65, bins_70, bins_75	Quantile smoothing spline which allows for different temperature slopes at different temperature ranges
β_2-β_5	Regression coefficients for the spline terms
DayOfWeek	Indicator variables for each of the 5 weekdays
β_6- β_{10}	Regression coefficients for five weekday variables
ε_i	Error term

Next, we use the regression coefficients estimated for each model run to predict average hourly demand for electricity for the set of ex-ante weather conditions. We computed weighted average weather conditions for each of the segments using the number of active SEP participants mapped to each constituent weather station. Figure 11 shows the 2025 predicted reference loads for all customers in black, with the LCA, Low Income (CARE Status), NEM, Tariff, and Zone Name categories on an September system worst day using SCE 1-in-2 weather. Due to the number of subcategories, the intent of Figure 11 is to highlight the variability in reference load rather than provide detailed insight on specific groups. Notably, the NEM customers show a prominent "duck curve" which differentiates these customers from some of the other subcategories.

Figure 11: 2025 Reference Load by Segment: September System Worst Day, SCE 1-in-2 Weather

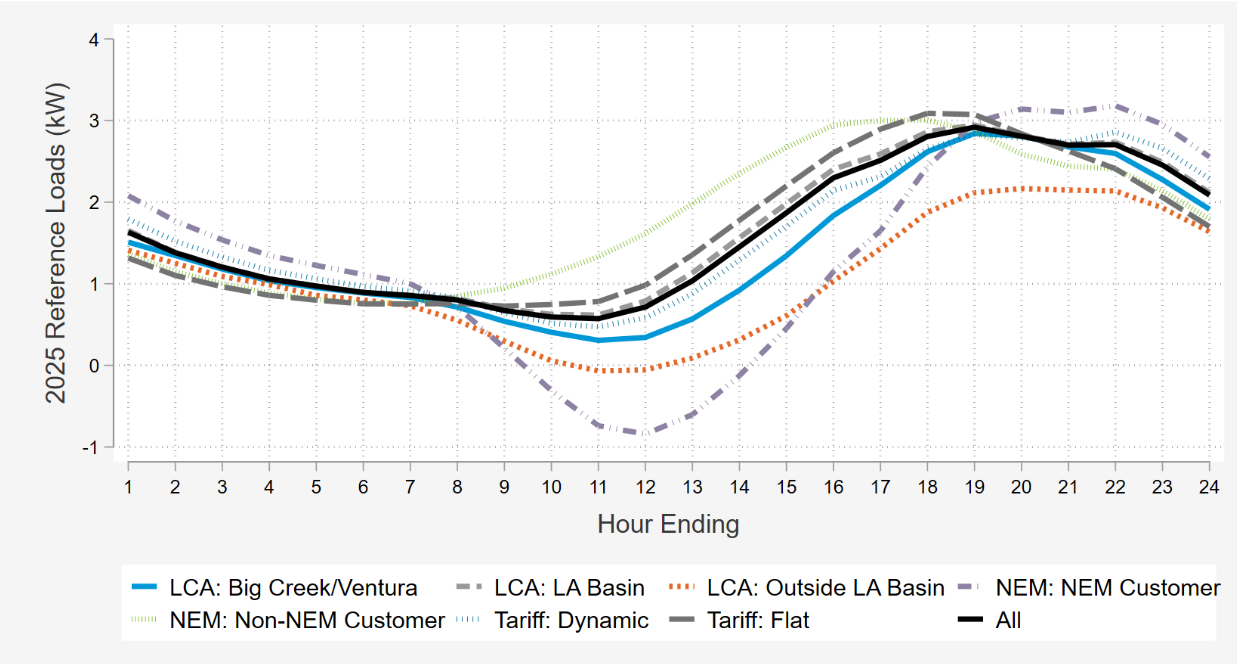


Figure 12 shows the modeled 2025 reference loads for each of the six SubLAPs on a September system worst day using SCE 1-in-2 weather. The Low Desert experiences the hottest conditions of all the SubLAPs and has the highest per-customer peaks but is overall a very small portion of the SEP population.

Figure 12: 2025 Reference Load by SubLAP: September System Worst Day, SCE 1-in-2 Weather

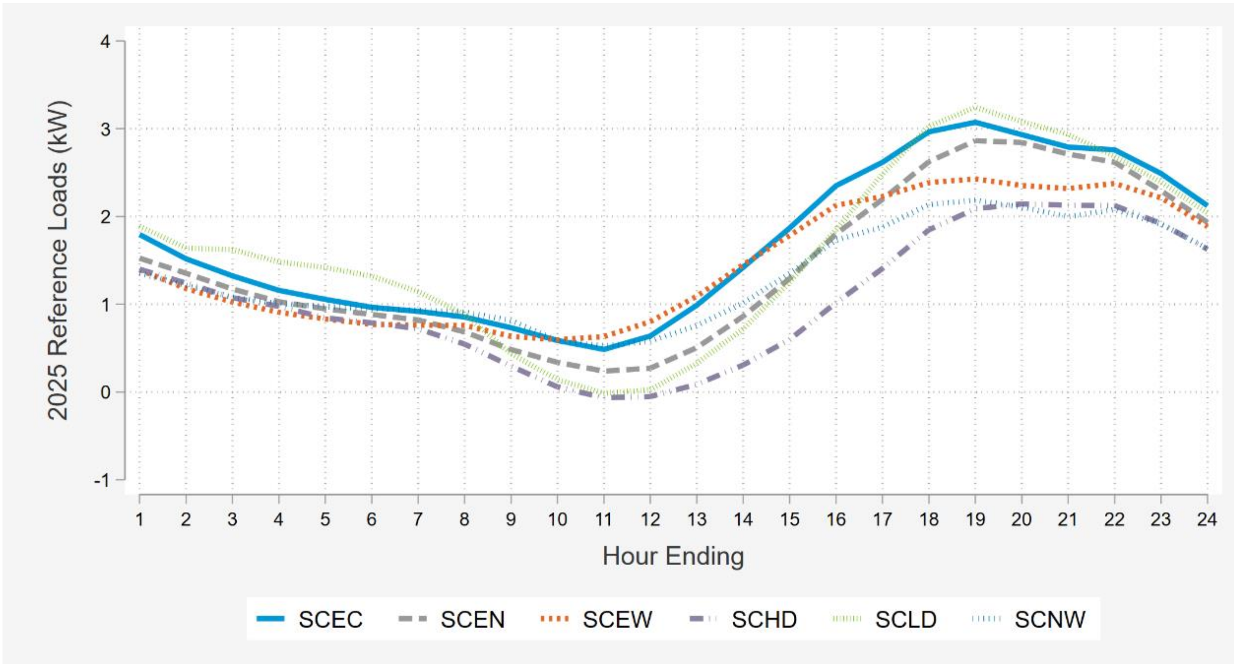
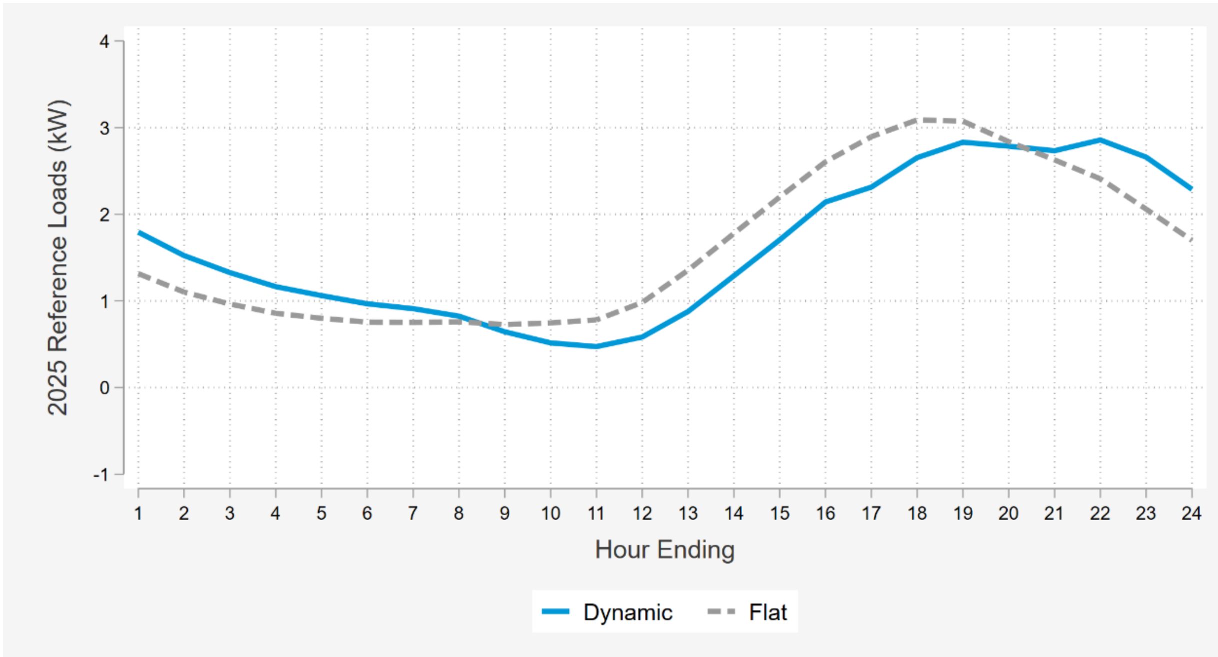


Figure 13 shows the modeled 2025 reference loads for both tariff rate groups on a September system worst day using SCE 1-in-2 weather. Dynamic rate customers now make up most customers in SEP. They tend to live in cooler climate zones and have lower loads in the middle of the day, typically due to solar generation, to take advantage of their rate structure. Flat rate customers tend to live in the hotter climate zones and have much higher loads in the middle of the day. Their load shapes typically peak right in the middle of the RA window (4pm-10pm).

Figure 13: 2025 Reference Load by Tariff Category: September System Worst Day, SCE 1-in-2 Weather



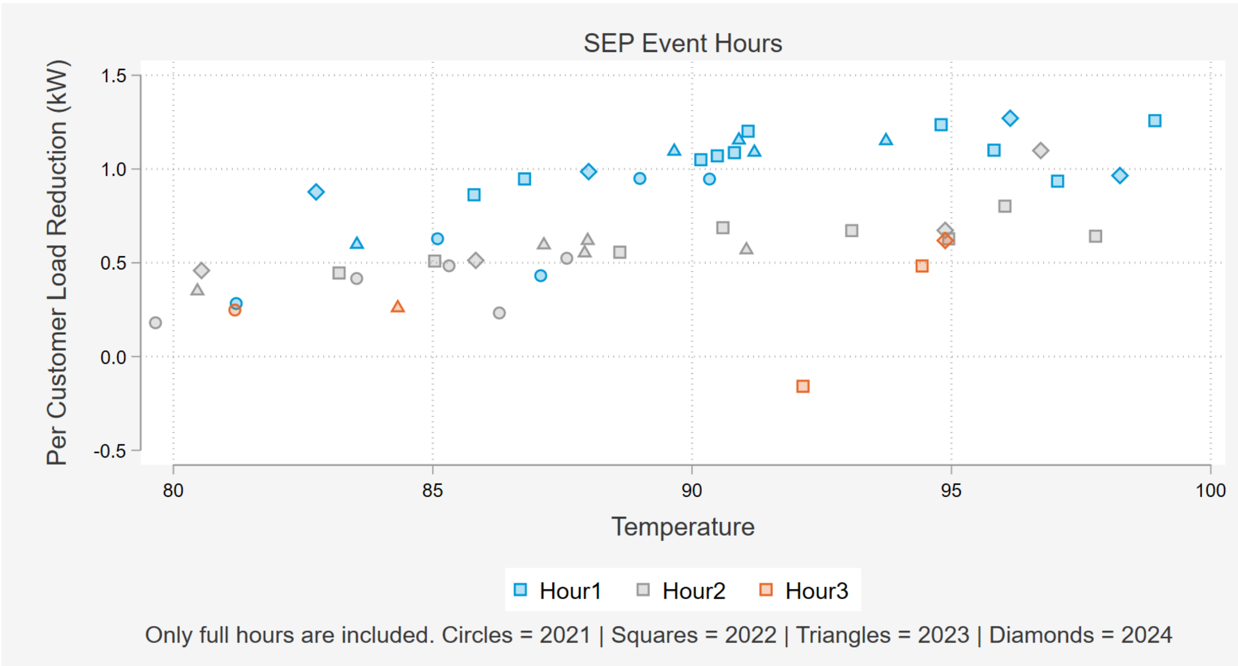
Ex-Ante Impacts Model

To estimate SEP per customer load reductions under varying conditions, DSA fit a second stage model using the PY2021, PY2022, PY2023, and PY2024 ex-post impacts as the dependent variable and dry bulb temperature as the independent variable and an indicator variable for each of the three observed SEP event hours as well as the three hours of post-event snapback. The model also includes an interaction term for temperature and event hour which lets the relationship between temperature and event impacts vary with each hour of the event and hour of snapback. We do not model the effects of pre-cooling in hour ending 16 for ex-ante. We do use event impacts from events that included pre-cooling in our impact modelling though. Pre-cooling is included in almost all SEP events and if impacts from events with pre-cooling were not included in the model, then there would not be enough data to reliably fit the model.

A key caveat to the event impacts included in the model concerns partial event hours. When event hours do not start or end on the hour, the impact estimates are diluted by the portions of the hour that were not controlled. In PY2024 there was one such event and there have been more in previous years. In these cases, we omit the partial hours. For events where we drop the first partial hour, we treat the following full hour as the normal second hour of the event. These modifications allow us to use as much of an event as possible without deflating hourly impacts with unperturbed pre-event periods or post-event snapback.

Figure 14 shows the PY2021- PY2024 hourly impacts by event hour. Each color represents a different event hour, with blue representing Hour 1 of the events and consistently showing the largest impacts regardless of temperature. Because events vary in length, there are more Hour 1 impacts than Hour 3 impacts. Impacts are largest in the first hour of an event and diminish with each subsequent hour.

Figure 14: Per Customer SEP Load Reductions by Event Hour



The decision to model impacts as a function of event hour rather than hour of the day was informed by the results of the ex-post analysis. Figure 15 illustrates the issue using the ex-post results from the PY2021 - PY2024 full hour events during hour ending 19 (6pm to 7pm). There were 23 events active from 6pm to 7pm during the four summers. However, for some of these events, the event hour was a partial event hour and those are not included in the below figure. Figure 15 shows that the same hour of day provides a consistently larger impact when it is the first hour of an event, regardless of temperature.

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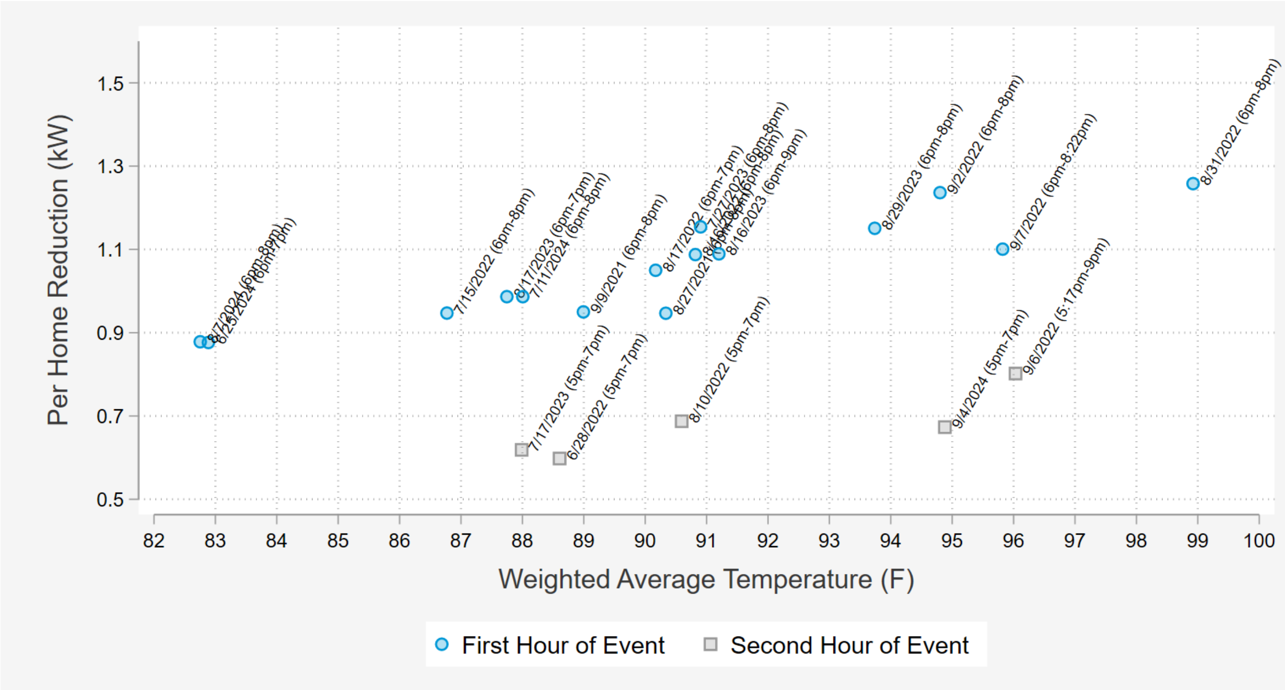
Figure 15: Hour Ending 19 Event Impacts vs. Temperature, by Event Hour



The average kW impact per participant household across the seventeen days where hour ending 19 was the first event hour was 0.98 kW with an average event hour temperature of 89.3°F. The average kW impact per participant household across the five days where hour ending 19 was the second event hour was just 0.68 kW with an average event hour temperature of 91.62°F. This example illustrates why the position of an hour within an event is a far more important predictor of load impact than time of day. Declining load shed is indicative of the thermostat setback strategy. However, once homes warm up to the new set point, air conditioners gradually come back on and the kW impact decays. Some program administrators implement tactics to mitigate the decay of impacts across the event. Four such approaches are:

1. Stagger the dispatch time so that participants come in and out of the event at different times. This approach reduces the aggregate impact in the first hour but produces impacts that are more consistent across event hours.
2. A cascading offset. Instead of implementing a four-degree (F) setback at the beginning of the event, raise the offset one degree per hour over the course of the event.
3. Implement a cycling strategy rather than a setpoint change. This change would cause SEP load impacts to look more like the Summer Discount Plan (SDP) program.
4. Pre-cooling of homes can also help slow the deterioration of load impacts by extending the amount of time it takes the home to warm to its event set point. Pre-cooling can also reduce participant opt-outs through increased participant comfort. This approach has been implemented by one SEP vendor, and they showed higher impacts than the other vendor who did not pre-cool.

4 EX-POST RESULTS

The ex-post results document the measured impacts for each SEP event called during PY2024. The variation in event start times, durations, and observed weather conditions provide useful information on the key drivers of SEP load impacts.

4.1 OVERALL RESULTS

SCE called 6 SEP events in PY2024 from June through September 2024. Table 8 shows average hourly impacts by event date. One of the PY2024 events did not start or end at the top of the hour. This creates a challenge for the analysis because most residential meters collect hourly interval data. When an event begins mid-hour the ex-post impacts for that hour are diluted by the portion of the hour prior to dispatch. Similarly, when an event ends mid-hour the ex-post impacts for that hour include a mix of DR (load reduction) and snapback (load increase). We typically exclude partial event hours from the average and aggregate impact column values in Table 8. We also show an Average Event Day segment row based on the most common event window for PY2024. This encompasses two events in PY2024. DSA used a customer-weighted average across the two events that shared the applicable dispatch profile.

Note that participant count varies during the SEP season. As customers enroll and exit SEP, the number of dispatched homes fluctuates. Event participation increased substantially from September 2023 to the first event in June 2024. Over the summer season, there was also a steady increase in enrollment.

The last two columns report average per customer kW reductions and average aggregate MW reductions. These values are calculated by taking the average of the hourly impacts. The largest per customer reduction occurred on August 20th, 2024, with 1.25 kW reduced per customer. This was only a one hour event, which is why its impacts are higher than other events that had higher temperatures. The general trend for SEP events is a large reduction in the first hour of an event followed by diminishing reductions in each subsequent hour. While longer event windows can contribute to greater overall savings for the day, they will create lower average hourly impacts.

Table 8: 2024 SEP Event Impacts

Event Date	Start Time	End Time	Dispatch Region	Participants	Average Event Temp	Daily Max Temp	Average Full Hour Impact (kW Reduction)	Average Aggregate Full Hour Impact (MW Reduction)	Pre-Cooling
6/25/2024	6:00 PM	7:00 PM	Territory Wide	77,321	82.9	85.8	0.88	67.8	Yes
7/11/2024	6:00 PM	8:00 PM	Territory Wide	77,876	86.9	90.6	0.75	58.4	Yes
8/7/2024	6:00 PM	8:00 PM	Territory Wide	79,647	81.6	86.1	0.67	53.3	Yes
8/20/2024	4:00 PM	5:00 PM	Territory Wide	80,205	94.4	94.4	1.25	99.9	Yes
9/4/2024	5:00 PM	7:00 PM	Territory Wide	80,528	95.5	96.2	0.97	78.3	Yes
9/6/2024	5:15 PM	8:02 PM	Partial Dispatch of SCEC	436	95.8	104.8	0.86	0.4	No
Average Event Day	6:00 PM	8:00 PM	Territory Wide	78,771	84.3	88.1	0.71	55.8	Yes

Figure 16 shows ex-post load impacts for the Average Event Day window. Figure 17 provides aggregate load impacts. The 6pm to 8pm window includes impact estimates from two event days in PY2024. The following figures provide detail on average number of participants, temperature, average event impact and percent impact. These figures come directly from the Microsoft Excel ex-post load impact table generators that accompany this report. The table generators provide estimated reference load, observed load, impact, and temperature by the hour, with an included visual display of the load curves and statistical significance of the impact. The average impact value provided under the 'Event Day Information' heading aligns with the average hourly impacts shown in Table 8.

There is a notable snapback effect beginning in the hour after each SEP event and tapering off for the remainder of the event day. These snapback effects are significant – approximately 27.4 MW during the hour immediately following dispatch – and may be an important consideration for event planning as SEP enrollment continues to grow. Hour ending 18 shows that, on most of the event days, there was evidence of pre-cooling in the loads leading up the first event hour. This leads to an increase in loads of about 11.4 MW on the average event day.

Figure 16: SEP Ex-post Load Impact per Participant for Average 2024 Event (6pm-8pm) (kW)

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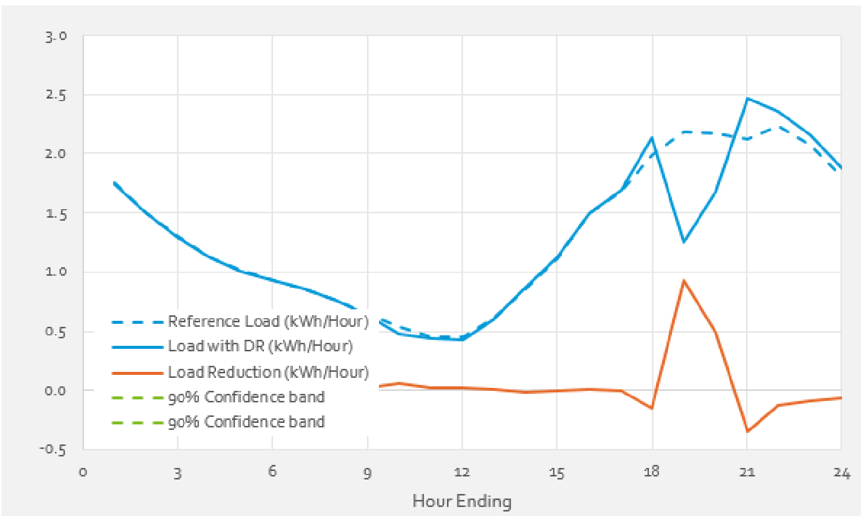
2024 Ex Post Load Impacts - SEP Program

Table 1: Menu options

Type of Result	Per Customer
Category	All
Segment	All Customers
Date	Average Event Day
Hour Ending View	HE (Prevailing Time)

Table 2: Event day information

Total sites	78,771
Daily Max Temp	88.1
Average Impact - kW	0.71
Average Impact - %	32.6%
Full Hours Only - Average Impact - kW	0.71
Full Hours Only - Average Impact - %	32.6%



Hour Ending	Reference Load (kWh/Hour)	Load with DR (kWh/Hour)	Load Reduction (kWh/Hour)	% Load Reduction	Avg Temp (°F, Site-Weighted)
1	1.76	1.74	0.02	1%	75.71
2	1.50	1.49	0.00	0%	74.56
3	1.29	1.29	0.00	0%	73.73
4	1.13	1.13	0.00	0%	72.56
5	1.02	1.01	0.01	1%	71.82
6	0.94	0.93	0.00	0%	71.19
7	0.86	0.86	0.00	0%	70.72
8	0.76	0.76	0.01	1%	70.77
9	0.65	0.63	0.02	3%	72.23
10	0.53	0.48	0.05	10%	74.74
11	0.46	0.44	0.02	4%	77.56
12	0.45	0.43	0.03	6%	80.30
13	0.61	0.60	0.01	2%	82.80
14	0.85	0.87	-0.02	-2%	84.89
15	1.12	1.12	0.00	0%	86.53
16	1.50	1.49	0.01	0%	87.78
17	1.68	1.69	-0.01	0%	88.13
18	1.99	2.13	-0.15	-7%	86.83
19	2.18	1.25	0.93	43%	85.35
20	2.17	1.68	0.49	22%	83.16
21	2.12	2.47	-0.35	-16%	79.98
22	2.23	2.36	-0.12	-6%	76.86
23	2.07	2.16	-0.08	-4%	75.09
24	1.81	1.87	-0.06	-4%	73.81

By Period:	Reference Load (kWh/Hour)	Load with DR (kWh/Hour)	Energy Savings (kWh/Hour)	% Change	Average Temperature (°F)
Average Event Hour	2.17	1.47	0.71	32.6%	84.3
Daily	1.32	1.29	0.03	2.5%	78.2

Figure 17: Aggregate SEP Ex-post Load Impact for Average 2024 Event (6pm-8pm) (MW)

Southern California Edison

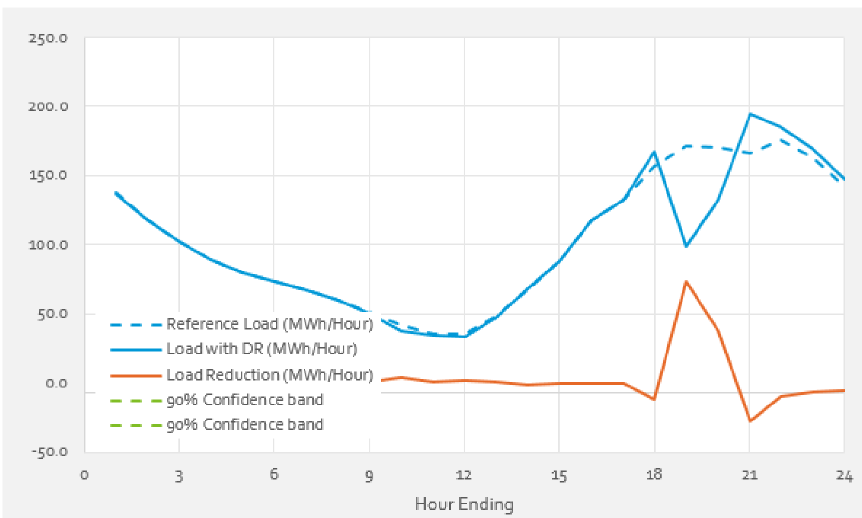
2024 Ex Post Load Impacts - SEP Program

Table 1: Menu options

Type of Result	Aggregate
Category	All
Segment	All Customers
Date	Average Event Day
Hour Ending View	HE (Prevailing Time)

Table 2: Event day information

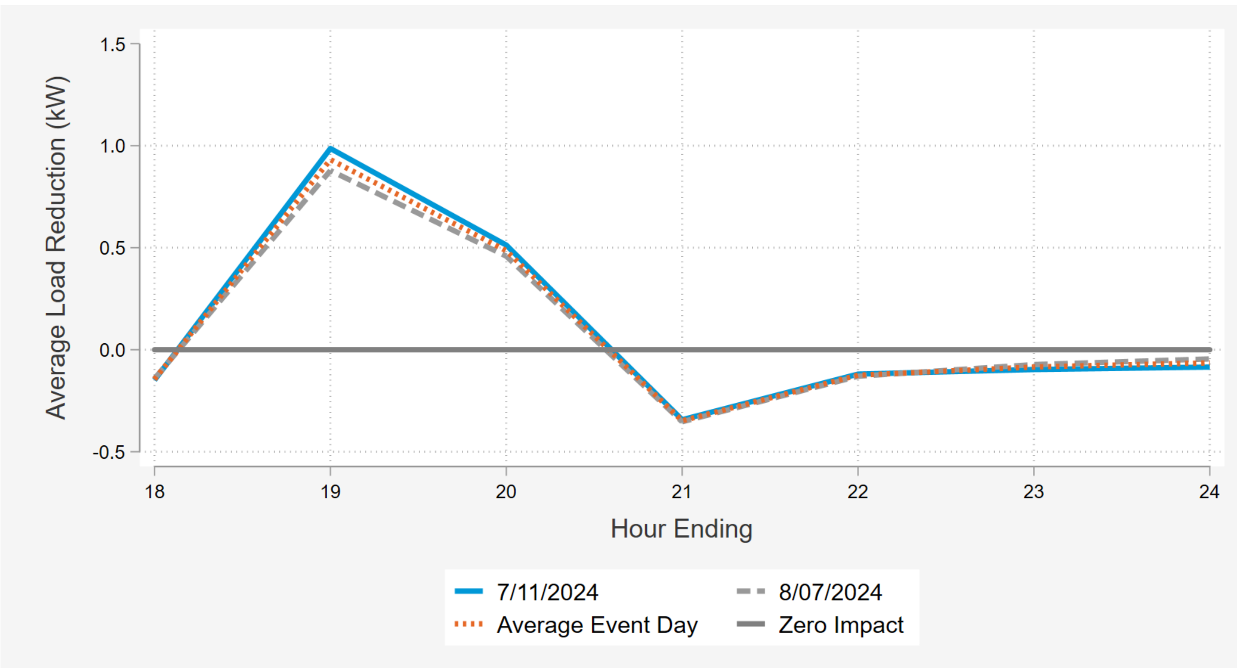
Total sites	78,771
Daily Max Temp	88.1
Average Impact - MW	55.83
Average Impact - %	32.6%
Full Hours Only - Average Impact - MW	55.83
Full Hours Only - Average Impact - %	32.6%



Hour Ending	Reference Load (MWh/Hour)	Load with DR (MWh/Hour)	Load Reduction (MWh/Hour)	% Load Reduction	Avg Temp (°F, Site-Weighted)
1	138.33	136.78	1.55	1%	75.71
2	117.90	117.63	0.27	0%	74.56
3	101.84	101.61	0.23	0%	73.73
4	89.17	89.04	0.13	0%	72.56
5	80.13	79.49	0.64	1%	71.82
6	73.67	73.35	0.32	0%	71.19
7	67.43	67.71	-0.29	0%	70.72
8	60.10	59.62	0.48	1%	70.77
9	51.43	49.98	1.46	3%	72.23
10	41.88	37.64	4.24	10%	74.74
11	35.88	34.37	1.52	4%	77.56
12	35.71	33.61	2.10	6%	80.30
13	48.29	47.31	0.97	2%	82.80
14	67.01	68.27	-1.26	-2%	84.89
15	88.26	88.39	-0.13	0%	86.53
16	117.95	117.52	0.43	0%	87.78
17	132.58	133.01	-0.43	0%	88.13
18	156.42	167.85	-11.43	-7%	86.83
19	172.00	98.60	73.40	43%	85.35
20	170.54	132.28	38.26	22%	83.16
21	166.78	194.20	-27.42	-16%	79.98
22	175.83	185.64	-9.81	-6%	76.86
23	163.14	169.81	-6.67	-4%	75.09
24	142.39	147.49	-5.10	-4%	73.81
By Period:	Reference Load (MWh/Hour)	Load with DR (MWh/Hour)	Energy Savings (MWh/Hour)	% Change	Average Temperature (°F)
Average Event Hour	171.27	115.44	55.83	32.6%	84.3
Daily	103.94	101.30	2.64	2.5%	78.2

Figure 18 shows the average load impacts, by hour, for the 2024 average event window. Positive numbers indicate reductions in demand (kW) and negative values indicate and increase in demand. Impacts are largest during the first of hour of dispatch and decline in each subsequent event hour. Prior to the event impacts, there is clear evidence of pre-cooling, from one of the vendors, which leads to an increase of about 0.12 kW per customer. Following each event, we see a "snapback" period where demand exceeds the reference load by 0.35-0.40 kW in the hour immediately following dispatch. For the remainder of the evening, this snapback diminishes as impacts return to zero.

Figure 18: Hourly Load Reductions for Average Event Day



4.2 PERFORMANCE ON SYSTEM PEAK AND RELIABILITY DAYS

Figure 19 shows the ex-post per customer impacts on the SCE system peak day of September 6th, 2024. The first hour of the event, hour ending 18, had an average impact of 0.97 kW. However, the first hour was a partial dispatch hour, starting control at 5:15. This means that the signal for load drop was not sent out at the top of the hour. Partial hour dispatch leads to lower impacts than would generally be seen in the first hour of an event. This can be seen as the impacts for hour 2 go up to 1.10 kW per customer. The final hour of the event was also a partial hour dispatch being only first 2 minutes of 8 o'clock hour.

The event on September 6th was intended exclusively for customers in the Mira Loma A-Bank area, where 3,094 SEP customers were eligible for dispatch. However, due to SCE's Grid Control Center error when dispatching the event, only 436 customers were actually dispatched.

Figure 19: Per Customer System Peak Day, September 6th, 2024

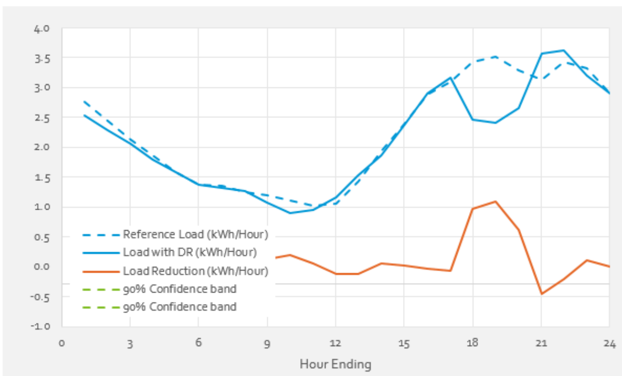
Southern California Edison
2024 Ex Post Load Impacts - SEP Program

Table 1: Menu options

Type of Result	Per Customer
Category	All
Segment	All Customers
Date	9/6/2024
Hour Ending View	HE (Prevailing Time)

Table 2: Event day information

Total sites	436
Daily Max Temp	104.8
Average Impact - kW	0.56
Average Impact - %	16.7%
Full Hours Only - Average Impact - kW	0.86
Full Hours Only - Average Impact - %	25.3%



Hour Ending	Reference Load (kWh/Hour)	Load with DR (kWh/Hour)	Load Reduction (kWh/Hour)	% Load Reduction	Avg Temp (°F, Site-Weighted)
1	2.76	2.54	0.21	8%	83.81
2	2.44	2.29	0.15	6%	81.40
3	2.13	2.06	0.08	4%	80.07
4	1.88	1.80	0.08	4%	79.22
5	1.58	1.59	-0.01	-1%	78.37
6	1.38	1.37	0.01	1%	77.67
7	1.36	1.32	0.03	3%	77.27
8	1.26	1.26	-0.01	-1%	76.82
9	1.21	1.08	0.12	10%	78.88
10	1.11	0.91	0.21	18%	82.24
11	1.03	0.96	0.07	6%	86.35
12	1.07	1.17	-0.11	-10%	91.62
13	1.42	1.53	-0.11	-8%	96.96
14	1.93	1.87	0.06	3%	101.44
15	2.39	2.37	0.02	1%	104.76
16	2.89	2.91	-0.02	-1%	103.09
17	3.10	3.16	-0.06	-2%	99.82
18	3.42	2.46	0.97	28%	98.25
19	3.52	2.42	1.10	31%	96.72
20	3.28	2.66	0.62	19%	94.88
21	3.12	3.57	-0.45	-14%	90.99
22	3.43	3.63	-0.19	-6%	86.59
23	3.32	3.20	0.12	4%	83.70
24	2.91	2.90	0.01	0%	81.98

By Period:	Reference Load (kWh/Hour)	Load with DR (kWh/Hour)	Energy Savings (kWh/Hour)	% Change	Average Temperature (°F)
Average Event Hour	3.34	2.78	0.56	16.7%	95.2
Daily	2.25	2.13	0.12	5.4%	88.0

While the event on September 6th had small aggregate impacts due to the smaller number of customers dispatched, the localized load relief provided to the distribution system on that day was valuable. Load relief value can often vary considerably from location to location within the SCE system based on distribution circuit loading and local conditions. In this case, while there were some dispatch issues, SEP was able to provide resources to a specific geographic area that was in need on this day. Program flexibility in dispatching small-scale events may be a source of future value for SEP.

4.3 RESULTS BY CATEGORY

DSA estimated the SEP impacts for each event for a variety of segments of interest. Table 9 presents the average impacts based on all full event hours from PY2024. The average events discussed in Section 4.1 only include those with a standard event window of 6pm to 8pm. In 2024 all events were called territory wide except for the emergency dispatch on September 6th. The average load impacts vary slightly by SubLAP, but the percent load impacts throughout most of the region are approximately 16-27%.

Table 9: Ex-post Full Hour Load Impact Estimates by Customer Category

Segmentation Variable	Segment Description	Participants	Percentage	Avg. Reference Load (kW)	Avg. DR Load (kW)	Avg. Load Impact (kW)	% Load Impact	Agg. Load Impact (MW)
All Customers		80,528	100%	2.62	1.86	0.76	29%	45.7
LCA	Big Creek/Ventura	11,287	14%	2.71	1.69	1.02	38%	11.2
	LA Basin	66,852	83%	2.18	1.34	0.83	38%	54.8
	Outside LA Basin	2,389	3%	2.68	1.65	1.03	38%	2.4
Low Income	CARE	19,373	24%	2.69	1.76	0.93	34%	17.6
	Non-CARE	61,155	76%	2.13	1.29	0.84	40%	50.9
NEM	NEM Customer	28,655	36%	2.26	1.23	1.03	45%	29.0
	Non-NEM Customer	51,873	64%	2.27	1.49	0.77	34%	39.4
Size	Above Median (2.11 kW)	40,367	50%	3.36	2.12	1.25	37%	49.5
	Below Median (2.11 kW)	40,161	50%	1.16	0.68	0.48	41%	18.9
SubLAP	SCEC	35,512	44%	2.62	1.59	1.03	39%	35.9
	SCEN	9,109	11%	2.92	1.80	1.12	38%	10.0
	SCEW	31,341	39%	1.68	1.08	0.61	36%	18.9
	SCHD	2,332	3%	2.64	1.62	1.02	39%	2.3
	SCLD	57	0%	4.11	2.74	1.37	33%	0.1
	SCNW	2,178	3%	1.80	1.21	0.59	33%	1.2
Tariff	Dynamic	53,121	66%	2.12	1.29	0.82	39%	43.0
	Flat	27,407	34%	2.55	1.61	0.94	37%	25.5
Thermostats	1 Thermostat	68,025	84%	2.21	1.40	0.82	37%	54.7
	2 Thermostats	10,832	13%	2.49	1.40	1.09	44%	11.6
	3+ Thermostats	1,672	2%	2.87	1.63	1.24	43%	2.1
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Zone	Remainder of System	39,209	49%	1.57	1.02	0.55	35%	36.8
	South Orange County	13,489	17%	1.57	1.02	0.55	35%	7.3
	South of Lugo	27,841	35%	2.29	1.40	0.89	39%	24.3

Regardless of segment, there is not much variety in the percent load impacts. The small size segment (participants with demand less than 2.11 kW on average during the resource adequacy window) has the lowest average load impact of 0.48 kW. Customers in SCLD (Low Desert) had the highest average load impacts at 1.37 kW per customer. However, on a percent basis these two segments were still relatively close at 37% and 33% respectively. Overall, most segments are not that off from the "All Customers" category with 29% reduction in net household load. The average aggregate load impact for all customers is 45.7 MW.

The following figures show segment specific impacts for the average 2024 event day, which starts at 6:00 pm and ends 8:00 pm. Figure 20 shows the average event day impacts by SubLAP. The "All Customers" group is represented by a black line, and the zero impact line is drawn in gray. The "All" category represents a participant weighted average of each segment category and is therefore shown approximately in the middle of the SubLAPs. Impacts are highest in hour 1 for SCEN, SCLD, and SCEC, while SCEW and SCNW fall on the lower side of the overall average. Hour ending 18 shows increases in load associated with pre-cooling prior to the events. "Snapback" effects can be seen in hour ending 21-24. "Snapback" effects are largest in hour ending 21 and slowly decay overtime just like event impacts during event hours.

Figure 20: Average Customer Impact on Average Event Day, by SubLAP

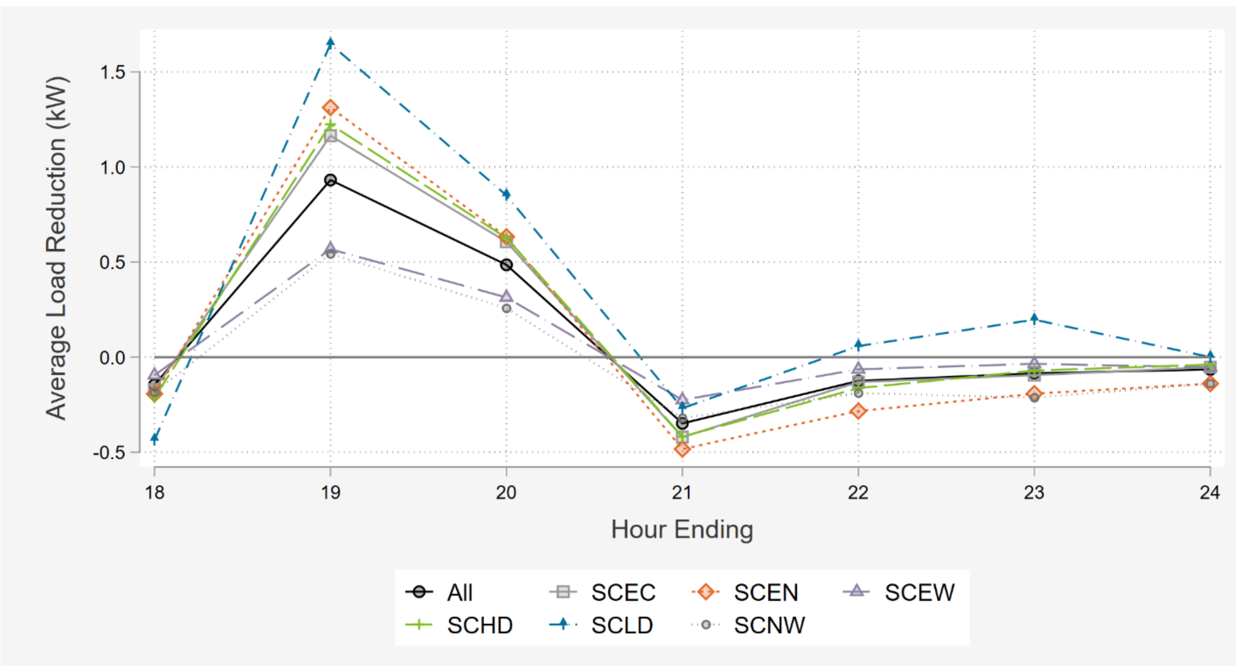
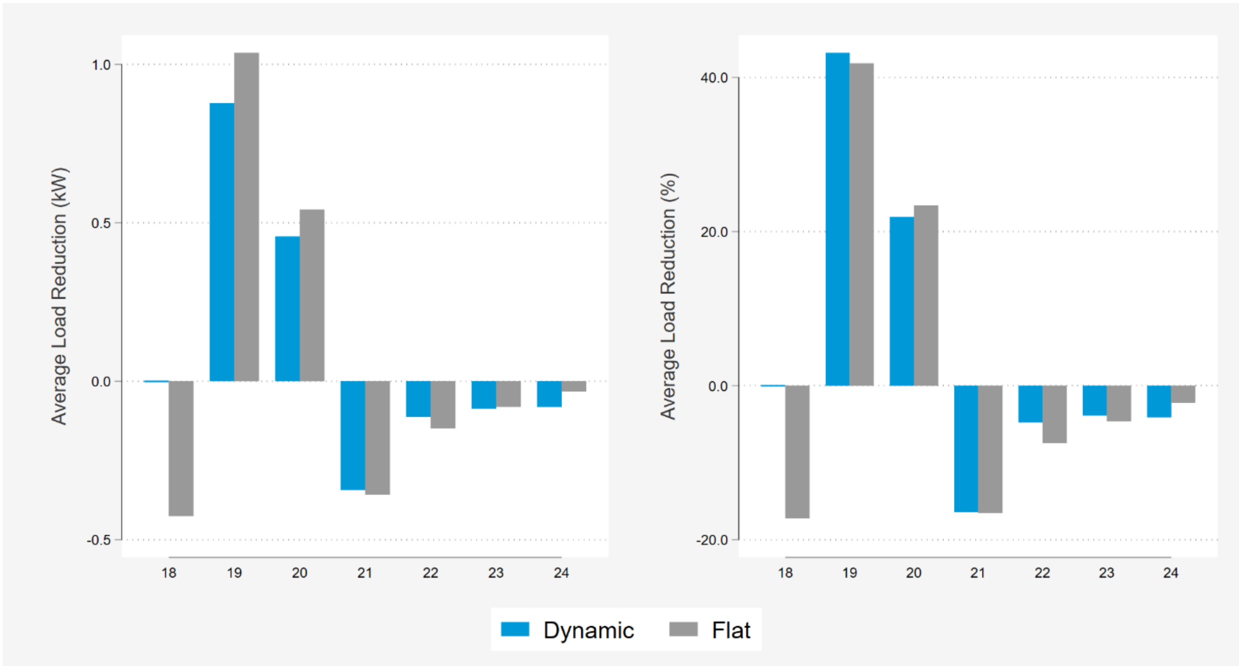


Figure 21 shows the average reductions for SEP participants who face flat and dynamic time-of-use (TOU) rates. The left side of Figure 21 shows absolute impacts in kW by hour and the right side shows percent savings. Participants on dynamic rates show similar percent reductions to those on flat rates, but on average basis the flat rate customers experience slightly higher load reductions. In 2024 only 34% of all SEP participants were on flat rates. Those with flat rates tend to live in warmer areas and have higher loads in the RA window, which means there is more load to be curtailed with those customers. Flat rate customers experienced temperatures on the average event day that were 3 degrees (F) warmer than those on Dynamic rates. Hour ending 18 shows the effects of pre-cooling for flat rate customers. Because hour ending 18 is during most dynamic rate customer's peak period, they are not pre-cooled while the flat rate customers are pre-cooled. Pre-cooling increases energy usage when initiated, so dynamic rate customers are intentionally not included.

Figure 21: Average and Percent Impacts on Average Event Day, by Tariff and Hour Ending



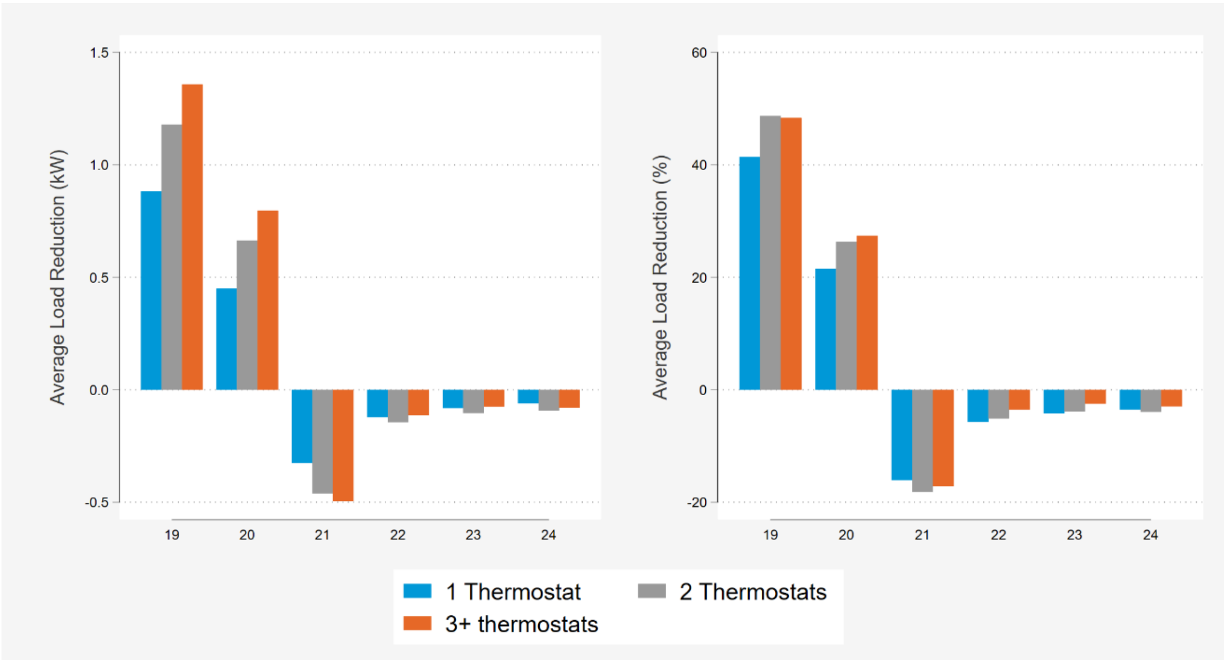
[redacted]

Figure 22: [redacted]

[redacted]

Figure 23 shows the ex-post results by count of thermostats per customer. The average kW reduction increases by approximately 37% for homes with two thermostats along with an additional 17% increase when moving from two to 3+ thermostats. In percent impacts, all three thermostat groups save between 41% -49% in hour one. The relatively tight spread of percentage impacts indicates that the different groups respond similarly to events, but customers with more thermostats tend to have higher loads on average, so their event impacts are higher. Only 2% of participants have 3+ thermostats so the estimates for those customers are noisy.

Figure 23: Average Ex-post Average Event Day Impact, by Thermostat Count and Hour Ending



4.4 COMPARISON TO PRIOR YEAR

SEP dispatched fewer events in PY2024 in comparison to previous years. All but one of the events in PY2024 were dispatched to each SubLAP, while all of the events in 2023 were territory wide. Summer 2023 experienced fewer extreme temperatures than 2024. For the territory wide events in 2024, average event hour temperatures ranged from 81.6°F to 95.5°F. In 2023, the average event temperatures spanned from 80.4°F to 93.7°F. While the more extreme weather events in summer 2024 will be helpful for accurate predictions of the more extreme ex-ante weather conditions, the mild days from summer 2024 can help to give more information for predicting impacts during relatively mild events. This underscores the importance of using multiple years of data to predict future event impacts. The wide range of temperatures experienced in 2024 should provide greater insight into ex-ante forecasting conditions and in tandem with out of sample predictions from other years should prove to be more accurate in ex-ante. For example, SCE 1-in-10 conditions for a September monthly system worst day is expected to peak at 98.4 degrees (F) during event hours. In 2024, the highest temperature experienced during a planned event hour in September was 96.2 degrees Fahrenheit. When making an ex-ante prediction for that September monthly system worst day, we would like more data that covers temperatures even more extreme than 1-in-10 conditions which allows us to more easily make an accurate prediction. In PY2024, only one of the 6 events was dispatched as a "Reliability" event, on September 6th. All other events were self-scheduled in the day ahead market.

Peak temperature during the average event day falls between 2pm and 5pm and events typically started between 5pm and 6pm. In 2017 and 2018, average event hours included the 2pm-6pm window, which is concurrent with the peak temperature of the day. AC load tends to lag temperature due to heat buildup and occupancy, suggesting that an event window following the peak temperature of the day may better capture the peak AC usage window. Notice in Table 8 that on an average event day, the average event temperatures are several degrees lower than the daily max. Even though average event temperature does affect impacts, heat buildup plays a role as well.

The overall SEP population continued to grow through 2024 summer season. Customer counts do fluctuate over the course of the season as customer attrition and enrollments happen continuously. The SEP participant population was larger in PY2024 by about 10,000 customers, when comparing the average 6-8pm event days in 2023 to the average 6-8PM days in 2024.

In past years, like 2022, extreme weeks where multiple events were called consecutively tended to lead to large amounts of customers dropping out of the program quickly. In 2024, however, there were no sustained periods of high temperatures and enrollments steadily rose throughout the summer. This sort of growth is vital to the value of the SEP program as a resource.

Table 10 shows the characteristics of the average event day windows PY2021- PY 2024. Reference loads in PY2024 were the lowest of the four years, mostly attributable to differing temperature profiles. The average event day in 2024 was the least extreme weather represented in the average event profiles. The increase in percentage impacts in 2024, when compared to previous years is most likely due to the stronger implementation of pre-cooling in 2024. Enrollment changes between the four years though, means that aggregate impacts differ substantially, with 2024 being the largest.

Table 10: Comparison of Historical and Current Average Event Ex-post Load Impact Estimates

Measure	2021 (6-8 PM)	2022 (6-8 PM)	2023 (6-8 PM)	2024 (6-8 PM)
Avg. Reference Load (kW)	2.49	2.67	2.37	2.17
Avg. Load Impact (kW)	0.73	0.86	0.73	0.71
% Load Impact	29.32%	32.40%	30.88%	32.6%
Avg. Event Temperature	88.0	92.0	87.8	84.3
Heat Buildup (Avg. F, 12 AM to 5 PM)	78.5	79.3	79.0	77.4
Enrollment	48,498	56,668	69,286	78,771

4.5 COMPARISON TO 2023 EX-ANTE

A key question for program administrators, regulators, and system planners is whether the ex-post performance of demand response programs was consistent with the projected capability in the 2023 ex-ante analysis for PY2024. There are two elements to consider when reviewing the accuracy of the 2023 ex-ante projections.

1. Did the actual number of enrollments match the projected number of enrollments in SCE's PY2023 enrollment forecast? The number of enrolled accounts is a key component of the aggregate capability of the program in MW.

2. Did the program deliver ex-post impacts on a per-customer basis consistent with the ex-ante projections for comparable weather conditions?

On an aggregate basis, 2024 SEP ex-post impacts are in line with the MW projections from the 2023 ex-ante analysis. The SEP program forecast of enrollments in 2024 underestimated the actual numbers by only about 3%. True enrollments exceeding expectations along with strong per customer performance across many events in summer 2024 meant that SEP was able to outperform the 2023 ex-ante projections.

In Table 11, Table 12, and Table 13, we compare the ex-post results from select 2024 events to our 2023 ex-ante results for monthly system worst day conditions at comparable weather conditions. In each comparison, hour 1 for the ex-ante forecasts is 4-5pm while each ex-post event started at 5 or 6pm, so hour 1 corresponds to 5-6 or 6-7pm.

Table 11 compares the July 11th SEP event impacts to our projected 2023 impacts for a July Monthly System Worst Day at SCE 1-in-2 weather conditions. Ex-post weighted average maximum daily temperature conditions were just below the SCE 1-in-2 conditions. This means that we would expect the impacts of the event to fall just short of the ex-ante projections, and that is exactly what we see in the table. The actual number of customers enrolled in the program also exceeded the ex-ante expectations. This led to aggregate savings exceeding the ex-ante expectations on this event day.

Table 11: July 11, 2024 Ex-post Impacts vs. Comparable 2023 Ex-ante Conditions

7/11/2024 (6-8 PM)			Per-Customer Impact (kW)			
Results	Daily Max Temp (F)	Customers	Hour 1	Hour 2	Hour 3	Hour 4
SCE 1-in-2 July Worst Day (2023 Ex-ante Predictions for 2024)	94.6	76,312	1.15	0.65	0.38	0.26
Ex-Post	90.6	77,876	0.99	0.51		

Table 12 presents a similar comparison for August 7th, 2024. We compare this event with the August worst day during CAISO 1-in-2 conditions. The daily max temperature was lower than the projection by 6 degrees. Per customer impacts were lower in hour one by 0.19 kW, and 0.11 kW lower in the second hour. Actual enrollments, once again, exceeded projections, by more nearly 3,000 customers, which means aggregate MW performance exceeded the projected.

Table 12: August 7, 2024 Ex-post Impacts vs. Comparable 2023 Ex-ante Conditions

9/7/2024 (6-8 PM)			Per-Customer Impact (kW)			
Results	Daily Max Temp (F)	Customers	Hour 1	Hour 2	Hour 3	Hour 4
CAISO 1-in-2 August Worst Day (2023 Ex-ante Predictions for 2024)	92.21	76,886	1.07	0.59	0.34	0.23
Ex-Post	86.1	79,647	0.88	0.48		

Table 13 presents a comparison for the September 4th, 2024, SEP event, with the 2023 September monthly worst day under SCE 1-in-2 conditions. The weather in 2024 was similar to the expected 1-in-2 conditions with a daily maximum temperature during the 2024 being about 1.4 degrees below the ex-ante conditions. Despite the lower temperatures in 2024 the hour 1 impacts were higher than the ex-ante predictions.

Table 13: September 4, 2024 Ex-post Impact vs. Comparable 2023 Ex-ante Conditions

9/4/2024 (5-7 PM)			Per-Customer Impact (kW)			
Results	Daily Max Temp (F)	Customers	Hour 1	Hour 2	Hour 3	Hour 4
SCE 1-in-2 September Worst Day (2023 Ex-ante Predictions for 2024)	97.6	77,380	1.19	0.67	0.41	0.3
Ex-Post	96.2	80,528	1.27	0.67		

5 EX-ANTE RESULTS

The ex-ante results for SEP show increasing aggregate MW impacts based on the growth projections in SCE's enrollment forecast. Since it relies on direct load control of residential air conditioning, SEP impacts are inherently weather dependent. The projected impacts are largest during the summer months, more modest during the shoulder months, and non-existent during the winter heating season. For 2024 RA compliance year, the RA window is from 5pm-10pm in March, April, and May and 4pm-9pm in all other months of the year.[6]

5.1 ENROLLMENT FORECAST

SCE provided an eleven-year forecast of SEP enrollments 2025-2035 representing the expected number of participants as of August of each calendar year. To place the forecast on an even monthly basis, DSA imputed the estimated enrollments in each month of the forecast.

Figure 24 compares this new forecast with the forecast we received for the PY2021-PY2023 SEP evaluations. The PY2024 forecast shows a similar rate of growth as PY 2022 and PY 2023, but due to successful marketing efforts has a higher starting point than the predicted enrollment in PY 2023.

SCE expects the total number of enrollments to grow over the next decade from the current level of approximately 80,500 to nearly 135,000 enrollments by 2035. The sustained growth is expected due to integrated marketing with other demand response programs and OEM marketing.

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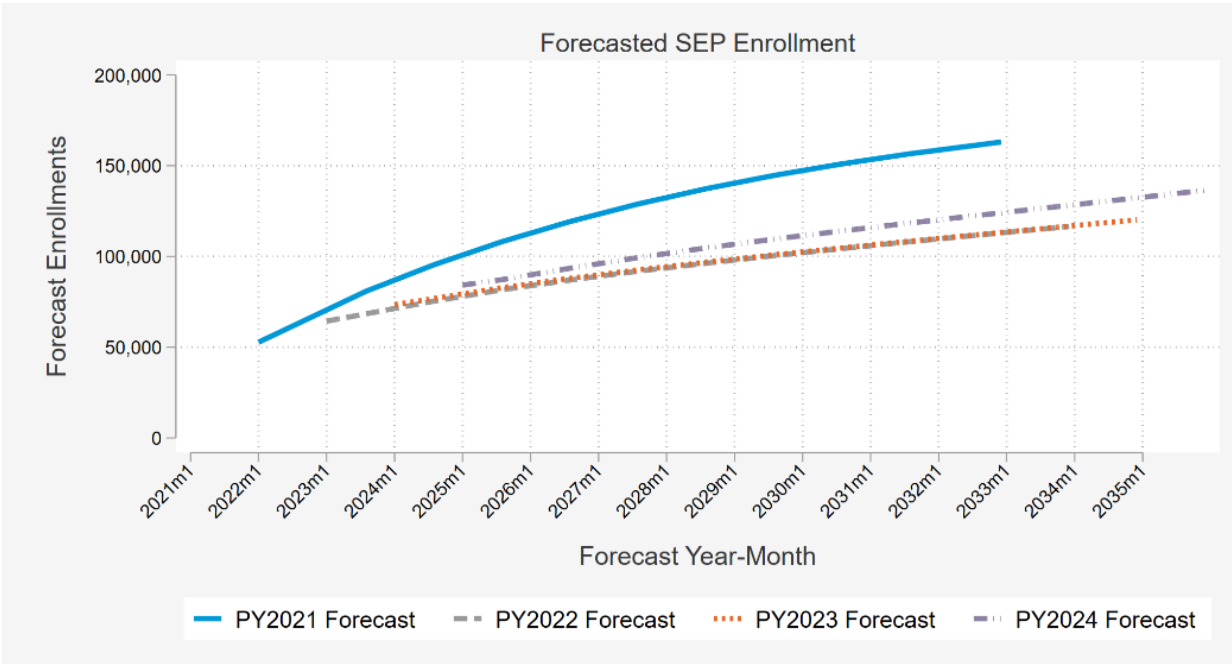
[6] D.23-06.029 Ordering Paragraph 5

Figure 24: Comparison of PY2021-PY2024 SEP Enrollment Forecasts



5.2 OVERALL RESULTS

Figure 25 shows the average ex-ante load impacts per SEP participant for each hour of a September system worst day in 2025 using the SCE 1-in-2 weather forecast. Figure 26 shows the 2025 per-participant impact estimates using SCE 1-in-10 weather for a September system worst day. These figures come from the companion Microsoft Excel reporting table generators that accompany this evaluation report. Via a series of pick lists, the ex-ante table generators allow users to view specific sets of results. Per customer (kW) and aggregate (MW) impacts are available for each forecast year 2025-2035 and for the different weather forecasts described in Section 3.2. Users can also view the ex-ante results for a subcategory within LCA, Low Income (CARE Status), NEM, SubLAP, Tariff, and Zone Name. The table generators utilize an "hour ending" time convention. The results presented for hour ending 19 correspond to the average reference load, DR impact, and weather for the hour from 6pm to 7pm Pacific Prevailing Time. In Figure 25 and Figure 26, the five hours of the RA window are shaded light green. Hours ending 17 through 21 correspond to the RA window in September of 4pm to 9pm. These two event profiles happen to have the same percent load reduction (20.6%), but most months show a slight difference in expected percent reduction between 1-in-2 and 1-in-10 weather. Additionally the table can be toggled between Pacific Prevailing Time (as shown in the figures) or UTC-8 time, which shifts the ending hour by one.

Figure 25: SEP Average Load Impact (kW) per Customer in 2025: September Monthly Worst Event Day, SCE 1-in-2 Weather

Southern California Edison

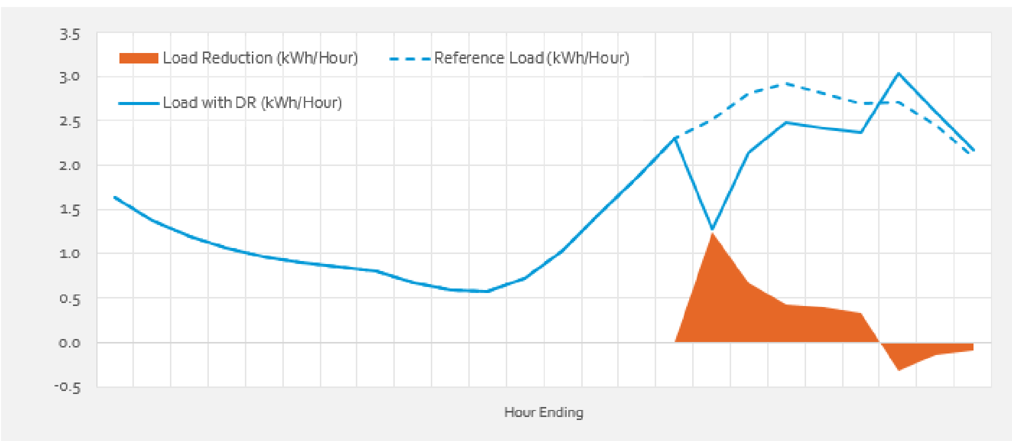
PY2024 Ex Ante - SEP

Table 1: Menu options

Type of result	Per Customer
Category	All
Segment	All Customers
Weather Data	SCE
Weather Year	1-in-2
Day Type	September Monthly Worst Day
Forecast Year	2025
Portfolio Level	Portfolio
Hour Ending View	HE (Prevailing Time)

Table 2: Event day information

Event start	4:00 PM
Event end	9:00 PM
Total sites	87,774
Event window temperature (F)	91.8
Event window load reduction (kWh/Hour)	0.62
% Load reduction (Event window)	22.4%
Redaction Information	Public



Hour Ending	Reference Load (kWh/Hour)	Load with DR (kWh/Hour)	Load Reduction (kWh/Hour)	% Load Reduction	Avg Temp (°F, Site-Weighted)
1	1.63	1.63	0.00	0.0%	76.81
2	1.38	1.38	0.00	0.0%	75.41
3	1.20	1.20	0.00	0.0%	74.37
4	1.06	1.06	0.00	0.0%	73.13
5	0.97	0.97	0.00	0.0%	72.45
6	0.89	0.89	0.00	0.0%	71.52
7	0.86	0.86	0.00	0.0%	71.52
8	0.80	0.80	0.00	0.0%	72.44
9	0.67	0.67	0.00	0.0%	74.86
10	0.59	0.59	0.00	0.0%	80.27
11	0.57	0.57	0.00	0.0%	86.68
12	0.72	0.72	0.00	0.0%	91.51
13	1.04	1.04	0.00	0.0%	94.91
14	1.45	1.45	0.00	0.0%	96.85
15	1.87	1.87	0.00	0.0%	97.52
16	2.30	2.30	0.00	0.0%	96.69
17	2.51	1.27	1.24	49.3%	95.22
18	2.80	2.13	0.67	23.9%	93.79
19	2.92	2.48	0.44	15.0%	92.39
20	2.81	2.41	0.40	14.1%	90.35
21	2.70	2.36	0.34	12.5%	87.46
22	2.71	3.03	-0.33	-12.0%	84.65
23	2.45	2.59	-0.14	-5.7%	82.66
24	2.09	2.17	-0.09	-4.2%	80.58
By Period:	Reference Load (kWh/Hour)	Load with DR (kWh/Hour)	Energy Savings (kWh/Hour)	% Change	Average Temperature (°F)
Average Event Hour	2.75	2.13	0.62	22.4%	91.84
Daily	1.62	1.52	0.11	6.5%	83.92

Figure 26: SEP Average Load Impact (kW) per Customer in 2025: September Monthly Worst Event Day, SCE 1-in-10 Weather

Southern California Edison

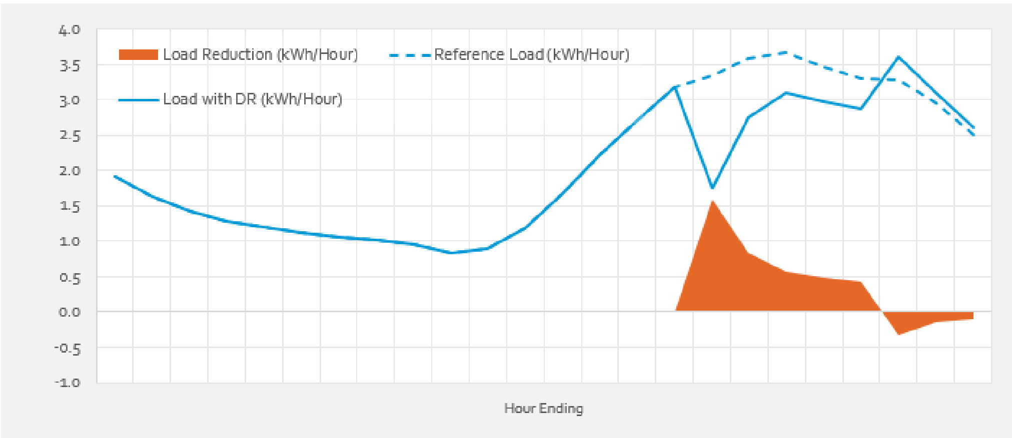
PY2024 Ex Ante - SEP

Table 1: Menu options

Type of result	Per Customer
Category	All
Segment	All Customers
Weather Data	SCE
Weather Year	1-in-10
Day Type	September Monthly Worst Day
Forecast Year	2025
Portfolio Level	Portfolio
Hour Ending View	HE (Prevailing Time)

Table 2: Event day information

Event start	4:00 PM
Event end	9:00 PM
Total sites	87,774
Event window temperature (F)	98.4
Event window load reduction (kWh/Hour)	0.78
% Load reduction (Event window)	22.6%
Redaction Information	Public



Hour Ending	Reference Load (kWh/Hour)	Load with DR (kWh/Hour)	Load Reduction (kWh/Hour)	% Load Reduction	Avg Temp (°F, Site-Weighted)
1	1.92	1.92	0.00	0.0%	81.88
2	1.64	1.64	0.00	0.0%	80.50
3	1.43	1.43	0.00	0.0%	79.47
4	1.29	1.29	0.00	0.0%	78.70
5	1.19	1.19	0.00	0.0%	78.32
6	1.12	1.12	0.00	0.0%	78.28
7	1.06	1.06	0.00	0.0%	77.83
8	1.03	1.03	0.00	0.0%	78.94
9	0.96	0.96	0.00	0.0%	82.86
10	0.84	0.84	0.00	0.0%	88.15
11	0.89	0.89	0.00	0.0%	93.84
12	1.19	1.19	0.00	0.0%	98.11
13	1.67	1.67	0.00	0.0%	101.24
14	2.21	2.21	0.00	0.0%	103.31
15	2.70	2.70	0.00	0.0%	104.33
16	3.17	3.17	0.00	0.0%	104.51
17	3.34	1.75	1.59	47.6%	104.28
18	3.59	2.74	0.84	23.5%	102.01
19	3.67	3.10	0.57	15.6%	99.09
20	3.46	2.98	0.48	14.0%	94.77
21	3.29	2.87	0.43	12.9%	91.82
22	3.28	3.61	-0.33	-10.0%	89.90
23	2.95	3.10	-0.15	-5.2%	88.06
24	2.50	2.60	-0.11	-4.3%	86.10
By Period:	Reference Load (kWh/Hour)	Load with DR (kWh/Hour)	Energy Savings (kWh/Hour)	% Change	Average Temperature (°F)
Average Event Hour	3.47	2.69	0.78	22.6%	98.40
Daily	2.10	1.96	0.14	6.6%	90.26

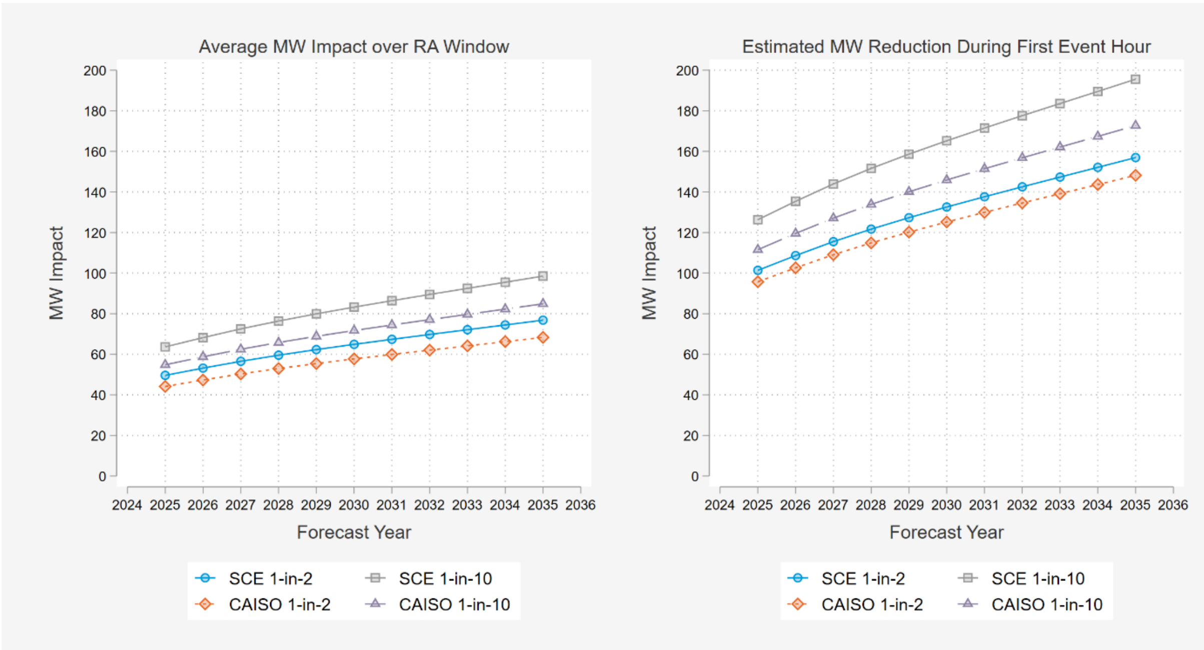
The PY2024 ex-ante forecasts of impacts are generally higher than the PY2023 per-participant impacts for the same ex-ante weather conditions. We generally attribute this to the programs continued efforts to take non-performing participants out of the program and more events utilizing pre-cooling in each of the last 4 years. The impact of pre-cooling on events is difficult to quantify. It is generally accepted that pre-cooling increases load impacts because the homes must warm up more before reaching its event setpoint. This means that AC units won't reach their event setpoint until later in the event. Pre-cooling may also improve comfort and reduce opt-outs. DSA does not receive device telemetry data showing indoor temperatures or details about event opt outs, so it is difficult to quantify the magnitude of the effect. In PY2024, all but one event included pre-cooling for participants eligible to be pre-cooled because there was only one reliability event called during which pre-cooling is not an option. Reliability events are called in real-time meaning that, when dispatched, SEP must respond as soon as possible leaving no time to pre-cool homes. Because of this, the second stage impact model that was fit in 2024 includes more impacts that are influenced by pre-cooling effects than prior years, which did include pre-cooled events, but to a smaller extent.

We do not explicitly model the hypothetical ex-ante event as having or not having pre-cooling. This means that impacts in the hour prior to hour 1 of the event are zero. While the ex-ante event profile does not assume pre-cooling, we do not believe pre-cooling is always mutually exclusively with a reliability event. During a heat wave, SCE could pre-cool in advance of a reliability event, strategically estimating event dispatch start times. Inclusion of impacts from events with pre-cooling in the second stage model has an upward influence on the ex-ante impacts but excluding them would drastically limit the amount and recency of data used to model impacts. We believe an SEP event without pre-cooling would have slightly lower expected impacts than an SEP event with pre-cooling, but the study design and available data don't allow us to estimate this difference. Our decision to use events with and without pre-cooling in the second stage model means our ex-ante estimates are likely somewhere in between an event that includes pre-cooling and one that does not.

AGGREGATE IMPACTS

The MS Excel reporting tables include the functionality to view aggregate MW impacts for any forecast year under the various day types and sets of weather conditions. Figure 27 consolidates multiple estimates to show the change in the size of the SEP resource over time. The growth over time is a function of the enrollment forecast. The left panel of Figure 27 shows the average SEP MW impact over the five hour RA window on a typical event day. The right panel shows the average SEP MW impact over the first event hour, which is assumed to occur from 4pm to 5pm. The load reduction capability of SEP during the first event hour is significantly larger than the five-hour average. This is due to the reduced impacts over each subsequent hour in the event. The difference between these two views of load reduction capability has important implications for valuation of SEP as a capacity resource.

Figure 27: Aggregate SEP Impacts over Time by Weather Conditions: Typical Event Day



The SCE weather conditions tend to be warmer than CAISO weather conditions on the typical event day. In both the 1-in-2 and 1-in-10 cases, the SCE conditions lead to higher projected event impacts. The highest overall impacts coming from the SCE 1-in-10 conditions. The more extreme weather assumptions lead to higher reference loads, per-participant impacts, and MW capability.

Table 14 shows the aggregate ex-ante load impact estimates in forecast year 2025 by hour and peaking conditions for a typical event day. The estimated load impacts of SEP from 2025-2035 ranges from 95.7 MW to 126.3 MW during hour ending 17. Estimated impacts decline across the RA window and range from 18.8 MW to 35.1 MW in hour ending 21.

Table 14: 2025 Typical Event Day Aggregate Impacts (MW) by Hour and Weather Conditions

Hour Ending	SCE 1-in-2	CAISO 1-in-2	SCE 1-in-10	CAISO 1-in-10
17	101.4	95.7	126.3	111.6
18	55.0	51.7	68.9	60.6
19	34.8	30.0	47.0	39.4
20	31.3	24.5	41.0	34.1
21	25.7	18.8	35.1	28.5
RA Window	**49.6**	**44.2**	**63.7**	**54.8**

In addition to the typical event day, DSA estimated ex-ante impacts for monthly system worst days. Table 15 shows the average estimated MW reduction capability of SEP during the RA window for SCE 1-in-2 and SCE 1-in-10 weather. Table 16 presents the same results using CAISO 1-in-2 and CAISO 1-in-10 weather. The SCE 1-in-2 and both CAISO weather year conditions show the largest impacts on September worst days. The SCE 1-in-10 estimates are largest for the July monthly system worst day.

The weather conditions used for ex-ante weather predictions were last updated in PY2022, any differences in the expected weather conditions for SEP as a whole can be attributed to participant location changes over time. The impacts in Table 15 and Table 16 follow the expected temperatures very closely.

Table 15: Aggregate Average Load Impacts (MW) on Monthly System Worst Days 2025-2035: SCE Weather

Weather Year	Month	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
1-in-2	January	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	February	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	March	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	April	25.2	27.0	28.8	30.4	31.9	33.2	34.5	35.8	37.0	38.2	39.4
	May	24.1	25.8	27.4	29.0	30.4	31.7	32.9	34.1	35.2	36.4	37.6
	June	43.9	47.0	50.0	52.7	55.2	57.6	59.8	61.9	64.1	66.1	68.3
	July	50.1	53.7	57.1	60.2	63.1	65.7	68.2	70.6	73.0	75.4	77.8
	August	50.1	53.7	57.0	60.1	62.9	65.5	68.0	70.4	72.8	75.1	77.5
	September	54.1	57.9	61.5	64.7	67.7	70.5	73.2	75.8	78.3	80.8	83.4
	October	44.8	47.9	50.9	53.5	56.0	58.3	60.4	62.6	64.7	66.8	68.9
	November	23.4	25.0	26.5	27.9	29.1	30.3	31.5	32.6	33.6	34.7	35.8
	December	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1-in-10	January	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	February	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	March	23.3	24.9	26.6	28.1	29.5	30.8	32.0	33.1	34.3	35.4	36.5
	April	38.0	40.6	43.3	45.7	48.0	50.0	52.0	53.9	55.7	57.5	59.4
	May	49.8	53.2	56.7	59.8	62.7	65.4	67.9	70.4	72.8	75.2	77.6
	June	57.3	61.4	65.3	68.9	72.2	75.2	78.1	80.9	83.7	86.4	89.2
	July	73.4	78.6	83.6	88.1	92.3	96.1	99.8	103.4	106.9	110.3	113.8
	August	54.7	58.6	62.3	65.6	68.7	71.5	74.3	76.9	79.5	82.1	84.7
	September	68.7	73.6	78.2	82.3	86.1	89.6	93.0	96.3	99.5	102.8	106.0
	October	53.6	57.4	60.9	64.1	67.0	69.7	72.4	74.9	77.4	79.9	82.4
	November	32.4	34.7	36.8	38.7	40.4	42.1	43.6	45.2	46.7	48.2	49.7
	December	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 16: Aggregate Average Load Impacts (MW) on Monthly System Worst Days 2025-2035: CAISO Weather

Weather Year	Month	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
1-in-2	January	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	February	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	March	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	April	27.6	29.5	31.5	33.2	34.9	36.4	37.8	39.2	40.5	41.8	43.2
	May	16.9	18.1	19.2	20.3	21.3	22.2	23.0	23.9	24.7	25.5	26.3
	June	41.0	43.8	46.7	49.2	51.6	53.7	55.8	57.8	59.8	61.7	63.7
	July	40.4	43.2	46.0	48.5	50.7	52.9	54.9	56.8	58.8	60.7	62.6
	August	45.4	48.7	51.8	54.5	57.1	59.4	61.7	63.9	66.0	68.2	70.3
	September	49.5	53.1	56.4	59.3	62.1	64.6	67.1	69.4	71.8	74.1	76.4
	October	43.9	46.9	49.8	52.4	54.8	57.0	59.2	61.3	63.3	65.4	67.4
	November	23.0	24.6	26.1	27.4	28.6	29.8	30.9	32.0	33.1	34.1	35.2
	December	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1-in-10	January	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	February	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	March	25.7	27.4	29.2	30.9	32.4	33.8	35.2	36.5	37.7	39.0	40.2
	April	34.4	36.8	39.2	41.4	43.4	45.3	47.0	48.8	50.4	52.1	53.8
	May	40.7	43.5	46.4	48.9	51.3	53.5	55.6	57.6	59.5	61.5	63.5
	June	56.0	59.9	63.8	67.3	70.5	73.5	76.3	79.1	81.8	84.4	87.1
	July	52.0	55.7	59.3	62.5	65.4	68.2	70.8	73.3	75.8	78.3	80.7
	August	53.8	57.6	61.3	64.5	67.5	70.3	73.0	75.6	78.2	80.7	83.2
	September	57.1	61.1	64.9	68.3	71.5	74.4	77.2	80.0	82.6	85.3	88.0
	October	56.9	60.8	64.6	67.9	71.0	73.9	76.7	79.4	82.1	84.7	87.4
	November	31.6	33.8	35.9	37.7	39.4	41.0	42.6	44.1	45.5	47.0	48.5
	December	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

5.3 RESULTS BY CATEGORY

Table 17 presents the aggregate SEP impacts for a typical event day in 2025 under each set of weather conditions by local capacity area. The majority of SEP participants are located in the LCA: LA Basin so this LCA shows the majority of the projected load reduction capacity. Because we model ex-ante impacts separately by segment, the subcategories may not add up exactly to the SEP total, which come from a pooled model of all participants.

Table 17: Ex-ante Aggregate 2025 Impacts (MW) by LCA: Typical Event Day

LCA	Enrollment	SCE 1-in-2	CAISO 1-in-2	SCE 1-in-10	CAISO 1-in-10
LCA: Big Creek/Ventura	12,229	6.8	6.7	8.5	7.9
LCA: LA Basin	72,434	41.0	35.7	52.5	44.8
LCA: Outside LA Basin	2,588	1.4	1.4	1.7	1.6
SEP Total	**87,252**	**49.6**	**44.2**	**63.7**	**54.8**

Approximately 83% of SEP participants are located in the LA Basin LCA, and between 81% and 82.7% of the ex-ante MW impacts come from the LA Basin. Average customer impacts in the LA Basin LCA are about the same as Big Creek/Ventura, with Outside LA Basin customers having the lowest. For SCE 1-in-2 weather conditions the Big Creek/Ventura LCA has an average customer impact of 0.56 kW, Outside LA Basin has an average customer impact of 0.53 kW and LA Basin has an average customer impact of 0.57 kW.

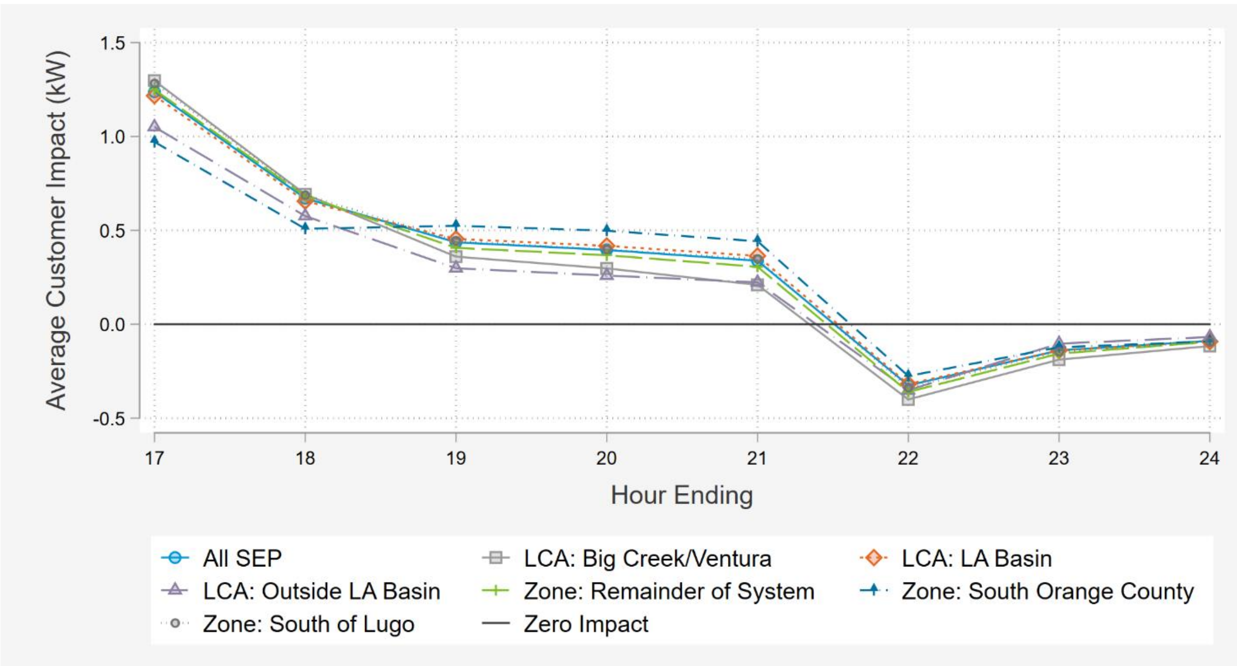
Table 18 provides a similar breakdown for each region of the SCE system affected by the SONGS closure. For SCE 1-in-2 weather conditions, we expect 35.8% of the SEP load reduction to come from South of Lugo, 14.3% from South Orange County, and 50.0% from the Remainder of the System unaffected by the SONGS closure. While South Orange County has 16.7% of the participants, the average customer impacts are lower, so the region only provides approximately 11-13.4% of the total load reduction capability. Remainder of the System has the opposite trend with approximately 48% of the customers and 50-52.6% of the impacts.

Table 18: Ex-ante Aggregate 2025 Impacts (MW) by SONGs Region: Typical Event Day

Region	Enrollment	SCE 1-in-2	CAISO 1-in-2	SCE 1-in-10	CAISO 1-in-10
Zone: Remainder of System	42,483	24.8	23.2	31.9	28.2
Zone: South Orange County	14,603	6.7	4.9	8.2	6.7
Zone: South of Lugo	30,165	17.8	15.7	22.8	19.5
SEP Total	**87,252**	**49.6**	**44.2**	**63.7**	**54.8**

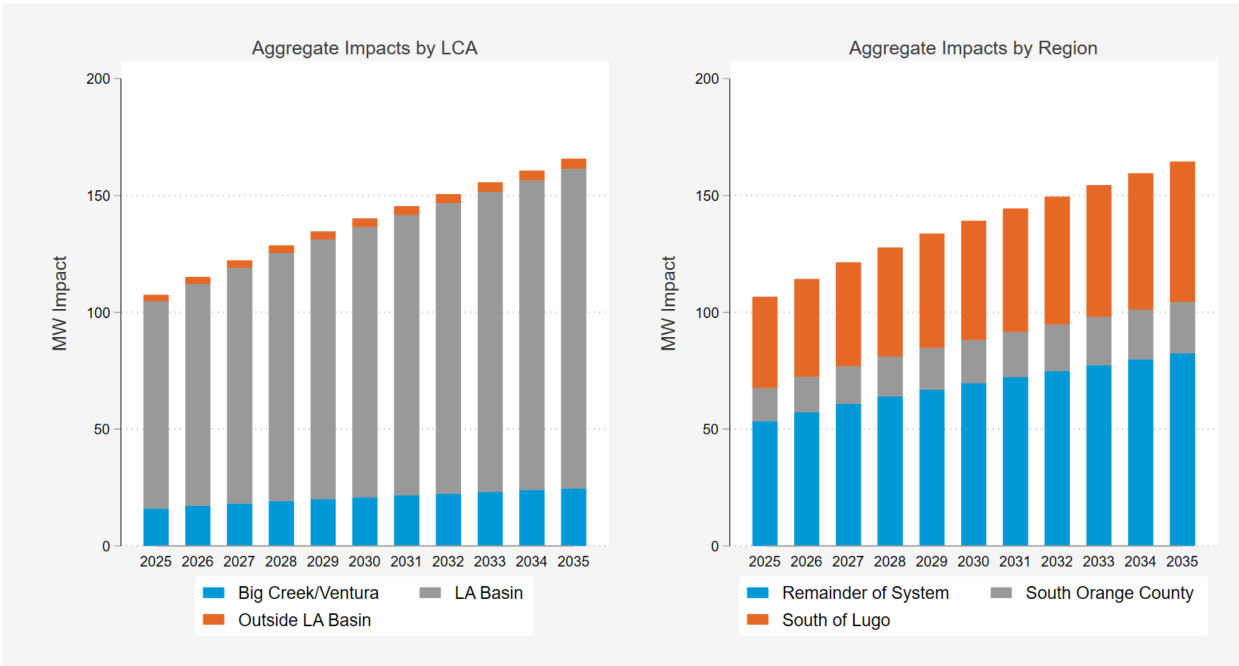
Readers should note that the aggregate impacts shown in Table 17 and Table 18 are an average across the five-hour RA window. Figure 28 shows the average impact on a September system worst day by segment and hour across the RA window and post-event snapback period using SCE 1-in-2 weather and reveals that that average MW impacts across the RA window mask a significant amount of inter-hour diversity in estimated performance. Figure 28 presents load reductions as a positive impact and load increases as negative values. The largest impact occurs during the first dispatch hour, which is assumed to occur from 4pm to 5pm. Impacts degrade steadily for the remainder of the RA window. The post-event snapback is largest during hour immediately following the conclusion of the event and has largely vanished by midnight.

Figure 28: Average Customer Load Impacts by Segment and Hour: September System Worst Day, SCE 1-in-2 (2025 – 2035)



As shown in Figure 28, the per-participant impact is greatest during the first hour of event dispatch. The forecasted enrollments are the same in each hour. Figure 29 shows the projected aggregate MW impacts for SEP 2025-2035 by LCA and Region using SCE 1-in-2 weather conditions for a September system worst day.

Figure 29: First Event Hour Ex-ante MW Reduction by LCA and Region: September System Worst Day, SCE 1-in-2 Weather



5.4 COMPARISON TO PRIOR YEAR

The PY2024 ex-ante forecasts of impacts are generally higher than the PY2023 per-participant impacts for the same ex-ante weather conditions. We attribute this change to two key factors:

- SEP program staff remove customers who opt out or don't perform. This means that, over time, only customers who perform during events are left, increasing the average per customer impacts from events.
- [redacted]

Table 19 compares the average customer impacts on an absolute and percent basis and shows the weighted average temperature (°F) across the SEP population for the 2024 August system worst day using SCE 1-in-2 weather. Weather conditions have not changed much from year to year. Average per-customer impacts were generally lower in 2023. This is likely due to the improvement year over year in the SEP program impacts.

Table 19: Comparison of PY2023 and PY2024 Average Customer Impacts: 2025 August System Worst Day, SCE 1-in-2 Weather

Hour Ending	2023 (kW)	2024 (kW)	2023 (%)	2024(%)	2023 (Temp)	2024 (Temp)
17	1.12	1.17	46.1%	48.7%	93.6	93.5
18	0.63	0.63	23.2%	23.4%	92.0	92.0
19	0.37	0.40	13.4%	14.1%	90.6	90.5
20	0.27	0.37	10.2%	13.5%	88.9	88.8
21	0.23	0.30	8.8%	11.4%	85.6	85.5
RA Window Average	**0.52**	**0.57**	**20.4%**	**22.2%**	**90.1**	**90.1**

Table 20 shows the same comparison for SCE 1-in-10 weather. The PY2024 average customer impacts during the RA window are higher than the PY2023 impacts on an absolute and percentage basis. We calculate the percent reductions by dividing the average RA Window kW reduction by the average RA Window Reference Load.

Table 20: Comparison of PY2023 and PY2024 Average Customer Impacts: 2025 August System Worst Day, SCE 1-in-10 Weather

Hour Ending	2023 (kW)	2024 (kW)	2023 (%)	2024(%)	2023 (Temp)	2024 (Temp)
17	1.21	1.27	43.2%	45.7%	95.8	96.0
18	0.69	0.69	22.5%	22.6%	94.7	94.8
19	0.41	0.45	13.2%	14.2%	93.0	93.1
20	0.29	0.39	9.9%	13.1%	90.1	90.2
21	0.25	0.33	8.9%	11.6%	87.2	87.2
RA Window Average	**0.57**	**0.63**	**19.5%**	**21.4%**	**92.2**	**92.2**

Table 21 and Table 22 show the same comparison for CAISO 1-in-2 and CAISO 1-in-10 weather conditions on an August system worst day in 2025. Absolute and percentage impacts in PY2024 are higher than those in PY 2023.

Table 21: Comparison of PY2023 and PY2024 Average Customer Impacts: 2024 August System Worst Day, CAISO 1-in-2 Weather

Hour Ending	2023 (kW)	2024 (kW)	2023 (%)	2024(%)	2023 (Temp)	2024 (Temp)
17	1.07	1.12	48.4%	51.1%	92.2	92.2
18	0.59	0.60	23.5%	23.8%	90.2	90.2
19	0.34	0.35	12.9%	13.3%	88.1	88.1
20	0.23	0.30	9.2%	12.0%	85.8	85.7
21	0.18	0.23	7.6%	9.7%	82.4	82.3
RA Window Average	**0.48**	**0.52**	**20.3%**	**22.0%**	**87.7**	**87.7**

Table 22: Comparison of PY2023 and PY2024 Average Customer Impacts: 2024 August System Worst Day, CAISO 1-in-10 Weather

Hour Ending	2023 (kW)	2024 (kW)	2023 (%)	2024(%)	2023 (Temp)	2024 (Temp)
17	1.21	1.28	44.2%	47.0%	96.0	96.2
18	0.68	0.69	22.7%	22.8%	94.4	94.6
19	0.40	0.44	13.1%	14.1%	92.4	92.4
20	0.28	0.37	9.6%	12.6%	89.2	89.2
21	0.23	0.31	8.5%	10.9%	86.1	86.0
RA Window Average	**0.56**	**0.62**	**19.6%**	**21.5%**	**91.6**	**91.7**

The comparisons shown in Table 19 through Table 22 show a trend of improving impacts under each set of conditions for PY2024 when compared to PY2023. This is partially due to continuing strong performance relative to outdoor temperatures for the SEP program in PY2024. Another contributing factor for stronger impacts in PY2024, that is connected to the trend impact estimates, is regression weights. In PY2024, the ex-ante model used to predict future impacts weighs the more recent event impacts more heavily. We believe that more recent years of ex-post impacts should be weighed more heavily when estimating future impacts. This means that the recent years, which have generally strong performance, are more important in the forecasts than past years.

Aggregate Impacts

In addition to the variation in average participant impacts discussed in the prior section, the estimated number of SEP enrollments affects aggregate impact estimates. As discussed in Section 5.1, the PY2024 enrollment forecast is greater than what was predicted in PY 2023. Enrollment is expected to continue to grow over the next eleven years at a steady rate. In this section, we compare the PY2024 ex-ante impacts to the official filed PY2023 ex-ante numbers.

For a 2025 typical event day, the PY2023 ex-ante impacts assumed 82,818 participants. For comparison, the PY2024 ex-ante impacts assume 87,252 participants – an increase of 5.35%. In past years, forecasts were typically much further apart, differing by more than 30% between some years. The differences in the two forecasts increase over time.

Table 23 compares the PY2023 and PY2024 aggregate ex-ante load reduction estimates for forecast year 2025 on a typical event day using SCE peaking conditions. The 2024 average estimated performance across the five-hour RA window is quite a bit higher under both sets of weather conditions. The difference is due to the difference in forecasted enrollment, and increased per-customer impacts

Table 23: Comparison of 2025 Aggregate Typical Event Day Ex-ante Impacts (MW): PY2023 vs. PY2024 with SCE Weather

Hour Ending	SCE 1-in-2		SCE 1-in-10	
	PY2023	PY2024	PY2023	PY2024
17	85.5	101.4	106.1	126.3
18	47.9	55.0	60.9	68.9
19	28.8	34.8	37.2	47.0
20	20.6	31.3	26.4	41.0
21	17.2	25.7	22.8	35.1
RA Window Average	**40.0**	**49.6**	**50.7**	**63.7**

Table 24 presents the same comparison using CAISO peaking conditions. Impacts are once again much higher from year to year, with the PY2024 numbers being the higher ones.

Table 24: Comparison of 2025 Aggregate Typical Event Day Ex-ante Impacts (MW): PY2023 vs. PY2024 with CAISO Weather

Hour Ending	CAISO 1-in-2		CAISO 1-in-10	
	PY2023	PY2024	PY2023	PY2024
17	80.8	95.7	93.8	111.6
18	44.8	51.7	53.0	60.6
19	25.4	30.0	31.9	39.4
20	16.3	24.5	22.2	34.1
21	12.9	18.8	18.8	28.5
RA Window Average	**36.0**	**44.2**	**43.9**	**54.8**

5.5 EX-POST TO EX-ANTE COMPARISON

Weather conditions during the average PY2024 event day were cooler than SCE 1-in-2 ex-ante weather conditions for the typical event day. Figure 30 comes directly from the MS Excel ex-post reporting template and shows the average SEP 6pm to 8pm event from PY2024. Figure 31 shows the average customer ex-ante impacts for SCE 1-in-2 weather conditions for the typical event day. It should be noted in the comparisons of the following figures that, the average event in 2024 was in the timeframe 6pm-8pm and ex-ante is predicted in the window 4pm-9pm.

Figure 30: PY2024 Ex-Post Average Event Day 6pm-8pm

Southern California Edison

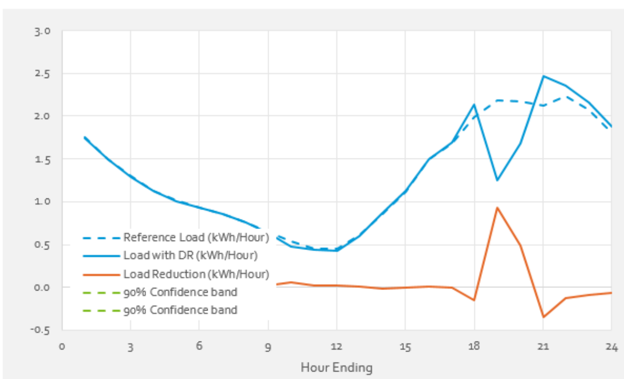
2024 Ex Post Load Impacts - SEP Program

Table 1: Menu options

Type of Result	Per Customer
Category	All
Segment	All Customers
Date	Average Event Day
Hour Ending View	HE (Prevailing Time)

Table 2: Event day information

Total sites	78,771
Daily Max Temp	88.1
Average Impact - kW	0.71
Average Impact - %	32.6%
Full Hours Only - Average Impact - kW	0.71
Full Hours Only - Average Impact - %	32.6%



Hour Ending	Reference Load (kWh/Hour)	Load with DR (kWh/Hour)	Load Reduction (kWh/Hour)	% Load Reduction	Avg Temp (°F, Site-Weighted)
1	1.76	1.74	0.02	1%	75.71
2	1.50	1.49	0.00	0%	74.56
3	1.29	1.29	0.00	0%	73.73
4	1.13	1.13	0.00	0%	72.56
5	1.02	1.01	0.01	1%	71.82
6	0.94	0.93	0.00	0%	71.19
7	0.86	0.86	0.00	0%	70.72
8	0.76	0.76	0.01	1%	70.77
9	0.65	0.63	0.02	3%	72.23
10	0.53	0.48	0.05	10%	74.74
11	0.46	0.44	0.02	4%	77.56
12	0.45	0.43	0.03	6%	80.30
13	0.61	0.60	0.01	2%	82.80
14	0.85	0.87	-0.02	-2%	84.89
15	1.12	1.12	0.00	0%	86.53
16	1.50	1.49	0.01	0%	87.78
17	1.68	1.69	-0.01	0%	88.13
18	1.99	2.13	-0.15	-7%	86.83
19	2.18	1.25	0.93	43%	85.35
20	2.17	1.68	0.49	22%	83.16
21	2.12	2.47	-0.35	-16%	79.98
22	2.23	2.36	-0.12	-6%	76.86
23	2.07	2.16	-0.08	-4%	75.09
24	1.81	1.87	-0.06	-4%	73.81
By Period:	Reference Load (kWh/Hour)	Load with DR (kWh/Hour)	Energy Savings (kWh/Hour)	% Change	Average Temperature (°F)
Average Event Hour	2.17	1.47	0.71	32.6%	84.3
Daily	1.32	1.29	0.03	2.5%	78.2

The "Average Impact (kW)" characteristic in Figure 31 is lower than the ex-post impacts, because our "Average Event Day" in 2024 was only a two-hour window. If you compare the averages of the first two hours of both figures, impacts are 0.90 kW from ex-ante and 0.71 for ex-post. This higher impacts for the ex-ante predictions here would be due to the higher expected temperatures for the typical event day when compared with the average 2024 event.

Figure 31: Ex-Ante Typical Event Day under SCE 1-in-2 Conditions: 4pm to 9pm

Southern California Edison

PY2024 Ex Ante - SEP

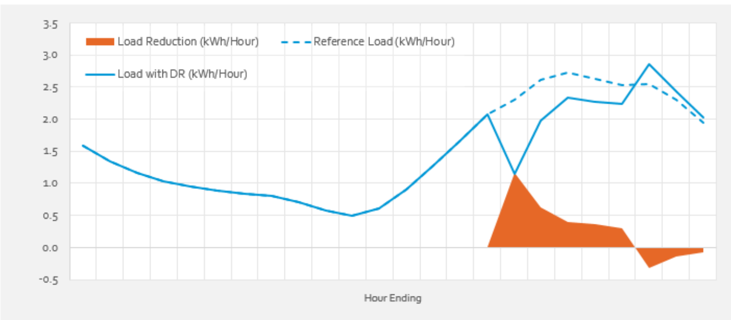
Demand Side Analytics — DATA DRIVEN RESEARCH AND INSIGHTS | SOUTHERN CALIFORNIA EDISON — Energy for What's Ahead®

Table 1: Menu options

Type of result	Per Customer
Category	All
Segment	All Customers
Weather Data	SCE
Weather Year	1-in-2
Day Type	Typical Event Day
Forecast Year	2025
Portfolio Level	Portfolio
Hour Ending View	HE (Prevailing Time)

Table 2: Event day information

Event start	4:00 PM
Event end	9:00 PM
Total sites	87,252
Event window temperature (F)	89.9
Event window load reduction (kWh/Hour)	0.57
% Load reduction (Event window)	22.2%
Redaction Information	Public



Hour Ending	Reference Load (kWh/Hour)	Load with DR (kWh/Hour)	Load Reduction (kWh/Hour)	% Load Reduction	Avg Temp (°F, Site-Weighted)
1	1.59	1.59	0.00	0.0%	76.00
2	1.35	1.35	0.00	0.0%	74.71
3	1.17	1.17	0.00	0.0%	73.60
4	1.04	1.04	0.00	0.0%	72.52
5	0.95	0.95	0.00	0.0%	71.76
6	0.88	0.88	0.00	0.0%	71.07
7	0.84	0.84	0.00	0.0%	70.94
8	0.80	0.80	0.00	0.0%	72.13
9	0.71	0.71	0.00	0.0%	75.36
10	0.57	0.57	0.00	0.0%	80.13
11	0.49	0.49	0.00	0.0%	84.96
12	0.61	0.61	0.00	0.0%	88.82
13	0.90	0.90	0.00	0.0%	91.58
14	1.27	1.27	0.00	0.0%	93.49
15	1.66	1.66	0.00	0.0%	94.50
16	2.08	2.08	0.00	0.0%	94.27
17	2.30	1.14	1.16	50.5%	93.27
18	2.60	1.97	0.63	24.2%	91.82
19	2.73	2.33	0.40	14.6%	90.49
20	2.63	2.28	0.36	13.6%	88.47
21	2.54	2.24	0.30	11.6%	85.31
22	2.54	2.86	-0.32	-12.7%	82.24
23	2.30	2.43	-0.13	-5.8%	79.93
24	1.95	2.03	-0.08	-4.1%	78.05
By Period:	Reference Load (kWh/Hour)	Load with DR (kWh/Hour)	Energy Savings (kWh/Hour)	% Change	Average Temperature (°F)
Average Event Hour	2.56	1.99	0.57	22.2%	89.87
Daily	1.52	1.42	0.10	6.3%	82.31

CAISO 1-in-2 peak conditions are milder than SCE 1-in-2 weather conditions for a typical event day. Figure 32 shows the ex-ante estimates for an average SEP customer on a typical event day in 2024 under CAISO 1-in-2 conditions. The weighted average maximum daily temperature is 92.2.°F and the average impact across the five-hour RA window is 0.51 kW.

Figure 32: Ex-Ante Typical Event Day under CAISO 1-in-2 Conditions: 4pm to 9pm Dispatch

Southern California Edison

PY2024 Ex Ante - SEP

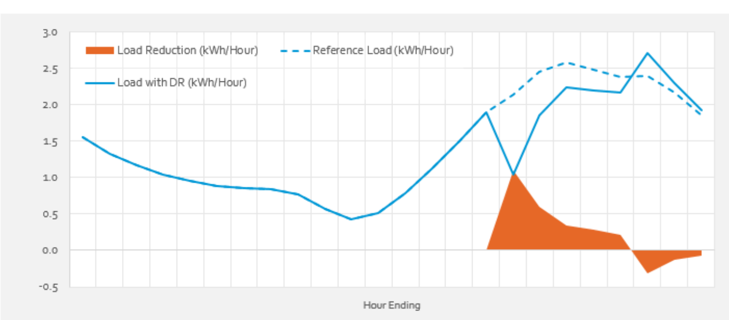
Demand Side Analytics — DATA DRIVEN RESEARCH AND INSIGHTS | SOUTHERN CALIFORNIA EDISON — Energy for What's Ahead®

Table 1: Menu options

Type of result	Per Customer
Category	All
Segment	All Customers
Weather Data	CAISO
Weather Year	1-in-2
Day Type	Typical Event Day
Forecast Year	2025
Portfolio Level	Portfolio
Hour Ending View	HE (Prevailing Time)

Table 2: Event day information

Event start	4:00 PM
Event end	9:00 PM
Total sites	87,252
Event window temperature (F)	87.1
Event window load reduction (kWh/Hour)	0.51
% Load reduction (Event window)	21.0%
Redaction Information	Public



Hour Ending	Reference Load (kWh/Hour)	Load with DR (kWh/Hour)	Load Reduction (kWh/Hour)	% Load Reduction	Avg Temp (°F, Site-Weighted)
1	1.55	1.55	0.00	0.0%	75.31
2	1.33	1.33	0.00	0.0%	74.30
3	1.16	1.16	0.00	0.0%	73.39
4	1.04	1.04	0.00	0.0%	72.60
5	0.95	0.95	0.00	0.0%	72.00
6	0.89	0.89	0.00	0.0%	71.42
7	0.86	0.86	0.00	0.0%	71.30
8	0.84	0.84	0.00	0.0%	72.99
9	0.76	0.76	0.00	0.0%	76.23
10	0.56	0.56	0.00	0.0%	80.22
11	0.43	0.43	0.00	0.0%	84.18
12	0.51	0.51	0.00	0.0%	87.48
13	0.78	0.78	0.00	0.0%	89.78
14	1.13	1.13	0.00	0.0%	91.20
15	1.49	1.49	0.00	0.0%	92.07
16	1.90	1.90	0.00	0.0%	92.20
17	2.14	1.04	1.10	51.4%	91.61
18	2.45	1.85	0.59	24.2%	90.05
19	2.58	2.24	0.34	13.3%	87.76
20	2.48	2.20	0.28	11.3%	84.57
21	2.38	2.17	0.22	9.1%	81.34
22	2.39	2.71	-0.32	-13.4%	79.04
23	2.17	2.30	-0.13	-5.9%	77.41
24	1.85	1.92	-0.07	-3.9%	76.14
By Period:	Reference Load (kWh/Hour)	Load with DR (kWh/Hour)	Energy Savings (kWh/Hour)	% Change	Average Temperature (°F)
Average Event Hour	2.41	1.90	0.51	21.0%	87.06
Daily	1.44	1.36	0.08	5.8%	81.02

Figure 33 shows ex-ante impacts for the average customer under SCE 1-in-10 conditions, which assume a weighted average maximum daily temperature of 101.1°F. The predicted load impact across the five-hour RA window is 0.73 kW and the estimated load impact during the first two hours of dispatch is 1.12 kW. The average post-event load increase estimates are 0.33 kW, 0.14 kW, and 0.09 kW during hours ending 22, 23, and 24.

Figure 33: Ex-ante Typical Event Day under SCE 1-in-10 Conditions: 4pm to 9pm

Southern California Edison

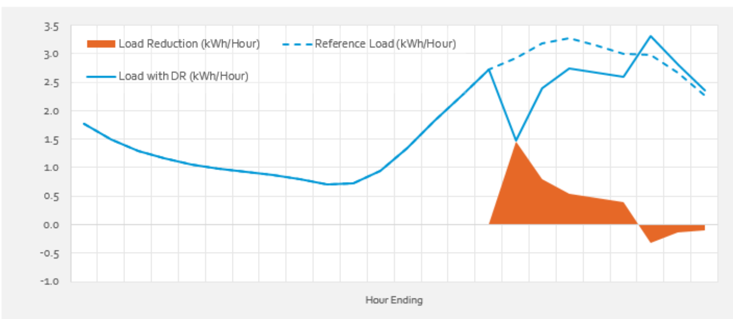
PY2024 Ex Ante - SEP

Table 1: Menu options

Type of result	Per Customer
Category	All
Segment	All Customers
Weather Data	SCE
Weather Year	1-in-10
Day Type	Typical Event Day
Forecast Year	2025
Portfolio Level	Portfolio
Hour Ending View	HE (Prevailing Time)

Table 2: Event day information

Event start	4:00 PM
Event end	9:00 PM
Total sites	87,252
Event window temperature (F)	96.5
Event window load reduction (kWh/Hour)	0.73
% Load reduction (Event window)	23.5%
Redaction Information	Public



Hour Ending	Reference Load (kWh/Hour)	Load with DR (kWh/Hour)	Load Reduction (kWh/Hour)	% Load Reduction	Avg Temp (°F, Site-Weighted)
1	1.78	1.78	0.00	0.0%	79.32
2	1.50	1.50	0.00	0.0%	77.78
3	1.30	1.30	0.00	0.0%	76.54
4	1.16	1.16	0.00	0.0%	75.59
5	1.06	1.06	0.00	0.0%	74.79
6	0.99	0.99	0.00	0.0%	74.19
7	0.92	0.92	0.00	0.0%	73.64
8	0.87	0.87	0.00	0.0%	74.70
9	0.80	0.80	0.00	0.0%	78.61
10	0.71	0.71	0.00	0.0%	84.18
11	0.73	0.73	0.00	0.0%	89.78
12	0.95	0.95	0.00	0.0%	94.05
13	1.36	1.36	0.00	0.0%	97.02
14	1.83	1.83	0.00	0.0%	99.10
15	2.27	2.27	0.00	0.0%	100.64
16	2.72	2.72	0.00	0.0%	101.05
17	2.92	1.47	1.45	49.6%	100.61
18	3.17	2.38	0.79	24.9%	99.47
19	3.28	2.74	0.54	16.4%	97.48
20	3.14	2.67	0.47	15.0%	94.05
21	3.00	2.60	0.40	13.4%	90.65
22	2.99	3.31	-0.33	-11.0%	87.42
23	2.67	2.82	-0.14	-5.4%	84.49
24	2.26	2.36	-0.09	-4.2%	82.43
By Period:	Reference Load (kWh/Hour)	Load with DR (kWh/Hour)	Energy Savings (kWh/Hour)	% Change	Average Temperature (°F)
Average Event Hour	3.10	2.37	0.73	23.5%	96.45
Daily	1.85	1.72	0.13	6.9%	86.98

Aggregate ex-ante impacts for 2025 are larger than the PY2024 ex-post impacts because of the projected increase in enrollment. The average number of households dispatched during the average PY2024 event from 6pm to 8pm was 78,771. The enrollment forecast for a 1-in-2 September peak day in 2025 is approximately 11% higher at 87,774. Table 25 compares the aggregate impacts for the most common PY2024 event profile to the October monthly worst day ex-ante estimates for 2025. Because the PY2024 events were shorter than the ex-ante events, we show the average impact during the first hour of dispatch.

Table 25: Comparison of PY2024 Ex-post Impacts to 2025 Ex-Ante October Worst Day Impacts

Event Date	Max Daily Temp (F)	Hour 1 Temp (F)	Participants	Hour 1 kW	Hour 1 MW
PY2024 Average Event Day (6pm-8pm)	88.1	85.4	78,771	0.93	73.4
2025 October Worst Day SCE 1-in-2 (4pm-9pm)	91.1	90.8	88,296	1.07	94.1
2025 October Worst Day SCE 1-in-10 (4pm-9pm)	97.9	96.8	88,296	1.30	114.6
2025 October r Worst Day CAISO 1-in-2 (4pm-9pm)	91.0	90.5	88,296	1.05	93.1
2025 October Worst Day CAISO 1-in-10 (4pm-9pm)	98.9	98.3	88,296	1.36	112.0

6 DISCUSSION

Based on the PY2024 ex-post and ex-ante evaluations, DSA highlights the following considerations for program design and future load impact evaluations.

- SEP program enrollment increased by ~7,000 customers in the offseason between PY2023 and PY2024 and a further ~3,000 customers during the PY2024 season. This growth trend is similar to the growth seen in the previous year. Continued marketing efforts played a large part in the healthy enrollments this year as well as previous years. The increase is in line with predictions made by the SEP program team in PY2023. Precise enrollment projections increase the accuracy of aggregate ex-ante forecasts as the enrollment forecasts play a large role in predicting future program capabilities.

- The most important predictor of SEP load impact is not time of day or weather, but the position of an hour within an event. Impacts are largest during the first event hour and decline sharply in each subsequent hour. Consequently, shorter events show larger average load impacts than longer events. Over the past several years, the SEP program has tended to call shorter events leading to higher average full hour impacts. While shorter events are likely preferred by customers, calling only short duration events poses a challenge with estimating ex-ante impacts. In PY2024 ex-ante, 2021-2024 event impacts were used for predicting future program impacts. Over that duration of time only single event was called with four full hours and no events with five hours. This lack of data on how program participants perform over long events means that predicting program performance over a hypothetical five hour event requires using performance from other event hours to predict hours four and five of control. DSA recommends a focus on calling longer events and, if possible, during hotter outdoor temperatures to ensure that ex-ante predictions of program impacts are as accurate as possible.

- [redacted]

- In PY2024 homes with two thermostats showed approximately 37% larger load reductions during events than homes with a single thermostat. Those with three or more thermostats had impacts about 17% higher than those with two program thermostats. These incremental increases in the estimated program impacts based on the number of thermostats enrolled are similar to those seen in previous years. Currently customer bill credits do not consider the number of thermostats controlled.

  - ✓ SCE may want to consider larger bill credits for homes with multiple program thermostats. This number may be scaled with the number of thermostats that the customer brings to the program.

- In PY2024, the event that took place on September 6th was a localized emergency event that was intended for all participants in the Mira Loma A-Bank area. However, only 435 out of intended 3,094 participants were dispatched due to an error in dispatch by SCE's Grid

Control Center. While this event had small aggregate impacts due to the smaller number of customers dispatched, the localized load relief provided to the distribution system on that day was valuable. In future program years, DSA recommends testing these granular geographic dispatch levels to ensure that in future emergency conditions the correct groups of participants can be reliably dispatched. The ability to dispatch program participants at granular geographic levels means that SEP has the potential to play an important part in system reliability in the future.

- PY2024 was a relatively mild summer with no event conditions reaching the level of a 1-in-2 weather year. For ex-ante forecasts relying on a single year's data, particularly a mild year, could lead to inaccurately estimating program performance under extreme weather conditions. Incorporating multiple years of historic event results is essential for building robust estimates of future program performance.

- The PY2024 ex-ante forecasts of impacts are generally higher than the PY2023 per-participant impacts for the same ex-ante weather conditions. We attribute this change to two key factors:

    - ✓ SEP program staff remove customers who opt out or don't perform. This means that, over time, only customers who perform well during events are left in the program, increasing the average per customer impacts from events.

    - ✓ [redacted]