Demand Side Analytics

DATA DRIVEN RESEARCH AND INSIGHTS

REPORT

2021 Smart Energy Program Load Impact Evaluation

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

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Prepared for Southern California Edison

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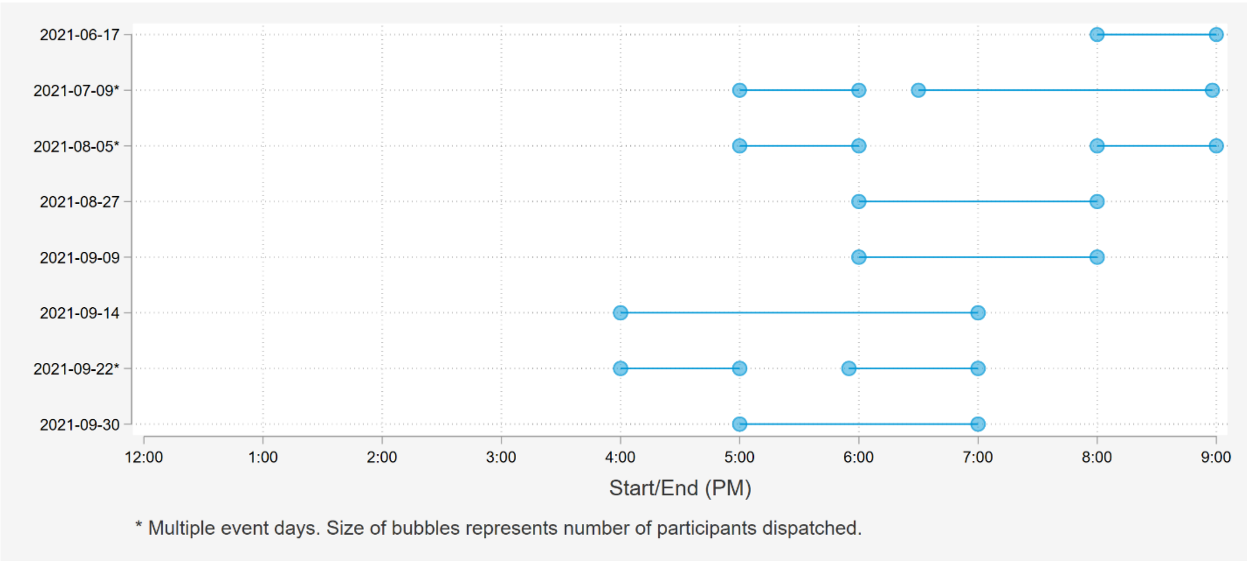
1 EXECUTIVE SUMMARY

This report documents the 2021 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 2021. The primary objectives of this report are to:

- Document the findings of an ex post (after the fact) load impact study for 2021 events
- Provide ex ante (forward looking) estimates of SEP's demand reduction capability over the next eleven years (2022 to 2032) under various weather conditions.

When SCE initiates SEP events, the two participating DR thermostat providers 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. SCE dispatched SEP on eight days during PY2021 between June and September. On three of these days, there were multiple events called, usually in response to need later in the day. In total, there were eleven events with ten being a result of self-scheduling in the day-ahead market and one for reliability purposes. SCE cited both types of dispatch triggers for the 9/9/2021 event. Figure 1 shows the eleven 2021 events along with the start and end time.

Figure 1: SEP 2021 Event Start and End Times (Pacific Daylight)



SEP enrollments decreased between the end of the summer 2020 DR season and the beginning of the summer 2021 season for two primary reasons.

- SCE removed participants who were not available for dispatch because they did not agree to updated terms and conditions with one of the thermostat manufacturers.

- New enrollments during this time were offset by other types of customer attrition such as service turn offs and CCA migrations.

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, 2020, and 2021 events were generally called later in the day compared to previous years when the program was dispatched based on other triggers, such as peak demand forecast. In 2017 and 2018, SCE generally called SEP events from 2pm to 6pm. During 2019, 2020, and 2021, SEP events have occurred primarily between 4pm and 9pm, which corresponds to the Resource Adequacy (RA) window established by the CAISO.

1.1 SUMMARY OF EX POST LOAD IMPACTS

There were eleven distinct SEP events in 2021 between June and September. SEP events may be dispatched by Sub-Load Aggregation Point (SubLAP), but are most often called for the entire SCE territory. In 2021, all events were called territory-wide and each SubLAP started and ended dispatch at the same time.

Weather conditions were milder in 2021 than 2020 when California faced extreme heat waves and capacity shortfalls. In 2020 SCE called SEP events on six consecutive days starting on 8/13/2020 as well as four weekend events. In 2021, there were no back-to-back event days and no weekend events.

Demand Side Analytics 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 2021 events and an "Average Event Day" profile.

Table 1: 2021 Ex Post Event Impacts

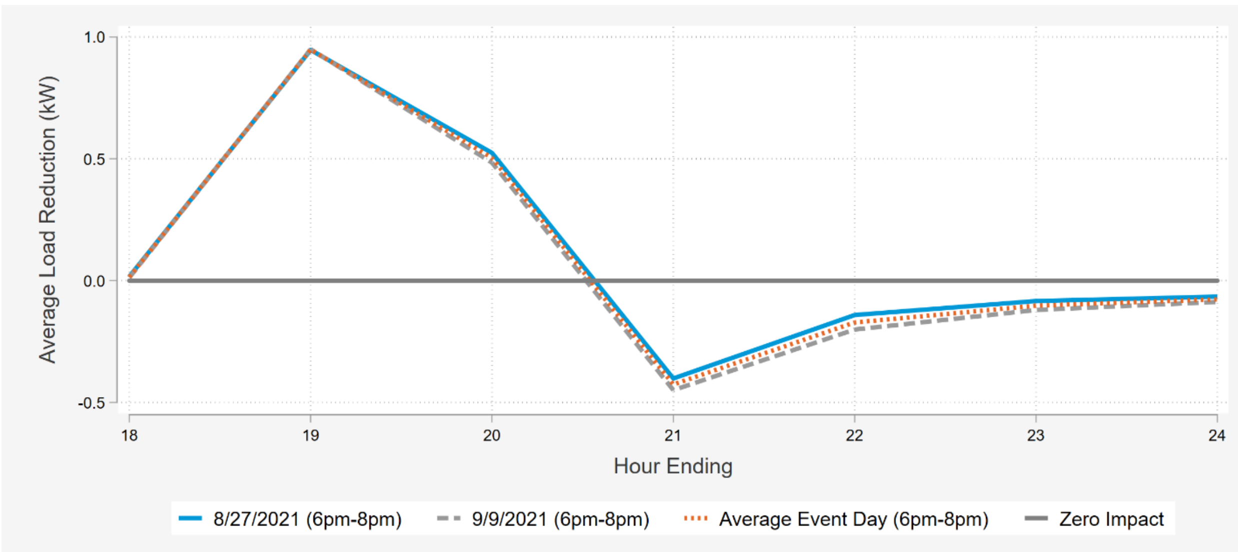
Event Date	Dispatch Region	Participants	Average Event Temp (F)	Daily Max Temp (F)	Average Full Hour Impact (kW Reduction per Participant)	Average Aggregate Full Hour Impact (MW Reduction)
6/17/2021 (8pm-9pm)	Territory Wide	43,847	77.9	87.7	0.63	27.6
*7/9/2021 (5pm-6pm & 6:30pm-8:58pm)	Territory Wide	45,957	87.2	91.7	0.86	39.7
8/5/2021 (5pm-6pm & 8pm-9pm)	Territory Wide	47,389	85.2	88.9	0.78	36.9
8/27/2021 (6pm-8pm)	Territory Wide	47,185	89.0	94.2	0.74	34.7
**9/9/2021 (6pm-8pm)	Territory Wide	49,743	87.2	93.2	0.72	35.7
9/14/2021 (4pm-7pm)	Territory Wide	49,825	83.3	85.6	0.43	21.5
*9/22/2021 (4pm-5pm & 5:55pm-7pm)	Territory Wide	50,160	89.5	93.3	0.84	42.4
9/30/2021 (5pm-7pm)	Territory Wide	49,929	86.7	87.2	0.33	16.6
Average Event Day (6pm-8pm)	Territory Wide	48,498	88.0	93.7	0.73	35.2

* Only full hours are included in impacts

** 2021 System Peak Day

DSA defines an "Average Event Day" for 2021 as the weighted average of the two territory-wide events that began at 6pm and ended at 8pm (two-hour duration). Figure 2 shows the average along with its contributing dates. The impacts are consistent across events. By far the most important predictor of 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 0.95 kW per household, while the second hour had a reduction of 0.50 kW per household. 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 average event impact with each additional hour of dispatch.

Figure 2: Hourly Load Reductions for 2021 Average Event Day



The "Average Event Day" had an average per customer hourly reduction of 0.73 kW and aggregate hourly reduction of 35.21 MW. The system peak day in 2021 was September 9thth. The two-hour event on that day had an average per customer hourly reduction of 0.72 kW and an average aggregate hourly savings of 35.67 MW.

1.2 SUMMARY OF EX ANTE LOAD IMPACTS

Historically, ex ante load impact evaluations assume the same average customer impact for each year of the forecast. In 2020 due to the COVID pandemic, we adjusted the methodology to include a COVID effect and gradually withdrew the COVID effect over the forecast horizon. For the 2021 load impact evaluations, the IOUs and Evaluation Contractors decided to treat 2021 as the "new normal" in regards to residential energy usage and load impacts. This means that the declining effect of COVID is no longer present in our models. We also removed March 2020 – December 2020 data from the models used to estimate per-household reference loads.

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, beginning at 4pm and lasting until 9pm. This event profile prevents any post-event snapback from occurring during the RA window. However, the estimated load reduction capability of SEP during the later hours of the RA window is lower than the initial event hours. Figure 3 illustrates this trend for monthly system peak days using SCE and CAISO 1-in-2 weather conditions. The impacts during hour 20 are only slightly larger than the impacts in hour 21, shown in purple and green respectively in Figure 3. 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 peak days, we estimate non-zero SEP capability in March through November for both SCE and CAISO weather conditions.

Figure 3: Average Customer Ex Ante Impacts on 2022 Monthly System Peak Days: 1-in-2 Conditions

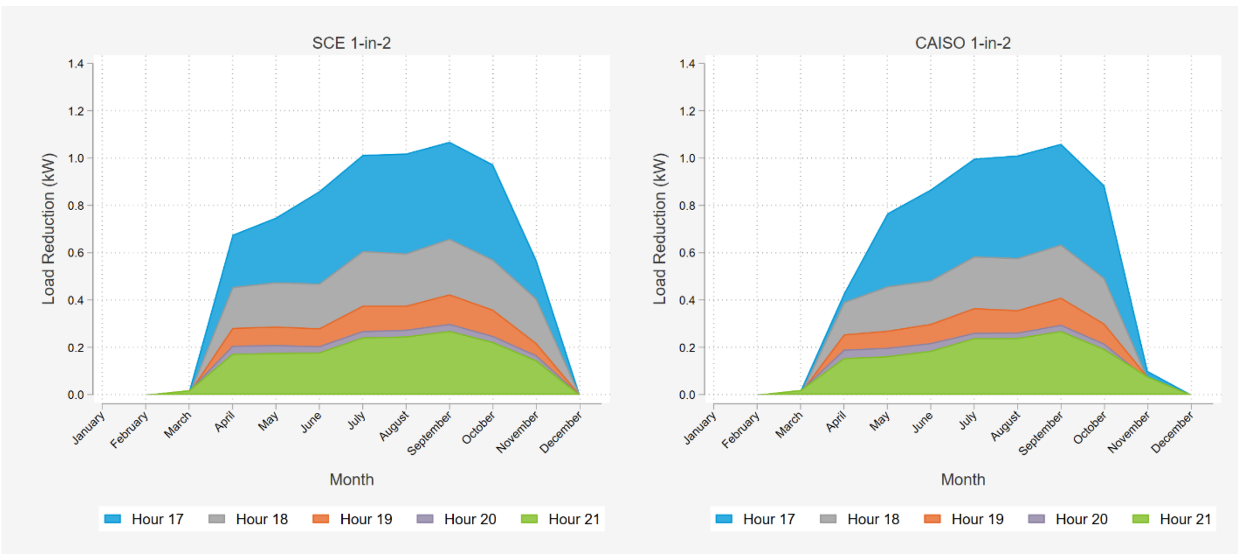
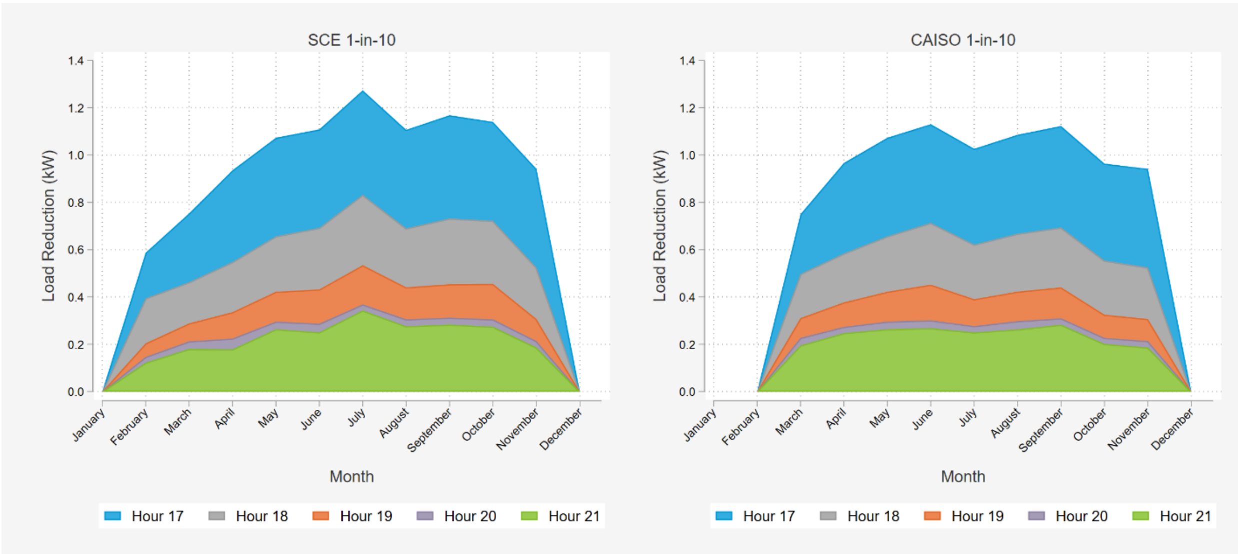


Figure 4 shows the same set of results for 1-in-10 weather conditions, which are hotter than 1-in-2 conditions.

Figure 4: Average Customer Ex Ante Impacts on 2022 Monthly System Peak Days: 1-in-10 Conditions



The weighted average maximum daily temperature on a July system peak day using SCE 1-in-10 weather is 104.35°F and the estimated average load impact per customer is 1.27 kW during the first hour of dispatch. For comparison, the weighted average maximum daily temperature for a July system peak day using CAISO 1-in-10 weather is 94.05°F and the estimated load impact is 1.03 kW during the first hour of dispatch.

- **For SCE 1-in-10 weather conditions**: SEP is projected to have load impact capability in all calendar months except January and December.
- **For CAISO 1-in-10 weather conditions**: SEP is projected to have load impact capability on all monthly system peak days except January, February, and December.

Table 2 shows the SEP aggregate ex ante load impacts for an August Monthly Peak Day in 2022. Current forecasts expect enrollment to increase to 63,114 customers by that time. The estimated load impact of SEP in 2022 ranges from 63.8 MW to 69.8 MW during hour ending 17. Estimated impacts decline across the RA window and range from 15.1 MW to 17.4 MW in hour ending 21. Average impacts for the five-hour RA window range from 30.9 MW to 35.6 MW.

Table 2: SEP Aggregate Ex Ante Impacts (MW) During RA Window: 2022 August Monthly Peak Day

Hour Ending	SCE 1-in-2	CAISO 1-in-2	SCE 1-in-10	CAISO 1-in-10
17	64.3	63.8	69.8	68.5
18	37.7	36.5	43.6	42.1
19	23.7	22.5	27.8	26.7
20	17.3	16.6	19.3	18.8
21	15.6	15.1	17.4	16.6
RA Window	**31.7**	**30.9**	**35.6**	**34.5**

SCE forecasts that SEP enrollments will exceed 161,000 households by 2032. 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 81.2 MW for SCE 1-in-2 weather conditions on an August system peak day and 91.0 MW for SCE 1-in-10 conditions on an August system peak day in 2032. Using CAISO peaking conditions, we estimate an aggregate impact of 79.1 MW for 1-in-2 conditions and 88.4 MW for 1-in-10 conditions on an August system peak day.

1.3 KEY FINDINGS AND RECOMMENDATIONS

Based on the findings of the PY2021 load impact evaluation, Demand Side Analytics makes the following program and evaluation recommendations for SEP.

- [redacted]

- DSA estimated 2021 ex post impacts using both net and delivered loads to quantify the implications of settlement methods limited to delivered loads. During the first hour of the RA window (4-5pm) analysis of delivered loads reduces the MW performance of the program by 10% overall and 31% for NEM customers.

    - ✓ Later in the evening, once solar production fades, the delivered load bias goes away and impact estimates using net and delivered loads converge.

    - ✓ CAISO's use of delivered loads in day-ahead market settlement calculations negatively affects SEP's valuation. Reduced valuation might discourage SCE from enrolling NEM customers into SEP or offering it for economic dispatch before 6-7pm in the evening, when NEM customers are exporting to the grid.

- Since PY2021 was such a mild weather year, the value of using multiple years of data was vital for predicting the capability of the DR program under more extreme weather conditions. We recommend continuing the usage of several years of events in order to get the most accurate estimates of ex ante capabilities possible.

- 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.

- DSA added a new ex post reporting category for 2021 that segments participant households by the number of Wi-Fi thermostats under program control. Homes with two thermostats showed approximately 50% larger load reductions during 2021 events than homes with a single thermostat. Currently customer bill credits do not take into account the number of thermostats controlled.

    - ✓ Based on the 2021 ex post evaluation results, SCE may want to consider larger bill credits for homes with multiple thermostats. However, we do not recommend giving homes with two thermostats twice the bill credit because they do not provide twice the load reduction, on average.

- Rollout of default TOU pricing for residential customers is underway in SCE territory. As shown in Table 4, nearly 32% of SEP participants faced time-varying pricing during PY2021. Since a majority of customers will be on TOU rates by summer 2022, it will be important to continue to monitor the effect of TOU on SEP participant reference loads and load impacts.

- The COVID-19 pandemic affected all aspects of life in 2020. With the availability of vaccines in early 2021, California gradually re-opened and residential energy consumption patterns stabilized. In the 2020 load impact evaluation, we used a glide path that assumed the effects of COVID would slowly dissipate over several years. For this evaluation, we elected to model 2021 as the "new normal" and remove the COVID glide path from our ex ante analysis. When estimating reference loads, we did not include data from March 2020 – December 2020.

- In PY2021, three of the eight event days were double event days, meaning that SCE dispatched an event, that event ended, and then SCE called another event later in the day. Two of those double events also either began or ended mid-hour. The double events and irregular start/end times resulted in evaluation challenges and reporting modifications. Partial event hours, at either the start or end of an event, result in diluted impacts for those hours. As a result, when reporting impacts in this report, we only report on full event hours. To the extent that SCE has control over timing, events should start and end on the hour to obtain the most accurate impact estimates.

- SCE received approval to use pre-cooling during economic dispatch for summer 2022 events. Pre-cooling may reduce participant opt-outs and deliver more sustained load impacts during the later hours of events. It will be important to consider the time-varying prices faced by participants when initiating pre-cooling. We recommend SCE and its vendors pre-cool during off-peak hours, where possible. For participants on the TOU 5-8pm plan, pre-cooling from 4pm-

5pm would be ideal. For participants on the TOU4-9pm plan, pre-cooling from 3-4pm would be ideal.

2 PROGRAM DESCRIPTION

SCE's Smart Energy Program (SEP) 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 recently approved by the California Public Utilities Commission (CPUC) and can only be reached for emergency purposes.[1] 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 the Summer Discount Plan (SDP) program is prohibited.

SEP has evolved considerably in recent years 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

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

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.

In 2021, SEP economic dispatches (Trigger C) were self-scheduled in the day-ahead market by SCE. SEP events were dispatched on a total of eight days in 2021 between June and September. Table 3 lists the event dates and dispatch reason. Each event day had an event that was self-scheduled day-ahead market , but one double event day also had a later reliability event called. The event on the system peak day, 9/9/2021, highlighted in green in Table 3, was also a "Measurement & Evaluation" event.

Table 3: 2021 SEP Event Days and Dispatch Reason

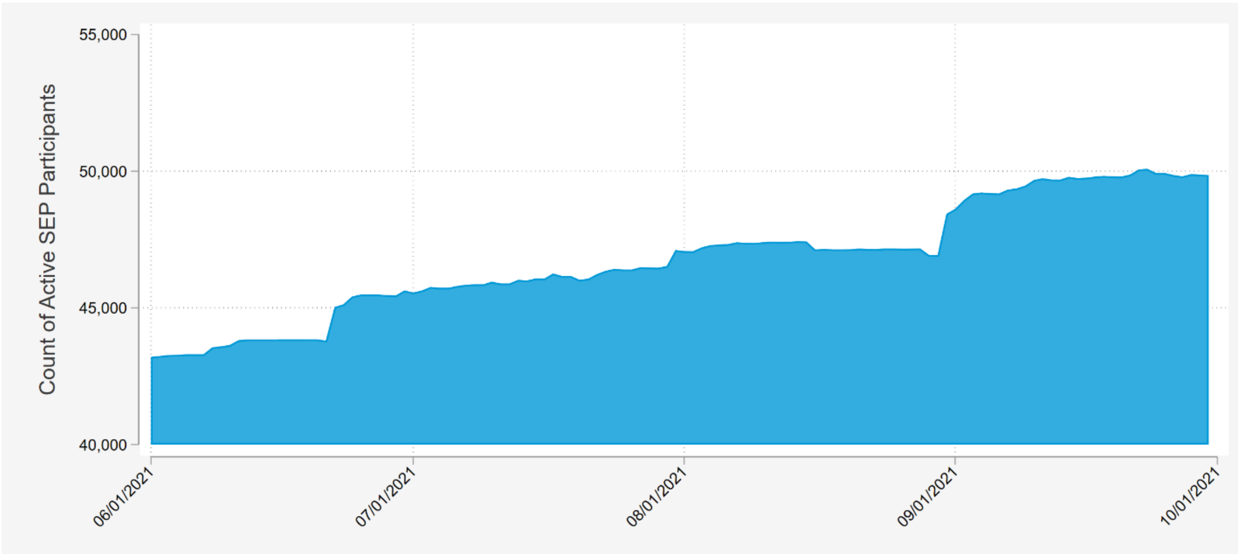
Date	Dispatch Trigger	SubLAPs Dispatched
6/17/2021	Self-Scheduled DAM	Territory Wide
7/9/2021*	Self-Scheduled DAM, Reliability	Territory Wide
8/5/2021*	Self-Scheduled DAM, Self-Scheduled DAM	Territory Wide
8/27/2021	Self-Scheduled DAM	Territory Wide
9/9/2021	Measurement & Evaluation, Self-Scheduled DAM	Territory Wide
9/14/2021	Self-Scheduled DAM	Territory Wide
9/22/2021*	Self-Scheduled DAM, Self-Scheduled DAM	Territory Wide
9/30/2021	Self-Scheduled DAM	Territory Wide
10/4/2021	Self-Scheduled DAM	Territory Wide

* Double event day

There were approximately 49,929 active participants in SEP at the end of the summer 2021 event season. Despite active marketing and recruitment efforts, the end of summer 2021 participant count is lower than the count from the 2019 (53,048) and 2020 (50,809) event seasons.

Figure 5 shows the cumulative enrollment of households over the summer 2021 DR season. Historically, enrollments have been highest during the summer months when bill credits are available and SCE's marketing efforts are most active. The enrollment spikes in June and late August correspond to vendors enrolling large sets of customers to the program all at one time.

Figure 5: Summer 2021 Enrollment Trend



There was also churn among the SEP participant population during the PY2021 event season. Approximately 3,200 households that were active during the first PY2021 event on June 17, 2021 left the program prior to the last event on September 30, 2021. Conversely, approximately 9,400 households were active during the final PY2021 event that had not enrolled on June 17, 2021 when SCE called its first SEP event of the season.

There were approximately 50,000 active participants in SEP at the conclusion of PY2021. Table 4 shows the distribution of active participants across various segmentation variables of interest.

- The LCA variable indicates the load capacity area. Almost 85% of SEP participants are located in the LA Basin LCA.
- SEP participants also enrolled in the CARE or FERA programs are indicated by the 'Income Qualified' segment
- Approximately 22% of SEP participants have net energy metering (NEM) of rooftop solar arrays. The NEM percentage is about the same as in 2020. In order to understand the impact that NEM customers have on load shed, we produced separate ex post load impacts using both net and delivered loads in 2021. Section 4.4 compares the results. As noted in the discussion of participant matching in Section 3.1, we match NEM participants with NEM non-participants for analysis.
- The 'Size' variable is based on customer's 2021 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 1.88 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 2021. 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 87% of participants have a single smart thermostat enrolled in the program.

- [redacted]

- Region 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	Percent
	All Customers	49,929	100.0%
LCA	Big Creek/Ventura	5,793	11.6%
	LA Basin	42,750	85.6%
	Outside	1,386	2.8%
Low Income	CARE	10,608	21.2%
	Non-CARE	39,321	78.8%
NEM	NEM Customer	11,145	22.3%
	Non-NEM Customer	38,784	77.7%
Size	Less than 1.88 kW during RA window	24,964	50.0%
	Greater than 1.88 kW during RA window	24,965	50.0%
SubLAP	SCEC	20,370	40.8%
	SCEN	5,037	10.1%
	SCEW	22,381	44.8%
	SCHD	1,338	2.7%
	SCLD	47	0.1%
	SCNW	755	1.5%
Tariff	Dynamic	15,990	32.0%
	Flat	33,939	68.0%
Thermostats	1 Thermostat	43,584	87.3%
	2 Thermostats	5,848	11.7%
	3+ Thermostats	497	1.0%
[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]
Zone	South Orange County	10,678	21.4%
	Remainder of System	20,882	41.8%
	South of Lugo	18,368	36.8%

The SEP participant population is located across SCE service territory and experiences a wide range of weather conditions. At the conclusion of the PY2021 event season, there were active participants in nine of the sixteen California climate zones. For both the ex post and ex ante analysis we map each participant to one of 23 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, 2018 to September 30, 2021.

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.

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

Weather Station	SEP Enrollments	CDD60	HDD60
173	14,691	2,324	317
121	7,662	2,508	1,203
122	7,293	3,684	487
172	3,543	1,696	523
171	2,277	2,082	404
132	2,166	2,525	900
112	2,164	2,574	347
111	2,035	2,460	678
51	1,990	3,323	1,310
181	1,501	5,754	388
194	995	2,935	1,856
161	950	1,619	320
193	696	3,397	1,599
123	382	1,395	946
151	381	928	793
131	283	1,162	3,456
191	238	4,222	1,572
195	188	3,200	1,804
113	85	1,131	773
192	79	3,928	1,423
101	57	478	5,982
182	48	5,652	536
141	38	2,199	2,992

3 EVALUATION METHODOLOGY

3.1 EX POST METHODS

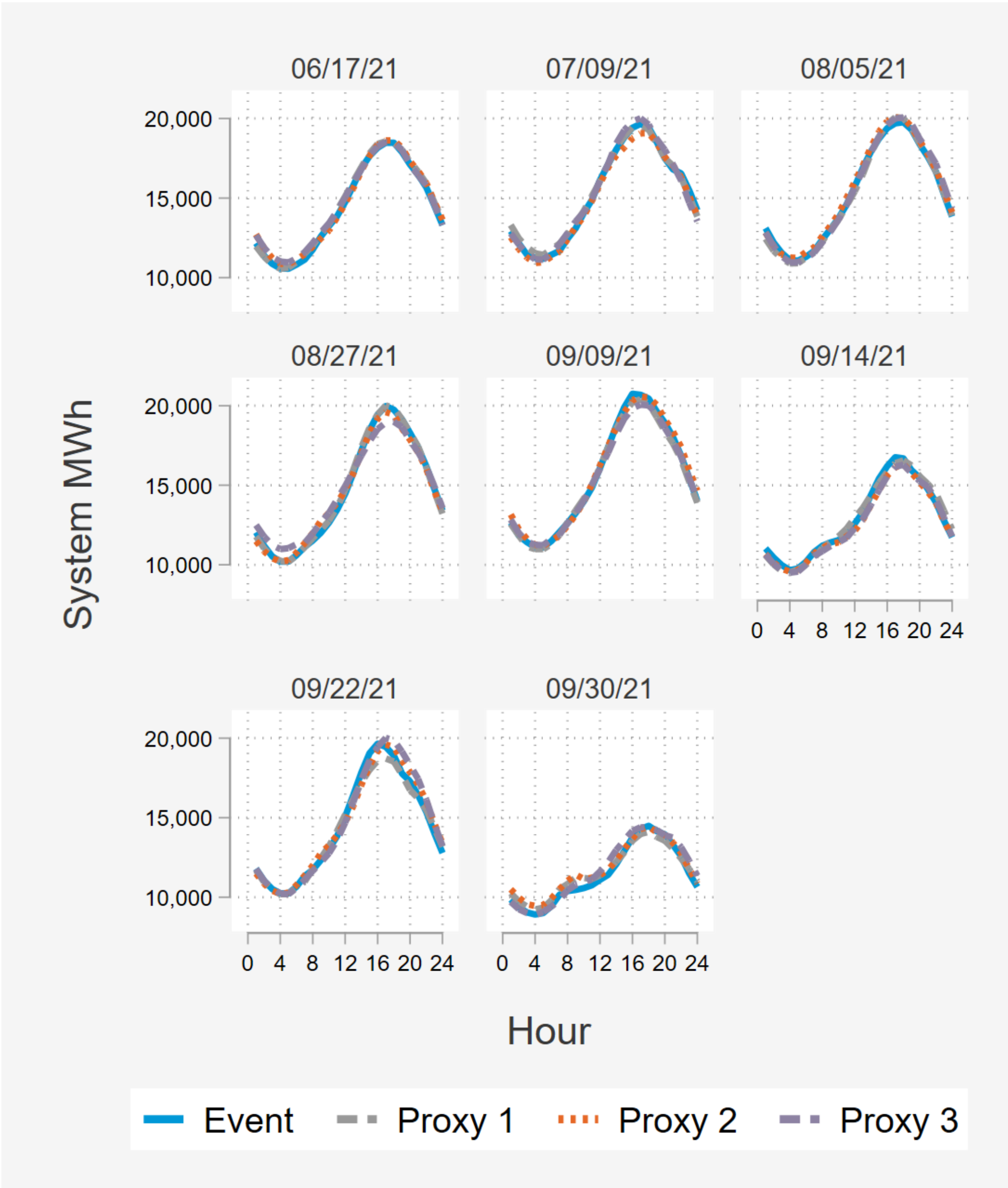
OVERVIEW OF EVALUATION METHOD SELECTED

DSA utilized a matched control group and panel regression analysis for the 2021 SEP load impact evaluation. We select the matched control group customers from a stratified random sample, which ensures that large and/or unique participants are still likely to find an appropriate match. We select the control group using non-event day load patterns on 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 simple 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 the set of non-holiday, summer weekdays in 2021. The first 2021 SEP event was in June and the last was in September, so summer is defined here as June through September. For every event date, we select the three most similar SCE system load days. 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. September 30th has a visibly different load shape than the other days. This day was particularly cool in the morning leading up to the event, which, lead to lower impacts than other event days.

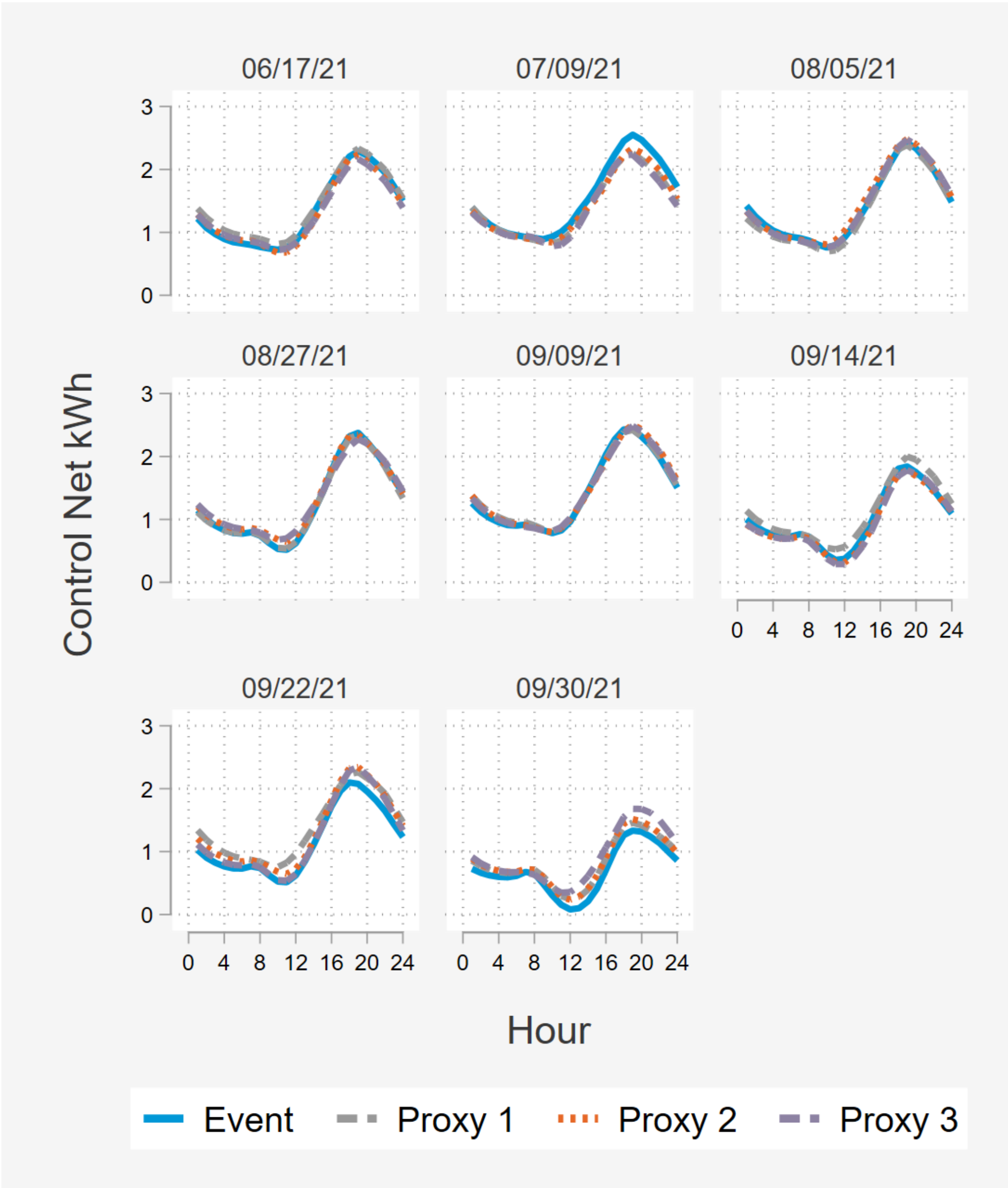
Figure 6: Event and Proxy Day System Load



While we use SCE system load to select the proxy days, the control customers come from a sample of non-participant customers within the SCE system. These customers, or the "pool" of potential control customers, should be representative of the system, 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 days loads line well with the event day loads 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[2] customers and those who participate in other demand response programs from the eligible control pool. 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 presence of net metering, climate zone, and CDD bin. Net metering indicates the household has rooftop solar. Section 2 provides an overview of climate zones. The CDD bin classifies customers by weather sensitivity into 10 bins based on the slope coefficient when daily kWh regressed on CDD. 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, and a load shape variable to describe load distribution throughout the day.

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 2021 analysis, 2,417 participants are not matched: this is about 4% 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.

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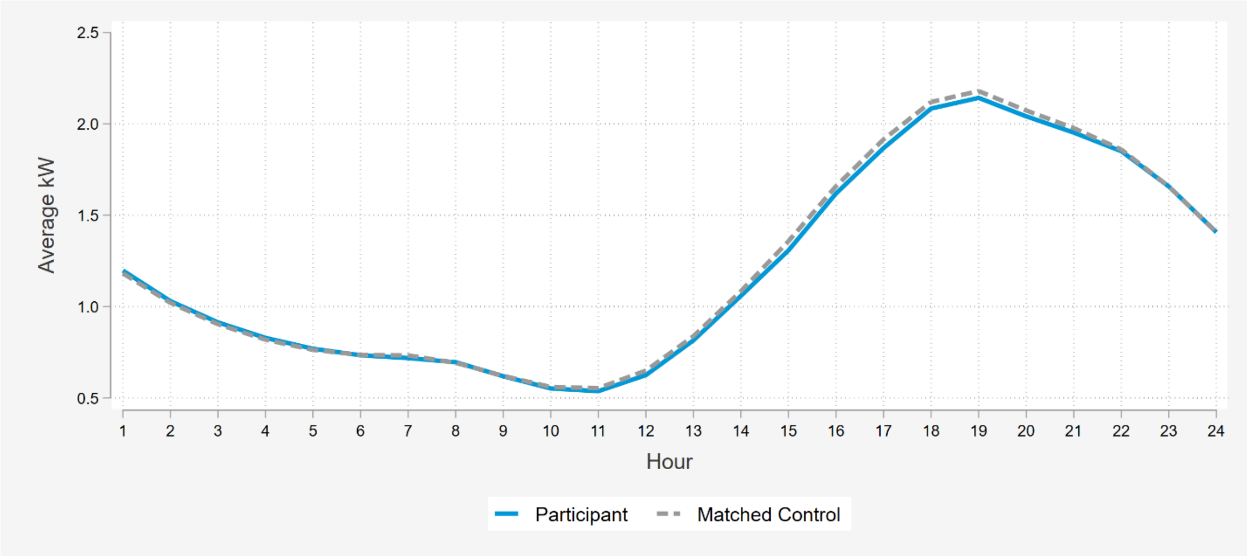
[2] Rule 24 customers are enrolled in other third party Demand Response programs. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M037/K189/37189001.pdf

Figure 8: Average Hourly kW on Proxy Days



Ex Post Model

Demand Side Analytics 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. We append the hourly impacts to form full event impacts, which are detailed in Section 4. 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 of the eight event days and 24 hours of the day, this regression estimates per customer impacts which are then extended to the aggregate impacts based on the number of participants dispatched for each event. We estimate the regression model separately for All Customers as well as each subcategory. Table 4 lists each subcategory and the associated number participants.

Available For Dispatch

During summer 2020, approximately 15% of enrolled SEP participants were not available for dispatch due to contractual issues with one of the thermostat manufacturers. SCE remedied this problem and dropped unavailable participants from the program before the start of the 2021 DR season. Readers should keep this in mind when comparing 2021 ex post results to the previous year.

Net versus Delivered Impacts

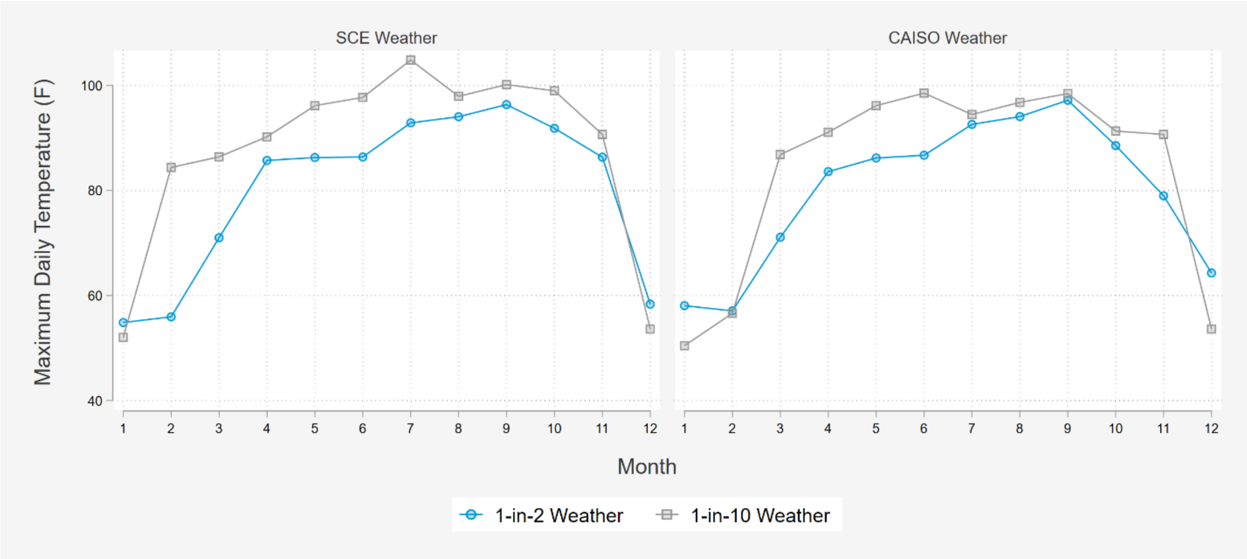
In 2021, we produced load impact estimates using both the net loads and delivered loads. The impacts only differ between the two for NEM customers, which in 2021 made up approximately 22% of customers. SCE metering configuration records two channels – energy delivered from the grid to the home and energy received by the grid from the home. Homes with solar will often show no delivered load during the day as the output from the solar panels exceeds the gross load and the home exports energy to the grid. When SEP dispatch curtails air conditioning load, NEM participants export more energy to the grid than they would on a non-event day. For example, a home with net reference load of -2.5 kW might have net load of -3.5 kW during SEP dispatch. Our impact analysis of net loads treats this change as a 1.0 kW load reduction. Conversely, CAISO settlement relies on delivered loads and would estimate 0.0 kW load reduction for this hypothetical participant. Given the prevalence of NEM customers in SEP, the evaluation team felt it was important to quantify the differences in ex post impacts using net and delivered loads. Over time as the share of NEM customers grows, and those customers install batteries capable of discharging stored solar electrons during the RA window, this difference will become more important. Section 4.4 compares the results of the two methods and implications for program planning.

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 conditions for a normal year
- 1-in-10 weather reflects conditions that would be observed in an extreme year
- Monthly system peak 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 peak 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 PY2021 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 10°F higher than the CAISO forecast for a monthly system peak day in July 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 July system peak day.

Figure 9: Monthly System Peak Day Comparison by Forecast



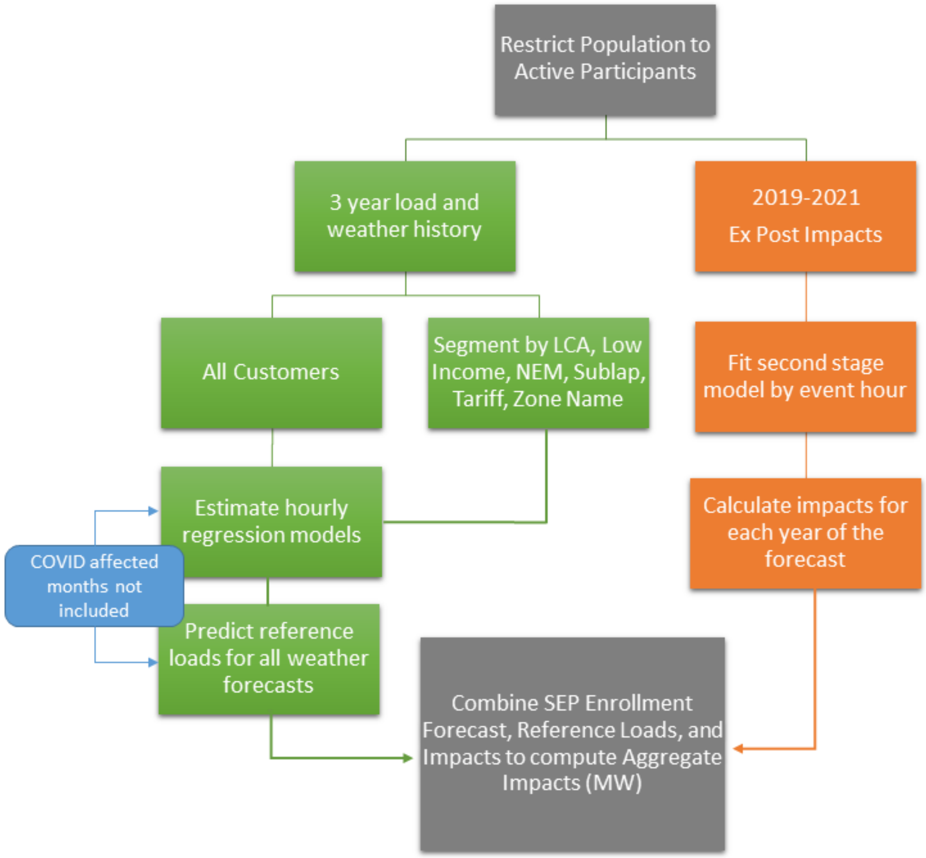
During PY2021 SEP dispatched events at different times of day, the duration of events varied from one to three hours, and some days had multiple events called. Ex ante estimation requires a single event profile to be selected. The ex ante event profile was selected to mirror the CAISO RA window, which begins at 4pm and ends at 9pm for all months of the year. This event profile avoids post-event snapback during the RA window. There were no events in 2021 that matched this profile, with the closest being a 4pm to 7pm event. Dispatch from 5pm to 9pm was a common event profile in PY2019 and occurred twice in PY2020. This shows the value of including events from prior years in our model. There were no five-hour events during PY2021 or prior years so we assume the impacts during the final hour of the RA window will reflect the expected impacts during the fourth hour of an SEP event dispatch.

Overview of Evaluation Method Selected

Figure 10 provides an overview of the SEP ex ante estimation methodology. The left side of the figure, in green, lists the steps involved in modeling reference loads – or what average customer loads would be absent SEP. The right side of the figure, in orange, lists the steps used to estimate SEP load impacts. The ex ante segmentation is similar to the ex post segmentation of customers, but excludes the "size", "thermostats", and "vendor" segments. We calculate the share of active participants by LCA, Low Income (CARE Status), NEM, SubLAP, Tariff, and Zone Name. We assume these ratios will hold constant over time as the enrollment forecast grows. We use the territory wide events from 2019, 2020, and 2021 events to estimate the second stage model, described further in the Ex Ante Impacts Model Section.

The reference loads, average per-customer impacts, and enrollment forecast come together 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 2019 through October 2021. Drop out the data from March 2020 through December 2020 since that data will have the most COVID effect.
- Drop any SEP event days.
- Drop dates where 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 peak 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 – Glossary of Terms

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 array 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 2022 predicted reference loads for all customers in black, with the LCA, Low Income (CARE Status), NEM, Tariff, and Zone Name categories on an August system peak 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 form some of the other subcategories.

Like the PY2018, PY2019 and PY2020 evaluations, the Big Creek/Ventura LCA has the highest reference load during the RA window while the South Orange County region has the smallest reference load during the RA window.

Figure 11: 2022 Reference Load by Segment: August System Peak Day, SCE 1-in-2 Weather

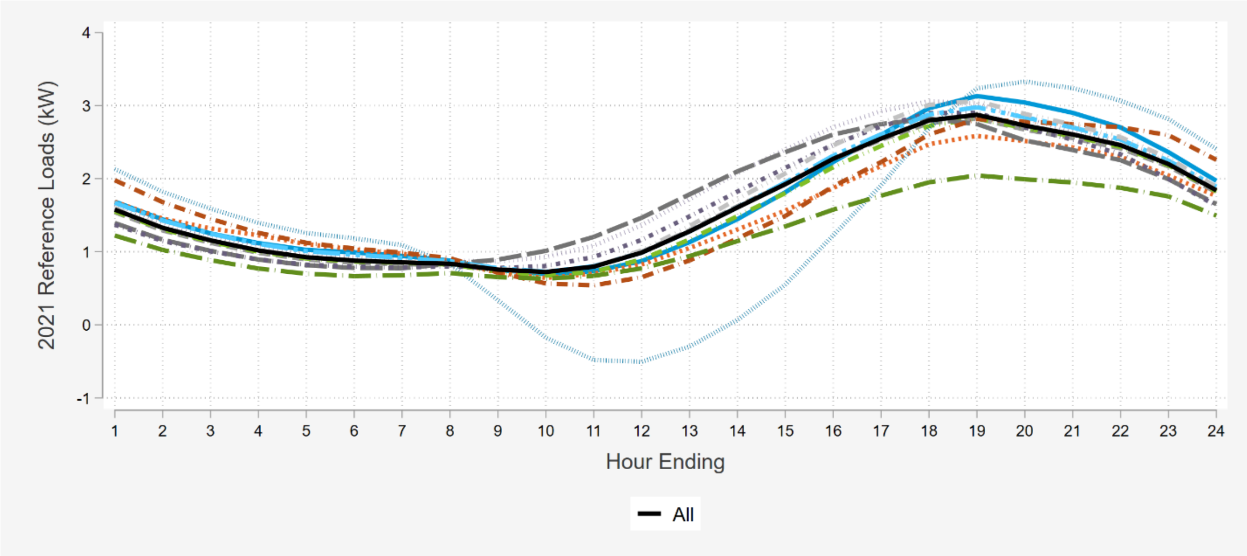
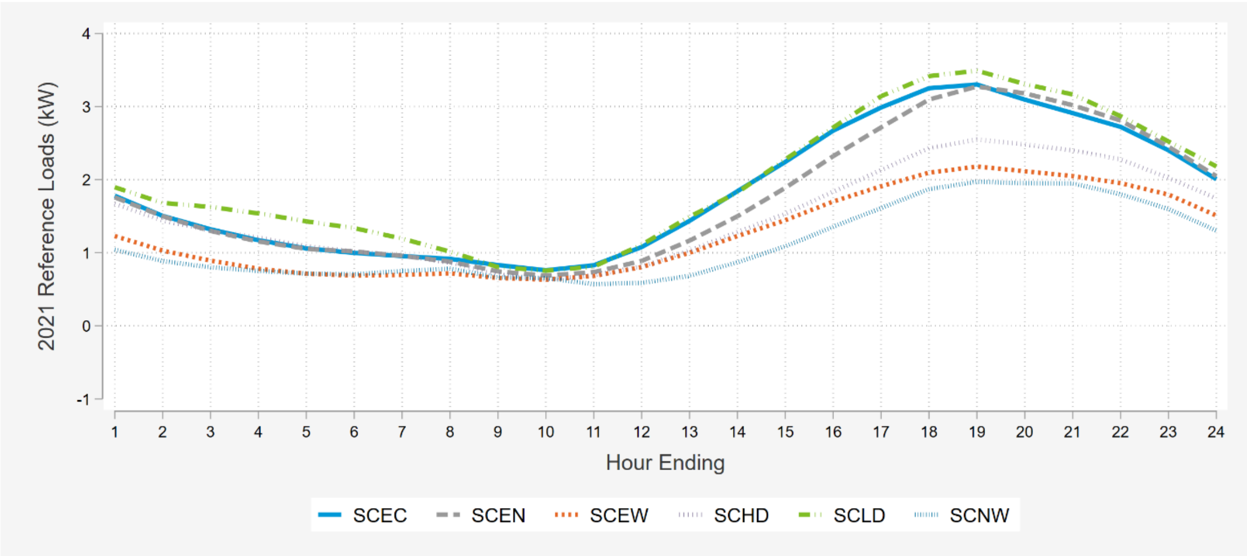


Figure 12 shows the modeled 2022 reference loads for each of the six SubLAPs on an August system peak day using SCE 1-in-2 weather. The Low desert experiences the hottest conditions of all the SubLAPs and has the highest per-customer peaks, but is overall a very small portion of the SEP population.

Figure 12: 2022 Reference Load by SubLAP: August System Peak Day, SCE 1-in-2 Weather



Ex Ante Impacts Model

In order to estimate SEP per customer load reductions under varying conditions, DSA fitted a second stage model using the PY2019, PY2020, and PY2021 ex post impacts as the dependent variable and dry bulb temperature as the independent variable.

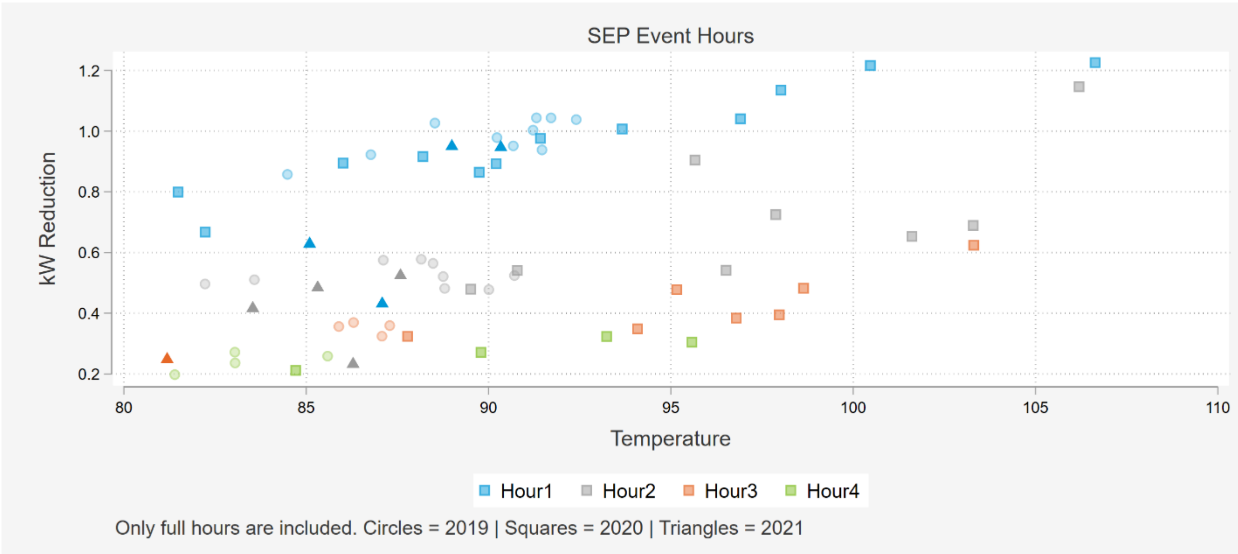
We fit a separate linear regression model for each of the four observed SEP event hours as well as the three hours of post-event snapback. Figure 13 shows the results for the "All Customers" category, but the process is similar for each of the subcategories. Event hour impacts are negative (a reduction in demand) and post-event snapback hours are positive (an increase in demand). As observed in the ex post results, impacts are largest during the first event hour and diminish significantly in the second, third, fourth hours of the event. Similarly, the post-event snapback is largest during the hour immediately following the event and shrinks in each subsequent hour.

As was the case in PY2020, a key caveat to the PY2021 events deals with the partial event hours. Two of the events started and ended mid-hour. In this case, we omitted the partial start hour of an event as well as the final partial hour. For the partial hour events that started in the first 30 minutes of an hour, we use the first full hour as a second event hour and this event will not have an hour 1. Events that start in the second 30 minutes of an hour will use the first full hour as event hour 1. 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.

A second difference between the PY2021 events and PY2020 events was the common occurrence of double event days. On three separate occasions in PY2021, SCE called two events called on the same day. We include the first event on those days, but exclude the second due to the influence of snapback from the first event. Snapback hours of the second event on double event days are still used in modeling the snapback.

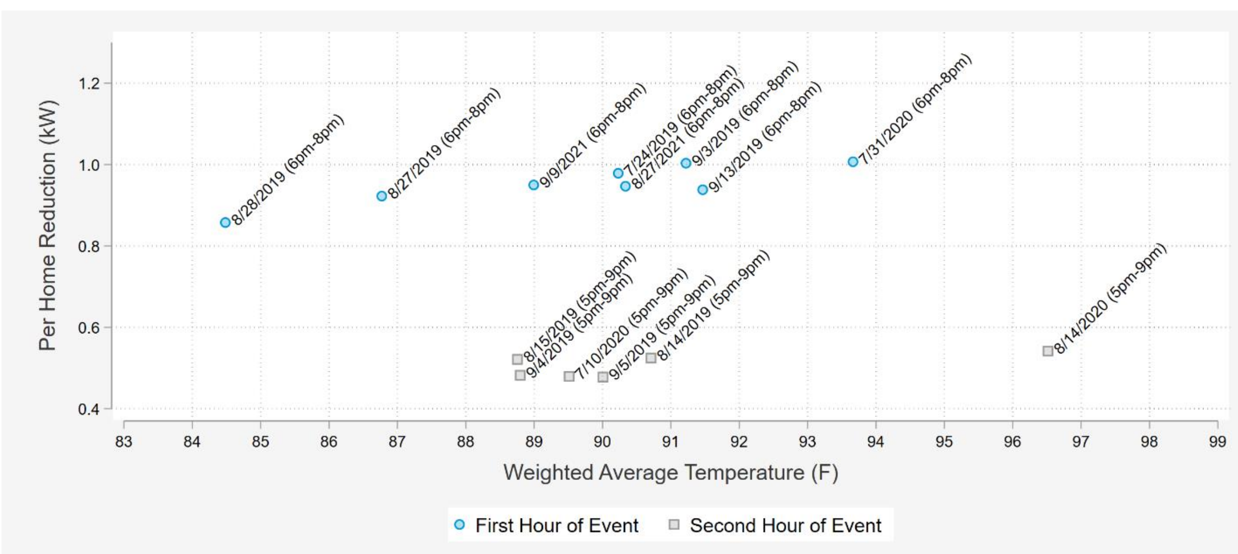
Figure 13 shows the PY2019, PY2020, and PY2021 hourly impacts by event hour. PY2019 impacts are circles, PY2020 impacts are squares, and PY2021 impacts are triangles. Each color represents a different event hour, with blue representing Hour 1 of the events and consistently showing the largest impacts regardless of temperature. Because events vary in length, there are more Hour 1 impacts than Hour 4 impacts. Impacts are largest in the first hour of an event and diminish with each subsequent hour. [redacted]

Figure 13: Per Customer SEP Load Reductions by Event Hour



The decision to model impacts a function of event hour rather than hour of the day was informed by the results of the ex post analysis. Figure 14 illustrates the issue using the ex post results from the PY2019 territory wide events and PY2020 and PY2021 full hour events during hour ending 19 (6pm to 7pm). There were 18 events active from 6pm to 7pm during the three summers. However, for some of these events, the event hour was either 3 or 4, and for a few events, the partial hours do not allow for a clean hour 1 and hour 2 of the event. Figure 14 shows that the same hour of day provides a consistently larger impact when it is the first hour of an event, regardless of temperature.

Figure 14: Hour Ending 19 Event Impacts vs. Temperature, by Event Hour



The average kW impact per participant household across the eight days where hour ending 19 was the first event hour was 0.95 kW with an average temperature of 89.6°F. The average kW impact per participant household across the six days where hour ending 19 was the second event hour was just 0.50 kW with an average temperature of 90.7°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. SEP has been authorized to start using pre-cooling in PY2022, but, since we have no prior information on the effectiveness of pre-cooling on SEP events, the evaluation team was not able to include it in our ex ante predictions for PY2021 LIP filing.

4 EX POST RESULTS

The ex post results document the measured impacts for each SEP event called during PY2021. 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 11 SEP events in 2021 over eight event days during the months of June through September. Table 8 shows average hourly impacts by event date. Two of the PY2021 events did not start or end at the top of the hour. This creates a challenge for the analysis because 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 as shown in Figure 19. 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 exclude partial event hours from the average and aggregate impact values in Table 8. In addition, there were three days where SCE called multiple events. Table 8 also shows an Average Event Day segment based on the most common event window for summer 2021. This only encompasses two events in PY2021. 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 count of dispatched homes fluctuates. In general, event participation increased over the course of summer 2021.

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 a double event day, September 22, 2021 with 0.84 kW reduced per customer. This double event was 125 minutes long in total but only included two full event hours. It was also one of the three double events called in 2021. Because load impacts are largest during the first hour of dispatch, short events have larger average impacts than longer events. Since this day had two events, with time in between for snapback to subside, the two full event hours both had large effects.

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. This year, there was only one event that had more than two full hours, September 14, 2021, which had the second lowest overall hourly impacts due to being averaged over the full three hours. It was only ahead of the event on September 30, 2021, which was muted by abnormally cool morning temperatures. Figure 15 and Figure 16 provides hourly breakdowns.

Table 8: 2021 SEP Event Impacts

Event Date	Dispatch Region	Participants	Average Event Temp (F)	Daily Max Temp (F)	Average Full Hour Impact (kW Reduction per Participant)	Average Aggregate Full Hour Impact (MW Reduction)
6/17/2021 (8pm-9pm)	Territory Wide	43,847	77.9	87.7	0.63	27.6
*7/9/2021 (5pm-6pm & 6:30pm-8:58pm)	Territory Wide	45,957	87.2	91.7	0.86	39.7
8/5/2021 (5pm-6pm & 8pm-9pm)	Territory Wide	47,389	85.2	88.9	0.78	36.9
8/27/2021 (6pm-8pm)	Territory Wide	47,185	89.0	94.2	0.74	34.7
**9/9/2021 (6pm-8pm)	Territory Wide	49,743	87.2	93.2	0.72	35.7
9/14/2021 (4pm-7pm)	Territory Wide	49,825	83.3	85.6	0.43	21.5
*9/22/2021 (4pm-5pm & 5:55pm-7pm)	Territory Wide	50,160	89.5	93.3	0.84	42.4
9/30/2021 (5pm-7pm)	Territory Wide	49,929	86.7	87.2	0.33	16.6
Average Event Day (6pm-8pm)	Territory Wide	48,498	88.0	93.7	0.73	35.2

* Only full hours are included in impacts

** 2021 System Peak Day

Figure 15 shows average ex post load impacts for the Average Event Day window. Figure 16 provides aggregate load impacts. The 6pm to 8pm window includes impact estimates from August 27 and September 9, which was the system peak day for SCE. 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 Characteristics' 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 20 MW during the hour immediately following dispatch – and may be an important consideration for event planning as SEP enrollment grows.

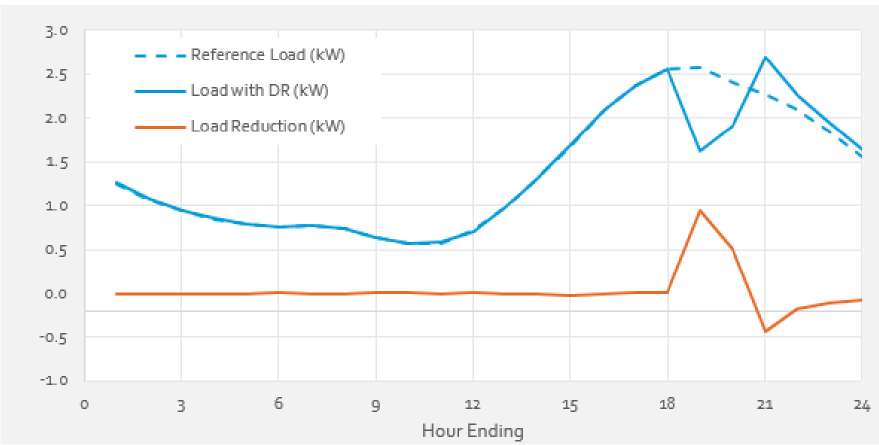
Figure 15: SEP Ex Post Load Impact per Participant for Average 2021 Event (6pm-8pm) (kW)

Table 1: Menu options

Type of Result	Per Customer
Category	All
Segment	All Customers
Date	Average Event Day (6pm-8pm)

Table 2: Event day information

Total sites	48,498
Daily Max Temp	93.7
Average Impact - kW	0.73
Average Impact - %	29.1%
Full Hours Only - Average Impact - kW	0.73
Full Hours Only - Average Impact - %	29.1%



Hour Ending	Reference Load (kW)	Load with DR (kW)	Load Reduction	% Load Reduction	Avg Temp (°F, Site-Weighted)
1	1.25	1.26	-0.01	-1%	73.57
2	1.07	1.08	-0.01	-1%	72.42
3	0.94	0.95	-0.01	-1%	71.40
4	0.85	0.86	-0.01	-1%	70.73
5	0.79	0.79	0.00	-1%	70.20
6	0.76	0.76	0.00	0%	69.80
7	0.77	0.77	-0.01	-1%	69.39
8	0.74	0.74	0.00	0%	69.11
9	0.63	0.63	0.00	0%	71.04
10	0.57	0.56	0.01	1%	75.48
11	0.58	0.58	0.00	0%	80.37
12	0.72	0.71	0.01	1%	84.63
13	0.98	0.98	0.00	0%	87.74
14	1.32	1.33	-0.01	-1%	90.22
15	1.67	1.69	-0.02	-1%	91.95
16	2.08	2.09	-0.01	-1%	93.69
17	2.37	2.36	0.01	0%	93.46
18	2.57	2.55	0.01	1%	91.79
19	2.58	1.63	0.95	37%	89.65
20	2.41	1.91	0.50	21%	86.42
21	2.27	2.70	-0.43	-19%	82.31
22	2.09	2.27	-0.17	-8%	79.17
23	1.84	1.95	-0.10	-6%	76.97
24	1.56	1.63	-0.08	-5%	75.31
Daily	Reference Load (kWh)	Load with DR (kWh)	Energy Savings (kWh)	% Change	Daily Avg Temp (°F)
	33.40	32.77	0.62	2%	79.9

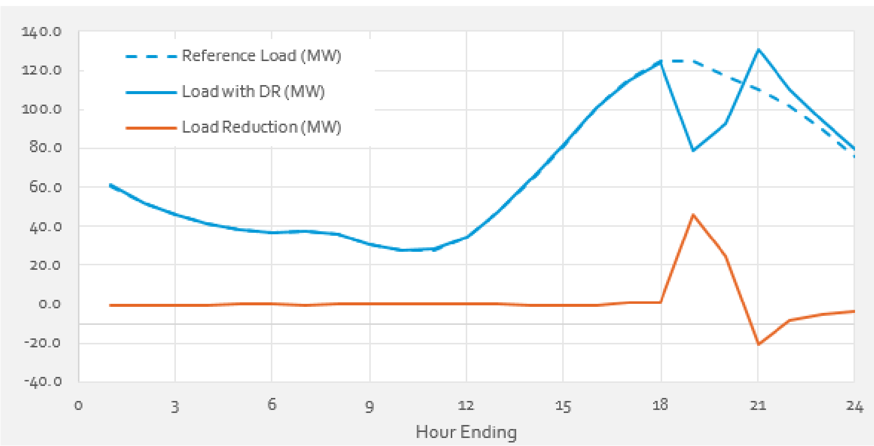
Figure 16: Aggregate SEP Ex Post Load Impact for Average 2021 Event (6pm-8pm) (MW)

Table 1: Menu options

Type of Result	Aggregate
Category	All
Segment	All Customers
Date	Average Event Day (6pm-8pm)

Table 2: Event day information

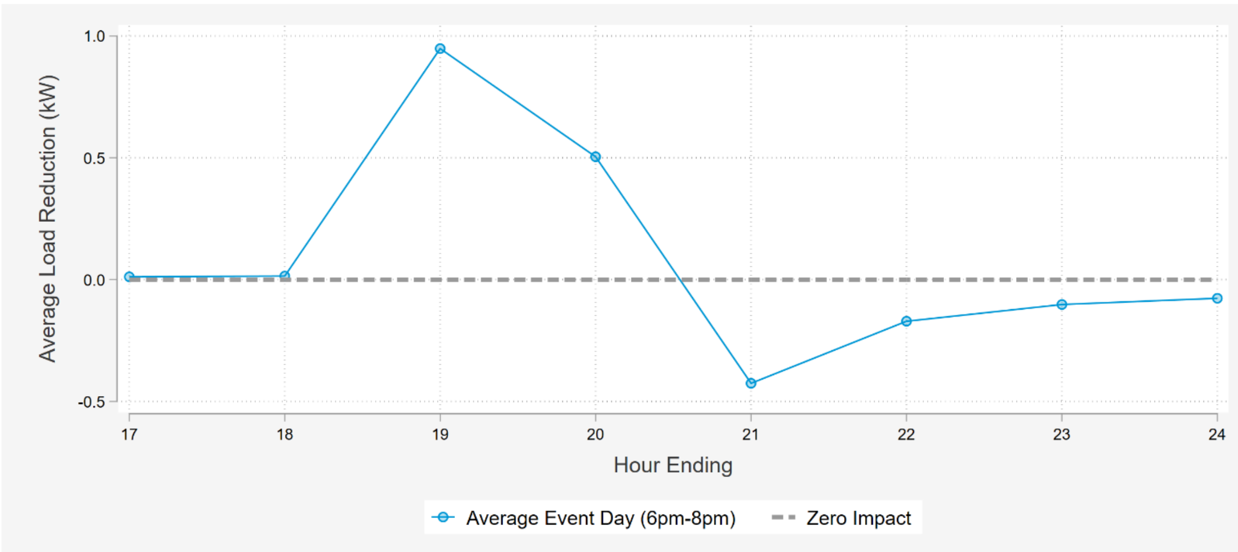
Total sites	48,498
Daily Max Temp	93.7
Average Impact - MW	35.21
Average Impact - %	29.1%
Full Hours Only - Average Impact - MW	35.21
Full Hours Only - Average Impact - %	29.1%



Hour Ending	Reference Load (MW)	Load with DR (MW)	Load Reduction	% Load Reduction	Avg Temp (°F, Site-Weighted)
1	60.72	61.22	-0.50	-1%	73.57
2	51.90	52.40	-0.50	-1%	72.42
3	45.57	46.05	-0.48	-1%	71.40
4	41.18	41.51	-0.33	-1%	70.73
5	38.10	38.34	-0.24	-1%	70.20
6	36.89	36.76	0.13	0%	69.80
7	37.18	37.58	-0.41	-1%	69.39
8	35.72	35.75	-0.03	0%	69.11
9	30.78	30.68	0.10	0%	71.04
10	27.60	27.34	0.26	1%	75.48
11	27.97	28.06	-0.09	0%	80.37
12	34.73	34.35	0.38	1%	84.63
13	47.51	47.69	-0.18	0%	87.74
14	63.90	64.28	-0.38	-1%	90.22
15	80.82	81.76	-0.94	-1%	91.95
16	100.79	101.35	-0.56	-1%	93.69
17	115.17	114.61	0.56	0%	93.46
18	124.45	123.74	0.71	1%	91.79
19	125.01	79.01	46.00	37%	89.65
20	116.98	92.55	24.43	21%	86.42
21	110.15	130.81	-20.67	-19%	82.31
22	101.54	109.86	-8.32	-8%	79.17
23	89.48	94.45	-4.97	-6%	76.97
24	75.53	79.26	-3.72	-5%	75.31
Daily	Reference Load (MWh)	Load with DR (MWh)	Energy Savings (MWh)	% Change	Daily Avg Temp (°F)
	1,619.65	1,589.42	30.22	2%	79.9

Figure 17 shows the average load impacts, by hour, for the 2021 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. Following each event, there is a "snapback" period where demand exceeds the reference load by 0.3-0.4 kW in the hour immediately following dispatch. For the remainder of the evening, this snapback diminishes as impacts return to zero.

Figure 17: Hourly Load Reductions for Average Event Day



4.2 PERFORMANCE ON SYSTEM PEAK AND RELIABILITY DAYS

Figure 18 shows the ex post per customer impacts on September 9, the system peak day. The first hour of the event, hour ending 19, had an average impact of 0.95 kW, decreasing to and average impact of 0.48 kW in the second hour, hour ending 20. This event is one of the two events that make up the "average event day" profile in 2021.

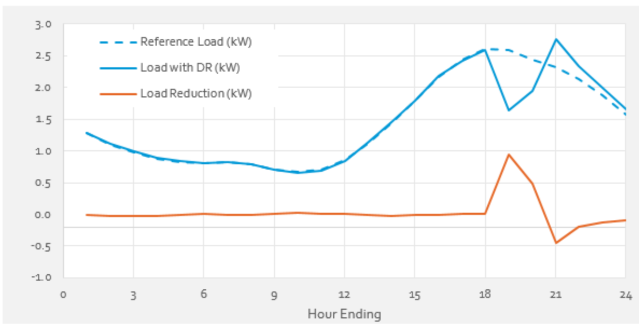
Figure 18: System Peak Day, September 9, 2021

Table 1: Menu options

Type of Result	Per Customer
Category	All
Segment	All Customers
Date	9/9/2021 (6pm-8pm)

Table 2: Event day information

Total sites	49,743
Daily Max Temp	93.2
Average Impact - kW	0.72
Average Impact - %	28.5%
Full Hours Only - Average Impact - kW	0.72
Full Hours Only - Average Impact - %	28.5%



Hour Ending	Reference Load (kW)	Load with DR (kW)	Load Reduction	% Load Reduction	Avg Temp (°F, Site-Weighted)
1	1.29	1.29	0.00	0%	72.45
2	1.10	1.12	-0.02	-2%	71.91
3	0.97	0.99	-0.02	-2%	71.50
4	0.88	0.90	-0.02	-2%	71.20
5	0.83	0.84	-0.01	-2%	71.16
6	0.81	0.81	0.00	0%	71.12
7	0.82	0.82	-0.01	-1%	71.23
8	0.79	0.80	0.00	-1%	71.01
9	0.71	0.71	0.01	1%	72.40
10	0.67	0.65	0.02	3%	76.09
11	0.70	0.70	0.01	1%	80.39
12	0.86	0.85	0.01	2%	84.23
13	1.12	1.13	-0.01	-1%	86.84
14	1.44	1.46	-0.02	-1%	89.17
15	1.79	1.80	-0.01	-1%	91.07
16	2.17	2.18	-0.01	0%	93.19
17	2.44	2.43	0.01	0%	93.02
18	2.60	2.59	0.01	0%	91.50
19	2.60	1.65	0.95	37%	88.99
20	2.44	1.95	0.48	20%	85.31
21	2.32	2.77	-0.45	-19%	81.70
22	2.14	2.34	-0.20	-9%	79.15
23	1.87	1.99	-0.12	-6%	77.07
24	1.57	1.66	-0.09	-6%	75.69
Daily	Reference Load (kWh)	Load with DR (kWh)	Energy Savings (kWh)	% Change	Daily Avg Temp (°F)
	34.94	34.42	0.52	1%	79.9

Figure 19 shows the only day in 2021 that had a reliability event called, July 9, 2021. This was a double event day with a one-hour event from 5pm - 6pm self-scheduled in the day-ahead market, as well as the reliability event from 6:30pm – 8:58pm. SCE and CAISO called the second event in response to transmission restraints caused by the Bootleg Fire. The first hour of the first event had an average impact of 1.12 kW. The first full hour of the reliability event had an average impact of 0.61 kW. However, it followed a partial event hour and loads were presumably affected by snapback from the 5pm-6pm event.

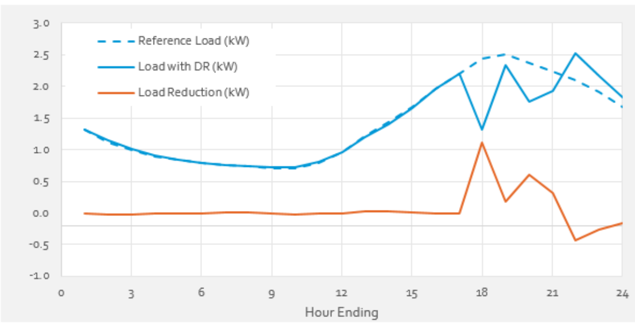
Figure 19: Reliability Event, July 9, 2021

Table 1: Menu options

Type of Result	Per Customer
Category	All
Segment	All Customers
Date	7/9/2021 (5pm-6pm & 6:30pm-8:58pm)

Table 2: Event day information

Total sites	45,957
Daily Max Temp	91.7
Average Impact - kW	0.55
Average Impact - %	23.2%
Full Hours Only - Average Impact - kW	0.86
Full Hours Only - Average Impact - %	35.9%



Hour Ending	Reference Load (kW)	Load with DR (kW)	Load Reduction	% Load Reduction	Avg Temp (°F, Site-Weighted)
1	1.31	1.33	-0.02	-1%	74.08
2	1.12	1.14	-0.02	-2%	73.45
3	0.99	1.01	-0.02	-2%	72.77
4	0.90	0.91	-0.02	-2%	72.19
5	0.84	0.84	0.00	-1%	71.73
6	0.79	0.80	-0.01	-1%	71.11
7	0.76	0.76	0.00	0%	70.70
8	0.75	0.74	0.01	1%	71.27
9	0.70	0.72	-0.01	-2%	73.76
10	0.71	0.73	-0.02	-3%	77.38
11	0.80	0.80	-0.01	-1%	81.33
12	0.96	0.97	0.00	0%	84.41
13	1.22	1.20	0.02	2%	86.63
14	1.43	1.41	0.03	2%	88.65
15	1.67	1.66	0.01	1%	89.88
16	1.96	1.97	-0.01	0%	90.97
17	2.20	2.20	0.00	0%	91.71
18	2.44	1.32	1.12	46%	90.96
19	2.51	2.33	0.18	7%	89.39
20	2.37	1.76	0.61	26%	86.87
21	2.23	1.92	0.31	14%	83.53
22	2.09	2.53	-0.44	-21%	80.09
23	1.92	2.17	-0.25	-13%	78.31
24	1.67	1.83	-0.16	-10%	76.90
Daily	**Reference Load (kWh)**	**Load with DR (kWh)**	**Energy Savings (kWh)**	**% Change**	**Daily Avg Temp (°F)**
	34.36	33.06	1.29	4%	80.3

4.3 RESULTS BY CATEGORY

Demand Side Analytics estimated the SEP impacts for all events for a variety of segments of interest. Table 9 presents the average impacts based on all full event hours. The average events discussed in Section 4.1 only include those with a standard event window of 6pm to 8pm. While SCE can dispatch only specific SubLAPs, in 2021 all events were called territory-wide. SCEC and SCEW are the two largest SubLAPs and make up 86% of the participant population. The average load impacts vary slightly by SubLAP, but the percent load impacts throughout most of the region are approximately 28-34%. The exception being SCNW (22%). SCNW is the second smallest of the six SubLAPs with only 750 participants. The average reference load for SCNW is the lowest of all SubLAPs (1.59 kW) suggesting relatively limited demand due to low temperatures. SCLD only had 47 participants. This small sample size leads to increased noise in the estimation as well as wide confidence intervals.

Percent impacts in 2021 were higher than the previous year because PY2021 events tended to be shorter than PY2020 events, meaning that the higher impact early event hours make up more of the averages in 2021. Weather conditions during 2020 events were also much hotter. Percent impacts invariably get smaller as the differential between setpoint and outdoor temperature increases.

Table 9: Ex Post Full Hour Load Impact Estimates by Customer Category*

Segmentation Variable	Segment Description	Participants	Avg. Reference Load (kW)	Avg. DR Load (kW)	Avg. Load Impact (kW)	% Load Impact	Agg. Load Impact (MW)
All		48,378	2.11	1.46	0.65	31%	31.5
LCA	Big Creek/Ventura	5,607	2.48	1.67	0.81	33%	4.5
	LA Basin	41,429	2.05	1.42	0.63	31%	26.0
	Outside LA Basin	1,341	2.32	1.58	0.74	32%	1.0
Low Income	CARE	9,967	2.40	1.70	0.70	29%	6.9
	Non-CARE	38,411	2.04	1.39	0.64	32%	24.6
NEM	NEM Customer	10,967	2.34	1.48	0.87	37%	9.5
	Non-NEM Customer	37,411	2.04	1.45	0.59	29%	22.0
Size	Above Median (1.88 kW)	24,156	3.02	2.05	0.97	32%	23.3
	Below Median (1.88 kW)	24,222	1.18	0.84	0.34	29%	8.2
Sublap	SCEC	19,557	2.52	1.69	0.82	33%	16.0
	SCEN	4,856	2.62	1.74	0.88	34%	4.2
	SCEW	21,873	1.64	1.18	0.46	28%	10.0
	SCHD	1,295	2.30	1.56	0.73	32%	0.9
	SCLD	47	2.97	2.07	0.90	30%	0.0
	SCNW	750	1.59	1.24	0.35	22%	0.3
Tariff	Dynamic	15,551	2.03	1.40	0.63	31%	9.8
	Flat	32,827	2.15	1.49	0.66	31%	21.7
Thermostats	1 Thermostat	42,147	2.04	1.43	0.61	30%	25.8
	2 Thermostats	5,740	2.55	1.63	0.92	36%	5.3
	3+ Thermostats	491	2.85	1.87	0.99	35%	0.5
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Zone	Remainder of System	20,189	2.32	1.58	0.74	32%	14.8
	South Orange County	10,374	1.51	1.11	0.40	27%	4.2
	South of Lugo	17,814	2.22	1.52	0.71	32%	12.5

** Results in this table are the average of the per-customer results for all full-hour event hours in SEP ex post, and cannot be compared directly to results in the accompanying load impact tables*

Regardless of segment, there is not much variety in the percent load impacts. The size segment has the highest and lowest average load impact, with 0.34 kW impact for participants smaller than 1.88 kW during the resource adequacy window and 0.97 kW for participants greater than 1.88 kW during the RA window. However, on a percent basis the two size segments are relatively close at 29 and 32%.

Overall, most segments are similar to the "All Customers" category with 31% load reduction. The average aggregate load impact for all customers is 31.5 MW. The following figures show segment specific impacts for the average 2021 event day, which starts at 6:00 pm and ends 8:00 pm. In Figure 20, "All Customers" are represented by a black line, and the zero impact line is drawn in gray. Figure 20 shows just the SubLAP breakout. The "All" category represents a participant weighted average of each segment category and is therefore shown approximately in the middle of the SubLAPs. SCLD stands out as an outlier with the largest snapback. Recall from Table 9 that this SubLAP only has an average of 47 customers during all events, which leads to a wide margin of error in the estimates.

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

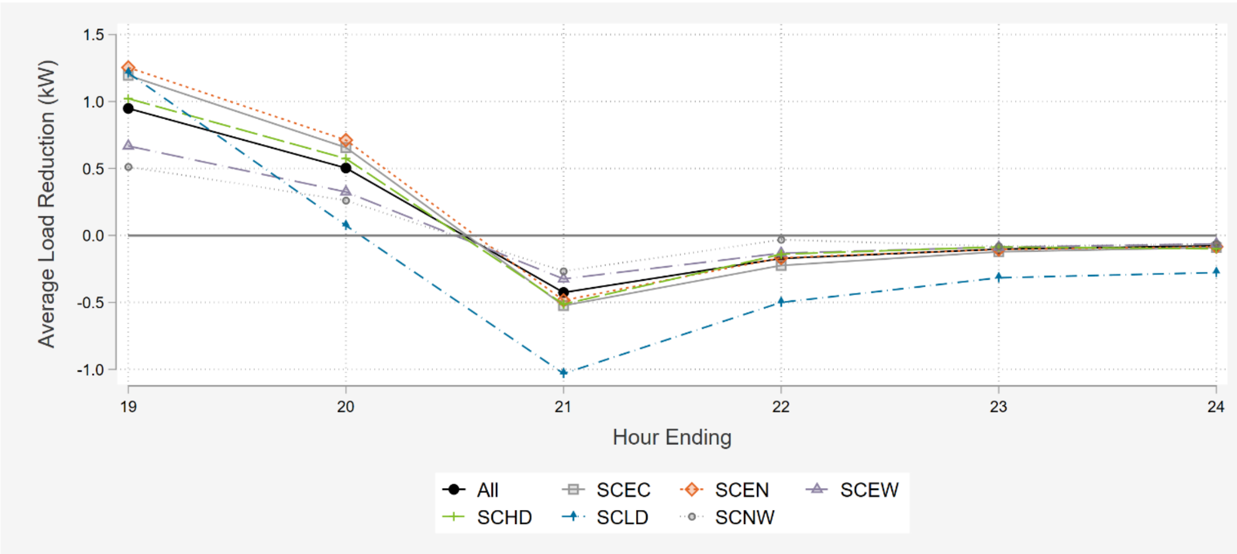


Figure 21 shows the average reductions for SEP participants who face flat and dynamic time-of-use (TOU) rates. The left side of Figure 21 shows absolute impacts in kW by hour and the right side shows percent savings. Participants on dynamic rates show smaller load impacts and smaller percent reductions than those on flat rates. SCE is working on moving the majority of residential customers to default TOU rates by the beginning of summer 2022. In 2021, though 68% of all SEP participants were on flat rates as compared to 72% in 2020.

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

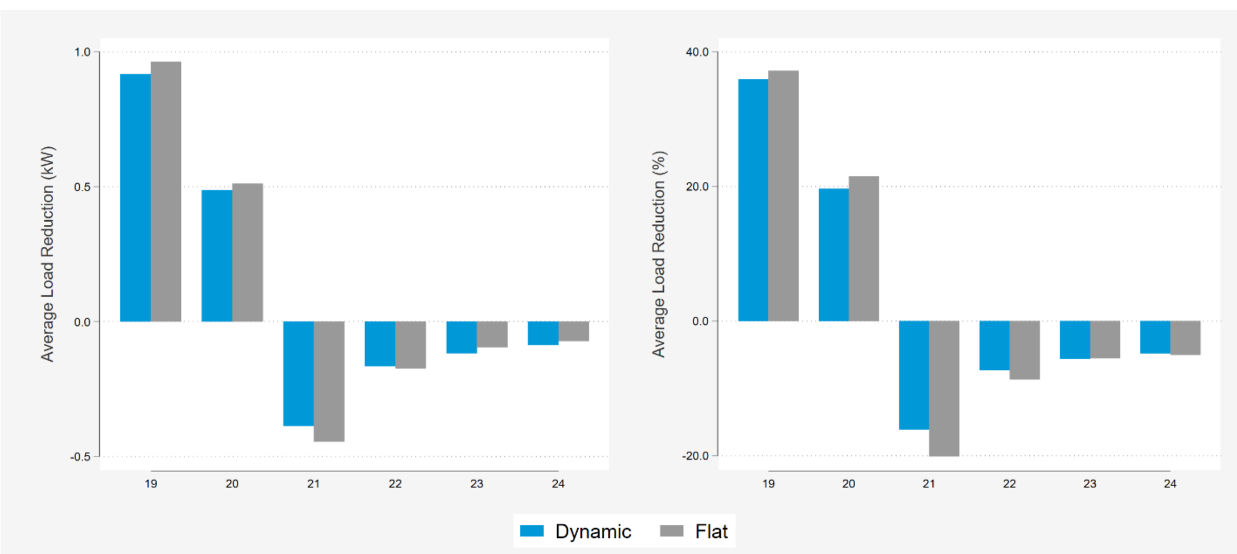


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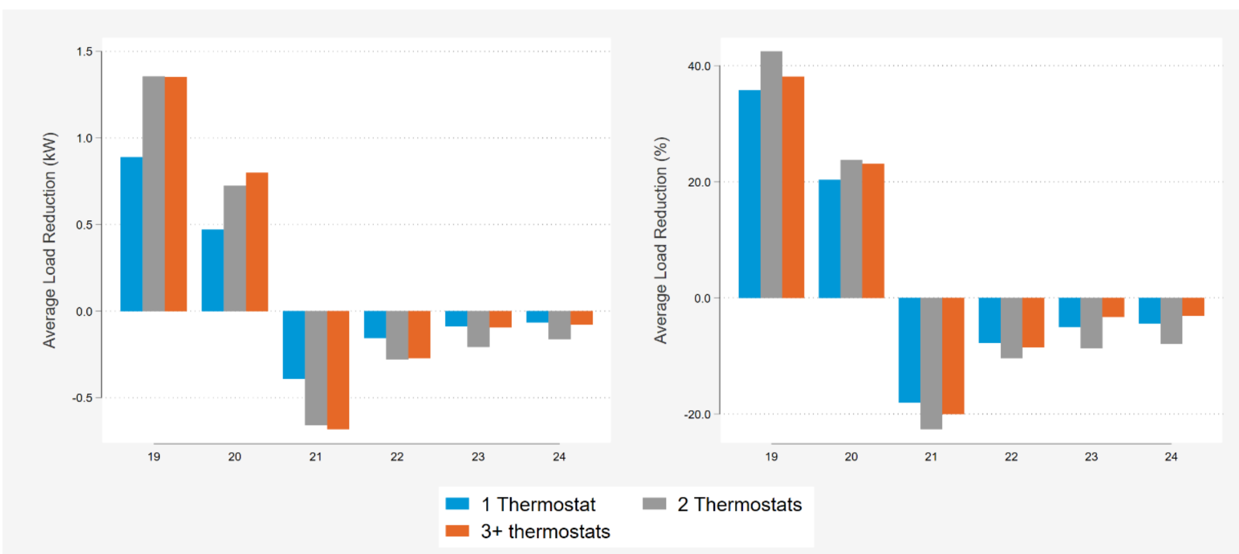
Figure 22: IMAGE REDACTED

Figure 23 shows the results by count of thermostats per customer. The average kW reduction increases by approximately 50% for homes with two thermostats. We see minimal differences amongst homes with two thermostats and those with three or more, although only 1% of participants have 3+ thermostats so the estimates are noisy.

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



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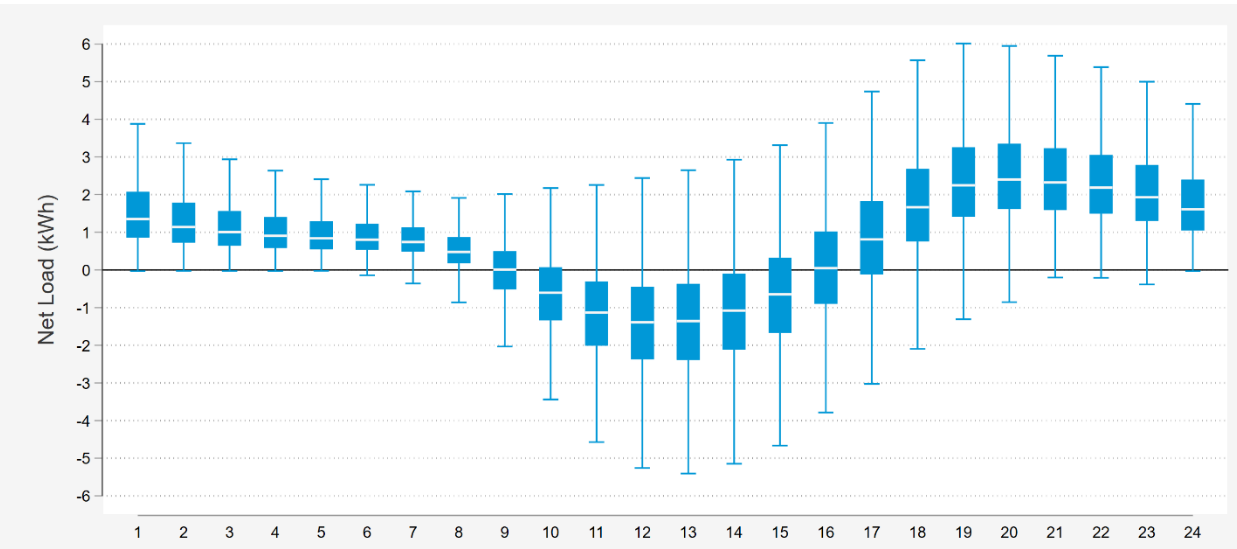
4.4 NET VS. DELIVERED RESULTS

DSA evaluates SEP and other SCE programs using net loads because we believe this returns an unbiased estimate of program performance. However, we understand CAISO settlement relies on delivered loads. When SEP dispatch overlaps with solar production, many NEM customers are net exporters and become larger net exporters once SCE curtails their cooling load. Figure 24 plots the distribution of net loads on 2021 proxy days. During the first hour of the RA window (hour 17), over half of the SEP NEM participants have net load of less than 1 kW. An average customer kW reduction would make these homes a net exporter, or a larger net exporter than they already are. Modeling load impacts with net loads credits SEP for the surplus energy that these customers are putting back into the grid. In the middle of the day, as solar energy starts to come back into the grid, there is a large dip in loads for NEM customers.

Figure 24: Average Net Load Distribution by Hour for NEM Customers on Proxy Days



The following figures compare the impacts for NEM customers during the SEP event on September 14th (4pm- 7pm) when modeled using net loads (Figure 25) and delivered loads (Figure 26). The impacts of the first hour of the event, which was 4-5 pm, were 0.88 kW when estimating using net loads and 0.61 kW when using delivered loads. This difference of 0.27 kW translates to almost a 3 MW differential in aggregate, or 10% of the SEP program ex post impact during that hour. The difference between the two load types dissipates quickly after the first hour of the event with the estimated impacts becoming almost identical as solar production fades in the evening hours.

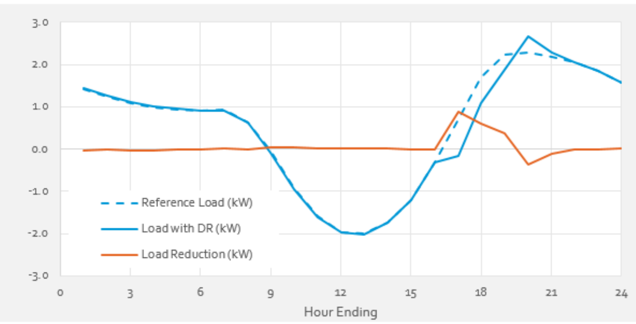
Figure 25: Impacts of Event on September 14, 2021 Estimated Using Net Loads for NEM Customers

Table 1: Menu options

Type of Result	Per Customer
Category	NEM
Segment	NEM Customer
Date	9/14/2021 (4pm-7pm)

Table 2: Event day information

Total sites	11,158
Daily Max Temp	87.7
Average Impact - kW	0.61
Average Impact - %	39.5%
Full Hours Only - Average Impact - kW	0.61
Full Hours Only - Average Impact - %	39.5%



Hour Ending	Reference Load (kW)	Load with DR (kW)	Load Reduction	% Load Reduction	Avg Temp (°F, Site-Weighted)
1	1.42	1.45	-0.04	-3%	69.33
2	1.24	1.25	-0.01	-1%	68.11
3	1.09	1.11	-0.02	-2%	66.77
4	0.97	1.01	-0.04	-4%	66.03
5	0.93	0.95	-0.02	-2%	65.16
6	0.91	0.92	-0.01	-1%	64.25
7	0.94	0.92	0.02	3%	63.59
8	0.64	0.64	0.00	-1%	63.25
9	-0.05	-0.10	0.05	-111%	63.94
10	-0.92	-0.95	0.03	-4%	67.94
11	-1.60	-1.61	0.01	-1%	72.84
12	-1.96	-1.97	0.01	0%	77.88
13	-2.00	-2.02	0.02	-1%	82.49
14	-1.74	-1.75	0.01	-1%	85.60
15	-1.21	-1.20	-0.01	1%	87.06
16	-0.31	-0.31	0.00	1%	87.73
17	0.71	-0.16	0.88	123%	87.31
18	1.69	1.10	0.59	35%	85.79
19	2.24	1.88	0.37	16%	83.22
20	2.30	2.67	-0.37	-16%	79.34
21	2.19	2.29	-0.10	-4%	74.81
22	2.05	2.07	-0.02	-1%	71.71
23	1.85	1.85	0.00	0%	69.57
24	1.58	1.57	0.01	1%	68.08
Daily	Reference Load (kWh)	Load with DR (kWh)	Energy Savings (kWh)	% Change	Daily Avg Temp (°F)
	12.97	11.60	1.37	11%	73.8

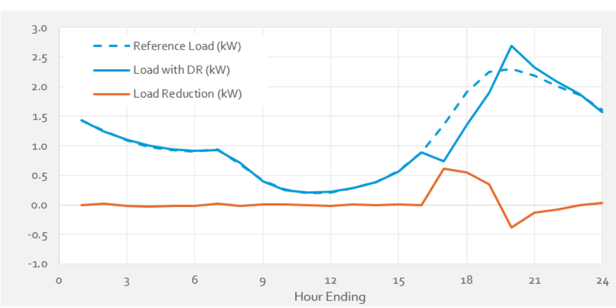
Figure 26: Impacts of Event on September 14, 2021 Estimated Using Delivered Loads for NEM Customers

Table 1: Menu options

Type of Result	Per Customer
Category	NEM
Segment	NEM Customer
Date	9/14/2021 (4pm-7pm)

Table 2: Event day information

Total sites	11,158
Daily Max Temp	87.7
Average Impact - kW	0.50
Average Impact - %	27.4%
Full Hours Only - Average Impact - kW	0.50
Full Hours Only - Average Impact - %	27.4%



Hour Ending	Reference Load (kW)	Load with DR (kW)	Load Reduction (kW)	% Load Reduction	Avg Temp (°F, Site-Weighted)
1	1.43	1.44	-0.01	0%	69.33
2	1.25	1.24	0.02	1%	68.11
3	1.09	1.11	-0.01	-1%	66.77
4	0.98	1.00	-0.02	-2%	66.03
5	0.93	0.95	-0.02	-2%	65.16
6	0.90	0.91	-0.01	-1%	64.25
7	0.94	0.92	0.02	2%	63.59
8	0.69	0.71	-0.02	-3%	63.25
9	0.41	0.40	0.01	3%	63.94
10	0.26	0.25	0.01	2%	67.94
11	0.20	0.21	-0.01	-5%	72.84
12	0.21	0.23	-0.01	-5%	77.88
13	0.28	0.28	0.00	1%	82.49
14	0.38	0.39	-0.01	-2%	85.60
15	0.57	0.56	0.01	2%	87.06
16	0.89	0.89	0.00	0%	87.73
17	1.35	0.74	0.61	45%	87.31
18	1.90	1.36	0.55	29%	85.79
19	2.25	1.90	0.35	15%	83.22
20	2.30	2.68	-0.38	-16%	79.34
21	2.18	2.32	-0.14	-6%	74.81
22	2.01	2.09	-0.08	-4%	71.71
23	1.86	1.87	-0.01	0%	69.57
24	1.61	1.57	0.04	2%	68.08
Daily	Reference Load (kWh)	Load with DR (kWh)	Energy Savings (kWh)	% Change	Daily Avg Temp (°F)
	26.88	26.00	0.88	3%	73.8

Estimating impacts using delivered loads clearly understates the capabilities of SEP. Since the estimation method determines valuation, the CAISO's use of delivered loads should discourage SEP from enrolling NEM customers if SEP is going to be offered into the market before 6pm.

4.5 COMPARISON TO PRIOR YEAR

SEP PY2021 events were called during similar event windows as the PY2019 and PY2020 events, but there were fewer events. For all 2021 events, SCE dispatched all six SubLAPs in unison, whereas 2019 included events where SCE dispatched individual SubLAPs and 2020 had some events with only five of the SubLAPs. Summer 2021 experienced mild temperatures. For the territory wide events in 2020, average event temperatures ranged from 81.5°F to 104.7°F. In 2021, the average event temperatures spanned from 77.9°F to 89.5°F. The limited range of temperatures experienced in 2021 provides less insight into ex ante forecasting across a wide range of temperatures. For example, SCE 1 in 10 conditions for a July monthly system peak day is expected to peak at 104.35 degrees Fahrenheit during event hours. In 2021, the event in July peaked at 93.19 degrees Fahrenheit. In order to make an ex ante prediction for that July monthly system peak day, we would have to predict more than ten degrees outside of the sample we have for just 2021. Demand response is a tool that works best under hot conditions and having lower average temperatures in 2021 means that there was less AC load to curtail. In PY2021, only one of the 11 events was dispatched as a "Reliability" event, which was the second of a double event day on 7/9/2021. Whereas PY2020 saw six such events. Almost all other events were self-scheduled in the day-ahead market, with one other being called for "Measurement & Evaluation" purposes.

Peak temperature during the average event days falls between 2pm and 5pm and the events typically started at 4pm or 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 behind 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 about five degrees lower than the daily max. Table 10 indicates that, even though average event temperature does affect impacts, heat buildup plays a role as well. Note that the 2020 event window is only one hour long while the other two are two hours.

The overall SEP population grew slightly from 2018 to 2019, but decreased in 2020 and 2021. The customer counts vary over the course of the season as customer attrition and enrollments happen continuously. The SEP participant population was smaller in PY2021 by about 3,000 customers, when comparing the average 5pm to 9pm event days in 2020 to the average 6-8PM days in 2021.

The standard 9-to-5 workday results in many households unoccupied during the 2017 & 2018 event window. If more individuals are home during the new window (5pm to 9pm), the likelihood of participant opt out may increase. Future analysis should consider the impact of opt outs to determine the number of dispatched participants that successfully complete an event.

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

Measure	2019 (6-8PM)	2020 (7-8 PM)	2021 (6-8 PM)
Avg. Reference Load (kW)	2.48	2.45	2.49
Avg. Load Impact (kW)	0.74	0.75	0.73
% Load Impact	30.00%	31.00%	29.10%
Avg. Event Temperature	83.8	88.6	88.0
Event Hours	6-8PM	7-8PM	6-8PM
Heat Buildup (Avg. F, 12 AM to 5 PM)	80.6	77.3	78.5
Enrollment	52,139	51,437*	48,498

*Actual number available for dispatch was 43,721.

There were 11 SEP events in 2021. Weather conditions, population differences, and the lessened effect of the COVID pandemic contributed to differences in the impact estimates, but weather conditions are the most effectual difference between PY2020 and PY2021. While per-customer impacts were higher in 2021, it is important to remember that 15% of SEP participants were unavailable for dispatch in 2020. If we adjust for availability, the 2020 events showed larger average customer impacts because weather conditions were hotter.

4.6 COMPARISON TO 2020 EX ANTE

Following the grid emergencies and rolling blackouts in California during summer 2020, there was significant scrutiny of the performance of different market actors, including demand response programs like SEP. 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 2020 ex ante analysis. There are two elements to consider when reviewing the accuracy of the 2020 ex ante projections.

1. Did the actual number of enrollments match the projected number of enrollments in the PY2020 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, 2021 SEP ex post impacts fell well short of the MW projections in the 2020 ex ante analysis. SCE fell about 9,000 projected participants short of the forecast in 2021. This is the main reason the projected aggregate impacts in 2021 fell short of 2020 ex ante impact estimates.

In Table 11, Table 12, and Table 13 we compare the ex post results from select 2021 events to our 2020 ex ante results for monthly system peak conditions and typical event days at comparable weather conditions.

Table 11 compares the July 9th SEP event impacts to our projected 2021 impacts for a July Monthly System Peak Day at SCE 1-in-2 weather conditions, which has a warmer weighted average maximum daily temperature by just 0.7°F. As discussed above, the actual number of enrolled customers during summer 2021 was lower than projected in the 2020 enrollment forecast. Asterisks indicate partial event hours and italicized impacts also correspond to partial hours.

- Hour 1 impacts are slightly higher than forecasted at 1.12 kW versus the 1.01 kW estimate from our 2020 ex ante evaluation.
- Hour 2 impacts were short of ex ante projections at 0.18 kW as this was a partial hour. The impacts of this hour are also affected by snapback from the previous event
- Hour 3 impacts were well above projections at 0.61 kW. The hour 3 estimated from 2020 ex ante is a true third consecutive event hour, while the third hour of the 7/9/2021 event was the first full hour of a second event.
- Hour four impacts slightly outperformed our ex ante projections. This was a partial hour, but the event spanned 58 minutes of the hour, so very close to a full event hour.

Overall, though, the aggregate savings fell short of projections due to the actual number of participating customers falling short of projections by almost 13,000 in July.

Table 11: July 9, 2021 Ex Post Impacts vs. Comparable 2020 Ex Ante Conditions

7/9/2021 (5-6 PM) &(6:30-8:58 PM)			Per-Customer Impact (kW)			
Results	Daily Max Temp (F)	Customers	Hour 1	Hour 2*	Hour 3	Hour 4*
SCE 1-in-2 July Peak Day (2020 Ex Ante Predictions for 2021)	92.4	58,796	1.01	0.60	0.36	0.26
Ex Post	91.7	45,957	1.12	*0.18*	*0.61*	*0.31*

Table 12 presents a similar comparison for August 27, 2021. We compare this event with the "Average Event Day" rather than an August peak day. The daily max temperature was higher than the projection by 2.7 degrees. Despite the higher temperatures, the projected per customer impacts were slightly lower than the projections. This is due, in part, to the timing of the event. The 2020 ex ante projection expects the event to start at 4pm, while the real event started at 6pm. Actual enrollments fell short of projections by more than 12,000 customers, which means aggregate MW performance fell well short.

Table 12: August 27, 2021 Ex Post Impacts vs. Comparable 2020 Ex Ante Conditions

8/27/2021 (6:00-8:00 PM)			Per-Customer Impact (kW)			
Results	Daily Max Temp (F)	Customers	Hour 1	Hour 2	Hour 3	Hour 4
SCE 1-in-2 Typical Event Day (2020 Ex Ante Predictions for 2021)	91.5	59,498	0.99	0.58	0.35	0.25
Ex Post	94.2	47,185	0.95	0.52		

Table 13 presents a comparison for the September 9, 2021 SEP event, which was the system peak day for 2021. Even though this was the system peak day, max temperatures were actually cooler than the SCE 1-in-2 projections of a September peak day by 2.3 degrees. Like the 8/27/2021 event, both per-customer impacts and enrollments fell short of projections, which means the aggregate ex post MW performance was lower than our 2020 ex ante estimates. Like 8/27/2021, the timing of the event on 9/9/2021 differed from the ex ante event window by two hours, starting at 6pm. This timing difference affects the available AC load as well as participant behavior. [redacted]

Table 13: September 9, 2021 Ex Post Impact vs. Comparable 2020 Ex Ante Conditions

9/9/2021 (6:00-8:00 PM)			Per-Customer Impact (kW)			
Results	Daily Max Temp (F)	Customers	Hour 1	Hour 2	Hour 3	Hour 4
SCE 1-in-2 September Peak Day (2020 Ex-Ante Predictions for 2021)	95.5	61,017	1.06	0.66	0.43	0.30
Ex-Post	93.2	49,743	0.95	0.48		

5 EX ANTE RESULTS

The ex ante results for SEP assume 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. Our 2020 ex ante projections addressed the COVID-19 pandemic with a decaying effect over many years, which, while small, did change the projections for future events. In 2021 though, we are under the assumption that we are living in a 'new normal' which means that there will be no decaying effect of COVID over the next few years and load shapes have permanently shifted to where they are now.

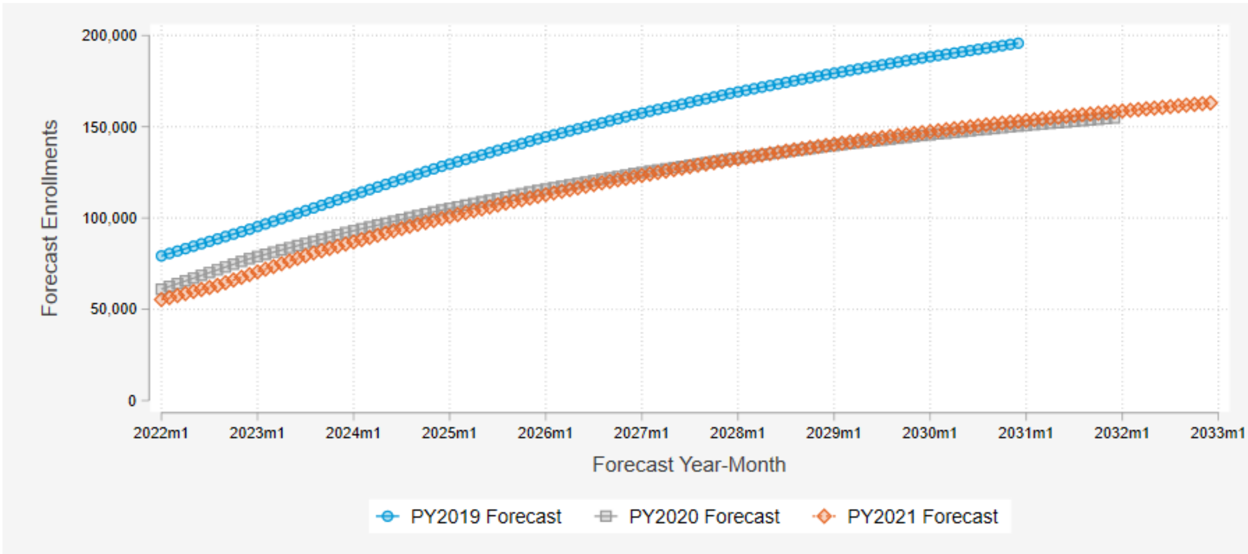
5.1 ENROLLMENT FORECAST

SCE provided an eleven-year forecast of SEP enrollments 2022-2032 representing the expected number of participants as of August of each calendar year. In order to place the forecast on an even basis, DSA imputed the estimated enrollments in each month of the forecast. Figure 27 compares this new forecast with the forecast we received for the PY2019 and PY2020 SEP evaluation. The PY2021 forecast is lower in the coming years than the prior year's forecast for several reasons.

- After 2020 enrollments declined due to the extreme weather and volume of events called, which caused some tempering of expectations for enrollment in the short-term.
- Enrollments have been generally lower than expected versus projections over the last few years and with this new information, SCE is able to make a more informed projection than in prior years.
- During PY2020, an issue with new terms & conditions for one thermostat manufacturer meant SEP was unable to communicate with ~15% of customers. In the months after PY2020, SCE dropped those customers from the program.

As discussed in Section 5.4, the lower enrollment forecast reduces the estimated aggregate MW impacts. However, SCE still expects the total number of enrollments to more than triple over the next decade from the current level of approximately 50,000 to over 160,000 enrollments by 2032. SCE plans to work with CPUC staff to remove enrollment barriers for SEP by allowing unbundled service customers (e.g., CCA members) to enroll and through increased coordination with SCE's energy efficiency programs.

Figure 27: Comparison on PY2019, PY2020, and PY2021 SEP Enrollment Forecasts



5.2 OVERALL RESULTS

Figure 28 shows the average ex ante load impacts per SEP participant for each hour of an August system peak day in 2022 using the SCE 1-in-2 weather forecast. Figure 29 shows the 2022 per-participant impact estimates using SCE 1-in-10 weather for an August system peak 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 specifics sets of results. Per customer (kW) and aggregate (MW) impacts are available for each forecast year 2022-2032 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 28 and Figure 29, the five hours of the RA window are shaded light green. Hours ending 17 through 21 correspond to the RA window of 4pm to 9pm.

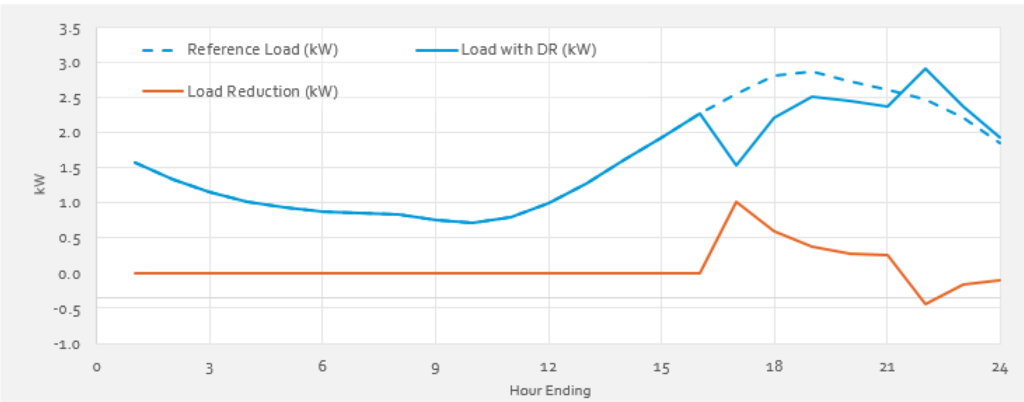
Figure 28: SEP Average Load Impact (kW) per Customer in 2022: August Monthly Peak Event Day, SCE 1-in-2 Weather

Table 1: Menu options

Type of result	Per Customer
Category	All
Segment	All Customers
Weather Data	SCE
Weather Year	1-in-2
Day Type	August Monthly Peak Day
Forecast Year	2022
Portfolio Level	Portfolio

Table 2: Event day information

Event start	4:00 PM
Event end	9:00 PM
Total sites	63,114
Event window temperature (F)	89.6
Event window load reduction (kW)	0.50
% Load reduction (Event window)	18.5%
Redaction Information	Public



Hour Ending	Reference Load (kW)	Load with DR (kW)	Load Reduction (kW)	% Load Reduction	Avg Temp (°F, Site-Weighted)
1	1.58	1.58	0.00	0.0%	78.42
2	1.33	1.33	0.00	0.0%	77.27
3	1.16	1.16	0.00	0.0%	76.45
4	1.02	1.02	0.00	0.0%	75.48
5	0.93	0.93	0.00	0.0%	74.74
6	0.88	0.88	0.00	0.0%	74.26
7	0.85	0.85	0.00	0.0%	73.67
8	0.84	0.84	0.00	0.0%	73.67
9	0.76	0.76	0.00	0.0%	75.68
10	0.72	0.72	0.00	0.0%	79.75
11	0.80	0.80	0.00	0.0%	83.92
12	0.99	0.99	0.00	0.0%	87.49
13	1.28	1.28	0.00	0.0%	89.90
14	1.61	1.61	0.00	0.0%	92.00
15	1.92	1.92	0.00	0.0%	93.50
16	2.27	2.27	0.00	0.0%	93.56
17	2.55	1.53	1.02	40.0%	93.03
18	2.80	2.20	0.60	21.3%	91.57
19	2.87	2.50	0.38	13.1%	90.12
20	2.73	2.45	0.27	10.1%	88.44
21	2.61	2.36	0.25	9.5%	85.01
22	2.46	2.90	-0.44	-18.0%	81.76
23	2.20	2.36	-0.16	-7.4%	79.70
24	1.84	1.93	-0.09	-5.1%	78.16
Daily	Reference Load (kWh)	Load with DR (kWh)	Energy Savings (kWh)	% Change	Daily Avg Temp (°F)
	38.98	37.16	1.81	4.7%	82.82

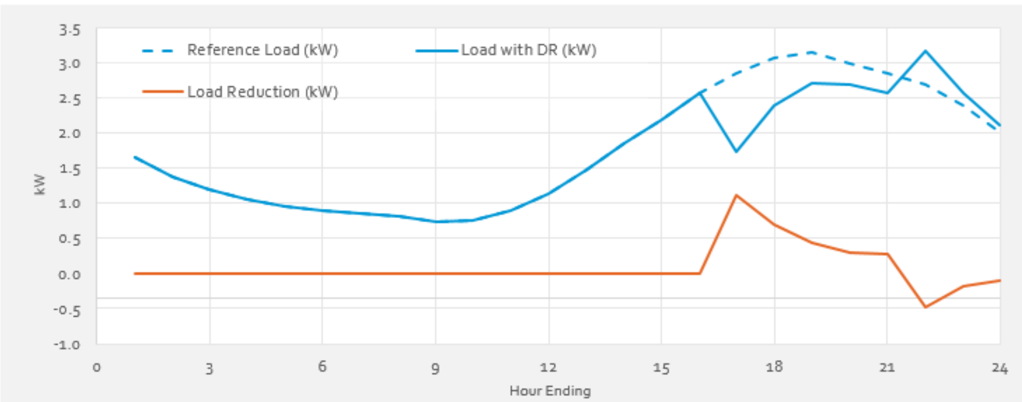
Figure 29: SEP Average Load Impact (kW) per Customer in 2022: August Monthly Peak Event Day, SCE 1-in-10 Weather

Table 1: Menu options

Type of result	Per Customer
Category	All
Segment	All Customers
Weather Data	SCE
Weather Year	1-in-10
Day Type	August Monthly Peak Day
Forecast Year	2022
Portfolio Level	Portfolio

Table 2: Event day information

Event start	4:00 PM
Event end	9:00 PM
Total sites	63,114
Event window temperature (F)	93.9
Event window load reduction (kW)	0.56
% Load reduction (Event window)	19.0%
Redaction Information	Public



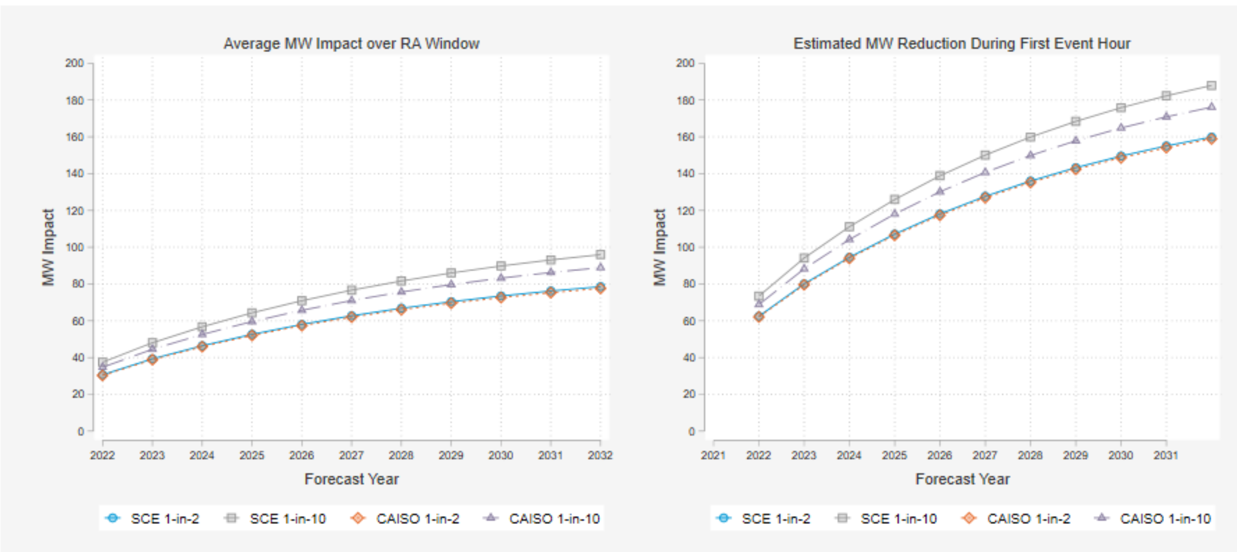
Hour Ending	Reference Load (kW)	Load with DR (kW)	Load Reduction (kW)	% Load Reduction	Avg Temp (°F, Site-Weighted)
1	1.65	1.65	0.00	0.0%	79.58
2	1.38	1.38	0.00	0.0%	78.28
3	1.19	1.19	0.00	0.0%	77.23
4	1.05	1.05	0.00	0.0%	76.14
5	0.94	0.94	0.00	0.0%	75.20
6	0.89	0.89	0.00	0.0%	74.32
7	0.85	0.85	0.00	0.0%	73.43
8	0.82	0.82	0.00	0.0%	73.42
9	0.74	0.74	0.00	0.0%	75.95
10	0.76	0.76	0.00	0.0%	80.95
11	0.90	0.90	0.00	0.0%	86.58
12	1.13	1.13	0.00	0.0%	90.37
13	1.48	1.48	0.00	0.0%	92.21
14	1.85	1.85	0.00	0.0%	93.90
15	2.20	2.20	0.00	0.0%	95.57
16	2.56	2.56	0.00	0.0%	97.04
17	2.84	1.73	1.11	39.0%	96.92
18	3.07	2.38	0.69	22.5%	96.37
19	3.14	2.70	0.44	14.0%	95.09
20	2.99	2.68	0.31	10.2%	92.24
21	2.85	2.57	0.28	9.7%	88.66
22	2.68	3.17	-0.49	-18.1%	85.42
23	2.39	2.57	-0.19	-7.8%	82.97
24	2.00	2.11	-0.11	-5.6%	81.53
Daily	Reference Load (kWh)	Load with DR (kWh)	Energy Savings (kWh)	% Change	Daily Avg Temp (°F)
	42.33	40.29	2.04	4.8%	84.97

Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

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 30 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 30 shows the average SEP MW impact over the five hour RA window. 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 during event hours 2-5. The difference between these two views of load reduction capability has important implications for valuation of SEP as a capacity resource.

Figure 30: Aggregate SEP Impacts over Time by Weather Conditions: Typical Event Day



The SCE and CAISO 1-in-2 weather conditions are very similar for a typical event day. Although not identical, it is difficult to distinguish the two trends in Figure 30. There is more variance in the 1-in-10 conditions, with the SCE 1-in-10 forecast showing hotter peaking conditions than the CAISO 1-in-10 forecast. The more extreme weather assumptions lead to higher reference loads, per-participant impacts, and MW capability in the SCE 1-in-10 aggregate ex ante impacts.

Table 14 shows the aggregate ex ante load impact estimates in forecast year 2022 by hour and peaking conditions for a typical event day. The estimated load impact of SEP in 2021 ranges from 62.1 MW to 73.5 MW during hour ending 17. Estimated impacts decline across the RA window and range from 14.7 MW to 18.2 MW in hour ending 21.

Table 14: 2022 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	62.5	62.1	73.5	68.9
18	36.8	36.0	46.5	42.5
19	23.0	22.6	29.4	26.9
20	16.5	16.4	20.1	18.7
21	14.8	14.7	18.2	16.8
RA Window	**30.7**	**30.4**	**37.5**	**34.8**

In addition to the typical event day, DSA estimated ex ante impacts for monthly system peak 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 peak days. The SCE 1-in-10 estimates are largest for the July monthly system peak day. Since the ex ante weather has not changed, these weather findings were the same for PY2019 and PY2020.

Table 15: Aggregate Load Impacts (MW) on Monthly System Peak Days 2022-2032: SCE Weather

Weather Year	Month	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
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	0.8	1.0	1.2	1.4	1.5	1.7	1.8	1.9	2.0	2.1	2.1
	April	20.8	26.6	32.2	36.9	41.1	44.7	47.8	50.5	52.9	55.0	56.8
	May	22.4	28.7	34.5	39.4	43.8	47.5	50.8	53.6	56.1	58.3	60.2
	June	24.3	31.1	37.1	42.3	46.8	50.8	54.2	57.2	59.8	62.1	64.1
	July	31.1	39.8	47.3	53.7	59.4	64.3	68.5	72.2	75.5	78.3	80.8
	August	31.7	40.7	48.0	54.4	60.0	64.8	69.0	72.7	75.9	78.7	81.2
	September	35.1	44.7	52.5	59.4	65.3	70.5	75.1	79.0	82.4	85.4	88.1
	October	31.4	39.5	46.3	52.2	57.4	61.9	65.8	69.2	72.1	74.7	77.0
	November	20.0	25.1	29.2	32.9	36.1	38.8	41.2	43.3	45.2	46.8	48.2
	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	16.2	20.7	25.4	29.3	32.7	35.7	38.3	40.6	42.5	44.2	45.7
	March	21.6	27.6	33.6	38.7	43.1	47.0	50.3	53.2	55.8	58.0	59.9
	April	26.1	33.3	40.3	46.2	51.4	55.9	59.8	63.2	66.2	68.8	71.0
	May	32.4	41.5	49.8	57.0	63.2	68.6	73.4	77.5	81.1	84.2	86.9
	June	33.7	43.2	51.6	58.8	65.1	70.5	75.3	79.5	83.1	86.3	89.0
	July	41.6	53.2	63.2	71.8	79.4	85.9	91.6	96.6	100.9	104.7	108.0
	August	35.6	45.6	53.8	61.0	67.3	72.7	77.4	81.6	85.2	88.3	91.0
	September	38.1	48.4	57.0	64.4	70.9	76.5	81.4	85.7	89.4	92.6	95.5
	October	38.3	48.3	56.5	63.8	70.0	75.5	80.3	84.4	88.0	91.2	94.0
	November	29.4	36.7	42.9	48.2	52.9	57.0	60.5	63.6	66.3	68.6	70.7
	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 Load Impacts (MW) on Monthly System Peak Days 2022-2032: CAISO Weather

Weather Year	Month	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
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	0.8	1.0	1.2	1.4	1.6	1.7	1.8	1.9	2.0	2.1	2.2
	April	16.5	21.1	25.4	29.2	32.5	35.3	37.8	39.9	41.8	43.5	44.9
	May	22.0	28.1	33.7	38.6	42.8	46.5	49.7	52.5	54.9	57.0	58.9
	June	25.0	32.0	38.2	43.6	48.2	52.3	55.8	58.9	61.6	63.9	66.0
	July	30.4	38.9	46.2	52.5	58.0	62.7	66.9	70.5	73.7	76.5	78.9
	August	30.9	39.6	46.8	53.0	58.4	63.1	67.3	70.9	74.0	76.7	79.1
	September	34.5	43.8	51.5	58.3	64.1	69.2	73.7	77.5	80.9	83.8	86.4
	October	27.6	34.7	40.7	45.9	50.4	54.4	57.8	60.8	63.4	65.6	67.7
	November	5.4	6.7	7.8	8.8	9.6	10.4	11.0	11.6	12.1	12.5	12.9
	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	22.5	28.8	35.0	40.3	44.9	48.9	52.4	55.5	58.1	60.5	62.5
	April	28.7	36.7	44.4	50.9	56.6	61.6	65.9	69.7	72.9	75.8	78.3
	May	32.4	41.5	49.8	57.0	63.2	68.6	73.4	77.5	81.1	84.2	86.9
	June	34.9	44.6	53.3	60.8	67.3	73.0	77.9	82.2	85.9	89.2	92.0
	July	31.8	40.7	48.4	55.0	60.7	65.8	70.1	73.9	77.2	80.1	82.6
	August	34.5	44.3	52.3	59.2	65.3	70.6	75.2	79.2	82.7	85.7	88.4
	September	36.8	46.8	55.0	62.2	68.4	73.9	78.6	82.8	86.4	89.5	92.2
	October	30.0	37.9	44.3	50.0	54.9	59.2	63.0	66.2	69.1	71.5	73.7
	November	29.4	36.7	42.9	48.2	52.9	57.0	60.5	63.6	66.3	68.6	70.7
	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 2022 under each set of weather conditions by local capacity area. The majority of SEP participants are located in the LA Basin LCA 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 2022 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	7,323	4.2	4.3	4.8	4.8
LCA: LA Basin	54,039	25.6	25.2	31.5	28.9
LCA: Outside LA Basin	1,752	0.9	0.9	1.1	1.0
SEP Total	**63,114**	**30.7**	**30.4**	**37.5**	**34.8**

Approximately 86% of SEP participants are located in the LA Basin LCA, and between 83% and 84% of the ex ante MW impacts come from the LA Basin. Reference loads and average customer impacts in the LA Basin LCA are slightly lower than Big Creek/Ventura or Outside LA Basin. For SCE 1-in-2 weather conditions the Big Creek/Ventura LCA has an average customer impact of 0.58 kW, Outside LA Basin has an average customer impact of 0.49 kW and LA Basin has an average customer impact of 0.47 kW.

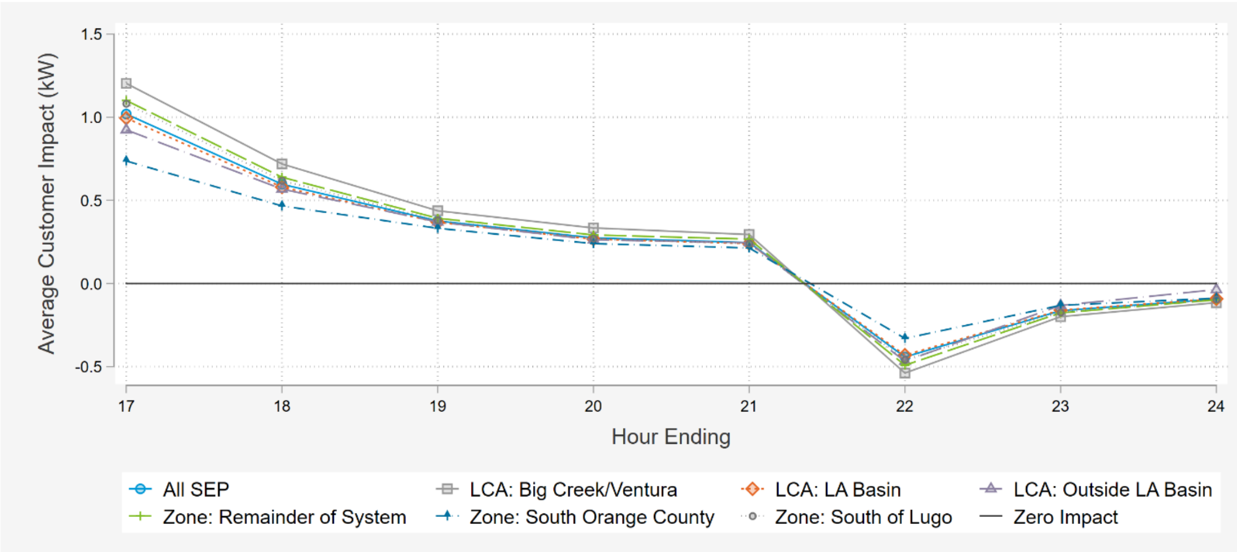
Table 18 provides a similar breakdown for each region of the SCE system affected by the SONGS closure. For SCE 1-in-2 weather conditions, we expect 37.8% of the SEP load reduction to come from South of Lugo, 16.6% from South Orange County, and 45.6% from the Remainder of the System unaffected by the SONGS closure. While South Orange County has 21.4% of the participants, the average customer impacts are lower so the region only provides approximately 16-17% of the total load reduction capability. Remainder of the System has the opposite trend with approximately 41.8% of the customers and 44-46% of the impacts.

Table 18: Ex Ante Aggregate 2022 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	26,397	14.0	13.9	16.6	15.9
Zone: South Orange County	13,498	5.1	5.0	6.4	5.6
Zone: South of Lugo	23,219	11.6	11.4	14.3	13.2
SEP Total	**63,114**	**30.7**	**30.4**	**37.5**	**34.8**

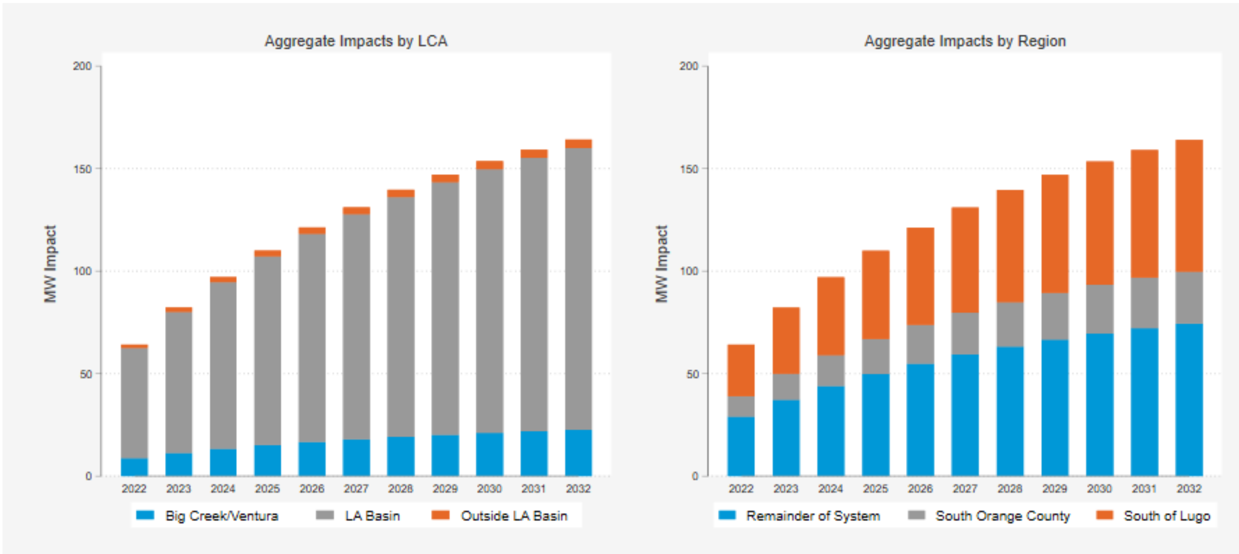
Readers should note that the aggregate impacts shown in Table 17 and Table 18 are an average across the five-hour RA window. Figure 31 shows the average impact on an August system peak day by segment and hour across the RA window and post-event snapback period using SCE 1-in-2 weather and reveals that that average MW impacts across the RA window mask a significant amount of inter-hour diversity in estimated performance. Figure 31 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 31: Average Customer Load Impacts by Segment and Hour: August System Peak Day, SCE 1-in-2 (2022 – 2032)



As shown in Figure 31, the per-participant impact is greatest during the first hour of event dispatch. The forecasted enrollments is the same in each hour. Figure 32 shows the projected aggregate MW impacts for SEP 2022-2032 by LCA and Region using SCE 1-in-2 weather conditions for an August system peak day.

Figure 32: First Event Hour Ex Ante MW Reduction by LCA and Region: August System Peak Day, SCE 1-in-2 Weather



5.4 COMPARISON TO PRIOR YEAR

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 2022 August system peak day using SCE 1-in-2 weather. The underlying ex ante weather for PY2021 is identical to PY2020. Temperature variations occur due to the changing regional distribution of enrolled customers. Per-customer impacts are similar across the RA window, but percent impacts are slightly lower in 2021.

A difference in PY2020 ex ante and PY2021 ex ante is the absence on the COVID glide path. In the 2020 ex ante analysis, SCE and its evaluators developed a glide path that forecasted the impact of COVID on loads to dissipate over the next decade until it no longer had any effect. In 2021, we assumed that we are under a 'new normal' scenario and that there is no longer any effect of COVID that will dissipate over time, since residential loads have mostly returned to pre-COVID levels. In order to model ex ante without the effects of COVID, we did not include load data from March to December 2020 when modeling reference loads. We did however include the events from 2020, as they spanned a wide range of temperatures and times, which is important information for predicting future events under extreme weather conditions.

Table 19: Comparison of PY2020 and PY2021 Average Customer Impacts: 2022 August System Peak Day, SCE 1-in-2 Weather

Hour Ending	2020 (kW)	2021 (kW)	2020 (%)	2021 (%)	2020 (Temp)	2021 (Temp)
17	1.03	1.02	40.2%	40.0%	92.8	93.0
18	0.60	0.60	21.4%	21.3%	91.3	91.6
19	0.39	0.38	13.6%	13.1%	89.8	90.1
20	0.28	0.27	10.5%	10.1%	88.1	88.4
21	0.25	0.25	9.7%	9.5%	84.7	85.0
RA Window Average	**0.51**	**0.50**	**18.9%**	**18.5%**	**89.3**	**89.6**

Table 20 shows the same comparison for SCE 1-in-10 weather. The PY2021 average customer impacts during the RA window are slightly lower than the PY2020 impacts on an absolute basis as well as a percent 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 PY2020 and PY2021 Average Customer Impacts: 2022 August System Peak Day, SCE 1-in-10 Weather

Hour Ending	2020 (kW)	2021 (kW)	2020 (%)	2021 (%)	2020 (Temp)	2021 (Temp)
17	1.11	1.11	39.0%	39.0%	96.7	96.9
18	0.70	0.69	22.8%	22.5%	96.1	96.4
19	0.47	0.44	15.3%	14.0%	94.8	95.1
20	0.32	0.31	10.9%	10.2%	91.9	92.2
21	0.28	0.28	10.2%	9.7%	88.4	88.7
RA Window Average	**0.58**	**0.56**	**19.6%**	**19.0%**	**93.6**	**93.9**

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 peak day in 2022. The CAISO ex ante weather conditions are slightly cooler in the PY2020 ex ante estimates for an August system peak day compared to the PY2021 ex ante estimates for both 1-in-2 and 1-in-10 conditions. Absolute impacts are similar for CAISO 1-in-2 and 1-in-10 conditions. The PY2021 percent impacts are lower in CAISO 1-in-2 and 1-in-10 weather conditions.

Table 21: Comparison of PY2020 and PY2021 Average Customer Impacts: 2022 August System Peak Day, CAISO 1-in-2 Weather

Hour Ending	2020 (kW)	2021 (kW)	2020 (%)	2021 (%)	2020 (Temp)	2021 (Temp)
17	1.02	1.01	39.4%	39.1%	92.4	92.7
18	0.58	0.58	20.4%	20.3%	90.4	90.6
19	0.36	0.36	12.6%	12.3%	88.5	88.7
20	0.27	0.26	9.8%	9.6%	86.7	87.0
21	0.24	0.24	9.3%	9.2%	84.0	84.2
RA Window Average	**0.49**	**0.49**	**18.2%**	**17.9%**	**88.4**	**88.6**

Table 22: Comparison of PY2020 and PY2021 Average Customer Impacts: 2022 August System Peak Day, CAISO 1-in-10 Weather

Hour Ending	2020 (kW)	2021 (kW)	2020 (%)	2021 (%)	2020 (Temp)	2021 (Temp)
17	1.09	1.09	40.9%	40.9%	95.7	96.0
18	0.67	0.67	23.4%	23.1%	94.9	95.2
19	0.45	0.42	15.3%	14.2%	93.3	93.7
20	0.31	0.30	11.1%	10.5%	90.8	91.3
21	0.26	0.26	10.1%	9.7%	86.6	87.1
RA Window Average	**0.56**	**0.55**	**20.1%**	**19.5%**	**92.2**	**92.6**

We offer the following observations about the comparisons shown in Table 19 through Table 22.

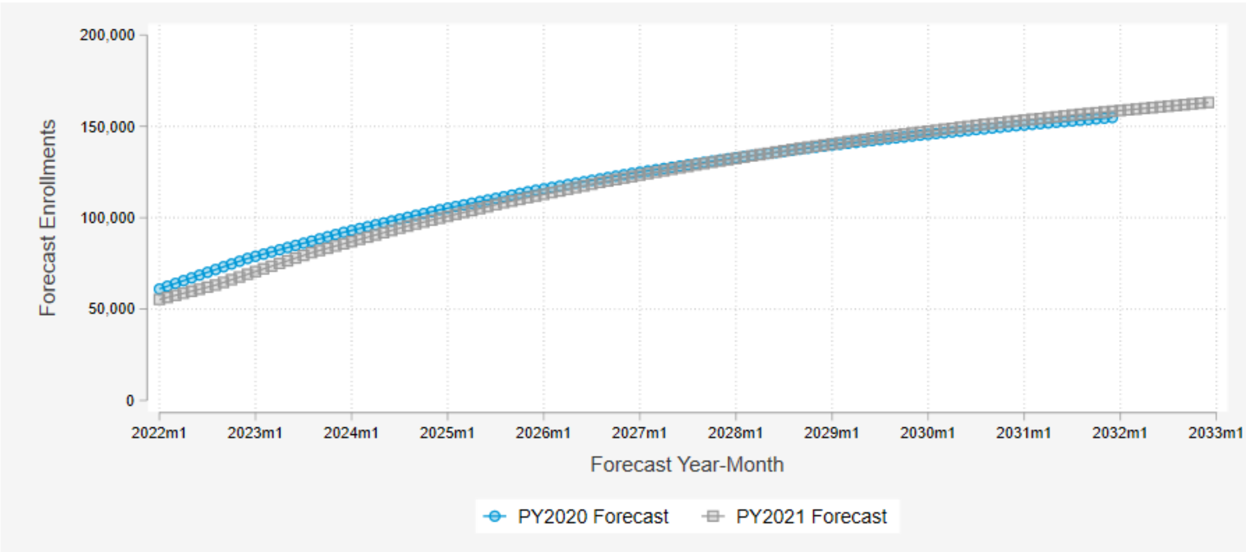
- The 2021 forecasted per-customer impacts are very similar between the two evaluation years despite a change to our second-stage impact model and an additional year of event data. PY2021 impacts tend to be slightly lower than PY2020. The other major difference between the two years is the effect of COVID applied to the 2020 impacts. The COVID impact increases reference loads and decreases impacts, leading to the smaller percent impacts shown in three of the four weather scenarios.

- The weighted average temperatures increase slightly between the PY2020 and PY2021 ex ante analyses due to a small shift in the regional balance of the SEP participant population.

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 PY2021 enrollment forecast is slightly lower than the PY2020 enrollment for every year until the 2028. We modify the annual forecasts to monthly assuming linear growth. However, in this section we do not recalculate the PY2020 ex ante impacts. Instead, we compare the PY2021 ex ante impacts to the official filed PY2020 ex ante numbers. Figure 33 compares the values on a monthly basis over an 11-year horizon.

Figure 33: Comparison of Ex Ante Enrollments: PY2021 vs. PY2020



For a 2022 typical event day, the PY2020 ex ante impacts assumed 77,727 participants. For comparison, the PY2021 ex ante impacts assume 63,114 participants – a reduction of 19%. The differences in the two forecasts decrease over time until 2028 when PY2021 forecast jumps ahead. Holding all other factors constant, the difference in expected enrollment will be 1% by 2031, bringing the expected aggregate impacts much closer together.

Typically, the only difference in impacts across years for the ex ante forecast is the enrollment forecast. Average per customer impacts are usually consistent across years. However, due to the assumed diminishing effect of COVID in 2020 ex ante, the per-customer impacts do not remain constant over time for the PY2020 projections. The PY2020 forecasted predicts approximately a 50% lingering effect of COVID in 2021, which then dissipated over time. This means that the overall difference between the 2020 and 2021 ex ante impacts would have converged to roughly the same outcome by the ends of their forecasts.

Table 23 compares the PY2020 and PY2021 aggregate ex ante load reduction estimates for forecast year 2022 on a typical event day using SCE peaking conditions. The 2021 average estimated performance across the five-hour RA window is 19% lower for 1-in-2 conditions and 21% lower for 1-in-10 conditions.

Table 23: Comparison of 2022 Aggregate Typical Event Day Ex Ante Impacts (MW): PY2020 vs. PY2021 with SCE Weather

Hour Ending	SCE 1-in-2		SCE 1-in-10	
	PY2020	PY2021	PY2020	PY2021
17	77.7	62.5	90.4	73.5
18	45.2	36.8	58.1	46.5
19	28.8	23.0	39.4	29.4
20	20.6	16.5	26.0	20.1
21	17.9	14.8	23.2	18.2
RA Window Average	**38.0**	**30.7**	**47.4**	**37.5**

Table 24 presents the same comparison using CAISO peaking conditions. Aggregate MW impacts are 19% lower for 1-in-2 weather and 20% lower for 1-in-10 weather.

Table 24: Comparison of 2022 Aggregate Typical Event Day Ex Ante Impacts (MW): PY2020 vs. PY2021 with CAISO Weather

Hour Ending	CAISO 1-in-2		CAISO 1-in-10	
	PY2020	PY2021	PY2020	PY2021
17	77.3	62.1	84.9	68.9
18	44.2	36.0	52.7	42.5
19	28.2	22.6	35.2	26.9
20	20.3	16.4	23.9	18.7
21	17.9	14.7	20.9	16.8
RA Window Average	**37.6**	**30.4**	**43.5**	**34.8**

5.5 EX POST TO EX ANTE COMPARISON

Weather conditions during PY2021 event days were cooler than the 1-in-2 ex ante weather conditions for the average 6pm to 8pm events. The observed weather during PY2021 was much cooler than 1-in-10 peak conditions. Figure 34 comes directly from the MS Excel ex post reporting template and shows the average SEP 6pm to 8pm event from PY2021. Figure 35 shows the average customer ex ante impacts for SCE 1-in-2 weather. It should be noted in the comparisons of the following figures that, the average event in 2021 was in the timeframe 6pm-8pm and ex ante is predicted in the window 4pm-9pm.

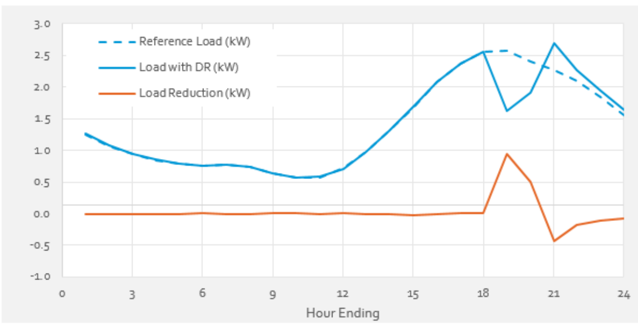
Figure 34: PY2021 Ex Post Average Event Day 6pm-8pm

Table 1: Menu options

Type of Result	Per Customer
Category	All
Segment	All Customers
Date	Average Event Day (6pm-8pm)

Table 2: Event day information

Total sites	48,498
Daily Max Temp	93.7
Average Impact - kW	0.73
Average Impact - %	29.1%
Full Hours Only - Average Impact - MW	0.73
Full Hours Only - Average Impact - %	29.1%



Hour Ending	Reference Load (kW)	Load with DR (kW)	Load Reduction	% Load Reduction	Avg Temp (°F, Site-Weighted)
1	1.25	1.26	-0.01	-1%	73.57
2	1.07	1.08	-0.01	-1%	72.42
3	0.94	0.95	-0.01	-1%	71.40
4	0.85	0.86	-0.01	-1%	70.73
5	0.79	0.79	0.00	-1%	70.20
6	0.76	0.76	0.00	0%	69.80
7	0.77	0.77	-0.01	-1%	69.39
8	0.74	0.74	0.00	0%	69.11
9	0.63	0.63	0.00	0%	71.04
10	0.57	0.56	0.01	1%	75.48
11	0.58	0.58	0.00	0%	80.37
12	0.72	0.71	0.01	1%	84.63
13	0.98	0.98	0.00	0%	87.74
14	1.32	1.33	-0.01	-1%	90.22
15	1.67	1.69	-0.02	-1%	91.95
16	2.08	2.09	-0.01	-1%	93.69
17	2.37	2.36	0.01	0%	93.46
18	2.57	2.55	0.01	1%	91.79
19	2.58	1.63	0.95	37%	89.65
20	2.41	1.91	0.50	21%	86.42
21	2.27	2.70	-0.43	-19%	82.31
22	2.09	2.27	-0.17	-8%	79.17
23	1.84	1.95	-0.10	-6%	76.97
24	1.56	1.63	-0.08	-5%	75.31
Daily	Reference Load (kWh)	Load with DR (kWh)	Energy Savings (kWh)	% Change	Daily Avg Temp (°F)
	33.40	32.77	0.62	2%	79.9

The "Average Impact (kW)" characteristic in Figure 35 is lower than the ex post impacts, because our "Average Event day" in 2021 was only a two-hour window. If you compare the first two hours of both figures, impacts are 0.79 kW from ex ante and 0.73 for ex post. This makes sense with the temperatures in 2021 being slightly lower than the 1-in-2 conditions.

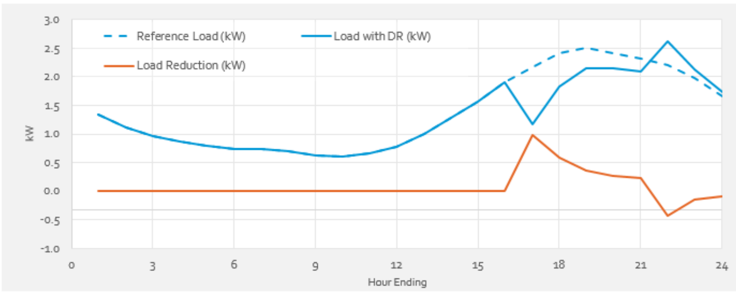
Figure 35: Ex Ante Typical Event Day under SCE 1-in-2 Conditions: 4pm to 9pm

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	2022
Portfolio Level	Portfolio

Table 2: Event day information

Event start	4:00 PM
Event end	9:00 PM
Total sites	63,114
Event window temperature (F)	88.4
Event window load reduction (kW)	0.49
% Load reduction (Event window)	20.6%
Redaction Information	Public



Hour Ending	Reference Load (kW)	Load with DR (kW)	Load Reduction (kW)	% Load Reduction	Avg Temp (°F, Site-
1	1.34	1.34	0.00	0.0%	74.11
2	1.12	1.12	0.00	0.0%	73.01
3	0.97	0.97	0.00	0.0%	72.07
4	0.86	0.86	0.00	0.0%	71.19
5	0.79	0.79	0.00	0.0%	70.43
6	0.75	0.75	0.00	0.0%	69.74
7	0.73	0.73	0.00	0.0%	69.21
8	0.71	0.71	0.00	0.0%	69.53
9	0.63	0.63	0.00	0.0%	72.04
10	0.61	0.61	0.00	0.0%	76.35
11	0.66	0.66	0.00	0.0%	80.80
12	0.79	0.79	0.00	0.0%	84.74
13	1.01	1.01	0.00	0.0%	87.54
14	1.29	1.29	0.00	0.0%	89.55
15	1.57	1.57	0.00	0.0%	91.15
16	1.90	1.90	0.00	0.0%	91.55
17	2.17	1.18	0.99	45.6%	91.75
18	2.41	1.83	0.58	24.2%	90.85
19	2.51	2.14	0.36	14.5%	89.21
20	2.42	2.16	0.26	10.8%	86.91
21	2.33	2.09	0.23	10.1%	83.52
22	2.20	2.62	-0.43	-19.4%	80.36
23	1.97	2.13	-0.15	-7.8%	78.22
24	1.66	1.74	-0.08	-5.1%	76.41
Daily	Reference Load (kWh)	Load with DR (kWh)	Energy Savings (kWh)	% Change	Daily Avg Temp (°F)
	33.39	31.62	1.77	5.3%	80.01

Figure 36 shows ex ante impact for the average customer under SCE 1-in-10 conditions, which assume a weighted average maximum daily temperature of 99.48°F. The predicted load impact across the five-hour RA window is 0.60 kW and the estimated load impact during the first two hours of dispatch is 0.95 kW. The average post-event load increase estimates are 0.50 kW, 0.19 kW, and 0.11 kW during hours ending 22, 23, and 24.

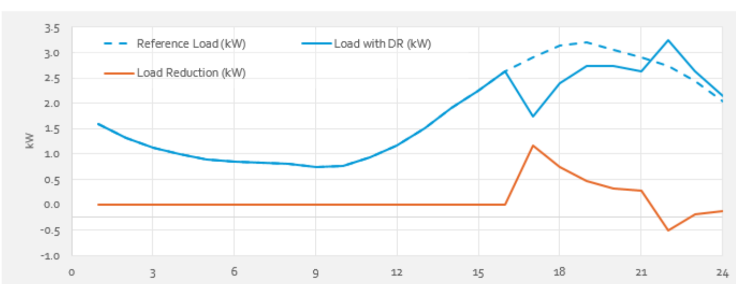
Figure 36: Ex Ante Typical Event Day under SCE 1-in-10 Conditions: 4pm to 9pm

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	2022
Portfolio Level	Portfolio

Table 2: Event day information

Event start	4:00 PM
Event end	9:00 PM
Total sites	63,114
Event window temperature (F)	95.8
Event window load reduction (kW)	0.59
% Load reduction (Event window)	19.6%
Redaction Information	Public



Hour Ending	Reference Load (kW)	Load with DR (kW)	Load Reduction (kW)	% Load Reduction	Avg Temp (°F, Site-
1	1.58	1.58	0.00	0.0%	78.36
2	1.31	1.31	0.00	0.0%	76.82
3	1.12	1.12	0.00	0.0%	75.49
4	0.99	0.99	0.00	0.0%	74.66
5	0.90	0.90	0.00	0.0%	73.76
6	0.85	0.85	0.00	0.0%	73.08
7	0.82	0.82	0.00	0.0%	72.50
8	0.80	0.80	0.00	0.0%	73.00
9	0.74	0.74	0.00	0.0%	76.13
10	0.77	0.77	0.00	0.0%	81.28
11	0.93	0.93	0.00	0.0%	86.83
12	1.17	1.17	0.00	0.0%	91.08
13	1.52	1.52	0.00	0.0%	93.83
14	1.90	1.90	0.00	0.0%	96.10
15	2.25	2.25	0.00	0.0%	97.96
16	2.62	2.62	0.00	0.0%	99.18
17	2.90	1.74	1.16	40.1%	99.48
18	3.12	2.39	0.74	23.6%	98.77
19	3.20	2.74	0.47	14.5%	96.97
20	3.05	2.73	0.32	10.4%	93.80
21	2.91	2.62	0.29	9.9%	90.13
22	2.74	3.24	-0.50	-18.3%	86.76
23	2.43	2.62	-0.19	-7.9%	83.82
24	2.04	2.15	-0.11	-5.6%	81.83
Daily	Reference Load (kWh)	Load with DR (kWh)	Energy Savings (kWh)	% Change	Daily Avg Temp (°F)
	42.67	40.50	2.17	5.1%	85.49

CAISO 1-in-10 peak conditions are milder than SCE 1-in-10 weather conditions for a typical event day. Figure 37 shows the ex ante estimates for an average SEP customer on a typical event day in 2022. The weighted average maximum daily temperature is 96.33°F and the average impact across the five-hour RA window is 0.55 kW.

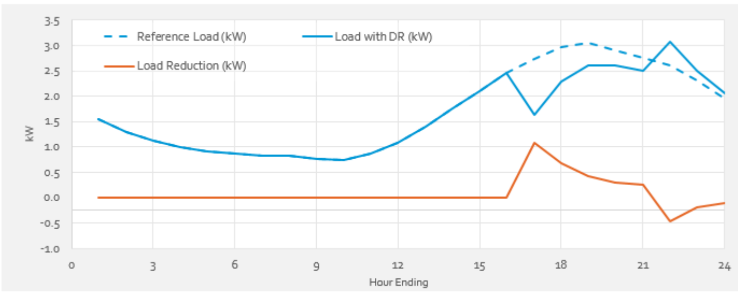
Figure 37: Ex Ante Typical Event Day under CAISO 1-in-10 Conditions: 4pm to 9pm Dispatch

Table 1: Menu options

Type of result	Per Customer
Category	All
Segment	All Customers
Weather Data	CAISO
Weather Year	1-in-10
Day Type	Typical Event Day
Forecast Year	2022
Portfolio Level	Portfolio

Table 2: Event day information

Event start	4:00 PM
Event end	9:00 PM
Total sites	63,114
Event window temperature (F)	92.9
Event window load reduction (kW)	0.55
% Load reduction (Event window)	19.1%
Redaction Information	Public



Hour Ending	Reference Load (kW)	Load with DR (kW)	Load Reduction (kW)	% Load Reduction	Avg Temp (°F, Site-
1	1.55	1.55	0.00	0.0%	77.81
2	1.30	1.30	0.00	0.0%	76.71
3	1.12	1.12	0.00	0.0%	75.67
4	1.00	1.00	0.00	0.0%	74.92
5	0.91	0.91	0.00	0.0%	74.10
6	0.86	0.86	0.00	0.0%	73.56
7	0.84	0.84	0.00	0.0%	73.08
8	0.82	0.82	0.00	0.0%	73.45
9	0.76	0.76	0.00	0.0%	76.10
10	0.75	0.75	0.00	0.0%	80.49
11	0.87	0.87	0.00	0.0%	85.29
12	1.08	1.08	0.00	0.0%	89.49
13	1.40	1.40	0.00	0.0%	92.28
14	1.75	1.75	0.00	0.0%	94.44
15	2.09	2.09	0.00	0.0%	95.79
16	2.45	2.45	0.00	0.0%	96.33
17	2.73	1.64	1.09	40.0%	96.24
18	2.96	2.29	0.67	22.7%	95.54
19	3.04	2.61	0.43	14.0%	93.99
20	2.89	2.60	0.30	10.3%	91.13
21	2.76	2.49	0.27	9.6%	87.40
22	2.60	3.07	-0.47	-18.1%	84.29
23	2.32	2.50	-0.18	-7.7%	82.13
24	1.94	2.05	-0.11	-5.4%	80.34
Daily	Reference Load (kWh)	Load with DR (kWh)	Energy Savings (kWh)	% Change	Daily Avg Temp (°F)
	40.79	38.80	2.00	4.9%	84.19

Aggregate ex ante impacts for 2022 are larger than the PY2021 ex post impacts because of the projected increase in enrollment. The average number of households dispatched during the average PY2021 event from 6pm to 8pm was 48,498. The enrollment forecast for a 1-in-2 August peak day in PY2022 is approximately 30% higher at 63,114. Table 25 compares the aggregate impacts for the most common PY2021 event profile to the August monthly peak day ex ante estimates for PY2022. Because the PY2021 events were short, we show the average impact during the first hour of dispatch.

Table 25: Comparison of PY2021 Ex Post Impacts to PY2022 Ex Ante Typical Event Day Impacts

Event Date	Max Daily Temp (F)	Hour 1 Temp (F)	Participants	Hour 1 kW	Hour 1 MW
Average Event Day (6pm-8pm)	93.7	89.7	48,498	0.95	46.0
2021 August Peak Day SCE 1-in-2 (4pm-9pm)	93.6	93.0	63,114	1.02	64.3
2021 August Peak Day SCE 1-in-10 (4pm-9pm)	97.0	96.9	63,114	1.11	69.8
2021 August Peak Day CAISO 1-in-2 (4pm-9pm)	93.4	92.7	63,114	1.01	63.8
2021 August Peak Day CAISO 1-in-10 (4pm-9pm)	96.2	96.0	63,114	1.09	68.5

6 DISCUSSION

Based on the 2021 ex post and ex ante evaluations, DSA highlights the following considerations for program design and future load impact evaluations.

- SCE resolved the contract issues that led to approximately 15% of participating households being unavailable for dispatch during summer 2020 DR events, but approximately 6,500 participants who did not agree to updated manufacturer terms and conditions were unenrolled from the program.
    - SEP had approximately 6,000 fewer enrollments at the beginning of the summer 2021 DR season than at the end of the summer 2020 DR season. Besides the 6,500 participants who were unenrolled due to not agreeing to updated terms and conditions, new enrollments during this time were offset by other types of customer attrition such as service turn offs and CCA migrations.
- For the third consecutive year, actual participation in SEP fell short of SCE's forecasted enrollment. The number of enrolled customers has a direct effect on the projected MW capability of the program so aggregate 2021 ex post load impacts were lower than our 2020 ex ante estimates.
    - ✓ The PY2021 enrollment forecast assumes a slower growth rate than prior forecasts. SCE recently received approval to enroll unbundled service customers (e.g., CCA members) who take delivery from SCE in SEP. Once SCE is able to implement this program change, DSA believes it will help program staff achieve the projected enrollment levels.
    - ✓ Our ex ante load impact estimates assume that the distribution of SEP enrollments in the future will mirror the program composition at the end of summer 2021. If SCE enrolls a significant number of participants in a specific CCA territory, it could shift the weighted average weather conditions of the program population.
- Our parallel ex post evaluation using delivered loads rather than net loads shows that the use of delivered loads for settlement systematically understates the performance of SEP due to the prevalence of NEM customers in the program. While the bias is pronounced during the afternoon when solar production is greatest, by hour ending 19:00, there is almost no difference in load impacts between net and delivered loads.
    - ✓ DSA recommends SCE discuss these findings with CAISO and the other IOUs and recommend net loads as the basis for economic settlements of programs like SEP. This change would remove the disincentive to enrolling NEM customers and better reflect program performance. We expect this issue to become more salient as NEM customers adopt batteries capable of discharging stored solar electrons across the RA window.

- Weather conditions in 2021 were relatively mild. The system peak day (9/9/2021) at 93.2 degrees (F) maximum daily temperature was actually milder than 1-in-2 weather conditions, which are projected to be 95.6 degrees (F).

  - ✓ For weather-sensitive programs like SEP, a change of a few degrees translates to MWs of load impact capability. The 2021 ex ante evaluation highlights the importance of using multiple years of ex post load impacts. Without results from 2019 and 2020, DSA would have needed to extrapolate well out of sample to estimate SEP's capability at 1-in-10 weather conditions.

- The COVID-19 pandemic affected all aspects of life in 2020. In the 2020 ex ante modeling of reference loads and impacts, we included a COVID indicator term to capture the differences between summer 2020 and prior years. At a high level, that means in 2020 we estimated slightly higher reference loads under COVID and slightly lower load impacts holding other conditions constant with the effect gradually decreasing until 2031. In 2021, however, we assume that we have entered a 'new normal', which means that we expect the current levels of reference loads to persist as they are.

  - ✓ SEP events during the heat waves of 2020 provide valuable information on program performance at extreme temperatures so we included those event impacts in our ex ante estimates. However, we excluded load data from March 2020 – December 2020 from the reference load modeling procedure.

- 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.

- The rollout of default TOU in SCE territory is underway. The COVID-19 pandemic altered the initial rollout plan, but SCE plans to transition the majority of residential customers before the summer 2022 DR season. As shown in Table 4, almost 28% of SEP participants faced time-varying pricing (TOU) during PY2021. The rollout of default TOU may alter SEP participant reference loads and potentially change the average load impact of SEP dispatch.

  - ✓ Figure 21 showed that ex post percent impacts on the 2021 system peak day (September 9, 2021) were larger for SEP participants that faced flat pricing, but comparable on kW basis.

- SEP does not hold a consistent load shed under the current event profile. Event impacts are largest during the first hour of dispatch and deteriorate in each subsequent hour. [redacted]

- ✓ [redacted]
- ✓ [redacted]
- ✓ [redacted]