REPORT

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2019 Smart Energy Program Load Impact Evaluation

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Prepared for Southern California Edison

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1 EXECUTIVE SUMMARY

This report documents the 2019 load impact evaluation of the 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 2019. The primary objectives of this report are to:

- Document the findings of an ex post (after the fact) load impact study for 2019 events
- Provide ex ante (forward looking) estimates of SEP peak demand reduction capability over the next eleven years (2020 to 2030) under various weather conditions.

When SCE initiates SEP events, the six participating thermostat providers adjust cooling setpoints upward by as much as four degrees (F) to limit air conditioning usage and reduce electric demand. SEP events can be called for either emergency or economic purposes. There were no emergency events called in PY2019. SEP was dispatched on 18 days during PY2019 between July and October. On 15 event days, the dispatch trigger was economic and the other three event days were for measurement and evaluation purposes.

SEP enrollments were consistent from 2018 to 2019 in terms of total participant count. However, approximately 25% of the PY2019 participants were new to the program since PY2018. Customers are required to receive bundled service from SCE in order to participate in SEP and in spring 2019 a significant number of accounts were released from SEP due to migration to Community Choice Aggregators (CCAs).

In 2019, SEP was integrated into the California Independent System Operator (CAISO) wholesale energy market where it was offered as a dispatch resource based on energy prices. As a result of integrating into the CAISO market, 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, SEP events were called from 2pm to 6pm. The two most common event profiles in 2019 were 5pm to 9pm (four hour duration) and 6pm to 8pm (two hour duration). This transition corresponds to the shift in the Resource Adequacy (RA) window established by the CAISO.

1.1 SUMMARY OF EX POST LOAD IMPACTS

There were 23 distinct SEP events dispatched in 2019 on 18 different days. SEP events are dispatched by Sub-Load Aggregation Point (sub-LAP) and are often, but not always called for the entire territory. Sub-LAPs can be dispatched at different hours on the same day. We consider events to be unique when sub-LAPs have different start times, end times, or event durations. Additionally, multiple events can be called for the entire territory on a single date, as occurred on August 13, 2019 when SEP was dispatched from 5pm-6pm and 8pm-9pm. For the purposes of analysis, the August 13th events were evaluated together because they occurred on the same date, across the same population.

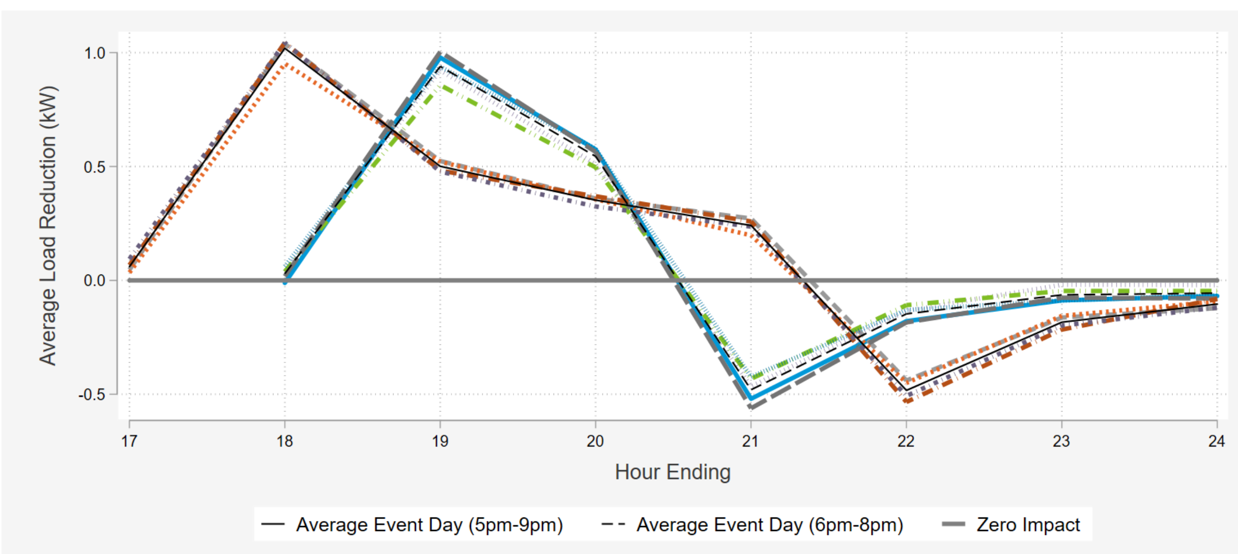
Demand Side Analytics utilized a matched control group with regression analysis to estimate the impacts of each event across the full participant group and a variety of segments. Table 1 shows the event details and average hourly impacts for the territory wide events.

Table 1: Territory Wide Event Impacts

Event Date	Dispatch Region	Start Time	End Time	Participants	Average Event Temp	Daily Max Temp	Average Hourly Impact (kW Reduction)	Average Aggregate Hourly Impact (MW Reduction)
7/24/2019	Territory Wide	6:00 PM	8:00 PM	51,009	84.8	96.5	0.78	39.6
8/13/2019	Territory Wide	5:00 PM	6:00 PM	51,946	81.9	90.0	0.83	43.0
	Territory Wide	8:00 PM	9:00 PM					
8/14/2019	Territory Wide	5:00 PM	9:00 PM	51,932	85.1	92.7	0.55	28.5
8/15/2019	Territory Wide	5:00 PM	9:00 PM	52,024	83.3	91.9	0.51	26.4
8/27/2019	Territory Wide	6:00 PM	8:00 PM	52,259	81.4	89.9	0.72	37.4
8/28/2019	Territory Wide	6:00 PM	8:00 PM	52,240	80.4	86.3	0.68	35.4
9/3/2019	Territory Wide	6:00 PM	8:00 PM	52,441	86.2	93.9	0.78	41.1
9/4/2019	Territory Wide	5:00 PM	9:00 PM	52,432	86.1	96.9	0.54	28.2
9/5/2019	Territory Wide	5:00 PM	9:00 PM	52,562	85.2	93.0	0.52	27.4
9/13/2019	Territory Wide	6:00 PM	8:00 PM	52,664	85.9	94.1	0.76	39.9
10/16/2019	Territory Wide	1:00 PM	5:00 PM	52,927	84.7	86.8	0.07	3.9
Average Event Day (6pm-8pm)	Territory Wide	6:00 PM	8:00 PM	52,129	83.8	92.0	0.74	38.7
Average Event Day (5pm-9pm)	Territory Wide	5:00 PM	9:00 PM	52,239	84.9	93.4	0.53	27.6

DSA defines Average Event Days as the weighted average of the applicable territory wide events with the standard event windows of either 5pm to 9pm (four hour duration) or 6pm to 8pm (two hour duration). The averages and their contributing dates are shown in Figure 1. The SEP impacts are fairly consistent across events. By far the most important predictor of load impact is event hour, or whether a given hour is the first, second, third, or fourth hour of dispatch. The first hour of the average events provide a reduction of approximately 1.0 kW. Each subsequent hour tapers off, but the average four hour event maintains positive reductions in all four event hours. Savings estimates presented in Table 1 show the average hourly impacts. It is important to note that events with longer event windows are expected to have lower hourly impacts because of this tapering trend, thus lowering the average event impact with each additional hour of dispatch.

Figure 1: Hourly Load Reductions for Territory Wide Average Events



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DATA DRIVEN RESEARCH AND INSIGHTS

The system peak day in 2019 was September 4th. The four hour event on that day had an average per customer hourly reduction of 0.54 kW and an average aggregate hourly savings of 28.2 MW. The Average Event Day with the four hour duration had an aggregate hourly reduction of 27.6 MW and the two hour duration Average Event Day had an aggregate hourly savings of 38.7 MW. Across all territory wide events (regardless of event window), hourly savings among all participants was 29.1 MW.

1.2 SUMMARY OF EX ANTE LOAD IMPACTS

SEP events can be called anytime during the year between 11:00 and 9:00 pm. In the ex ante impacts, SEP events are assumed to span the RA window, beginning at 4pm and last until 9pm. This event profile prevents any post-event demand increases 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 2 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 and difficult to detect visually in Figure 2. Although SEP can be dispatched year round, it is a weather sensitive program with little or no impact when air conditioning is not being used. Using SCE 1-in-2 weather for monthly system peak days, we estimate SEP impacts in April through November. Using CAISO 1-in-2 weather we estimate SEP impacts for May through October.

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

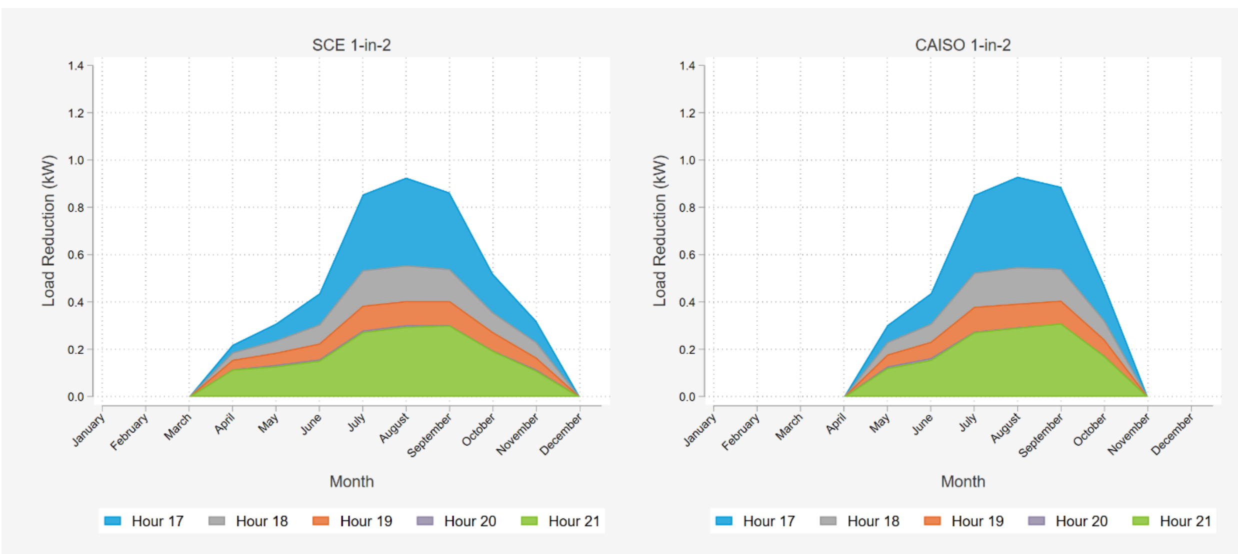
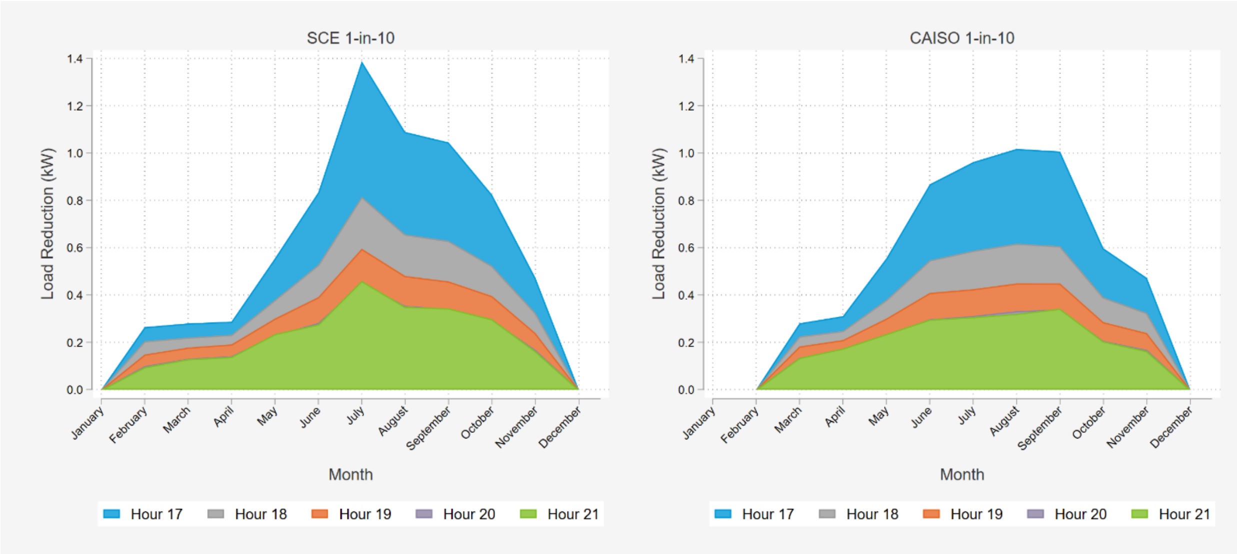


Figure 3 shows the same set of results for 1-in-10 weather conditions, which are more extreme than 1-in-2 conditions.

Figure 3: Average Customer Ex Ante Impacts on 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 104.5 degrees (F) and the estimated average load impact is 1.39 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 94.2 degrees (F) and the estimated load is 0.96 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 system peak day in 2020. The estimated load impact of SEP in 2020 ranges from 55.8 MW to 65.6 MW during hour ending 17:00. Estimated impacts decline across the RA window and range from 17.6 MW to 21.1 MW in hour ending 21:00. Average impacts for the five hour RA window range from 29.6 MW to 35.3 MW.

Table 2: SEP Aggregate Ex Ante Impacts (MW) During RA Window: 2020 August System Peak Day

Hour Ending	SCE 1-in-2	CAISO 1-in-2	SCE 1-in-10	CAISO 1-in-10
17	55.8	56.0	65.6	61.3
18	33.5	33.0	39.5	37.2
19	24.3	23.7	28.9	27.0
20	18.2	17.7	21.3	20.0
21	17.8	17.6	21.1	19.3
RA Window Average	**29.9**	**29.6**	**35.3**	**33.0**

SCE forecasts that SEP enrollments will approach 196,000 households by 2030. 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 97.2 MW for SCE 1-in-2 weather conditions on an August system peak day and 114.7 MW for SCE 1-in-10 conditions on an August system peak day in 2030. Using CAISO peaking conditions, we estimate an aggregate impact of 96.1 MW for 1-in-2 conditions and 107.1 MW for 1-in-10 conditions on an August system peak day.

1.3 RECOMMENDATIONS

Based on the findings of the PY2019 load impact evaluation, Demand Side Analytics makes the following program and evaluation recommendations for SEP.

- 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.
- If a more consistent load impact across dispatch hours is desired there are several tactics used by other program administrators to mitigate the decay of impacts across the event. We recommend SCE discuss the feasibility of these options with the program thermostat providers.
  - ✓ 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 more consistent impacts across event hours.
  - ✓ 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.
  - ✓ 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 setpoint. Pre-cooling can also reduce participant opt-outs through increased participant comfort. The required response time of the program is a key factor in determining whether pre-cooling is a viable option.

- The PY2019 analysis showed a more rapid decline in impacts across event hours than the PY2018 analysis. This may be weather related as outdoor temperatures are declining during the evening hours when PY2019 events were dispatched. Another potential reason for the observed decline is more frequent customer opt-outs due to increased occupancy during evening hours. SEP allows customers to override the thermostat setpoint modification, however marketing materials note that *"At SCE's discretion, customers may be removed from the Program for overriding all energy events dispatched in a calendar year, when overrides consistently occur within the first hour of events."*

  - ✓ We recommend SCE request thermostat-level operating data from the SEP thermostat providers. This supplemental information could provide valuable insights into whether customer opt-outs are driving the reduction in impacts in the second, third, and fourth hour of SEP events.

  - ✓ With granular thermostat runtime, setpoint, and indoor temperature data we would be able to examine SEP impacts as a function of cooling load, in addition to whole-house loads.

  - ✓ Thermostat operating data would also allow for an exploration of the changes in indoor temperature within homes during SEP events.

- SCE is deploying default TOU pricing for residential customers in 2020. The transition is scheduled to begin in October 2020 so much of the PY2020 SEP event activity will be prior to the transition. As shown in Table 4, less than 20% of SEP participants faced time-varying pricing during PY2019. The rollout of default TOU may alter SEP participant reference loads and potentially change the average load impact of SEP dispatch.

- Participating homes can have more than one thermostat. It would be a useful segmentation variable if the number of controlled thermostats or condensing units in the home was captured.

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 setpoint. During SEP events, thermostat providers can adjust cooling setpoints upward by as much as four degrees (F) to limit air conditioning usage during peak hours. Limiting air conditioning usage lowers electric demand by participating households. Multiple events can be called on a single day, but the number of hours of control cannot exceed four hours in a given day. Dual enrollment in Critical Peak Pricing (CPP) dispatchable pricing tariffs or the Summer Discount Plan (SDP) program is prohibited.

SEP has evolved considerable 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 are sent 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 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. Events can be called 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) may only be dispatched within 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 11:00 am to 9:00 pm. SEP dispatch for triggers A, B, and D can be activated at any time including weekends and holidays. No more than 180 hours of SEP events can be called in a calendar year for all dispatch triggers combined.

SEP events were called on a total of 18 days during 2019. Table 3 lists the event dates and dispatch reason. On three days, events were called for measurement and evaluation purposes. The other 15 event days were economic dispatch. SEP events can be dispatched by Sub-Load Aggregation Points (sub-LAPs). The September 4, 2019 event is shaded Table 3 because it was the system peak day for 2019.

Table 3: 2019 SEP Event Days and Dispatch Reason

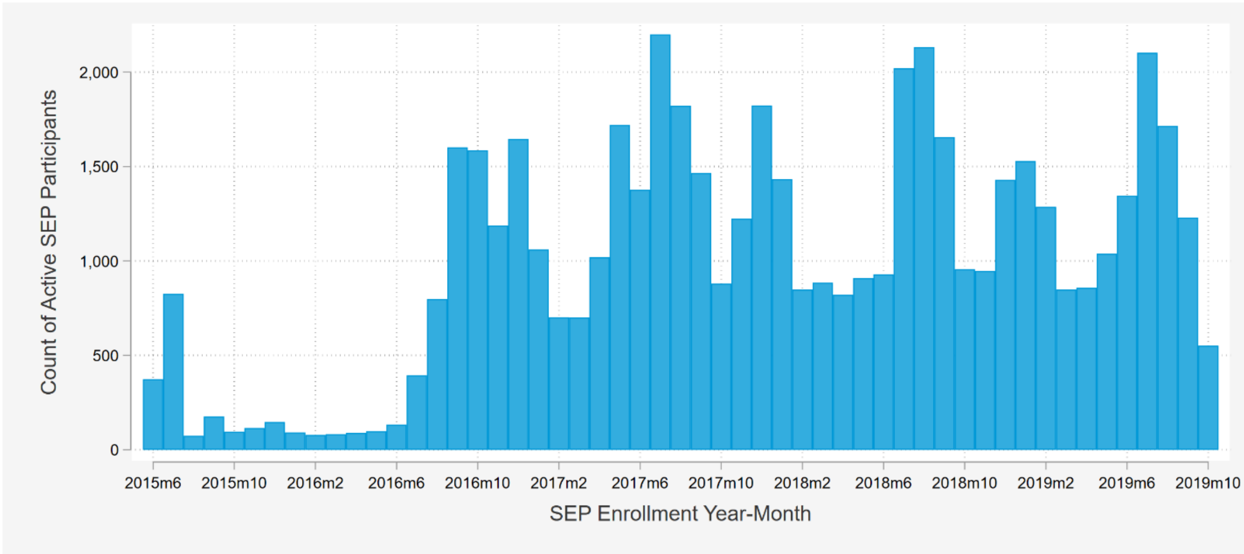
Date	Dispatch Trigger	Sub-LAPs Dispatched
7/24/2019	Measurement & Evaluation	Territory Wide
8/13/2019	Measurement & Evaluation	Territory Wide
8/14/2019	Economic	Territory Wide
8/15/2019	Economic	Territory Wide
8/21/2019	Economic	Territory Wide*
8/26/2019	Economic	SCEC, SCEW, SCHD, SCLD, SCNW
8/27/2019	Economic	Territory Wide
8/28/2019	Economic	Territory Wide
9/3/2019	Economic	Territory Wide
9/4/2019	Economic	Territory Wide
9/5/2019	Economic	Territory Wide
9/12/2019	Economic	SCNW
9/13/2019	Economic	Territory Wide
9/24/2019	Economic	Territory Wide*
9/25/2019	Economic	Territory Wide*
10/16/2019	Measurement & Evaluation	Territory Wide
10/21/2019	Economic	SCEN, SCNW
10/22/2019	Economic	SCEN
* All LCGs were dispatched but event start and end times varied by sub-LAP		

There were approximately 52,000 active participants in SEP during the summer 2019 event season. This is slightly higher than the approximately 51,000 active participants during the summer 2018 event season. However, the similar total number of enrollments is a result of two directionally opposite factors.

- Approximately 16,000 new participants were added to SEP since the conclusion of the PY2018 event season.
- To participate in SEP, customers must receive bundled service from SCE. Prior to the 2019 event season approximately 11,000 SEP participants were dropped from the program due to migration to Community Choice Aggregations (CCA).
    - SCE is exploring the possibility of enrolling unbundled customers in future years.

Figure 4 shows the distribution of enrollment month among households that were active in SEP at the conclusion of the PY2019 event season. Historically, enrollments have been highest during the summer months when bill credits are available and program marketing efforts are most active.

Figure 4: Distribution of Enrollment Month among Active SEP Participants



There was also churn among the SEP participant population during the PY2019 event season. Approximately 1,600 households that were active during the first PY2019 event on July 24, 2019 left the program prior to the last event on October 22, 2019. Conversely, approximately 4,000 households were active during the final PY2019 event that had not enrolled on July 24, 2019 when the first SEP event was called.

At the conclusion of PY2019, there were approximately 53,000 active participants in SEP. Table 4 shows the distribution of active participants across various segmentation variables of interest.

- 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 2019. Tiered rates based on consumption are considered flat because they do not vary by time of day.
- The 'Size' variable is based on the average net load on weekdays during the Resource Adequacy window of 4pm to 9pm. Participants were binned based on whether they were above or below the median value of 1.82 kW. By selecting the median value as the size cutoff, by definition, exactly half of the participants are below the size threshold and the other half are above.
- Approximately 17% of SEP participants have net energy metering (NEM) of rooftop solar arrays. All load impact analysis is conducted using net load so to the extent a home with solar becomes a larger net exporter because of reduced air conditioning demand, SEP is credited with those impacts. As noted in the discussion of participant matching in Section 3.1, NEM participants are matched with NEM non-participants for analysis.
- [redacted]
- SEP participants also enrolled in the CARE or FERA programs are indicated by the 'Income Qualified' segment

- The LCA variable indicates the load capacity area. Almost 86% of SEP participants are located in the LA Basin LCA.
- 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.
- The Sub-LAP variable segments participants by sub-load aggregation point.

Table 4: Summary of SEP Enrollment by Customer Segment

Segmentation Variable	Segment Description	Participants (N)	Participants (%)
Tariff Type	Dynamic	10,514	19.8%
	Flat	42,534	80.2%
Size	Greater than 1.82 kW during RA window	26,524	50.0%
	Less than 1.82 kW during RA window	26,524	50.0%
Net Energy Metering Status	Not NEM	43,892	82.7%
	NEM	9,156	17.3%
[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]
Income Qualified	Non-Care/FERA	46,412	87.5%
	CARE/FERA	6,636	12.5%
LCA	Big Creek/Ventura	6,329	11.9%
	LA Basin	45,472	85.7%
	Outside LA Basin	1,247	2.4%
Region	Remainder of System	23,287	43.9%
	South Orange County	10,602	20.0%
	South of Lugo	19,159	36.1%
Sub-LAP	SCEC	22,615	42.6%
	SCEN	5,265	9.9%
	SCEW	22,855	43.1%
	SCHD	1,279	2.4%
	SCLD	46	0.1%
	SCNW	988	1.9%
All Customers		**53,048**	**100.0%**

The SEP participant population is located across SCE service territory and experience a wide range of weather conditions. At the conclusion of the PY2019 event season, there were active participants in nine of the sixteen California climate zones. For both the ex post and ex ante analysis each participant was mapped 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 November 1, 2016 to October 31, 2019. CDD and HDD were each calculated using a base of 60 degrees (F). There are relatively few SEP participants in areas with mild summer weather that requires limited air conditioning.

Table 5: SEP Enrollments by Weather Station with Three-Year Average CDD60 and HDD60

Weather Station	SEP Enrollments	CDD60	HDD60
173	14,871	2,277	328
121	8,321	2,510	997
122	7,022	4,026	371
172	3,753	1,806	412
111	2,698	2,552	553
132	2,697	2,486	841
112	2,644	2,459	478
171	2,355	1,981	448
181	2,334	5,785	324
51	1,448	3,156	1,306
161	1,124	1,214	464
194	905	2,815	1,650
193	833	3,243	1,458
123	558	1,579	868
151	415	1,072	715
131	306	1,038	3,385
191	272	4,132	1,424
195	182	3,075	1,563
113	109	1,282	689
192	66	3,856	1,275
101	60	421	6,001
182	45	5,714	452
141	29	2,238	2,744

3 EVALUATION METHODOLOGY

3.1 EX POST METHODS

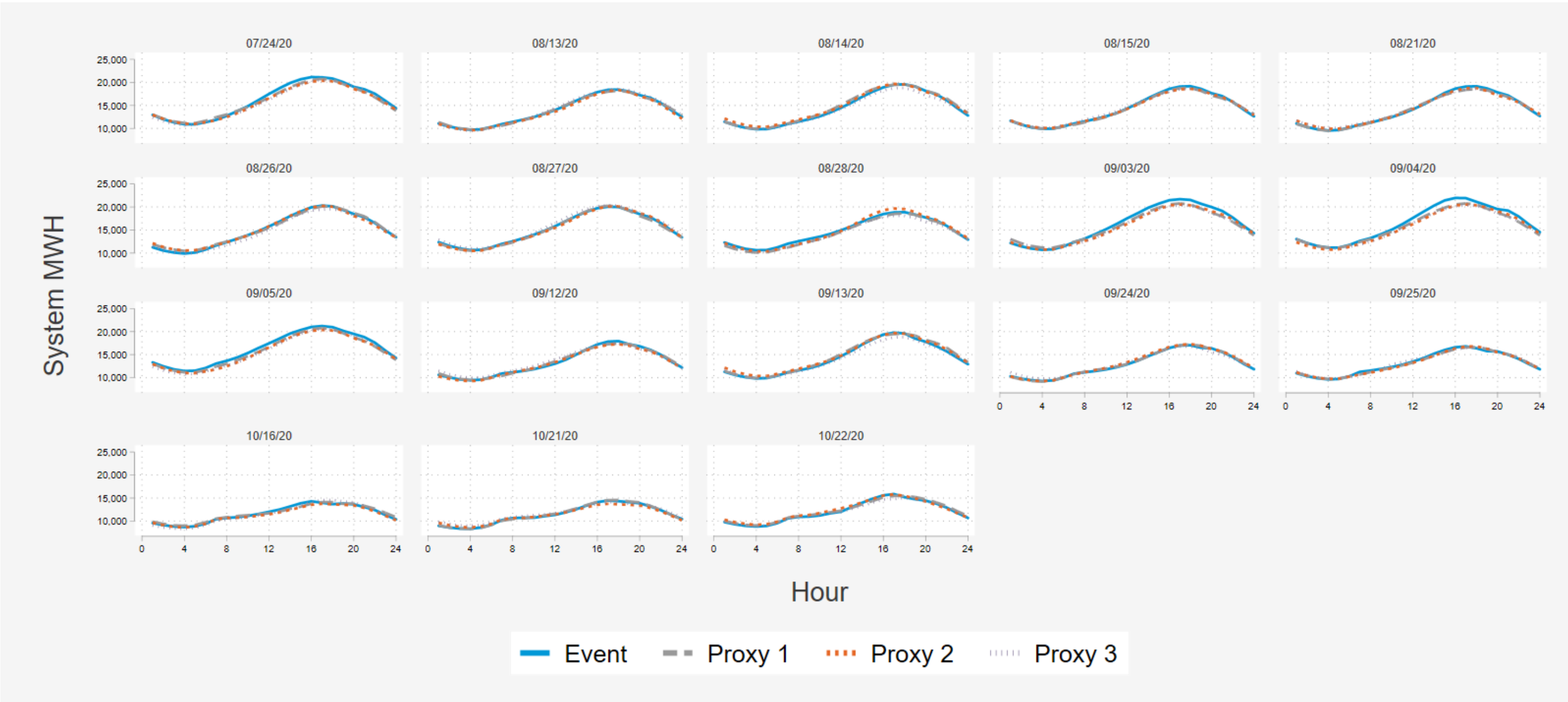
Overview of Evaluation Method Selected

DSA utilized a matched control group and regression analysis for the 2019 SEP program evaluation. The matched control group customers were pulled from a stratified random sample, which ensures that large and/or unique participants are still likely to find an appropriate match. The control group is selected using non-event day load patterns, geographic location, and other customer characteristics (e.g., net metering status) to develop propensity scores within each stratum. For each participant, the nearest neighbor based on propensity scores is identified. The matched control group was selected through the use of proxy days and propensity score matching and the regression analysis incorporated a simple difference in difference model. The small differences between the participant and matched control group on proxy days were netted off of the differences observed on event days. The program was evaluated across all customers as well as at a segment level for a variety of categories including sub-LAP, size, tariff rate, and more.

Proxy Day Selection

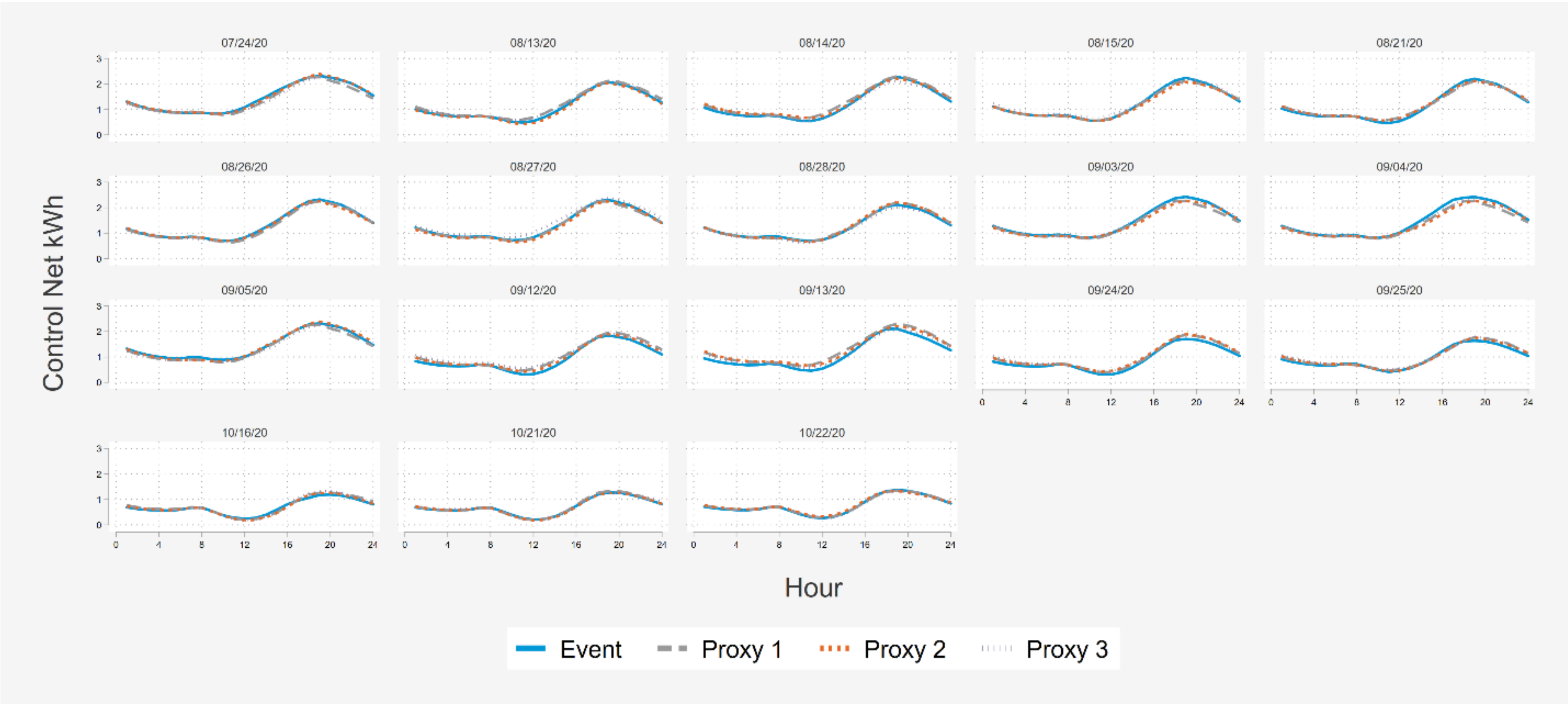
Euclidean distance matching was used to select a set of proxy days for each SEP event. Proxy days are chosen from the set of non-holiday, summer weekdays in 2019. The first 2019 SEP event was in July and the last was in October, so summer is defined here as July through October. The selected matches are chosen based on SCE system load. For every event date, the three most similar SCE system load days are chosen. 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 5 shows each event date with its three selected matches.

Figure 5: Event and Proxy Day System Load



The data used to construct a matched control group and the participant data do not represent the full SCE system. In order to confirm that selected proxy days are also a satisfactory match within our sample, we map a similar figure using the full stratified sample of non-participant homes provided for matched control group selection. Load shapes vary between Figure 5 and Figure 6 due to differences between our sample and the full population, but the proxy days are visibly well aligned with the event day loads for the full pool of non-participant homes from which the matched control group was selected.

Figure 6: Event Day and Proxy Day Loads for Matching Pool

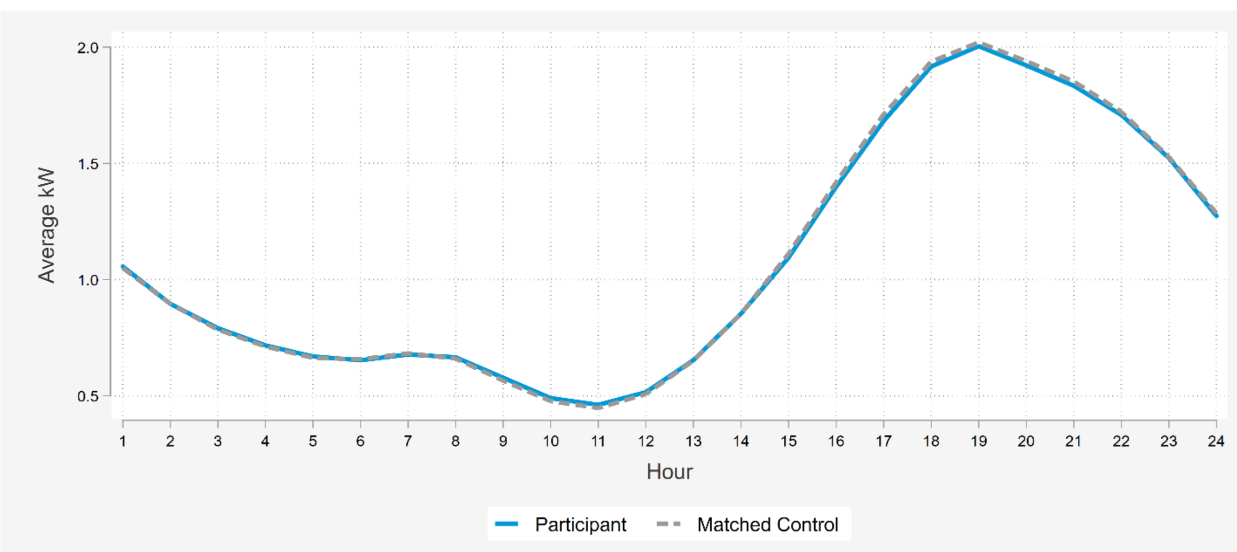


Participant Matching

Using the SEP participant and non-participant load data on the full set of proxy days, matches are selected for each participant with propensity score matching. 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. Climate zone is discussed in Section 2. 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. The best PSM model is selected 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 2019 analysis, all treatment households were matched. Matches are assigned pseudo characteristics, where each match takes on the characteristics of its participant household. For matches that are selected multiple times, the load will be represented multiple times in the regression analysis, but the characteristics will vary based on each unique participant. Figure 7 compares the average hourly kW by treatment and control group on all proxy days. There is a subtle deviation in the peak and trough, so an hourly difference-in-differences regression analysis is used to estimate load impacts and capture any remaining statistical difference between the treatment and control groups.

Figure 7: Average Hourly kW on Proxy Days



Ex Post Model

Demand Side Analytics used a difference-in-difference (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. Hourly impacts are then appended to form full event impacts, which are detailed in Section 4. The model specification is provided in Equation 1 and components are described in Table 6.

Equation 1: Ex Post Regression

$$kW_{ih} = \beta_{0h} + \beta_{1h} * date + \beta_{2h} * treat * eventDay + v_{ih} + \varepsilon_{ih}$$

Table 6: Regression Description

Model Term	Description
kW_{ih}	Net electrical demand in kW for customer i, in hour h
β_0	Mean demand for all customers on proxy days in hour h
β_1	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_2	Regression coefficient of interest
$treat$	Indicator variable for the SEP participant group
$eventDay$	Indicator variable for the SEP event day
$treat * eventDay$	Interaction term equal to 1 for treated customers on the event day and 0 otherwise
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, kWih 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. β_2 captures the coefficient on this interaction and represents the average impact of the SEP event. v_{ih} captures the customer fixed effects and the error term captures any remaining unobserved differences.

For each of the 22[1] events 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.

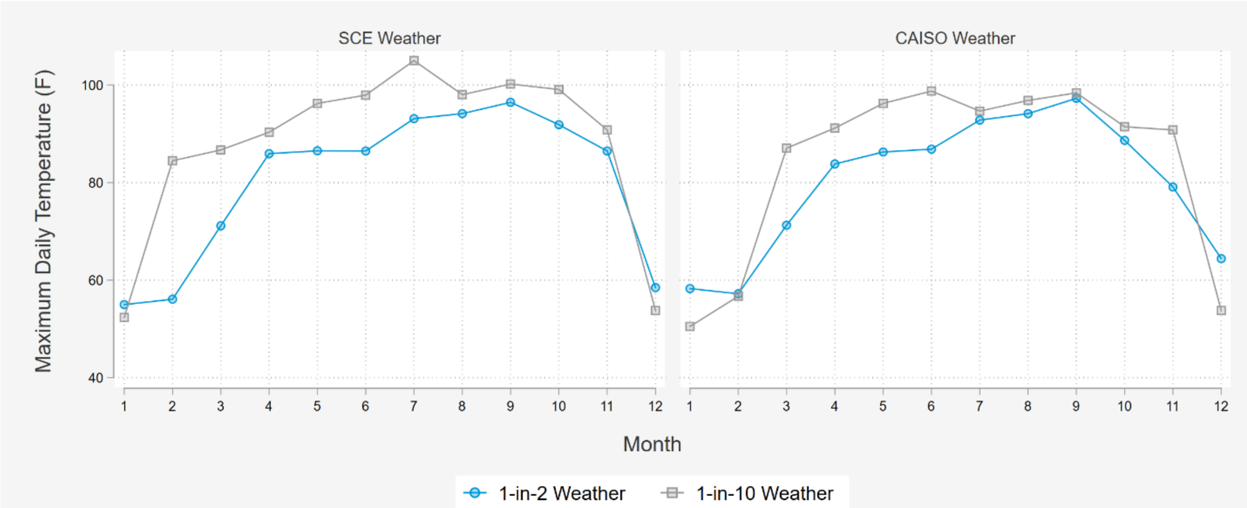
3.2 EX ANTE METHODS

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 estimation 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
- Average weekdays and a 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
- A SCE forecast and a CAISO forecast. Both forecasts have 1-in-2 and 1-in-10 weather for all weather stations.
- Figure 8 compares the maximum daily temperature for each month of the year for monthly system peak days using the 1-in-2 and 1-in-10 weather for the SCE and CAISO forecasts. The forecasts across weather stations are weighted using the number of active SEP participants at the conclusion of PY2019 that were shown in Table 5. These weights are assumed to hold 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 11 degrees (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.

[1] While there are 23 SEP events in PY 2019, the two events on 8/13/2019 are evaluated as a single event.

Figure 8: Monthly System Peak Day Comparison by Forecast

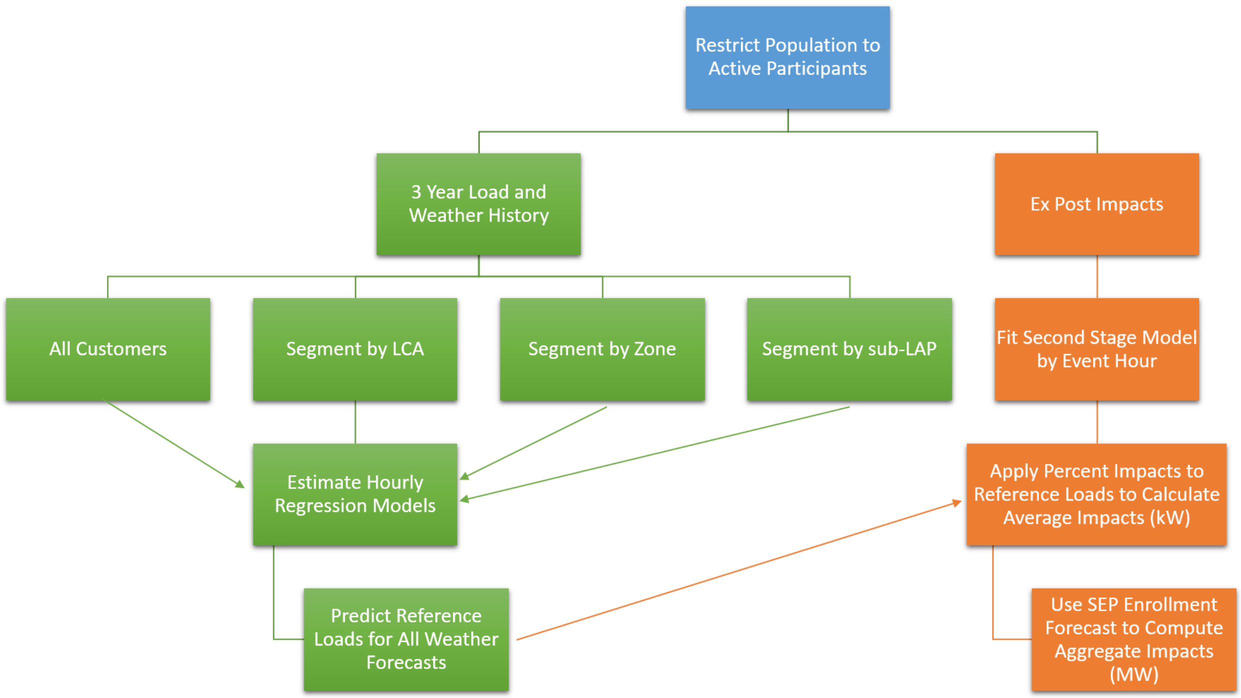


During PY2019 SEP events were dispatched at different times of day and the duration of events varied from one to four hours. Ex ante estimation requires a single event profile to be selected. The ex ante event profile was selected to mirror the CAISO RA window, which begins at 4pm and ends at 9pm for all months of the year. This event profile avoids post-event snapback during the RA window. Dispatch from 5pm to 9pm was a common event profile in PY2019, which makes the translation of ex post results to ex ante relatively straightforward and free of modeling assumptions. There were no five hour events during PY2019, or prior years so we assume the percent 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 9 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 less complex than the ex post segmentation of customers. We calculate the share of active participants by LCA, Region, and sub-LAP and assume these ratios will hold constant over time as the enrollment forecast grows. Because the PY2019 SEP events were called much later in the day than PY2017 and PY2018 events, we use a single year of ex post impacts to estimate percent reductions as a function of weather and event hour.

Figure 9: Ex Ante Estimation Process Diagram



Ex Ante Reference Load Model

DSA estimated a total of 13 different reference load regression models. One model was developed for all active participants. Separate models were developed for the three LCAs, three regions, and six sub-LAPs. The specific modeling steps taken were:

- Merge hourly load data and hourly weather data for all active SEP participants for November 2016 through October 2019.
- Drop any SEP or SPD event days.
- 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.
- Calculate the average hourly load and weather conditions for each of the seven segments of interest.
- Estimate the regression model shown in Equation 2

Equation 2: Reference Load Regression Model Specification

$$Net\ kW_i = \beta_0 + \beta_1 * CDD60 + \beta_2 * HDD60 + \beta_3 * RH + \beta_4 * HDH55 + \beta_5 * CDH70 + \beta_m * Month + \beta_h * Hour + \beta_{h,w} * Hour * (CDH70 + HDH55) + \beta_{m,w} * Month * (CDH70 + HDH55) + \varepsilon_i$$

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
CDD60	Cooling degree days base 60 degrees (F)
β_1	Regression coefficient for the CDD60 term
HDD60	Heating degree days base 60 degrees (F)
β_2	Regression coefficient for the HDD60 term
RH	Relative humidity
β_3	Regression coefficient for the RH term
HDH55	Heating degree hours base 55 degrees (F)
β_4	Regression coefficient for the HDH55 term
CDH70	Cooling degree hours base 70 degrees (F)
β_5	Regression coefficient for the HDH55 term
Month	Array of indicator variables denoting the month of the year
β_m	Regression coefficients for the month indicator variables
Hour	Array of indicator variables denoting the hour of the day
β_h	Regression coefficients for the hour indicator variables
$\beta_{h,w}$	Regression coefficients for the interactions between hour and the degree hour weather terms
$\beta_{m,w}$	Regression coefficients for the interactions between month and the degree hour weather terms
ε_i	Error term

The regression coefficients estimated for each model run were then used to predict average hourly demand for electricity for the array of ex ante weather conditions. Weighted average conditions were computed for each of the 13 segments using the number of active SEP participants mapped to each constituent weather station. Figure 10 shows the predicted reference loads for all customers, the three LCAs, and three Zones on an August system peak day using SCE 1-in-2 weather. Like the PY2018 evaluation, the Big Creek/Ventura LCA has the highest reference loads during the RA window while the South Orange County region has the smallest reference loads during the RA window.

Figure 10: Reference Load by Segment: August System Peak Day, SCE 1-in-2 Weather

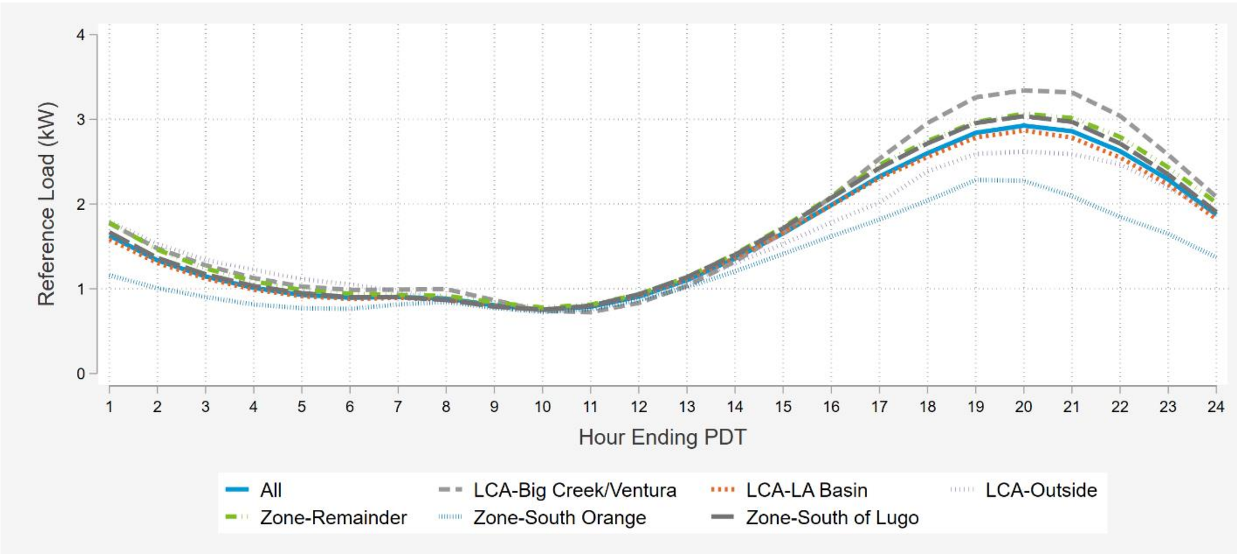
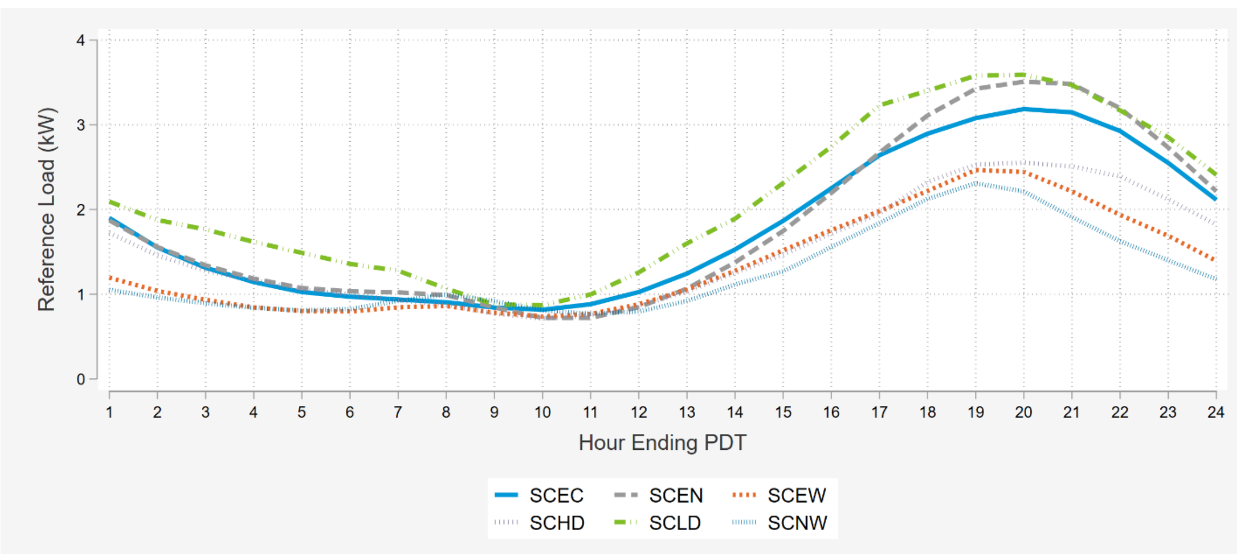


Figure 11 shows the modeled reference loads for each of the six sub-LAPs on an August system peak day using SCE 1-in-2 weather.

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



Ex Ante Impacts Model

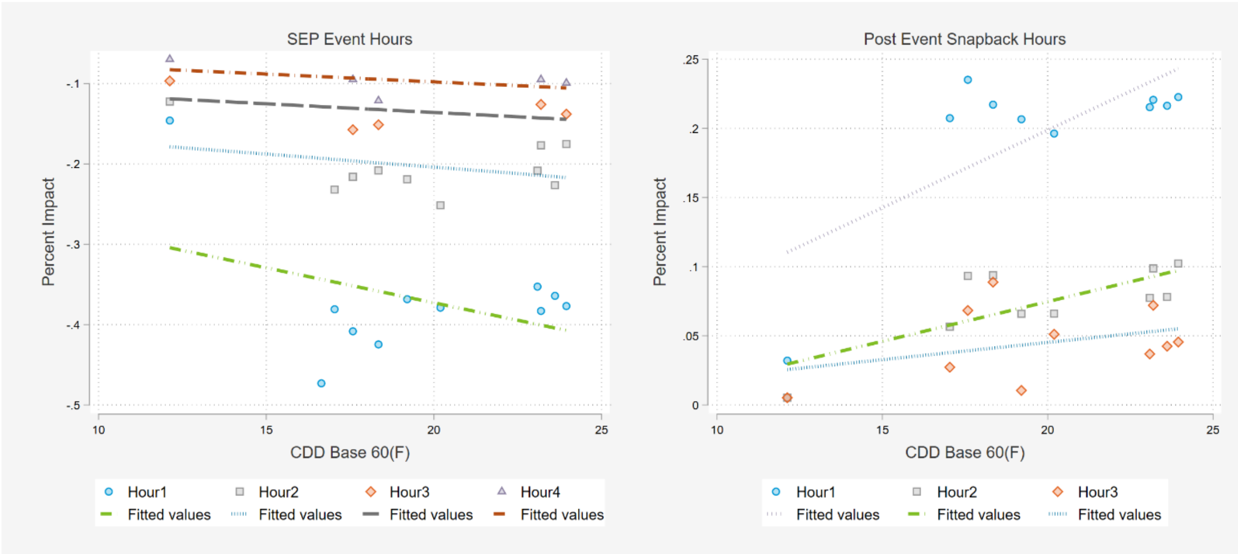
In order to estimate SEP per customer load reductions under varying conditions, DSA fitted a second stage model using the PY2019 ex post percent impacts as the dependent variable and cooling degree days base 60 degrees (F) as the independent variable. Although, the use of multiple years of historical performance data to estimate ex ante impacts is recommended in the California Load Impact

Protocols, only one year of ex post impacts was used to estimate the PY 2019 ex ante impact. This decision was based on several factors:

- The PY2019 events were called much later in the day than PY2018 and PY2017 events, which each began at 2pm and ended at 6pm.
- Although the absolute (kW) impacts were similar, reference loads are smaller in the early afternoon than during the current RA window. This difference is clearly observable in Figure 10. Premise loads increase as solar production falls off and participants come home from work and school and activate more electrical end uses within the home.
- As a result the PY2018 impacts were larger as a percent of premise load than the PY2019 impacts.
- With the exception of August 7, 2018, the PY2018 SEP events were all called on days with weighted average weather conditions much cooler than ex ante planning conditions a typical event day or monthly system peak days.
- Because the PY2019 events were called during the time period of interest given the current RA window, and because there were a relatively large number of SEP events in PY2019, DSA believes the use of a single year of performance data is appropriate in this case

A separate linear regression model was fitted for each of the four potential SEP event hours as well as the three hours of post-event snapback assumed to occur from 9pm to midnight. Figure 12 shows the results. Event hour impacts are negative (a reduction in demand) and post-event snapback hours are positive (in 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.

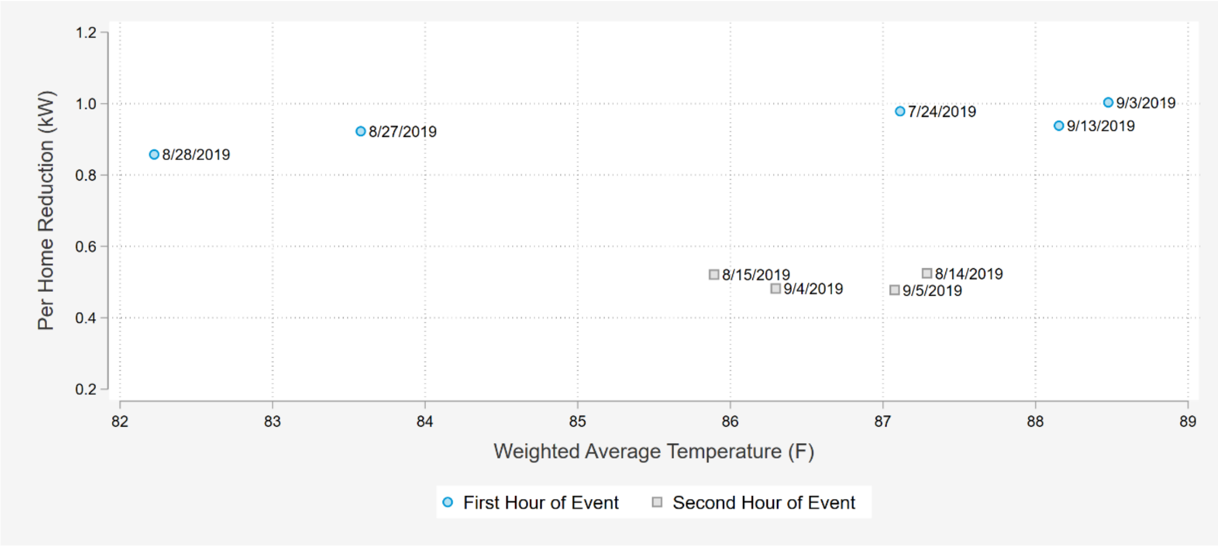
Figure 12: Second Stage Models of SEP Impacts by Event Hour



The left-most data points in Figure 12 are the October 16, 2019 event. Although the weighted average dry bulb temperature during the dispatch hours of the October 16th event were comparable to other PY2019 events, it occurred much earlier in the day and had much lower overnight temperatures and reduced heat build-up. While the ex post kW impacts were substantially lower than other territory-wide events, reference loads were also much lower. The average reference load on the system peak day (September 4, 2019) was 2.70 kW during dispatch and the average reference load on October 16, 2019 was just 0.74 kW during dispatch. As a result, the October 16th impacts are less of an outlier on a percent basis and provide useful information for modeling the performance of SEP during mild conditions during the shoulder months.

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 13 illustrates the issue using the ex post results from territory wide events during hour ending 19:00 (6pm to 7pm). There were a total of nine territory-wide event active from 6pm to 7pm during summer 2019. Four of these events were from 5pm to 9pm, and the other five events were from 6pm to 8pm. For the 6pm to 8pm events, hour ending 19:00 is the first hour of the event. For the 5pm to 9pm events, hour ending 19:00 is the second hour of the event.

Figure 13: Hour Ending 19 Event Impacts vs. Temperature, by Event Hour



The average kW impact per participant household across the five days where hour ending 19 was the first event hour was 0.94 kW with an average temperature of 85.9 degrees (F). The average kW impact per participant household across the four days where hour ending 19 was the second event hour was just 0.50 kW with an average temperature of 86.6 degrees (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. The reason hourly position is so important is because of how the thermostat providers modify setpoints. By increasing the setpoint up to four degrees (F) at the beginning of the event, SEP achieves a large impact initially. However, once homes warm up to the new setpoint, 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. Three 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 more consistent impacts 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. 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 setpoint. Pre-cooling can also reduce participant opt-outs through increased participant comfort.

4 EX POST RESULTS

The ex post results document the measured impacts for each SEP event called during PY2019. 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

SEP called 23 events in 2019 during the months of July through October. Two of these events occurred across the same population on the same day, August 13, and the impacts for that day are reported as a single event. Other same day events do not impact the same populations because they are dispatched separately by sub-LAP. Table 8 shows average hourly impacts by event for these 22 distinct population-date events. Events with separate sub-LAP dispatches are denoted in the table with their date and event window to clearly show the analysis was separately run by event. In addition to event impacts, Table 8 shows two Average Event Day segments based on the most common event windows for summer 2019. These were created using a customer-weighted average of each event that shares 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, territory wide event participation grows over the course of summer 2019.

Impacts are reported in the last two columns as average per customer kW reductions and average aggregate MW reductions. These values are calculated by taking the average of the hourly impacts. The largest per customer reduction occurred on August 21, 2019 with 1.03 kW reduced per customer. This event was called in the warmer sub-LAPs and was one hour in duration. Because load impacts are largest during the first hour of dispatch, short events have larger average impacts than longer events. October events show a large drop in both average and aggregate event impacts with negligible, insignificant savings. The largest aggregate savings occurred on August 13. This date is highly unique in that it had a one hour event window from 5pm to 6pm followed by a two hour break and another single hour event window from 8pm to 9pm. This is a somewhat uncommon DR strategy, but it allowed SCE to obtain two hours on the same day with large impacts.

The standard trend for DR 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 effect is evident in the two average event day windows. The longer window (5pm-9pm) has a lower average hourly kW reduction and lower average aggregate hourly MW reduction than the shorter window (6pm-8pm). However, the longer window actually has a slightly higher Hour 1 impact (1.02 kW compared to 0.94 kW). As the event progresses, this reduction decreases to 0.24 kW during Hour 4, ultimately diluting the average. Hourly breakdowns are provided in Figure 14 through Figure 17.

Table 8: Event Impacts

Event Date	Dispatch Region	Start Time	End Time	Participants	Average Event Temp	Daily Max Temp	Average Hourly Impact (kW Reduction)	Average Aggregate Hourly Impact (MW Reduction)
7/24/2019	Territory Wide	6:00 PM	8:00 PM	51,009	84.8	96.5	0.78	39.6
8/13/2019	Territory Wide	5:00 PM	6:00 PM	51,946	81.9	90.0	0.83	43.0
	Territory Wide	8:00 PM	9:00 PM					
8/14/2019	Territory Wide	5:00 PM	9:00 PM	51,932	85.1	92.7	0.55	28.5
8/15/2019	Territory Wide	5:00 PM	9:00 PM	52,024	83.3	91.9	0.51	26.4
8/21/2019 (6pm-8pm)	SCEW	6:00 PM	8:00 PM	22,550	77.2	83.8	0.57	12.9
8/21/2019 (7pm-8pm)	SCEC, SCEN, SCHD, SCLD, SCNW	7:00 PM	8:00 PM	29,626	88.3	99.4	1.03	30.6
8/26/2019	SCEC, SCEW, SCHD, SCLD, SCNW	6:00 PM	8:00 PM	47,018	81.6	91.2	0.73	34.3
8/27/2019	Territory Wide	6:00 PM	8:00 PM	52,259	81.4	89.9	0.72	37.4
8/28/2019	Territory Wide	6:00 PM	8:00 PM	52,240	80.4	86.3	0.68	35.4
9/3/2019	Territory Wide	6:00 PM	8:00 PM	52,441	86.2	93.9	0.78	41.1
9/4/2019	Territory Wide	5:00 PM	9:00 PM	52,432	86.1	96.9	0.54	28.2
9/5/2019	Territory Wide	5:00 PM	9:00 PM	52,562	85.2	93.0	0.52	27.4
9/12/2019	SCNW	6:00 PM	7:00 PM	975	73.8	79.8	0.54	0.5
9/13/2019	Territory Wide	6:00 PM	8:00 PM	52,664	85.9	94.1	0.76	39.9
9/24/2019 (5pm-8pm)	SCEC, SCHD, SCLD, SCEW	5:00 PM	8:00 PM	46,910	84.8	89.0	0.43	20.2
9/24/2019 (6pm-8pm)	SCEN, SCNW	6:00 PM	8:00 PM	6,086	83.8	92.1	0.58	3.5
9/25/2019 (6pm-7pm)	SCEN, SCEW, SCNW	6:00 PM	7:00 PM	28,970	74.7	81.3	0.47	13.8
9/25/2019 (6pm-8pm)	SCEC, SCHD, SCLD	6:00 PM	8:00 PM	23,996	76.2	90.2	0.42	10.0
10/16/2019	Territory Wide	1:00 PM	5:00 PM	52,927	84.7	86.8	0.07	3.9
10/21/2019 (6pm-7pm)	SCNW	6:00 PM	7:00 PM	990	74.3	88.0	-0.03	0.0
10/21/2019 (6pm-8pm)	SCEN	6:00 PM	8:00 PM	5,236	79.1	84.7	0.05	0.3
10/22/2019	SCEN	6:00 PM	8:00 PM	5,248	79.5	89.3	0.07	0.4
Average Event Day (5pm-9pm)	Territory Wide	5:00 PM	9:00 PM	52,239	84.9	93.4	0.53	27.6
Average Event Day (6pm-8pm)	Territory Wide	6:00 PM	8:00 PM	52,129	83.8	92.0	0.74	38.7

Average ex post load impacts for both Average Event Day windows are provided in Figure 14 and Figure 15. Aggregate load impacts are provided in Figure 16 and Figure 17. The 5pm to 9pm window includes impact estimates from August 14, August 15, September 4, and September 5. The 6pm to 8pm window incorporates results from July 24, August 27, August 28, September 3, and September 13. The following figures provide detail on average number of participants, temperature, average event impact and percent impact. These figures are obtained from the Microsoft Excel ex post load impact table generators that accompany this report. Estimated reference load, observed load, impact, and temperature are provided by the hour, with an included visual display of the load curves and significance of the impact. The average impact value provided under the 'Event Characteristics' heading aligns with the average hourly impacts shown in Table 8.

As can be seen in the observed load for each of the following figures, there is no pre-cooling effect for SEP. However, there is a notable snapback effect beginning in the hour after the event window and tapering off for the remainder of the event day. These snapback effects are significant – approximately 25 MW during the hour immediately following dispatch – and may be an important consideration for event planning as SEP enrollment grows.

The Average Event Day with the shorter window has larger average event impacts as well as percent impacts. The shorter window has an aggregate savings of 38.7 MW and the longer window has an average aggregate savings of 27.6 MW.

Figure 14: SEP Ex Post Load Impact per Participant for Average 2019 Event (5pm-9pm) (kW)

Selection Options	
Reporting Level	Average Customer
Date	Average Event Day (5pm-9pm)
Customer Segment	All: All Customers

Event Characteristics	
Event Hours	5pm-9pm
# Dispatched	52,239
Daily Max Temp	93.4
Average Impact - kW	0.53
Average Impact - %	21.1%

Hour Ending	Estimated Reference Load kW	Observed Load kW	Estimated Load Impact kW	Temp F	Estimated Load Impact Range 10th	30th	50th	70th	90th
1	1.29	1.33	(0.04)	74.2	(0.05)	(0.04)	(0.04)	(0.04)	(0.03)
2	1.09	1.12	(0.02)	73.3	(0.03)	(0.02)	(0.02)	(0.02)	(0.01)
3	0.95	0.97	(0.02)	72.4	(0.02)	(0.02)	(0.02)	(0.01)	(0.01)
4	0.86	0.86	(0.01)	71.7	(0.01)	(0.01)	(0.01)	(0.00)	(0.00)
5	0.78	0.79	(0.01)	71.0	(0.01)	(0.01)	(0.01)	(0.01)	(0.00)
6	0.76	0.77	(0.01)	70.5	(0.01)	(0.01)	(0.01)	(0.01)	(0.00)
7	0.79	0.80	(0.01)	70.4	(0.01)	(0.01)	(0.01)	(0.01)	(0.00)
8	0.76	0.77	(0.01)	72.6	(0.01)	(0.01)	(0.01)	(0.00)	(0.00)
9	0.68	0.67	0.01	76.2	0.01	0.01	0.01	0.01	0.02
10	0.63	0.61	0.02	81.1	0.01	0.02	0.02	0.02	0.03
11	0.68	0.65	0.03	85.6	0.02	0.02	0.03	0.03	0.04
12	0.82	0.79	0.03	88.9	0.02	0.02	0.03	0.03	0.03
13	1.06	1.02	0.04	91.0	0.03	0.03	0.04	0.04	0.05
14	1.35	1.31	0.03	92.5	0.02	0.03	0.03	0.04	0.05
15	1.66	1.64	0.01	93.4	0.00	0.01	0.01	0.02	0.02
16	2.04	2.01	0.02	93.1	0.01	0.02	0.02	0.03	0.04
17	2.36	2.30	0.06	91.5	0.05	0.06	0.06	0.07	0.07
18	2.57	1.55	1.02	89.6	1.01	1.01	1.02	1.02	1.03
19	2.60	2.10	0.50	86.6	0.49	0.50	0.50	0.51	0.51
20	2.48	2.12	0.35	83.3	0.34	0.35	0.35	0.36	0.36
21	2.36	2.12	0.24	80.3	0.23	0.24	0.24	0.25	0.25
22	2.16	2.64	(0.48)	78.0	(0.49)	(0.49)	(0.48)	(0.48)	(0.47)
23	1.88	2.07	(0.18)	76.5	(0.19)	(0.19)	(0.18)	(0.18)	(0.17)
24	1.55	1.65	(0.10)	75.0	(0.11)	(0.11)	(0.10)	(0.10)	(0.09)
Daily	Daily Energy kWh	kWh	kWh Δ	ΣCDH (75)	Estimated Energy Change 10th	30th	50th	70th	90th
	34.14	32.66	1.48	162.7	1.48	1.48	1.48	1.49	1.49

Figure 15: SEP Ex Post Load Impact per Participant for Average 2019 Event (6pm-8pm) (kW)

Selection Options	
Reporting Level	Average Customer
Date	Average Event Day (6pm-8pm)
Customer Segment	All: All Customers

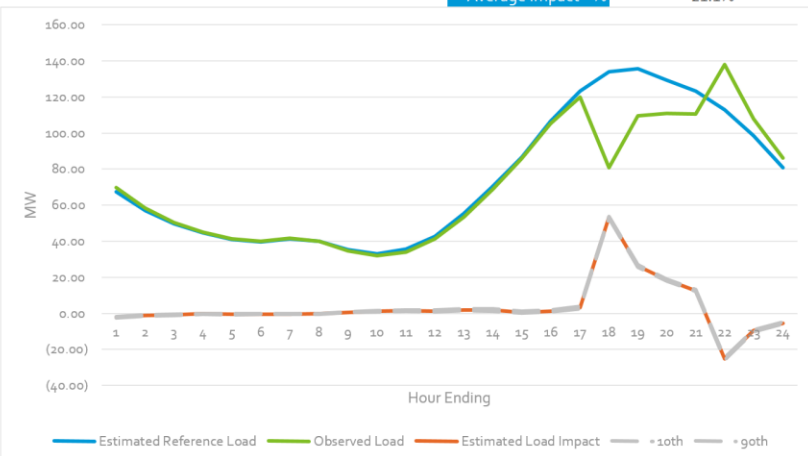
Event Characteristics	
Event Hours	6pm-8pm
# Dispatched	52,129
Daily Max Temp	92.0
Average Impact - kW	0.74
Average Impact - %	30.0%

Hour Ending	Estimated Reference Load kW	Observed Load kW	Estimated Load Impact kW	Temp F	Estimated Load Impact Range 10th	30th	50th	70th	90th
1	1.28	1.27	0.00	74.3	(0.00)	0.00	0.00	0.01	0.01
2	1.09	1.08	0.01	73.5	(0.00)	0.00	0.01	0.01	0.01
3	0.94	0.95	(0.00)	72.8	(0.01)	(0.00)	(0.00)	0.00	0.01
4	0.84	0.85	(0.00)	72.2	(0.01)	(0.01)	(0.00)	(0.00)	0.00
5	0.78	0.78	0.01	71.6	(0.00)	0.00	0.01	0.01	0.01
6	0.76	0.75	0.00	71.2	0.00	0.00	0.00	0.01	0.01
7	0.79	0.78	0.00	71.2	(0.00)	0.00	0.00	0.00	0.01
8	0.76	0.76	(0.00)	73.6	(0.01)	(0.01)	(0.00)	(0.00)	0.00
9	0.68	0.68	0.00	77.7	(0.00)	(0.00)	0.00	0.00	0.01
10	0.65	0.64	0.01	81.9	0.00	0.00	0.01	0.01	0.01
11	0.69	0.68	0.01	85.7	0.00	0.01	0.01	0.01	0.02
12	0.83	0.82	0.01	88.4	(0.00)	0.00	0.01	0.01	0.02
13	1.08	1.06	0.02	90.2	0.01	0.01	0.02	0.02	0.03
14	1.37	1.34	0.03	91.5	0.02	0.02	0.03	0.03	0.04
15	1.67	1.65	0.02	92.0	0.01	0.02	0.02	0.03	0.03
16	2.03	2.00	0.02	91.7	0.01	0.02	0.02	0.03	0.03
17	2.33	2.29	0.03	90.4	0.02	0.03	0.03	0.04	0.04
18	2.53	2.50	0.03	88.8	0.02	0.02	0.03	0.03	0.04
19	2.55	1.61	0.94	85.9	0.93	0.94	0.94	0.94	0.95
20	2.40	1.86	0.54	81.6	0.53	0.54	0.54	0.55	0.56
21	2.30	2.78	(0.48)	78.9	(0.49)	(0.48)	(0.48)	(0.48)	(0.47)
22	2.12	2.26	(0.15)	77.5	(0.16)	(0.15)	(0.15)	(0.14)	(0.14)
23	1.87	1.94	(0.06)	76.5	(0.07)	(0.07)	(0.06)	(0.06)	(0.05)
24	1.54	1.60	(0.06)	75.6	(0.07)	(0.06)	(0.06)	(0.05)	(0.05)
Daily	kWh	Daily Energy kWh	kWh Δ	ΣCDH (75)	Estimated Energy Change 10th	30th	50th	70th	90th
	33.87	32.94	0.92	154.2	0.92	0.92	0.92	0.93	0.93

Figure 16: Aggregate SEP Ex Post Load Impact for Average 2019 Event (5pm-9pm) (MW)

Selection Options	
Reporting Level	Aggregate
Date	Average Event Day (5pm-9pm)
Customer Segment	All: All Customers

Event Characteristics	
Event Hours	5pm-9pm
# Dispatched	52,239
Daily Max Temp	93.4
Average Impact - MW	27.61
Average Impact - %	21.1%



Hour Ending	Estimated Reference Load MW	Observed Load MW	Estimated Load Impact MW	Temp F	Estimated Load Impact Range 10th	30th	50th	70th	90th
1	67.50	69.66	(2.17)	74.2	(2.58)	(2.34)	(2.17)	(2.00)	(1.75)
2	57.14	58.28	(1.14)	73.3	(1.52)	(1.30)	(1.14)	(0.99)	(0.76)
3	49.66	50.45	(0.79)	72.4	(1.13)	(0.93)	(0.79)	(0.65)	(0.45)
4	44.69	45.03	(0.34)	71.7	(0.63)	(0.46)	(0.34)	(0.22)	(0.04)
5	40.92	41.35	(0.43)	71.0	(0.69)	(0.54)	(0.43)	(0.32)	(0.17)
6	39.66	40.05	(0.39)	70.5	(0.63)	(0.49)	(0.39)	(0.30)	(0.16)
7	41.21	41.57	(0.36)	70.4	(0.59)	(0.45)	(0.36)	(0.26)	(0.13)
8	39.82	40.13	(0.32)	72.6	(0.56)	(0.42)	(0.32)	(0.22)	(0.07)
9	35.40	34.77	0.62	76.2	0.35	0.51	0.62	0.74	0.90
10	33.05	32.02	1.03	81.1	0.70	0.89	1.03	1.16	1.35
11	35.50	34.05	1.45	85.6	1.06	1.29	1.45	1.61	1.83
12	42.70	41.38	1.32	88.9	0.87	1.14	1.32	1.50	1.77
13	55.28	53.33	1.95	91.0	1.45	1.75	1.95	2.16	2.46
14	70.40	68.60	1.80	92.5	1.25	1.57	1.80	2.03	2.35
15	86.51	85.88	0.62	93.4	0.04	0.39	0.62	0.86	1.21
16	106.48	105.19	1.29	93.1	0.69	1.05	1.29	1.53	1.89
17	123.27	120.10	3.17	91.5	2.57	2.93	3.17	3.41	3.77
18	134.16	80.90	53.25	89.6	52.64	53.00	53.25	53.50	53.86
19	135.65	109.47	26.18	86.6	25.58	25.94	26.18	26.42	26.78
20	129.33	110.91	18.41	83.3	17.85	18.18	18.41	18.64	18.98
21	123.27	110.66	12.60	80.3	12.06	12.38	12.60	12.83	13.15
22	112.82	138.05	(25.23)	78.0	(25.76)	(25.45)	(25.23)	(25.01)	(24.70)
23	98.39	107.97	(9.58)	76.5	(10.08)	(9.79)	(9.58)	(9.38)	(9.08)
24	80.77	86.20	(5.43)	75.0	(5.90)	(5.62)	(5.43)	(5.23)	(4.95)
Daily	Daily Energy MWh	MWh	MWh Δ	ΣCDH (75)	Estimated Energy Change 10th	30th	50th	70th	90th
	1,783.54	1,706.01	77.53	162.7	(378.99)	(109.06)	77.53	264.13	534.05

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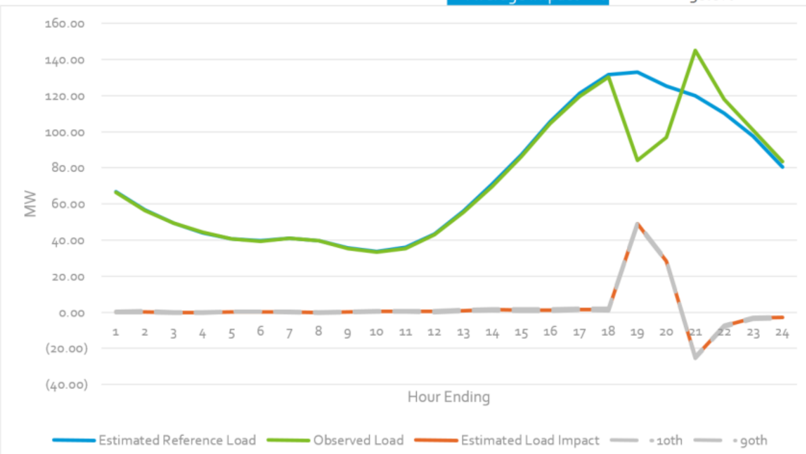
Figure 17: Aggregate SEP Ex Post Load Impact for Average 2019 Event (6pm-8pm) (MW)

Selection Options	
Reporting Level	Aggregate
Date	Average Event Day (6pm-8pm)
Customer Segment	All: All Customers

Event Characteristics	
Event Hours	6pm-8pm
# Dispatched	52,129
Daily Max Temp	92.0
Average Impact - MW	38.70
Average Impact - %	30.0%



Hour Ending	Estimated Reference Load MW	Observed Load MW	Estimated Load Impact MW	Temp F	Estimated Load Impact Range 10th	30th	50th	70th	90th
1	66.68	66.46	0.22	74.3	(0.20)	0.05	0.22	0.39	0.64
2	56.69	56.41	0.28	73.5	(0.10)	0.12	0.28	0.44	0.67
3	49.24	49.29	(0.05)	72.8	(0.40)	(0.19)	(0.05)	0.09	0.29
4	43.96	44.21	(0.25)	72.2	(0.55)	(0.37)	(0.25)	(0.12)	0.05
5	40.78	40.51	0.26	71.6	(0.00)	0.16	0.26	0.37	0.53
6	39.52	39.26	0.26	71.2	0.02	0.16	0.26	0.35	0.49
7	40.95	40.83	0.12	71.2	(0.11)	0.03	0.12	0.21	0.35
8	39.53	39.77	(0.24)	73.6	(0.49)	(0.34)	(0.24)	(0.14)	0.00
9	35.47	35.43	0.05	77.7	(0.23)	(0.07)	0.05	0.16	0.33
10	33.69	33.34	0.35	81.9	0.02	0.22	0.35	0.49	0.68
11	35.92	35.44	0.48	85.7	0.09	0.32	0.48	0.64	0.87
12	43.22	42.85	0.36	88.4	(0.09)	0.18	0.36	0.55	0.82
13	56.19	55.23	0.96	90.2	0.45	0.75	0.96	1.17	1.47
14	71.22	69.79	1.43	91.5	0.87	1.20	1.43	1.66	1.99
15	87.20	85.99	1.21	92.0	0.62	0.97	1.21	1.45	1.79
16	105.58	104.46	1.11	91.7	0.52	0.87	1.11	1.36	1.71
17	121.21	119.55	1.66	90.4	1.06	1.41	1.66	1.90	2.26
18	131.75	130.22	1.53	88.8	0.93	1.28	1.53	1.77	2.12
19	133.05	84.05	49.00	85.9	48.40	48.76	49.00	49.24	49.60
20	125.27	96.87	28.40	81.6	27.83	28.17	28.40	28.63	28.97
21	119.87	144.90	(25.03)	78.9	(25.58)	(25.25)	(25.03)	(24.81)	(24.48)
22	110.40	118.07	(7.67)	77.5	(8.18)	(7.88)	(7.67)	(7.46)	(7.15)
23	97.58	100.89	(3.30)	76.5	(3.80)	(3.51)	(3.30)	(3.10)	(2.80)
24	80.48	83.40	(2.92)	75.6	(3.39)	(3.11)	(2.92)	(2.73)	(2.45)

Daily	Daily Energy MWh	MWh	MWh Δ	ΣCDH (75)	Estimated Energy Change 10th	30th	50th	70th	90th
	1,765.44	1,717.22	48.22	154.2	(408.88)	(138.62)	48.22	235.05	505.32

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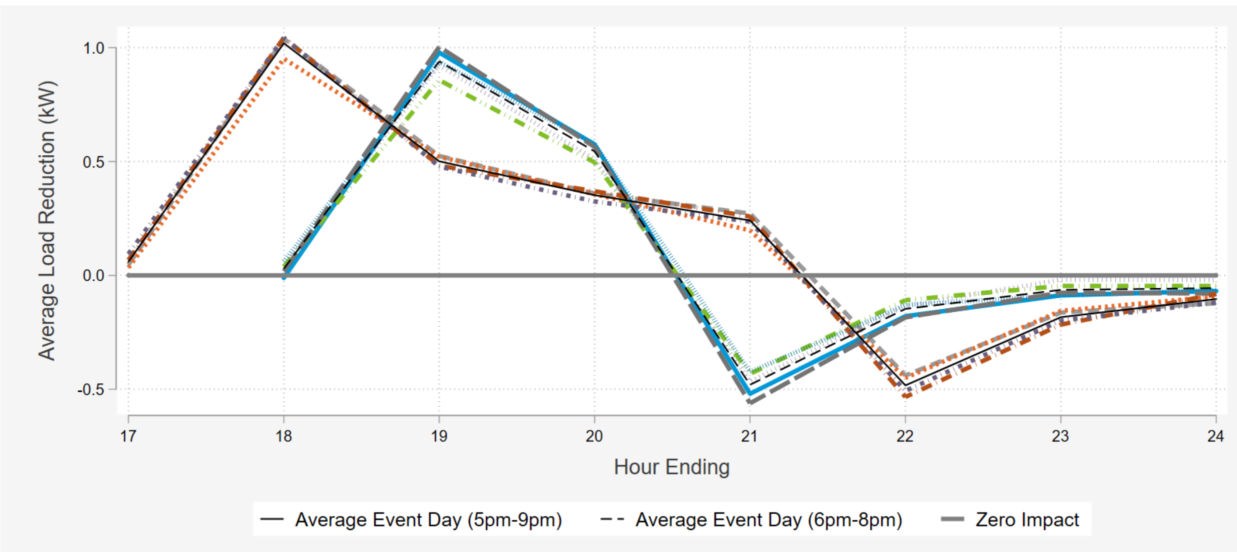
Figure 18 shows the average load impacts, by hour, for SEP territory wide events with the average event windows. Reductions in demand (kW) are presented as positive numbers and increases in demand are presented as negative values. While each event has some variety in average customer load impact, the overall trend and general magnitudes are consistent. During the first of hour of dispatch (hour ending 18 for a 5-9pm event and hour ending 19 for a 6-8pm event), impacts are approximately 1.0 kW. During the second event hour, load impacts drop to approximately 0.5 kW. The longer event maintains load reductions for the final two event hours. Following each event, there is a "snapback" period where demand exceeds the reference load by approximately 0.5 kW in the hour immediately following dispatch. For the remainder of the evening, this snapback diminishes as impacts return to zero. Average event day impacts are shown with thin black lines.

Figure 18: Hourly Load Reductions for Territory Wide Average Events



4.2 RESULTS BY CATEGORY

Demand Side Analytics estimated the SEP impacts for all events based on a variety of segments. The average impacts based on territory wide events are presented in Table 9. The sub-LAP category is notable because events are dispatched by sub-LAP. The average events discussed in Section 4.1 are also compiled with territory wide events, but only include those with the standard event windows of 5pm to 9pm and 6pm to 8pm. However, some events are dispatched at different times to different sub-LAPs, and on some event days only specific sub-LAPs were dispatched. The 'Dispatch Region' column in Table 8 indicates events where a subset of sub-LAPs were dispatched. SCEC and SCEW are the two largest sub-LAPs and make up 86% of the participant population. The average load impacts vary slightly by sub-LAP, but the percent load impacts throughout most of the region are approximately 25%. The two exceptions are SCNW (17%) and SCLD (19%). SCNW was dispatched on more event days than any other sub-LAP and is the second smallest of the six with only 990 participants. The average reference load for this SCNW is the lowest of all sub-LAPs (1.81 kW) suggesting relatively low demand. SCLD only had 54 participants. This small sample size leads to increased noise in the estimation as well as wide confidence intervals.

Table 9: Ex Post 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)
Tariff Type	Dynamic	10,484	2.42	1.80	0.62	26%	6.5
	Flat	41,786	2.21	1.66	0.54	25%	22.7
Size	Greater than 1.82 kW during RA window	26,298	3.16	2.36	0.80	25%	20.9
	Less than 1.82 kW during RA window	25,972	1.33	1.01	0.31	24%	8.2
Net Energy Metering Status	Not NEM	43,089	2.16	1.64	0.52	24%	22.4
	NEM	9,180	2.66	1.92	0.74	28%	6.8
[redacted]							
CARE Status	Non-CARE	45,789	2.24	1.67	0.57	25%	26.0
	CARE	6,480	2.31	1.82	0.49	21%	3.2
LCA	Big Creek/Ventura	6,100	2.54	1.90	0.64	25%	3.9
	LA Basin	44,988	2.21	1.66	0.55	25%	24.6
	Outside LA Basin	1,181	2.33	1.77	0.56	24%	0.7
Region	Remainder of System	22,787	2.42	1.81	0.61	25%	13.8
	South Orange County	10,376	1.70	1.30	0.41	24%	4.2
	South of Lugo	19,107	2.34	1.76	0.58	25%	11.1
Sub-LAP	SCEC	22,400	2.56	1.92	0.64	25%	14.4
	SCEN	5,074	2.68	1.98	0.70	26%	3.6
	SCEW	22,574	1.86	1.41	0.45	24%	10.2
	SCHD	1,232	2.27	1.71	0.55	24%	0.7
	SCLD	54	2.94	2.37	0.57	19%	0.0
	SCNW	936	1.81	1.49	0.31	17%	0.3
All Customers		52,270	2.25	1.69	0.56	25%	29.1

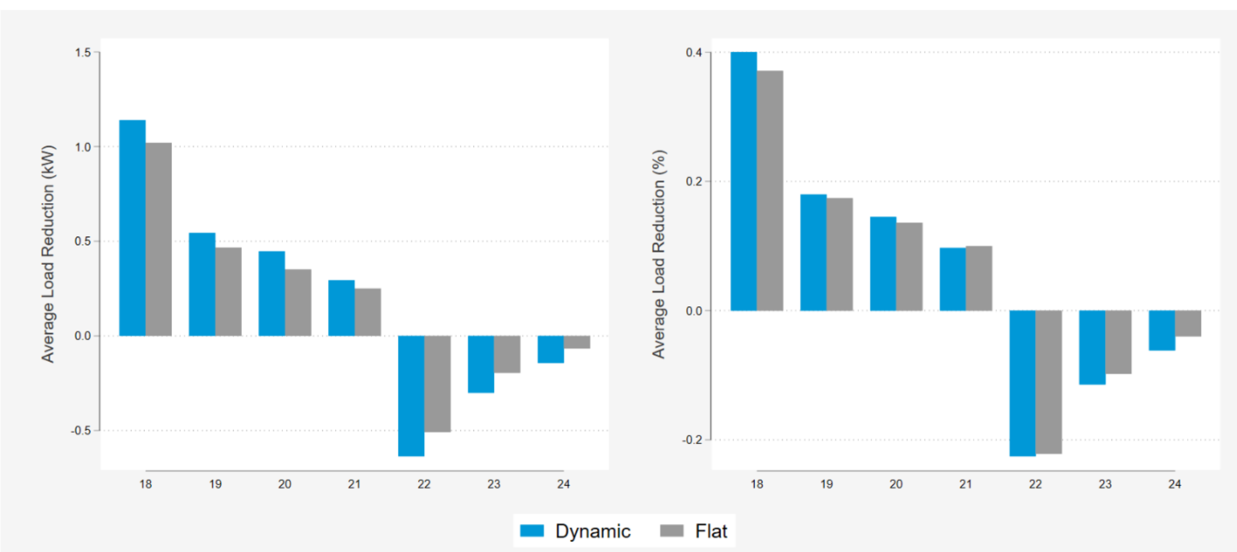
Regardless of segment, there is not much variety in the percent load impacts. The size segment has the highest and lowest average load impact, with 0.31 kW impact for participants less than 1.82 kW during the resource adequacy window and 0.80 kW for participants greater than 1.82 kW during the RA window. However, when considering these impacts relative to their reference load, the percent impacts are 24% and 25%, respectively.

Overall, most segments are similar to the "All Customers" category with 25% load impact. The average aggregate load impact across all territory wide events is 29.1 MW. The following figures show segment specific impacts for the summer peak day event on September 4, 2019. In Figure 19, "All Customers" are represented by a black line, and the zero impact line is drawn in gray. Figure 19 shows just the sub-LAP breakout. The "All" category represents a participant weighted average of each segment category and is therefore shown approximately in the middle of the sub-LAPs. SCLD stands out as an outlier with the largest impact and largest snapback. Recall from Table 9 that this sub-LAP only has an average of 54 customers during all territory wide events, which leads to a wide margin of error in the estimates.

Figure 19: Average Customer Impact on System Peak Day, by Sub-LAP

Figure 20 shows the average reductions for SEP participants who face flat and dynamic time-of-use (TOU) rates. The left side of Figure 20 shows absolute impacts in kW by hour and the right side shows percent savings. Although participants on dynamic rates show larger load impacts, and the differences are statistically significant, we cannot make a causal inference that the difference is due to the rate. The SEP participants who faced dynamic pricing in 2019 were part of a randomized encouragement pilot to enroll in TOU before the default transition and may not reflect the load shapes or SEP impacts of participants who were on a flat rate in 2019 once they have transitioned to TOU. SCE is transitioning to default TOU in 2020, but we cannot use these findings to estimate an expected incremental SEP load impact in the ex ante analysis.

Figure 20: Average and Percent Impacts on 2019 Peak Day, by Tariff and Hour Ending



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4.3 COMPARISON TO PRIOR YEAR

SEP 2019 events were called later in the day than 2018 events. Peak temperature during the average event days falls between 2pm and 5pm and the events typically started at 5pm 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 8 degrees lower than the daily max. However, Table 10 indicates that despite the window shift, average 2019 event temperatures fall between the 2017 and 2018 event temperatures.

The overall SEP population grew only slightly from 2018 to 2019, but participants are more concentrated in warmer areas of SCE territory with CCA attrition in milder areas backfilled by new enrollments in warmer areas. The customer counts vary by event window because the counts are a weighted average of the events that make up the average event day and customer participation is different for every event.

The average reference load is larger in 2019 for both the four hour and two hour event windows. The load impacts are larger in 2019 (0.53kW and 0.74 kW) than in 2018 (0.42 kW) and the four hour event window is smaller than the 2017 average load impact (0.64kW). For the four hour event windows, 2019 exhibited the smallest percent impact of all three years, but the highest reference loads. Readers should be cautious comparing average impacts from the 6pm-8pm events in 2019 with prior years because SEP impacts are largest during the first two hours of dispatch.

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

Measure	2017	2018	2019 (5-9PM)	2019 (6-8PM)
Avg. Reference Load (kW)	2.31	1.50	2.50	2.48
Avg. Load Impact (kW)	0.64	0.42	0.53	0.74
% Load Impact	27.8%	27.9%	21.1%	30.0%
Avg. Event Temperature	89.8	75.7	84.9	83.8
Event Hours	2-6PM	2-6PM	5-9PM	6-8PM
Heat Buildup (Avg. °F, 12 AM to 5 PM)	81.4	75.4	81.1	81.0

Participants	34,120	51,089	52,239	52,129

The standard 9 to 5 workday results in many households being unoccupied during the previous event window. If more individuals are home during the new window, 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. There were 23 SEP events in 2019 and a combined 20 non-EM&V events in 2017 and 2018. The 2019 season had greater variety in dispatch time and duration than previous years. Weather conditions, opt out patterns, and population differences over the years can contribute to differences in the impact estimates, but the shifting Resource Adequacy window means that the results cannot be directly compared to previous years.

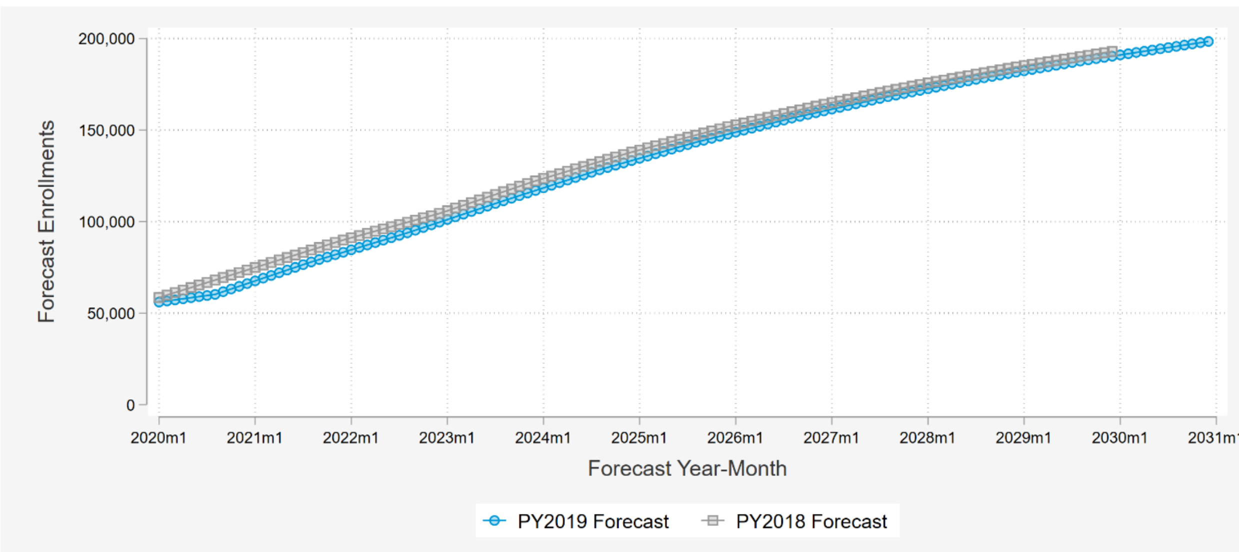
5 EX ANTE RESULTS

The ex ante results for SEP assume consistent kW impacts per participant household and 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.

5.1 ENROLLMENT FORECAST

SCE provided a forecast eleven-year forecast of SEP enrollments 2020-2030 representing the expected number of participants as of August of each calendar year. In addition, SCE provided DSA with the PY2018 forecast, which listed the expected number enrollments at the end of each year. In order to place these forecasts on an even basis, DSA imputed the estimated enrollments in each month of the two forecasts. Figure 22 compares the two forecasts. The PY2019 forecast is lower in the near term because of the migration of accounts to CCAs. As discussed in Section 5.4, the lower enrollment forecast reduces the estimated aggregate MW impacts. The two forecasts converge in the mid-2020s and SCE estimates by 2030 that SEP will have almost 200,000 active participating households.

Figure 22: Comparison on PY2019 and PY2018 SEP Enrollment Forecasts



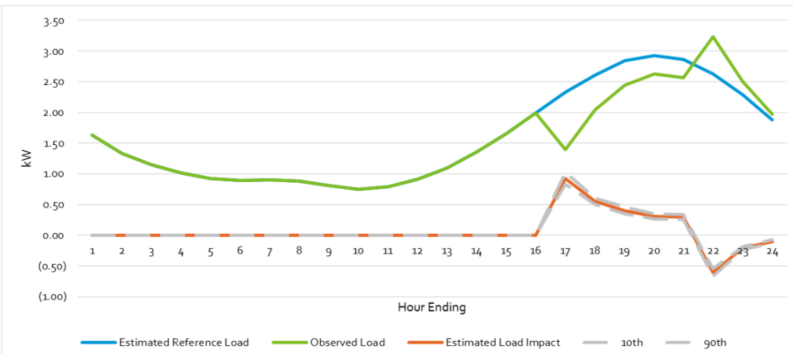
5.2 OVERALL RESULTS

Figure 23 shows the average ex ante load impact per SEP participant for each hour of an August system peak day in 2020 using the SCE 1-in-2 weather forecast. Figure 24 shows the 2020 per-participant impact estimates using SCE 1-in-10 weather for an August system peak day. These figures are taken 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 2020-2030 and for the different weather forecasts described in Section 3.2. Users can also view the ex ante results for an individual LCA, Region, or sub-LAP. 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 23 and Figure 24, the five hours of the RA window are shaded light blue. Hours ending 17 through 21 correspond to the RA window of 4pm to 9pm.

Figure 23: SEP Average Load Impact (kW) per Customer in 2020: August System Peak Day, SCE 1-in-2 Weather

Selection Options	
Reporting Level	Average Customer
Customer Segment	All
Day Type	Monthly System Peak Day
Month	August
Weather Year	SCE 1-in-2
Forecast Year	2020

Event Characteristics	
Event Hours	5pm-9pm (RA Hours 4pm-9pm)
# Dispatched	60,249
Daily Max Temp	93.7
Average Impact - kW	0.50
Average Impact - %	18.3%

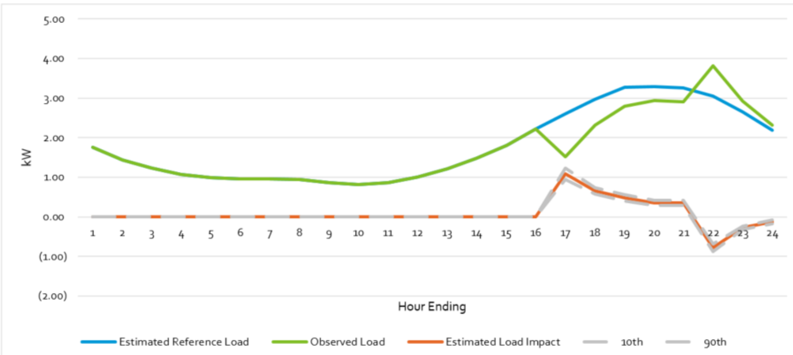


Hour Ending	Estimated Reference Load	Observed Load	Estimated Load Impact	Temp	Estimated Load Impact Range				
	kW	kW	kW	F	10th	30th	50th	70th	90th
1	1.63	1.63	0.00	78.5	0.00	0.00	0.00	0.00	0.00
2	1.34	1.34	0.00	77.4	0.00	0.00	0.00	0.00	0.00
3	1.14	1.14	0.00	76.6	0.00	0.00	0.00	0.00	0.00
4	1.01	1.01	0.00	75.6	0.00	0.00	0.00	0.00	0.00
5	0.93	0.93	0.00	74.8	0.00	0.00	0.00	0.00	0.00
6	0.90	0.90	0.00	74.4	0.00	0.00	0.00	0.00	0.00
7	0.90	0.90	0.00	73.8	0.00	0.00	0.00	0.00	0.00
8	0.88	0.88	0.00	73.8	0.00	0.00	0.00	0.00	0.00
9	0.81	0.81	0.00	75.8	0.00	0.00	0.00	0.00	0.00
10	0.75	0.75	0.00	79.9	0.00	0.00	0.00	0.00	0.00
11	0.79	0.79	0.00	84.0	0.00	0.00	0.00	0.00	0.00
12	0.91	0.91	0.00	87.6	0.00	0.00	0.00	0.00	0.00
13	1.10	1.10	0.00	90.0	0.00	0.00	0.00	0.00	0.00
14	1.36	1.36	0.00	92.1	0.00	0.00	0.00	0.00	0.00
15	1.65	1.65	0.00	93.6	0.00	0.00	0.00	0.00	0.00
16	1.99	1.99	0.00	93.7	0.00	0.00	0.00	0.00	0.00
17	2.33	1.40	0.93	93.1	0.83	0.89	0.93	0.97	1.02
18	2.60	2.05	0.56	91.6	0.50	0.53	0.56	0.58	0.61
19	2.84	2.44	0.40	90.1	0.35	0.38	0.40	0.43	0.46
20	2.93	2.62	0.30	88.5	0.26	0.29	0.30	0.32	0.34
21	2.86	2.56	0.30	85.1	0.26	0.28	0.30	0.31	0.34
22	2.62	3.23	(0.61)	81.9	(0.67)	(0.63)	(0.61)	(0.58)	(0.55)
23	2.29	2.50	(0.21)	79.8	(0.23)	(0.22)	(0.21)	(0.20)	(0.19)
24	1.88	1.97	(0.10)	78.3	(0.12)	(0.11)	(0.10)	(0.09)	(0.07)
Daily	Daily Energy				Estimated Energy Change				
	kWh	kWh	kWh Δ	ΣCDH (75)	10th	30th	50th	70th	90th
	38.43	36.87	1.57	193.1	1.54	1.56	1.57	1.58	1.60

Figure 24: SEP Average Load Impact (kW) per Customer in 2020: Typical Event Day, SCE 1-in-10 Weather

Selection Options	
Reporting Level	Average Customer
Customer Segment	All
Day Type	Monthly System Peak Day
Month	August
Weather Year	SCE 1-in-10
Forecast Year	2020

Event Characteristics	
Event Hours	5pm-9pm (RA Hours 4pm-9pm)
# Dispatched	60,249
Daily Max Temp	97.2
Average Impact - kW	0.59
Average Impact - %	19.0%



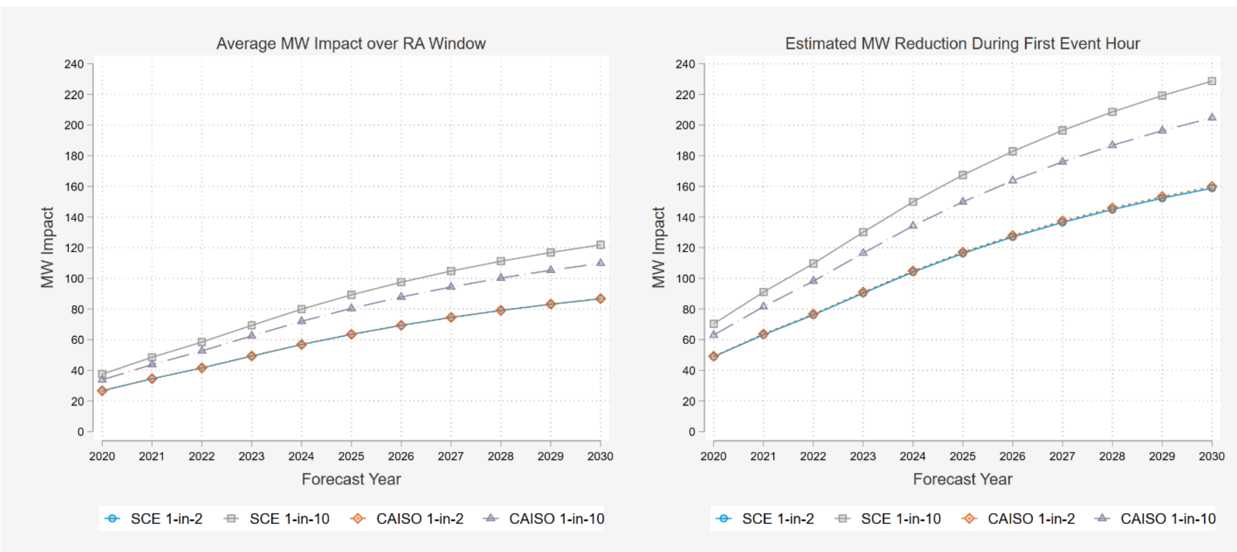
Hour Ending	Estimated Reference Load	Observed Load	Estimated Load Impact	Temp	Estimated Load Impact Range				
	kW	kW	kW	F	10th	30th	50th	70th	90th
1	1.76	1.76	0.00	79.8	0.00	0.00	0.00	0.00	0.00
2	1.44	1.44	0.00	78.5	0.00	0.00	0.00	0.00	0.00
3	1.22	1.22	0.00	77.4	0.00	0.00	0.00	0.00	0.00
4	1.08	1.08	0.00	76.3	0.00	0.00	0.00	0.00	0.00
5	0.99	0.99	0.00	75.4	0.00	0.00	0.00	0.00	0.00
6	0.95	0.95	0.00	74.5	0.00	0.00	0.00	0.00	0.00
7	0.96	0.96	0.00	73.5	0.00	0.00	0.00	0.00	0.00
8	0.95	0.95	0.00	73.5	0.00	0.00	0.00	0.00	0.00
9	0.86	0.86	0.00	76.1	0.00	0.00	0.00	0.00	0.00
10	0.81	0.81	0.00	81.1	0.00	0.00	0.00	0.00	0.00
11	0.86	0.86	0.00	86.7	0.00	0.00	0.00	0.00	0.00
12	1.01	1.01	0.00	90.5	0.00	0.00	0.00	0.00	0.00
13	1.22	1.22	0.00	92.4	0.00	0.00	0.00	0.00	0.00
14	1.48	1.48	0.00	94.1	0.00	0.00	0.00	0.00	0.00
15	1.81	1.81	0.00	95.8	0.00	0.00	0.00	0.00	0.00
16	2.22	2.22	0.00	97.2	0.00	0.00	0.00	0.00	0.00
17	2.61	1.52	1.09	97.0	0.94	1.03	1.09	1.15	1.24
18	2.97	2.32	0.66	96.5	0.58	0.62	0.66	0.69	0.74
19	3.27	2.79	0.48	95.2	0.40	0.45	0.48	0.51	0.56
20	3.29	2.93	0.35	92.4	0.29	0.33	0.35	0.38	0.41
21	3.25	2.90	0.35	88.8	0.29	0.33	0.35	0.37	0.41
22	3.04	3.82	(0.78)	85.6	(0.88)	(0.82)	(0.78)	(0.74)	(0.68)
23	2.65	2.93	(0.28)	83.1	(0.31)	(0.29)	(0.28)	(0.26)	(0.24)
24	2.19	2.32	(0.13)	81.7	(0.17)	(0.14)	(0.13)	(0.11)	(0.09)
Daily	Daily Energy				Estimated Energy Change				
	kWh	kWh	kWh Δ	ΣCDH (75)	10th	30th	50th	70th	90th
	42.90	41.15	1.75	246.3	1.70	1.73	1.75	1.77	1.79

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 25 consolidates multiple estimates to show the change in the size of the SEP resource over time. The growth over time is exclusively a function of the enrollment forecast discussed in Section 5.1 as the average participant impacts are held constant over the forecast horizon. The left panel of Figure 25 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. and the absence of any impact during hour ending 17:00 due to the four hour per day programmatic dispatch limit. The difference between these two views of load reduction capability has important implications for valuation of SEP as a capacity resource.

Figure 25: 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 25. There is more variance in the 1-in-10 conditions, with the SCE 1-in-10 forecast showing more extreme 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 11 shows the aggregate ex ante load impact estimates in forecast year 2020 by hour and peaking conditions for a typical event day. The estimated load impact of SEP in 2020 ranges from 48.9 MW to 70.4 MW during hour ending 17:00. Estimated impacts decline across the RA window and range from 15.7 MW to 22.2 MW in hour ending 21:00.

Table 11: 2020 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	48.9	49.2	70.4	63.0
18	30.6	30.3	42.1	38.1
19	22.2	22.1	30.5	27.7
20	16.1	16.1	22.4	20.3
21	15.7	15.8	22.2	19.9
RA Window	**26.7**	**26.7**	**37.5**	**33.8**

In addition to the typical event day, ex ante impacts were estimated for average weekdays and monthly system peak days. Table 12 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 13 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. In PY2018, the aggregate impacts were largest in August for SCE 1-in-2 weather and September for SCE 1-in-10 weather.

Table 12: Aggregate Load Impacts (MW) on Monthly System Peak Days 2020-2030: SCE Weather

Weather Year	Month	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1-in-2	January	0	0	0	0	0	0	0	0	0	0	0
	February	0	0	0	0	0	0	0	0	0	0	0
	March	0	0	0	0	0	0	0	0	0	0	0
	April	9.2	11.4	14.0	16.7	19.4	21.9	24.1	26.0	27.8	29.3	30.6
	May	11.6	14.6	17.9	21.3	24.7	27.8	30.5	32.9	35.0	36.9	38.5
	June	15.1	19.1	23.3	27.7	32.0	35.9	39.4	42.4	45.1	47.5	49.6
	July	27.7	35.6	43.0	51.1	59.0	66.1	72.3	77.8	82.7	87.0	90.7
	August	29.9	38.7	46.6	55.3	63.7	71.2	77.8	83.6	88.7	93.2	97.2
	September	29.8	38.2	46.0	54.4	62.5	69.6	76.0	81.6	86.5	90.8	94.7
	October	19.4	24.8	29.7	35.1	40.2	44.7	48.7	52.2	55.4	58.1	60.6
	November	12.2	15.4	18.5	21.7	24.8	27.6	30.0	32.1	34.0	35.6	37.2
	December	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
	February	9.2	11.2	13.9	16.7	19.4	22.0	24.3	26.4	28.1	29.7	31.1
	March	10.7	13.2	16.4	19.5	22.7	25.7	28.3	30.6	32.7	34.5	36.1
	April	11.5	14.3	17.5	20.9	24.3	27.4	30.1	32.5	34.7	36.6	38.2
	May	19.9	25.0	30.5	36.4	42.2	47.4	52.1	56.2	59.8	63.0	65.8
	June	27.3	34.7	42.1	50.1	58.0	65.1	71.3	76.8	81.7	86.0	89.8
	July	44.3	56.8	68.7	81.5	94.2	105.4	115.3	124.1	131.9	138.7	144.7
	August	35.3	45.7	55.0	65.2	75.2	84.0	91.7	98.6	104.6	110.0	114.7
	September	34.8	44.7	53.7	63.5	73.0	81.3	88.7	95.2	101.0	106.1	110.6
	October	29.5	37.6	45.2	53.3	61.1	67.9	74.0	79.3	84.1	88.2	92.0
	November	17.7	22.4	26.8	31.6	36.1	40.1	43.6	46.7	49.4	51.8	54.0
	December	0	0	0	0	0	0	0	0	0	0	0

Table 13: Aggregate Load Impacts (MW) on Monthly System Peak Days 2020-2030: CAISO Weather

Weather Year	Month	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1-in-2	January	0	0	0	0	0	0	0	0	0	0	0
	February	0	0	0	0	0	0	0	0	0	0	0
	March	0	0	0	0	0	0	0	0	0	0	0
	April	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	May	11.2	14.1	17.2	20.5	23.8	26.8	29.4	31.7	33.8	35.6	37.2
	June	15.3	19.4	23.6	28.1	32.5	36.5	40.0	43.1	45.8	48.2	50.4
	July	27.5	35.2	42.6	50.6	58.5	65.5	71.6	77.1	81.9	86.1	89.9
	August	29.6	38.3	46.1	54.7	63.0	70.4	76.9	82.6	87.7	92.2	96.1
	September	30.3	38.9	46.7	55.3	63.5	70.8	77.3	82.9	87.9	92.4	96.3
	October	17.5	22.3	26.7	31.5	36.1	40.2	43.8	46.9	49.7	52.2	54.4
	November	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	December	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
	February	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	March	11.0	13.5	16.7	19.9	23.2	26.2	28.9	31.3	33.3	35.2	36.8
	April	12.8	16.0	19.6	23.4	27.2	30.6	33.7	36.4	38.8	40.9	42.7
	May	19.9	25.0	30.5	36.4	42.2	47.4	52.1	56.2	59.8	63.0	65.8
	June	28.5	36.3	44.1	52.4	60.7	68.1	74.6	80.4	85.5	90.0	94.0
	July	30.9	39.6	48.0	57.0	65.8	73.6	80.6	86.7	92.1	96.9	101.1
	August	33.0	42.7	51.4	60.9	70.2	78.4	85.7	92.1	97.7	102.7	107.1
	September	33.9	43.5	52.3	61.9	71.1	79.2	86.4	92.8	98.4	103.3	107.7
	October	21.3	27.1	32.6	38.4	44.0	49.0	53.3	57.2	60.6	63.6	66.3
	November	17.7	22.4	26.8	31.6	36.1	40.1	43.6	46.7	49.4	51.8	54.0
	December	0	0	0	0	0	0	0	0	0	0	0

5.3 RESULTS BY CATEGORY

Table 14 presents the aggregate SEP impacts for a typical event day in 2020 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.

Table 14: Ex Ante Aggregate Impacts (MW) by LCA, 2020 Forecast Year: Typical Event Day

LCA	Enrollment	SCE 1-in-2	CAISO 1-in-2	SCE 1-in-10	CAISO 1-in-10
Big Creek/Ventura	7,188	3.7	3.8	4.7	4.7
LA Basin	51,644	22.4	22.3	31.9	28.3
Outside LA Basin	1,416	0.7	0.7	0.8	0.8
SEP Total	**60,249**	**26.7**	**26.7**	**37.5**	**33.8**

While nearly 86% of SEP participants are located in the LA Basin LCA, between 83% and 85% of the ex ante MW impacts are located in the LA Basin. This is due to the fact that the 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 0.51 kW, Outside LA Basin has an average customer impact of 0.46 kW and LA Basin has an average customer impact of 0.43 kW.

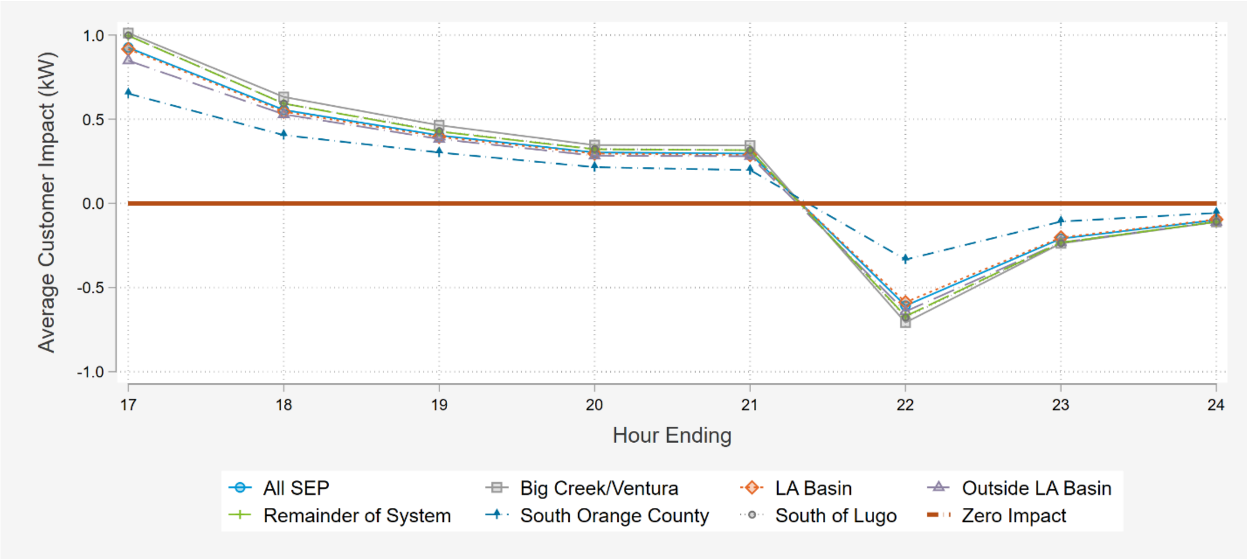
Table 15 provides a similar breakdown for each region of the SCE system affected by the SONGS closure. For SCE 1-in-2 weather conditions, 38.3% of the SEP load reduction is expected to come from South of Lugo, 13.6% from South Orange County, and 48.4% from the Remainder of the System unaffected by the SONGS closure.

Table 15: Ex Ante Aggregate 2020 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
Remainder of System	26,448	12.9	12.9	17.3	16.2
South Orange County	12,041	3.6	3.7	5.2	4.4
South of Lugo	21,760	10.2	10.0	15.0	13.3
SEP Total	**60,249**	**26.7**	**26.7**	**37.5**	**33.8**

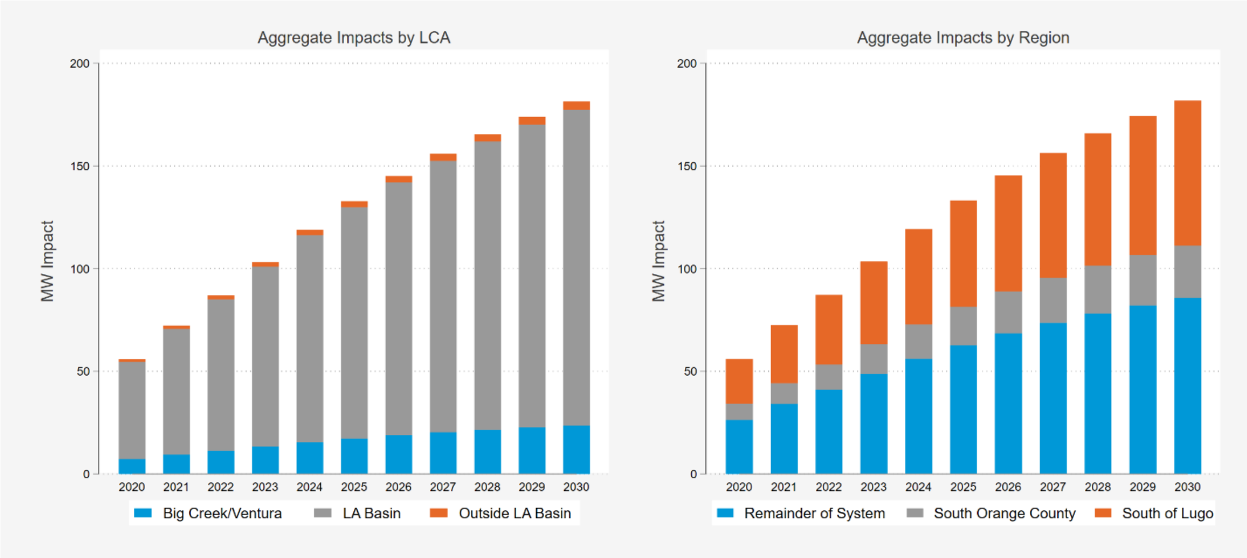
Readers should note that the aggregate impacts shown in Table 14 and Table 15 are an average across the five hour RA window. Figure 26 shows the average impact on an August system peak day by segment and hour across the RA window and post-event snapback period using SCE 1-in-2 weather and reveals that that average MW impacts across the RA window mask a significant amount of inter-hour diversity in estimated performance. In Figure 26, load reductions are presented as a positive impact and load increases are presented 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 26: Average Customer Impacts by Segment and Hour: August System Peak Day, SCE 1-in-2



As shown in Figure 26, the per-participant impact is greatest during the first hour of event dispatch. The forecasted enrollments is the same in each hour. Figure 27 shows the projected aggregate MW impacts for SEP 2020-2030 by LCA and Region using SCE 1-in-2 weather conditions for an August system peak day.

Figure 27: 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 16 compares the average customer impacts on an absolute and percent basis and shows the weighted average temperature (F) across the SEP population for an August system peak day using SCE

1-in-2 weather. The PY2019 weather is comparable to PY2018 for this set of ex ante weather conditions despite being based on an updated weather forecast.

Table 16: Comparison of PY2018 and PY2019 Average Customer Impacts: August System Peak Day, SCE 1-in-2 Weather

Hour Ending	2018 (kW)	2019 (kW)	2018 (%)	2019 (%)	2018 (Temp)	2019 (Temp)
17	1.11	0.93	48.1%	39.8%	93.8	93.1
18	0.79	0.56	31.1%	21.4%	92.6	91.6
19	0.58	0.40	21.6%	14.2%	90.5	90.1
20	0.42	0.30	16.3%	10.3%	87.9	88.5
21	0.41	0.30	16.3%	10.3%	83.7	85.1
RA Window Average	**0.66**	**0.50**	**26.7%**	**19.2%**	**89.7**	**89.7**

Table 17 shows the same comparison for SCE 1-in-10 weather. The PY2019 average customer impacts during the RA window are smaller than the PY2018 impacts, but the difference is less pronounced for SCE 1-in-10 weather than for SCE 1-in-2 weather.

Table 17: Comparison of PY2018 and PY2019 Average Customer Impacts: August System Peak Day, SCE 1-in-10 Weather

Hour Ending	2018 (kW)	2019 (kW)	2018 (%)	2019 (%)	2018 (Temp)	2019 (Temp)
17	1.28	1.09	51.8%	41.7%	96.9	97.0
18	0.88	0.66	32.4%	22.1%	96.4	96.5
19	0.62	0.48	21.8%	14.7%	95.6	95.2
20	0.45	0.35	16.3%	10.8%	92.8	92.4
21	0.44	0.35	16.3%	10.8%	88.4	88.8
RA Window Average	**0.73**	**0.59**	**27.7%**	**20.0%**	**94.0**	**94.0**

Table 18 and Table 19 show the same comparison for CAISO 1-in-2 and CAISO 1-in-10 weather conditions on an August system peak day in 2020. The CAISO 1-in-2 ex ante weather conditions are slightly cooler in the PY2019 ex ante estimates for an August system peak day compared to the PY2018 ex ante estimates. The opposite is true for CAISO 1-in-10 weather on an August system peak day.

Table 18: Comparison of PY2018 and PY2019 Average Customer Impacts: August System Peak Day, CAISO 1-in-2 Weather

Hour Ending	2018 (kW)	2019 (kW)	2018 (%)	2019 (%)	2018 (Temp)	2019 (Temp)
17	1.05	0.93	46.6%	40.0%	93.2	92.7
18	0.77	0.55	30.6%	21.4%	92.5	90.6
19	0.56	0.39	21.5%	14.3%	90.6	88.7
20	0.42	0.29	16.3%	10.4%	87.3	87.0
21	0.41	0.29	16.3%	10.4%	82.9	84.3
RA Window Average	**0.64**	**0.49**	**26.3%**	**19.3%**	**89.3**	**88.7**

Table 19: Comparison of PY2018 and PY2019 Average Customer Impacts: August System Peak Day, CAISO 1-in-10 Weather

Hour Ending	2018 (kW)	2019 (kW)	2018 (%)	2019 (%)	2018 (Temp)	2019 (Temp)
17	1.23	1.02	50.8%	40.5%	94.5	96.1
18	0.85	0.62	32.0%	21.6%	93.6	95.3
19	0.60	0.45	21.7%	14.4%	92.5	93.7
20	0.44	0.33	16.3%	10.5%	90.0	91.3
21	0.43	0.32	16.3%	10.5%	86.0	87.0
RA Window Average	**0.71**	**0.55**	**27.5%**	**19.5%**	**91.3**	**92.7**

We offer the following observations about the comparisons shown in Table 16 through Table 19.

- The 2019 average ex ante impacts across the RA window are smaller than the PY2018 average ex ante impacts on both an absolute and percent basis. However, the PY2019 reference loads are slightly higher.

- While both sets of ex ante results show the largest impact during the first event hour with decaying impacts each subsequent hour, the PY2019 ex ante impacts show a steeper decline in impacts across the event than the PY2018 impacts. Opt outs are a potential explanation for the steeper decline. One hypothesis is that participants are more likely to be home and opt-out of an SEP in the evening (PY2019) than an SEP event in the afternoon (PY2018). For the PY2020 impact evaluation we will explore the possibility of collecting device-level opt out data from the thermostat providers for analysis.

- The lower average kW impact per participant may be a function of methodology. In the PY2018 analysis, the evaluator was required to predict ex ante impacts for the new RA window using historic performance data from events dispatched from 2pm to 6pm. Air conditioning load typically makes up a larger share of premise load during the afternoon hours than in the evening when temperatures are cooling off and more end-uses within the home are activated.

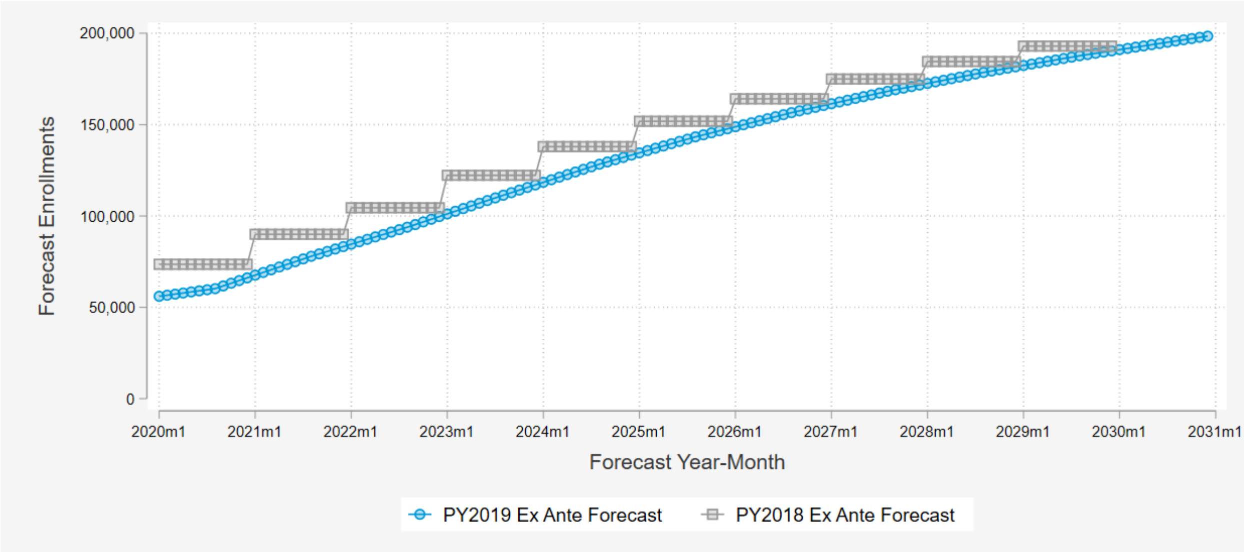
- The weighted average temperatures across the SEP participant population vary between the PY2019 and PY2018 ex ante analyses. The direction of the change varies by planning condition. These differences are due to two factors.
  - ✓ Updated ex ante weather conditions for SCE and CAISO were used in the PY2019 analysis.[2]
  - ✓ Turnover in the SEP participant population. The loss of participants from CCAs was offset by new enrollments in different areas of SCE territory. This changes the weights of each weather station's records in the composite SEP weather conditions.

AGGREGATE IMPACTS

In addition to the variation in average participant impacts discussed in the prior section, aggregate impact estimates are affected by the estimated number of SEP enrollments. As discussed in Section 5.1, the PY2019 enrollment forecast is noticeably lower than the PY2018 enrollment during 2020. When creating Figure 22, we converted the annual forecasts to monthly assuming linear growth. However, in this section we do not recalculate the PY2018 ex ante impacts. Instead, we compare the PY2019 ex ante impacts to the official PY2018 ex ante numbers that were filed. Figure 29 compares the values on a monthly basis over an 11-year horizon.

[2] Updated Ex Ante 1-in-2 and 1-in-10 Weather Conditions for SCE and CAISO memorandum. Produced by Nexant, Inc. for SCE. October 10, 2019

Figure 28: Comparison of Ex Ante Enrollments: PY2019 vs. PY2018



For a 2020 typical event day, the PY2018 ex ante impacts assumed 73,563 participants. For comparison, the PY2019 ex ante impacts assume 60,249 participants – a reduction of 18%. The differences in the two forecasts become less pronounced over time. Holding all other factors constants, the lower enrollment projection would result in an 18% reduction in predicted aggregate MW reduction. As discussed in the previous section, the ex ante average customer impacts are also lower for PY2019 than PY2018 due to a steeper decline in impacts across the event.

Table 20 compares the PY2018 and PY2019 aggregate ex ante load reduction estimates for forecast year 2020 on a typical event day using SCE peaking conditions. The average estimated performance across the five-hour RA window is 34% lower for 1-in-2 conditions and 25% lower for 1-in-10 conditions. However, during the first hour of assumed dispatch, the PY2019 estimates are 18% lower than the PY2018 estimates, which corresponds exactly with the 18% reduction in projected enrollments. This underscores the key difference in the ex ante estimates for the average customer estimates. The PY2019 analysis estimates similar per-participant impacts during the first hour of dispatch as the PY2018 evaluation, but the impacts deteriorate more rapidly in subsequent hours. Our hypothesis is that this decline is driven by increased opt-out rates during PY2019 compared to prior years.

Table 20: Comparison of 2020 Aggregate Typical Event Day Ex Ante Impacts (MW): PY2018 vs. PY2019 with SCE Weather

Hour Ending	SCE 1-in-2		SCE 1-in-10	
	PY2018	PY2019	PY2018	PY2019
17	59.6	48.9	85.2	70.4
18	47.7	30.6	60.1	42.1
19	37.9	22.2	43.2	30.5
20	28.5	16.1	31.6	22.4
21	28.1	15.7	30.8	22.2
RA Window Average	**40.4**	**26.7**	**50.2**	**37.5**

Table 21 presents the same comparison using CAISO peaking conditions. Aggregate MW impacts are 38% lower for 1-in-2 weather and 32% lower for 1-in-10 weather.

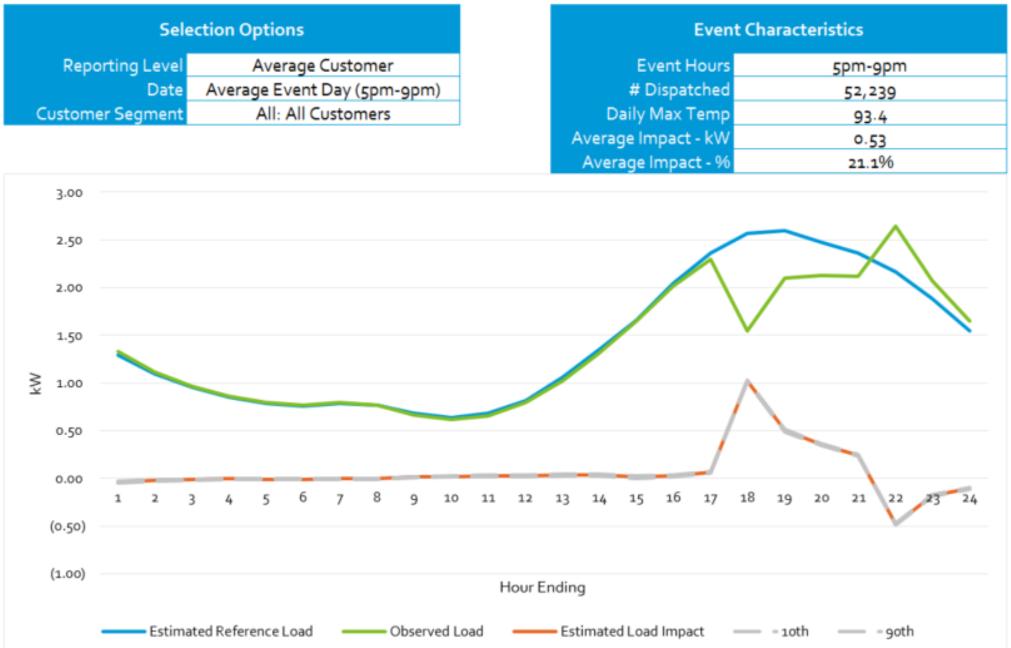
Table 21: Comparison of 2020 Aggregate Typical Event Day Ex Ante Impacts (MW): PY2018 vs. PY2019 with CAISO Weather

Hour Ending	CAISO 1-in-2		CAISO 1-in-10	
	PY2018	PY2019	PY2018	PY2019
17	67.6	49.2	84.1	63.0
18	51.5	30.3	59.7	38.1
19	39.4	22.1	43.0	27.7
20	29.4	16.1	31.5	20.3
21	28.9	15.8	30.8	19.9
RA Window Average	**43.4**	**26.7**	**49.8**	**33.8**

5.5 EX POST TO EX ANTE COMPARISON

Weather conditions during PY2019 event days were comparable to 1-in-2 ex ante weather conditions for both the average 5pm to 9pm events and average 6pm to 8pm events. The observed weather during PY2019 was milder than 1-in-10 peak conditions. Figure 29 is reproduced from the MS Excel ex post reporting template and shows the average SEP 5pm to 9pm event from PY2019. Figure 30 shows the average customer ex ante impacts for SCE 1-in-2 weather.

Figure 29: PY2019 Ex Post Average Event Day 5pm-9pm



The "Average kW Impact" characteristic in Figure 30 is lower because all five hours of the RA window are averaged and weather conditions are slightly cooler. The average kW impact for hours ending 17 through 20 in this set of ex ante results is 0.49 kW per participating household. The CAISO 1-in-2 results are virtually identical to the SCE 1-in-2.

Figure 30: Ex Ante Typical Event Day under SCE 1-in-2 Conditions: 4pm to 9pm

Selection Options	
Reporting Level	Average Customer
Customer Segment	All
Day Type	Typical Event Day
Month	Typical Event
Weather Year	SCE 1-in-2
Forecast Year	2020

Event Characteristics	
Event Hours	5pm-9pm (RA Hours 4pm-9pm)
# Dispatched	60,249
Daily Max Temp	91.9
Average Impact - kW	0.44
Average Impact - %	17.4%

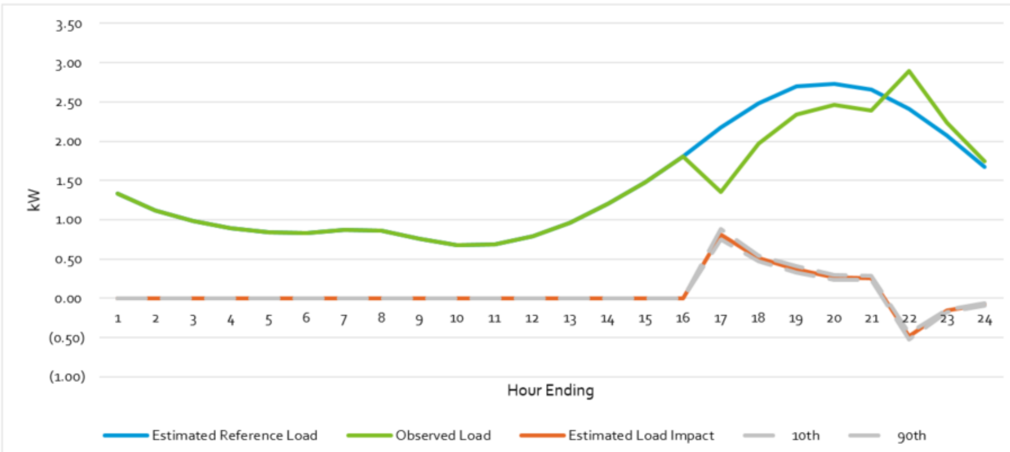
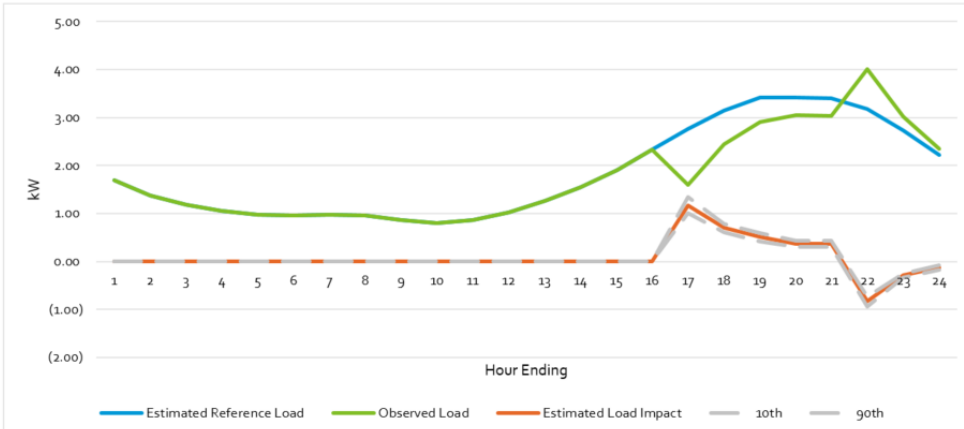


Figure 31 shows the average customer impacts for SCE 1-in-10 conditions, which assume a weighted average maximum daily temperature of 99.6 degrees (F). The predicted load impact across the five hour RA window is 0.62kW and the estimated load impact during the first four hours of dispatch is 0.69 kW. The average post-event load increase estimates are 0.83 kW, 0.29 kW, and 0.13 kW during hours ending 22, 23, and 24.

Figure 31: Ex Ante Typical Event Day under SCE 1-in-10 Conditions: 4pm to 9pm

Selection Options	
Reporting Level	Average Customer
Customer Segment	All
Day Type	Typical Event Day
Month	Typical Event
Weather Year	SCE 1-in-10
Forecast Year	2020

Event Characteristics	
Event Hours	5pm-9pm (RA Hours 4pm-9pm)
# Dispatched	60,249
Daily Max Temp	99.6
Average Impact - kW	0.62
Average Impact - %	19.3%

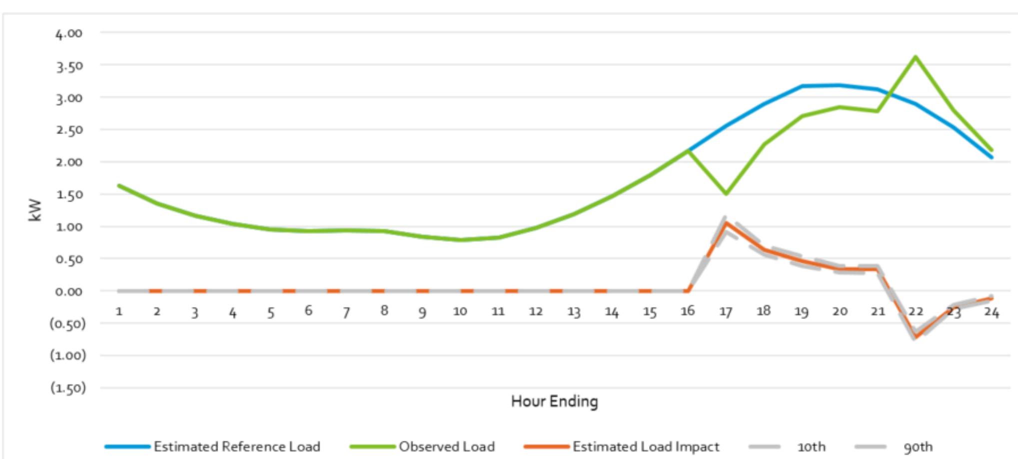


CAISO 1-in-10 peak conditions are less extreme than SCE 1-in-10 weather conditions for a typical event day. Figure 32 shows the ex ante average SEP customer impacts for a typical event day in 2020. The weighted average maximum daily temperature is 96.4 degrees (F) and the average impact across the five hour RA window is 0.56 kW.

Figure 32: Ex Ante Typical Event Day under CAISO 1-in-10 Conditions: 4pm to 9pm Dispatch

Selection Options	
Reporting Level	Average Customer
Customer Segment	All
Day Type	Typical Event Day
Month	Typical Event
Weather Year	CAISO 1-in-10
Forecast Year	2020

Event Characteristics	
Event Hours	5pm-9pm (RA Hours 4pm-9pm)
# Dispatched	60,249
Daily Max Temp	96.4
Average Impact - kW	0.56
Average Impact - %	18.8%



Aggregate ex ante impacts for PY2020 are generally larger than the PY2019 ex post impacts because of the projected increase in enrollment. The average number of households dispatched during the average PY2019 event from 5pm to 9pm was 52,239. The average number of households dispatched during the average 6pm to 8pm event was 52,129. The enrollment forecast for an August monthly peak day in PY2020 is approximately 15% higher at 60,249. Table 22 compares the aggregate impacts for the two most common PY2019 event profiles to the August monthly peak day ex ante estimates for PY2020. Because the PY2019 events varied in duration, we show the average impact during the first hour of dispatch. In order to facilitate an "apples to apples" comparison Table 22 also includes a column where PY2019 aggregate impacts are recalculated using the forecasted enrollment levels for PY2020.

Table 22: Comparison of PY2019 Ex Post Impacts to PY2020 Ex Ante Typical Event Day Impacts

Event Date	Max Daily Temp (F)	Participants	Hour 1 kW	Hour 1 MW	Hour 1 MW at 2020 Enrollment
Average Event Day (5pm-9pm)	93.4	52,239	1.02	53.3	61.4
Average Event Day (6pm-8pm)	92.0	52,129	0.94	49.0	56.6
2020 August Peak Day SCE 1-in-2 (4pm-9pm)	93.7	60,249	0.93	55.8	N/A
2020 August Peak Day SCE 1-in-10 (4pm-9pm)	99.6	60,249	1.09	65.6	N/A
2020 August Peak Day CAISO 1-in-2 (4pm-9pm)	92.0	60,249	0.93	56.0	N/A
2020 August Peak Day CAISO 1-in-10 (4pm-9pm)	96.4	60,249	1.02	61.3	N/A

6 DISCUSSION

Based on the 2019 ex post and ex ante load impact evaluation results, we highlight the following considerations for program design and future load impact evaluations.

- 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.

- SCE is deploying default TOU pricing for residential customers in 2020. The transition is scheduled to begin in October 2020 so much of the PY2020 SEP event activity will be prior to the transition. As shown in Table 4, less than 20% of SEP participants faced time-varying pricing during PY2019. The rollout of default TOU may alter SEP participant reference loads and potentially change the average load impact of SEP dispatch.

    - ✓ Figure 20 showed that ex post impacts on the 2019 system peak day (September 4, 2019) were larger for SEP participants that faced dynamic pricing. Although this difference may be entirely unrelated to rates, one potential explanation is that customers on a TOU rate are less likely to opt-out of SEP events because the thermostat setback creates bill savings for them.

- ✓ The impact of default TOU will be an important consideration for the PY2020 ex ante analysis.

- The PY2019 analysis showed a more rapid decline in impacts across event hours than the PY2018 analysis. This may be weather related as outdoor temperatures are declining during the evening hours when PY2019 events were dispatched. Another potential reason for the observed decline is more frequent customer opt-outs due to increased occupancy during evening hours. SEP allows customers to override the thermostat setpoint modification, however marketing materials note that "*At SCE's discretion, customers may be removed from the Program for overriding all energy events dispatched in a calendar year, when overrides consistently occur within the first hour of events.*"

  - ✓ We recommend SCE request thermostat-level operating data from the SEP thermostat providers. This supplemental information could provide valuable insights into whether customer opt-outs are driving the reduction in impacts in the second, third, and fourth hour of SEP events.

  - ✓ With granular thermostat runtime, setpoint, and indoor temperature data we would be able to examine SEP impacts as a function of cooling load, in addition to whole-house loads.

  - ✓ Thermostat operating data would also allow for an exploration of the changes in indoor temperature within homes during SEP events.

- Participating homes can have more than one thermostat. It would be a useful segmentation variable if the number of controlled thermostats or condensing units in the home was captured.

- SEP does not hold load shed under the current event profile. Event impacts are largest during the first hour of dispatch and deteriorate in each subsequent hour. If a more consistent load impact across dispatch hours is desired, there are several tactics used by other program administrators to mitigate the decay of impacts across the event.

  - ✓ 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 more consistent impacts across event hours.

  - ✓ 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.

- ✓ 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 setpoint. Pre-cooling can also reduce participant opt-outs through increased participant comfort.