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2021 Statewide Load Impact Evaluation of Non-Residential Critical Peak Pricing (CPP) Rates

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Executive Summary

This report documents ex-post and ex-ante load impact evaluations of non-residential critical peak pricing (CPP) rates at the three major investor-owned electric utilities (Joint Utilities): Pacific Gas and Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) for 2021. The evaluation produces estimates of the ex-post load impacts for each hour of each of the PG&E's and SCE's CPP events called in 2021. SDG&E didn't call any CPP events in 2021. The evaluation also develops ex-ante load impact forecasts of the programs through 2032.

ES.1 Resources Covered

California's CPP programs provide participating customers with lower rates during non-CPP summer season hours and momentary higher rates during CPP periods when an event is called. These "dynamic" pricing rates are designed to encourage price-responsive demand reductions during the higher priced critical periods. The rates are similar at the three utilities, though they are referred to by different names (e.g., Peak Day Pricing, or PDP, at PG&E). Various program provisions vary by utility, including the notification period for events, the specific hours when CPP events can be called, the number and duration of CPP events, and the minimum demand requirements for eligible customers. Note that the analysis of SDG&E's small CPP customers is included in a different study.

The primary goals of the evaluation include:

1. Estimate hourly ex-post load impacts of the CPP rates for each of the Joint Utilities in 2021, by size group and local capacity area (LCA);
2. Estimate ex-post load impacts for 2021 for each of the utilities' Automated Demand Response (Auto-DR) program for CPP customers enrolled in the program;
3. Produce ex-ante load impact forecasts for the CPP rates for 2022 through 2032;[1]
4. Estimate the incremental CPP load impacts due to dual participation in other programs.

Secondary goals include estimating the effect of event notification on load impacts and comparing the load impacts for subgroups of interest such as net energy metered (NEM) customers, C&I vs. agricultural customers, and customers assigned Business Energy Support (BES)/CRS for PG&E and Community Choice Aggregation (CCA) customers for SDG&E.

ES.2 Evaluation Methodologies

In this evaluation, we estimate CPP ex-post load impacts using two primary methodologies: within-subjects panel models and customer-specific regressions. In both

[1] PG&E and SDG&E request that the forecast period includes the program year being evaluated (i.e., 2021), with the values serving as weather-normalized versions of the ex-post load impacts.

cases, load impact estimates are based on comparisons of event-day loads to non-event day loads, controlling for weather conditions and day type characteristics (e.g., day of week or month of year). Panel models, which combine customers into a model with common estimates, are used for all but the largest CPP customers. For the largest customers, we estimate customer-specific models to properly account for any idiosyncrasies in their load profiles that may affect their load impact estimates. As requested by each utility, we also studied the load impacts for specific subsets of customers within each size group.

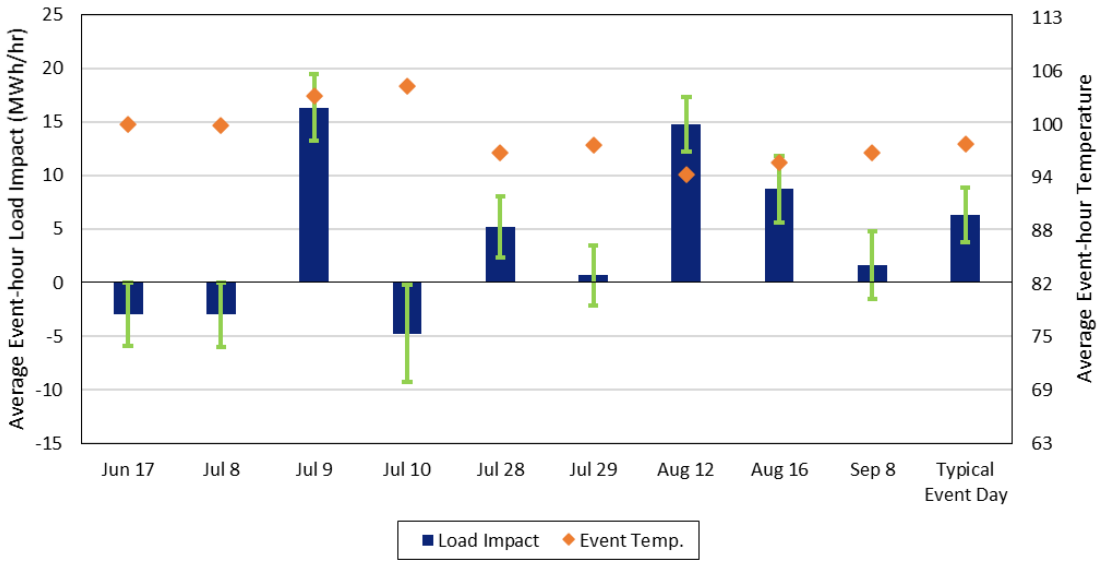
Ex-ante estimates are based on ex-post percentage load impacts (adjusted for changes in event hours as needed), with the reference loads simulated to represent the range of weather and day types required by the Protocols. PG&E and SDG&E will change its CPP event hours in 2022 (March 1st for PG&E and June 1st for SDG&E).

ES.3 Ex-Post Load Impacts

ES.3.1 PG&E

Figure ES.1 shows the estimates of the average event-hour load impacts by event day, along with a 90 percent confidence interval for all PG&E's PDP customers. These customers achieve statistically significant load reductions on 4 out of 9 event days as well as on the typical event day. The estimated load reduction for the typical event day is 6.3 MWh/hour, which is a 0.8 percent load reduction. Figure ES.1 doesn't provide evidence of a relationship between load impacts and average temperatures.

Table ES.1 Average Event-Hour Load Impacts by event, *PG&E All*

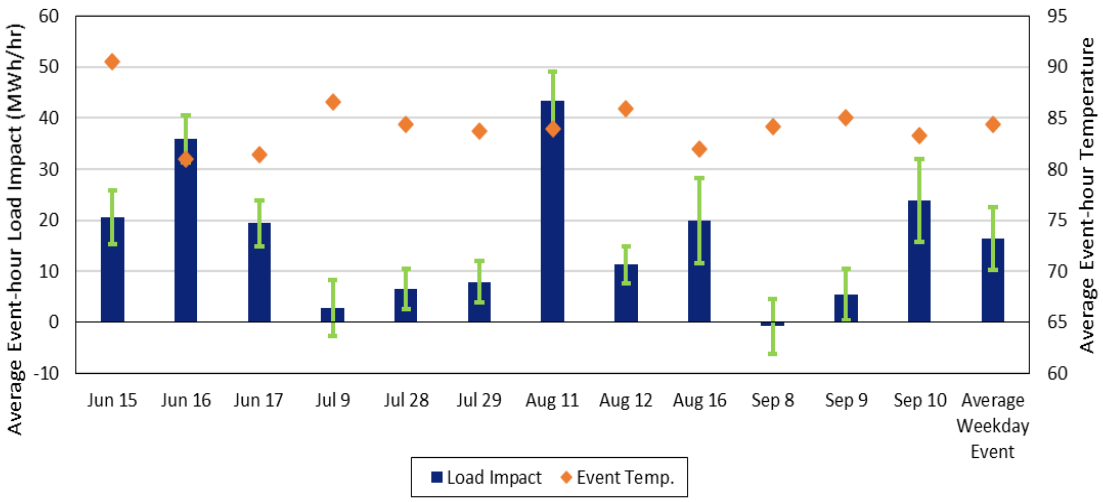


Large customers had statistically significant load reductions on 7 out of 9 event days. The estimated load reduction for the typical event day is 5.3 MWh/hour. Medium and small customers have statistically significant load reductions on 3 out of 9 event days. The estimated load reduction for the typical event day is positive but not statistically significant for medium and small customers.

ES.3.2 SCE

Figure ES.2 shows the ex-post load impacts for all SCE's CPP customers. Overall, SCE's customers had statistically significant load reductions on 10 out of 12 event days. The load impact averaged 16 MWh/hour across all event days, which is a 1.1 percent load reduction. Figure ES.2 doesn't provide evidence of a relationship between load impacts and average temperatures.

Figure ES.2: Average Event-Hour Load Impacts by Event, *SCE All*



Large customers had statistically significant load reductions on each of the 12 event days, ranging from 6 to 21 MWh/hour. The load impact averaged 11 MWh/hour across all event days. Medium customers had statistically significant load reductions on 5 out of 12 event days. The average event day load impact of 4.6 MWh/hour for medium customers is also statistically significant. For small customers, only four events exhibit reductions in usage that are statistically significant. The average weekday load impact is not statistically significant for small customers.

ES.4 Ex-Ante Load Impacts

Ex-ante load impacts represent forecasts of load impacts that are expected to occur when program events are called in future years under standardized weather conditions. Estimating ex-ante load impacts for future years requires three key pieces of information:

- A utility-provided *enrollment forecast* for relevant components of the program, which consists of forecasts of the number of customers by required type of customer;
- *Reference loads* by customer type;
- A forecast of *load impacts per customer*, again by relevant customer type, where the load impact forecast also varies with weather conditions (if applicable), as determined in the ex-post evaluation.

We conducted this process for each utility, size group (under 20 kW, 20 to 200 kW, and over 200 kW), and LCA. The load impacts are provided for the years 2022 through 2032, for a number of day types (monthly system peaks days) and weather scenarios (utility-specific and CAISO peaking conditions in both 1-in-2 and 1-in-10 scenarios).

ES.4.1 PG&E

Figures ES.3 summarizes the ex-ante load impact for all PG&E's PDP customers. The results reflect the Typical Event Day load impacts during the Resource Adequacy (RA) window at August enrollments. The RA window is from 4 to 9 p.m. (Beginning in 2022, PG&E's PDP event window aligns completely with the RA window.) For each year, we show the load impact associated with each weather scenario (1-in-2 and 1-in-10 weather conditions associated with each of the utility's peak day and the CAISO peak day). We assume that per-customer load impacts are constant across forecast years, so the pattern of load impacts across years reflects the underlying enrollment forecast.

There is a small increase in aggregate load impact from 2022 to 2023 due to increased enrollments. Load impacts decline after 2023 due to program attrition. There are relatively minor differences between forecasted load impacts across the weather scenarios over the forecast period. The highest load impacts for each year occur under PG&E 1-in-10 weather conditions. The load impacts for different customers sizes show similar patterns.

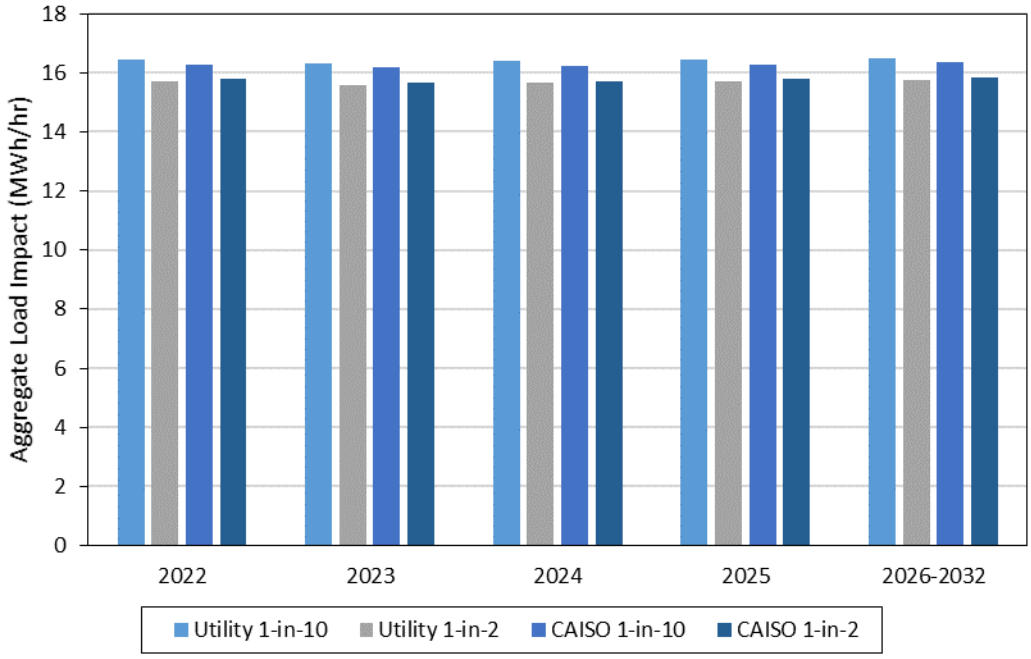
Figure ES.3: Aggregate Load Impacts for Typical Event Day by Year and Weather Scenario over RA Window, P*G&E All*

ES.4.2 SCE

Figures ES.4 summarizes the ex-ante load impact for all SCE's CPP customers. The results reflect the average weekday event day impacts during the Resource Adequacy (RA) window at August enrollments. The RA window is from 4 to 9 p.m. For each year, we show the load impact associated with each weather scenario (1-in-2 and 1-in-10 weather conditions associated with each of the utility's peak day and the CAISO peak day). We assume that per-customer load impacts are constant across forecast years, so the pattern of load impacts across years reflects the underlying enrollment forecast.

There is little forecast growth in load impacts because SCE forecasts a correspondingly small change in total CPP enrollments. The enrollment decreases slightly from 2022 to 2023 and then increases slightly until 2026, at which point enrollments are constant for the remainder of the forecast. The load impacts for 1-in-10 scenarios are higher than 1-in-2 scenarios. The highest load impacts for each year occur under utility-specific 1-in-10 weather conditions. The load impacts of different customer sizes show similar patterns.

Figure ES.4: Aggregate Load Impacts for Average Weekday Event by Year and Weather Scenario over RA Window, *SCE All*

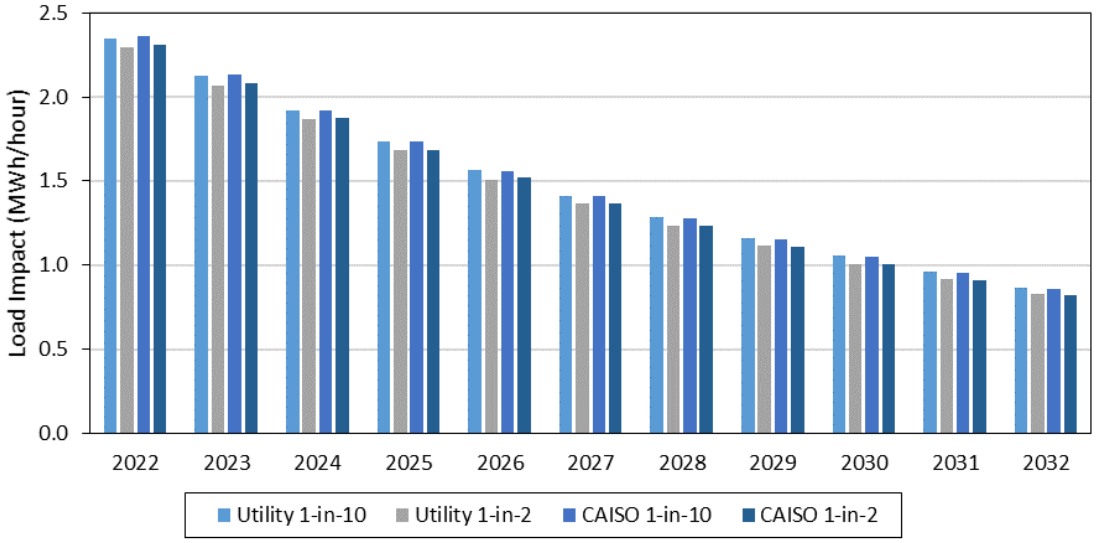


ES.4.3 SDG&E

Figures ES.5 summarizes the ex-ante load impact for all SDG&E's CPP customers. The results reflect the average weekday event day impacts during the Resource Adequacy (RA) window at August enrollments. The RA window is from 4 to 9 p.m. (Beginning in 2022, SDG&E's CPP event window aligns completely with the RA window.) For each year, we show the load impact associated with each weather scenario (1-in-2 and 1-in-10 weather conditions associated with each of the utility's peak day and the CAISO peak day). We assume that per-customer load impacts are constant across forecast years, so the pattern of load impacts across years reflects the underlying enrollment forecast.

Load impacts decrease after each year because of reductions in enrollments. SDG&E anticipates the total number of customers decreases by 12 percent each year. The load impacts of the 1-in-10 scenarios are slightly higher than 1-in-2 scenarios.

Figure ES.5: Aggregate Load Impacts for Average Weekday Event by Year and Weather Scenario over RA Window, *SDG&E All*



The load impacts of both large and medium customers decrease over time due to declining enrollments. For large customers, the largest load impacts occur for the SDG&E 1-in-10 weather year while the lowest load impacts occur during the CAISO 1-in-2 weather year. On the other hand, for medium customers, the 1-in-10 scenarios have lower load impacts than the 1-in-2 scenarios.

1. Introduction and Purpose of the Study

This report documents ex-post and ex-ante load impact evaluations of non-residential critical peak pricing (CPP) rates at the three major investor-owned electric utilities (Joint Utilities): Pacific Gas and Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) for 2021. The evaluation produces estimates of the ex-post load impacts for each hour of each of the utilities' CPP events called in 2021, and it develops ex-ante load impact forecasts of the programs through 2032.

California's non-residential CPP programs provide participating customers with lower rates during non-CPP summer season hours and momentary higher rates during CPP event hours when events are called. These "dynamic" pricing rates are designed to encourage price-responsive demand reductions during the higher priced critical periods. Customers should benefit financially from the lower rates for electricity consumed outside of the CPP periods, however new customers to the program are afforded bill protection for the first twelve months after enrollment to ensure that their energy costs on CPP do not exceed their pre-CPP costs while they learn how to respond to the program incentives.

PG&E, SCE, and SDG&E (henceforth the Joint Utilities) have implemented CPP as the default service for their non-residential customers (customers have the option to choose a different rate). PG&E began defaulting their large commercial and industrial (C&I) customers (over 200 kW) onto their CPP rates, called Peak Day Pricing (PDP), in 2010. Although PG&E began defaulting small and medium business (SMB) customers onto PDP in late 2014, they later delayed the process in anticipation of a change in TOU pricing periods and have since resumed defaulting customers onto PDP. Approximately 32,000 SMB customers were defaulted onto PDP in March 2021. SCE began defaulting their large C&I customers onto CPP rates in 2010 and their SMB customers in 2019. SDG&E began defaulting their large C&I customers onto CPP rates in 2009 and their SMB customers in 2018. SDG&E's small business CPP customer performance is analyzed in a separate evaluation and therefore will not be included in this evaluation. The Joint utilities had the following enrollments in CPP on the 2021 typical event day:

Table 1.1: Enrollment by Group Included in the Study

Size Group	PG&E	SCE	SDG&E
Large (Over 200kW)	1,235	1,915	459
Medium (20 to 199kW)	16,402	27,503	4,523
Small (Under 20kW)	89,806	229,582	Excluded

Among the CPP tariffs offered by the Joint Utilities, there are a number of common rate design elements, but also some significant differences. PG&E and SDG&E provide a Capacity Reservation option that protects a portion of a customer's load from the CPP rate during events. PG&E only provides this option to its largest C&I and Agricultural customers while SDG&E offers it to all non-residential customers above 20 kW.

Customers on the CPP tariffs offered by the Joint Utilities are also eligible to participate in Technical Assistance and Technology Incentives (TA/TI) and Automated Demand Response (Auto-DR) programs. The following table summarizes some of the program provisions that vary by utility:

Table 1.2: Event Hours and Allowed Number of Events by Utility

Program Characteristic	PG&E	SCE	SDG&E
Event hours	5 to 8 p.m.	4 to 9 p.m.	2 to 6 p.m.
Events / year	9 to 15	12 to 15	Maximum of 18
Days	All	Non-holiday, weekdays	All
Notification	Day ahead, by 4 p.m.	Day ahead	Day ahead, by 2 p.m.

1.1 Project Goals

The primary goals of the evaluation include:

1. Estimate hourly ex-post load impacts of the CPP rates for each of the Joint Utilities in 2021, by size group and local capacity area (LCA);
2. Estimate ex-post load impacts for 2021 for each of the utilities' Automated Demand Response (Auto-DR) program for CPP customers enrolled in the program;
3. Produce ex-ante load impact forecasts for the CPP rates for 2022 through 2032;[2]
4. Estimate the incremental CPP load impacts due to dual participation in other programs.

Secondary goals include estimating the effect of event notification on load impacts and comparing the load impacts for subgroups of interest such as net energy metered (NEM) customers, C&I vs. agricultural customers, and customers assigned Business Energy Support (BES)/CRS for PG&E and Community Choice Aggregation (CCA) customers for SDG&E. The evaluation conforms to the Load Impact Protocols adopted by the California Public Utilities Commission (CPUC) in April 2008 (D.08-04-050).

1.2 PY2021 Event Days

Table 1.3 summarizes the CPP events for each utility. PG&E called nine events (the minimum number of allowed events), SCE twelve events (the minimum number of required events), and SDG&E did not call an event. The July 10th event (in bold) was a weekend event.

[2] PG&E and SDG&E request that the forecast period includes the program year being evaluated (i.e., 2021), with the values serving as weather-normalized versions of the ex-post load impacts.

Table 1.3: PY2021 CPP Event Dates by Utility

Date	Day of Week	PG&E	SCE	SDG&E
6/15/2021	Tuesday		X	
6/16/2021	Wednesday		X	
6/17/2021	Thursday	X	X	
7/8/2021	Thursday	X		
7/9/2021	Friday	X	X	
7/10/2021	**Saturday**	**X**		
7/28/2021	Wednesday	X	X	
7/29/2021	Thursday	X	X	
8/11/2021	Wednesday		X	
8/12/2021	Thursday	X	X	
8/16/2021	Monday	X	X	
9/8/2021	Wednesday	X	X	
9/9/2021	Thursday		X	
9/10/2021	Friday		X	

1.3 Report organization

The report is organized as follows: Section 2 describes the evaluation methods used in the study; Section 3 contains PG&E's load impact results; Section 4 contains SCE's load impact results; Section 5 contains SDG&E's load impact results; and Section 6 provides recommendations. Appendices describe the results of our model validation process and contain electronic versions of the required Protocol table generators.

2. Study Methodology

The CPP ex-post load impact evaluation uses two methodologies: within-subjects panel models and customer-specific regressions.[3] In both cases, load impact estimates are based on comparisons of event-day loads to non-event day loads, controlling for weather conditions and day type characteristics (e.g., day of week or month of year). Panel models, which combine customers into a model with common estimates, are used for all but the largest CPP customers. For the largest customers, we estimate customer-specific models to properly account for any idiosyncrasies in their load profiles that may affect their load impact estimates.

[3] We also tested panel models with control-group customers, similar to methods used in previous evaluations, but did not find them to be effective. We were not able to find adequate matches between CPP customers and control group customers, likely due to the relatively small pool of remaining eligible control-group customers as most customers have been defaulted onto CPP.

Ex-ante estimates are based on ex-post load impacts, with the reference loads simulated to represent the range of weather and day types required by the Protocols. Details for the ex-post and ex-ante analyses are provided below.

2.1 Ex-post Load Impact Evaluation

The objectives of the ex-post impact evaluation were described in Section 1.1. This section describes the data and specific methods that we use to meet the objectives, including a discussion of the estimation of uncertainty-adjusted load impacts and distributions of load impacts.

2.1.1 Data

Analyses that address each of the load impact objectives require the following types of data:

- *Customer* information for CPP customers and potential control-group customers (e.g., date of enrollment and de-enrollment, enrollment dates for other DR programs, LCA, climate zone, weather station, NAICS code, size category);
- Monthly usage from billing data for a 12-month period (used in the initial matching process and to validate the interval data);
- Billing-based *interval load data* for treatment customers on event and event-like non-event days;
- Billing-based *interval load data* for a sample of treatment customers for a 12-month period (e.g., October 2020 through September 2021), used to simulate ex-ante reference loads;
- *Weather data* (i.e., hourly temperatures and other weather variables for each applicable weather station);
- *Program event data* (i.e., CPP event dates).

2.1.2 Event-Like Non-Event Day Selection

We select a set of event-like non-event days to best approximate the weather and day types associated with the event days. Weather conditions are assessed using CPP customer-weighted average temperatures across each utility's service territory. This ensures that the weather used in the analysis reflects the conditions faced by the program participants rather than the entire system. When selecting days, we exclude event days for dually enrolled programs and ensure that days are selected from a range of time periods (rather than just a series of consecutive dates).

Figure 2.1 and Figure 2.2 below displays the average event-hour temperature for all weekday and weekends between May and October 2021, for PG&E and SCE, respectively. Red diamond markers indicate weekend non-event days while blue circles indicate weekday non-event days. The filled in markers ("Hot Day") represent selected event-like non-event days with relatively comparable temperatures to event days. The

"X" markers represent event days. The event days were among the hottest days during 2021.

Figure 2.1: Average Event-Hour Temperatures, *PG&E*

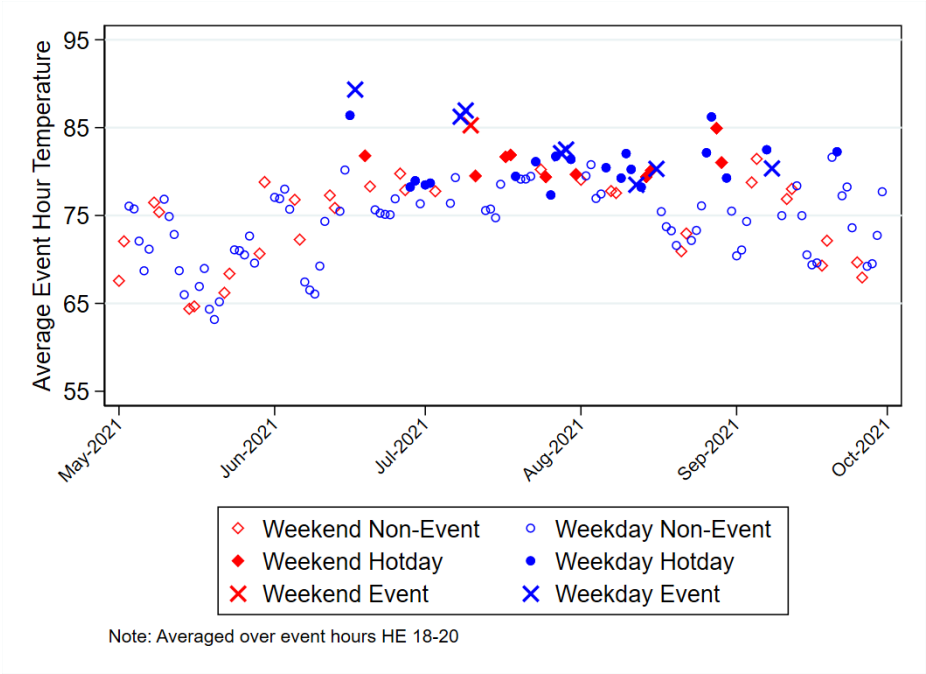
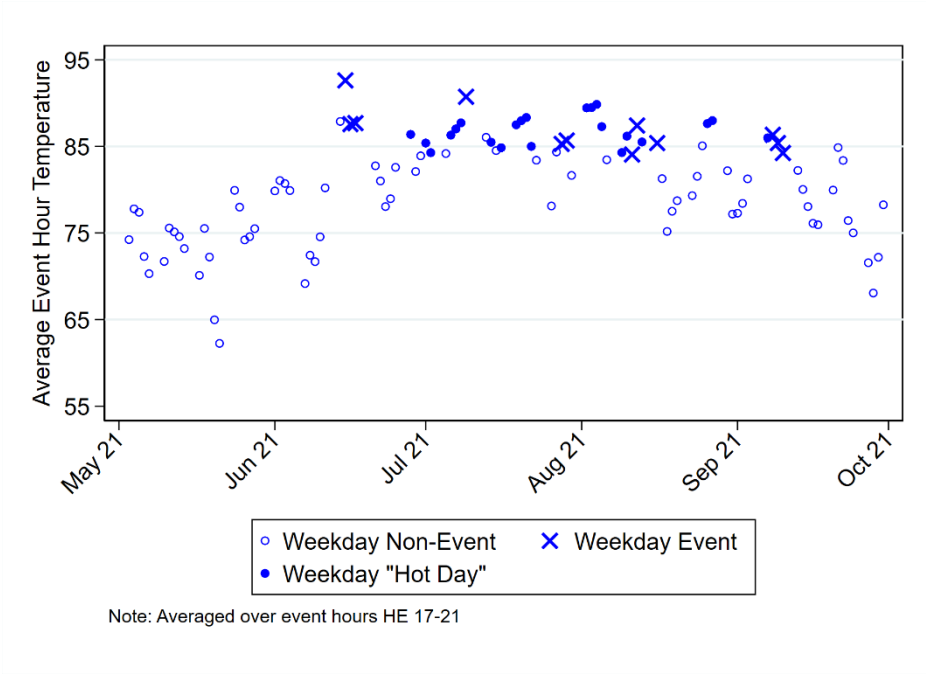


Figure 2.2: Average Event-Hour Temperatures, *SCE*



2.1.3 Model Validation Process

We estimate ex-post hourly load impacts using regression equations applied to hourly load data. The regression equation models hourly load as a function of a set of variables designed to control for factors affecting consumers' hourly demand levels, such as:

- Seasonal and hourly time patterns (e.g., month, day-of-week, and hour, plus various hour/day-type interactions);
- Weather, including hour-specific weather coefficients;
- Event variables. A series of indicator variables was included to account for each hour of each event day, allowing us to estimate the load impacts for all hours across the event days.

We employ both panel and customer-specific regressions, with the latter applied to the largest customers based on their average hourly usage during event hours on non-event days. For PG&E and SCE, we select the largest 5 percent of large customers for customer-specific regressions, which allows us to control for idiosyncratic load profiles of the largest customers separately. Table 2.1 below provides the classification of customers by regression approach. The usage level, displayed in parentheses, provides an approximation of the size threshold between panel and customer-specific regressions. Note that SDG&E does not have an ex-post analysis in this evaluation because they did not call any events during PY2021.

Table 2.1: Panel and Customer-Specific Regression Groups

Utility	Size	Panel	Customer-Specific
PG&E	Large	95% (<500 kWh/hour)	5% (≥ 500 kWh/hour)
	Medium	All	None
	Small	All	None
SCE	Large	95% (<600 kWh/hour)	5% (≥ 600 kWh/hour)
	Medium	All	None
	Small	All	None
SDG&E	Large	N/A	N/A
	Medium	N/A	N/A

We test a variety of weather variables to determine which set best explains usage on event-like non-event days. To determine which variables to include in the model, we go through a model selection and validation process. Model variations are evaluated according to the ability to predict usage on event-like *non-event days*.

Panel model specifications are evaluated for each utility and customer size. For the customer-specific models, we first classify customers according to whether or not their hourly loads are responsive to changes in weather conditions (weather-sensitive). Individual models for the largest customers are evaluated by utility, industry group, and weather sensitivity classification. We select specifications by customer group (i.e.,

sixteen groups, with eight industry groups for each of the non-weather-sensitive customers and weather-sensitive customers). This process and its results are explained in Appendix A.

2.1.4 Regression Model

A typical form for our within-subjects ex-post evaluation model is shown below. For customer-specific regressions, we estimate load impacts across all hours of the day by interacting these regression terms with the hour of the day. The model below is written to apply to a single customer; however, it can be modified to represent a panel model by adding customer fixed effects and customer subscripts to the appropriate variables. We estimate the panel models separately for each hour of the day and customer subgroup.[4] The specific form of the model varies across utilities and customer groups, as shown in Appendix A.[5]

$$Q_t = a + \sum_{Evt=1}^{E} (b^{Evt} \times CPP_t) + b^{MornLoad} \times MornLoad_t + b^{Wth} \times Wth_t + b^{OthDR} \times OthDR_t + \sum_{j=days\ of\ week} b^j \times DayType_t^j + \sum_{j=months} b^j \times Month_t^j + e_t$$

The variables are explained in Table 2.2.

[4] Regressions are estimated by size, LCA, and industry group. LCA level results are aggregated to calculate program-level load impacts. Other subsets of results are estimated by via LCA-level regressions that included an interaction term with the event variables and the specific subgroup of interest (e.g., AutoDR, dually enrolled, customers that receive event notifications).

[5] The selected model specification is sometimes adjusted and estimated separately for specific event days. Specifically, for SCE, the morning load variable is removed from the specification used for the August 11th event-day estimates. Because weather and loads display an unusual drop in the middle of that day, a model with morning load results overestimated load impacts due to the persistence effect imposed by the specification. Additionally, for SCE small customers, month indicator variables are removed from the specification used to estimate load impacts for the June 15th event to expand the set of comparison days.

Table 2.2: Regression Model Variables

Variable Name / Term	Variable / Term Description
Q_t	the customer's usage on day *t*
a and the various *b*s	the estimated parameters
CPP_t	an indicator variable for CPP event days
Wth_t	weather conditions on day *t* (e.g., measured by CDD, CDH, or THI)
E	the number of event days that occurred during the program year
$MornLoad_t$	variables equal to the average of the day's load in hours-ending 1 through 7 and separately for hours-ending 8 through 14.
$DayType^j_t$	an indicator variable for day of week *j* on date *t*
$Month^j_t$	a series of indicator variables for each month
$OthDR_t$	a series of indicator variables representing event days for other DR programs in which the service account is enrolled
e_t	the error term.

The first term in the equation containing a summation sign is the component that allows estimation of event-specific load impacts for each hour of the day (the b^{Evt} coefficients). The CPP_t variable equals one if date *t* is a CPP event day and the customer is enrolled in CPP and zero otherwise. The remaining terms in the equation are designed to control for weather and other periodic factors (e.g., days of the week and months of the year) that determine customers' loads. See Appendix A for a summary of the specifications considered for each size group and industry type.

The "morning load" variable is used in the same spirit as the optional day-of adjustment to the 10-in-10 baseline method currently used in some DR programs (e.g., CBP). That is, it is intended to adjust the reference load (the regression-based estimate of the loads that would have occurred in the absence of the event day) for unobserved exogenous factors that may affect customers' loads on a given day. The use of the morning load variable assumes that variations in the morning load are related to variations in reference loads later in the day; but that the changes in the morning load are not part of the customer's response to the event itself (e.g., pre-cooling the building in anticipation of an event).

Estimating distributions of load impacts for different customer segments

The distribution of load impacts across different subgroups of customers is explored by performing load impact analyses at the subgroup level (e.g., load impacts for AutoDR participants, by LCA, or industry group).

Calculating uncertainty-adjusted load impacts

The Load Impact Protocols require the estimation of uncertainty-adjusted load impacts. Thus, in addition to producing point estimates of the ex-post load impacts, we produce

uncertainty-adjusted program impacts for each event, which show the uncertainty around the estimated impacts, as required by the Protocols. These methods use the estimated load-impact parameter values and the associated variances to derive scenarios of hourly load impacts. We also report the uncertainty associated with the average event hour, both on an event-specific basis and for the typical event day, which are based on the standard errors from regression models that aggregate the corresponding load impacts (e.g., by estimating a single average event-hour load impact).

Validity assessment

Our models are validated using out-of-sample predictions for event-like non-event days. That is, we withhold one non-event day at a time, re-estimating the regression and evaluating the predicted vs. actual loads for the withheld day. We consider a variety of model specifications that differ by which weather variables and day type variables are included and choose the model that best predicts customer load profiles on non-event days. Model selections are based on statistical parameters such as mean and absolute percentage errors. In addition, we conduct robustness checks of our estimates, comparing them to alternate specifications and models that include a control group.

2.2 Developing Ex-Ante Load Impacts

Estimating ex-ante load impacts for future years requires three key pieces of information:

- A utility-provided *enrollment forecast* for relevant components of the program, which consists of forecasts of the number of customers by required type of customer;
- *Reference loads* by customer type;
- A forecast of *load impacts per customer*, again by relevant customer type, where the load impact forecast also varies with weather conditions (if applicable), as determined in the ex-post evaluation.

Ex-ante load impacts are created for the following subgroups of customers:

1. Utility program;
2. Size group (under 20 kW, 20 to 200 kW, and over 200 kW); and
3. LCA.

In addition, separate program-specific and portfolio-level forecasts are developed to account for dual enrollment in other DR programs. The program-specific load impacts reflect the full enrollment of the CPP program, while the portfolio-level impacts remove the load impacts from the dual enrolled customers.

The load impacts are provided for the years 2022 through 2032[6], for a number of day types, and weather scenarios, including the following:

- A typical event day under the four weather scenarios, defined by both utility-specific and CAISO peaking conditions in both 1-in-2 (normal) and 1-in-10 (extreme) scenarios; and
- The monthly system peak load day of each month, again under the above four weather scenarios.

2.2.1 Reference Loads

The per-customer reference loads are simulated based on regression models designed to reflect customer load patterns on non-event days during summer and non-summer months and the temperature changes across weather scenarios. The reference load regression models require a full year of load profile data (as opposed to the ex-post regression models, which include only event and event-like days), which we obtained for a representative sample of treatment customers.[7] Reference loads are simulated using the appropriate weather scenario data (i.e., the 1-in-2 and 1-in-10 weather-year conditions to be provided by the utilities) and event-day characteristics (e.g., weekday and weekend).

2.2.2 Per-customer Load Impacts

Per-customer load impacts are derived from an analysis of the current and previous ex-post load impact evaluations, with a particular focus on differences in load impacts across customer types. We use ex-post load impact estimates from the typical event day in 2021 to calculate percentage load impacts (the hourly load impact divided by the hourly reference load) for customer groups that are reported in the ex-ante analysis. The resulting per-customer percentage load impacts are then applied to the appropriate simulated reference loads to develop the forecast load impacts. CPP load impacts must be forecast for all months of the year even though we have historically observed events only during summer months.

PG&E and SDG&E are shifting their CPP event hours to 4 to 9 p.m. in March and June 2022, respectively (see Decision 21-03-056). To account for this, we map the ex-post percentage load impacts by hour type (e.g., pre-event hour, first event hour, last event hour, etc.) into a mapping for the ex-ante event window. See Section 3.2 and Section 5.1 for details regarding the mapping of the ex-post to ex-ante event window for PG&E and SDG&E, respectively.

Uncertainty-adjusted load impacts were generated using the standard errors from the ex-post typical event day load impacts. Scenario-specific percent load impacts were developed from 10th, 30th, 50th, 70th, and 90th percentile load changes estimated for the relevant program year.

[6] PG&E and SDG&E requested the inclusion of a "back-cast" of 2021 load impacts, which we also provide.
[7] PG&E and SDG&E provided a full year of interval load data for all enrolled customers.

As in all recent load impact evaluations, we present results of analyses of the relationship between current ex-post and ex-ante load impacts, focusing on key factors causing differences between them (e.g., differences between observed temperatures in the current program year and the temperatures in the various weather scenarios). We also compare current and previous ex-post load impacts, and current and previous ex-ante load impacts.

3. PG&E

3.1 PG&E Ex-Post Load Impacts

This section documents the findings from the ex-post load impact analysis for PG&E. The primary load impact results include estimates of average event-hour load impacts, in aggregate and per-customer, for the typical event day as well as for each individual event. Results for all hours for the typical event day are also illustrated in figures and presented in data tables. Detailed results for each hour for each event are available in electronic form in Protocol table generators provided along with this report.

As described in Section 2.1.3, all results presented in this section are derived from either customer specific or panel fixed-effects regression analyses of hourly data for PDP customers. The estimated model is described in Section 2.1.4, with the PG&E model including the variables that account for morning load and temperature variations. Furthermore, we control for concurrent BIP events by including indicators for customers who are dually enrolled in PDP and BIP and who are called for any BIP events that occur during any PDP event or non-event day. The evaluation of model specification selection is presented in the appendix.

3.1.1 All Customers

This section summarizes results for all PG&E customers. The average event-hour load impacts for all customers of PG&E are summarized in Figure 3.1. The blue bars indicate the magnitude of the aggregate load impact (in MWh/hour). The green bands correspond to 90 percent confidence intervals around these estimates (i.e., the 5th and 95th percentile outcomes). The orange diamond icons represent the average temperatures experienced by the customers during the event hours.

PG&E customers achieve statistically significant load reductions on four out of nine event days as well as on the typical event day. The load impact is highest on July 9th, which has the second highest temperature. The event on July 10th has the highest temperature, but it was a weekend event, which could explain the lack of load reduction. Overall, Figure 3.1 does not show strong evidence of a relationship between load impacts and average temperatures. The event on Aug 12th has the second highest load impact despite having the lowest event temperature.

Figure 3.1: Average Event-Hour Load Impacts by Event, *PG&E All*

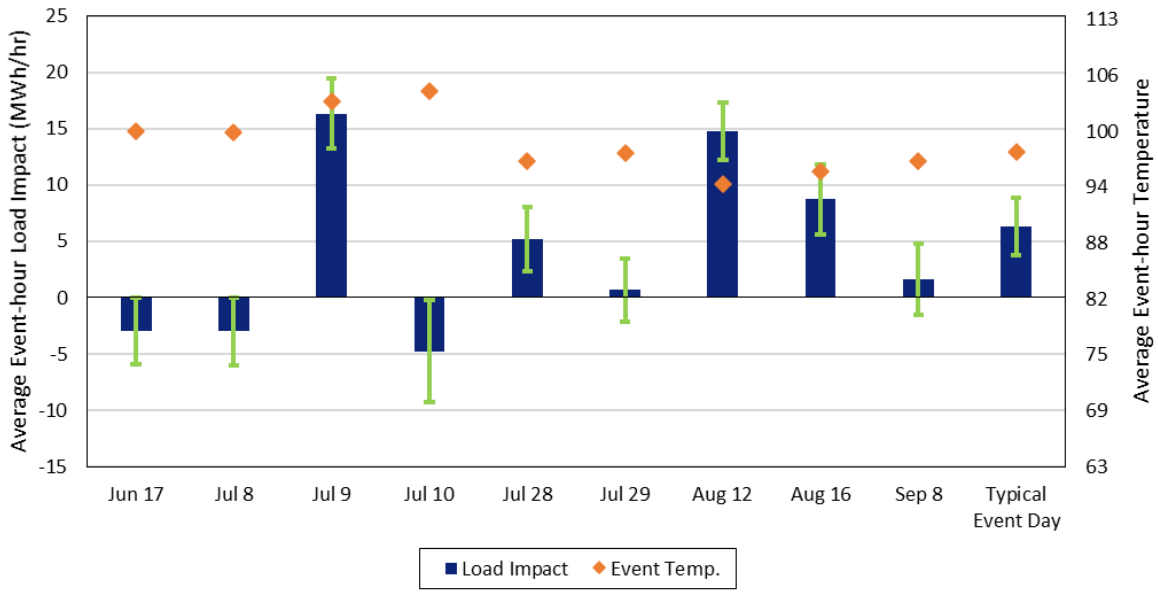


Table 3.1 summarizes enrollments, average event-hour load impacts, and reference loads for each event day and the typical event day. There was a decrease of more than 2,000 customers over the course of the season. Aggregate load impacts range from -4.7 MWh/hour on the weekend event (July 10th) to 16.3 MWh/hour on July 9th. The estimated load reduction for the typical event day is 6.3 MWh/hour, which is a 0.8 percent load reduction[8]. Detailed results by hour, industry group and LCA are presented in subsequent subsections by customer size.

[8] The typical event day excludes the June 17th event due to the notification problems and the weekend event (July 10th), so the typical event represents a weekday impact.

Table 3.1: Average Event-Hour Load Impacts by Event, *PG&E All*

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
6/17/2021	108,869	786	-3.0	7.2	-0.03	-0.4%	100.3
7/8/2021	108,167	778	-3.0	7.2	-0.03	-0.4%	100.1
7/9/2021	108,150	814	16.3	7.5	0.15	2.0%	103.5
7/10/2021	108,149	761	-4.7	7.0	-0.04	-0.6%	104.6
7/28/2021	107,523	770	5.2	7.2	0.05	0.7%	96.9
7/29/2021	107,502	785	0.7	7.3	0.01	0.1%	97.8
8/12/2021	107,145	768	14.8	7.2	0.14	1.9%	94.3
8/16/2021	107,095	766	8.7	7.1	0.08	1.1%	95.7
9/8/2021	106,511	768	1.6	7.2	0.01	0.2%	96.9
Typical Event Day	**107,443**	**779**	**6.3**	**7.2**	**0.06**	**0.8%**	**97.9**

3.1.2 Large Customers

This section summarizes results for all large PG&E customers, defined as customers with maximum demand over 200 kW. The presented results include: the average event-hour load impact by event day; the hourly load impact for the typical event day; and load impacts by industry group and LCA for the average event hour. Summaries of load impacts for dually enrolled customers, AutoDR customers, NEM customers, customers receiving event notifications, customers assigned Business Energy Support (BES/CRS), and for agricultural and commercial rate classes are presented in subsequent sub-sections.

The ex-post load impacts for PG&E's large PDP customers are summarized for all 9 events in Figure 3.2. The blue bars indicate the magnitude of the aggregate load impact (in MWh/hour). The green bands correspond to 90 percent confidence intervals around these estimates (i.e., the 5th and 95th percentile outcomes). The orange diamond icons represent the average temperatures experienced by the customers during the event hours.

Large customers had statistically significant load reductions on 7 out of 9 event days. The first event (June 17th) had a dispatch issue with event notifications; no customers received day ahead notification of the event. The event on July 10th was a weekend event, which could explain the lack of significant load impacts. Figure 3.2 does not show strong evidence of a relationship between load impacts and average temperatures. The event with the highest average temperature was the weekend event (July 10th), however the events with the third and fourth highest temperatures (July 8th and June 17th) have lower low impacts than events with lower temperatures.

Figure 3.2: Average Event-Hour Load Impacts by Event, *PG&E Large*

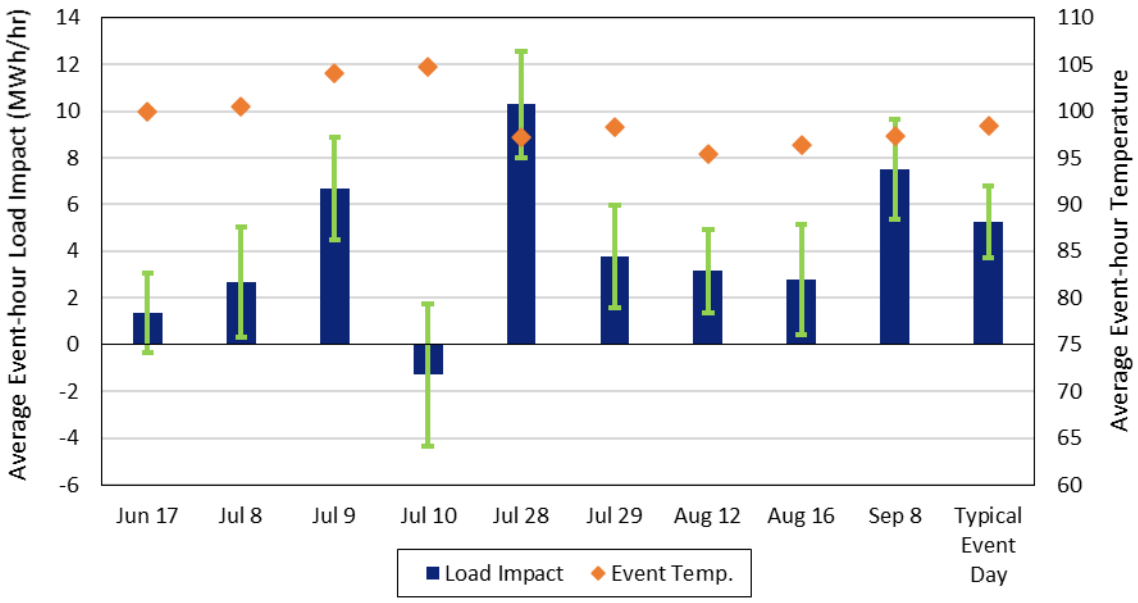


Table 3.2 summarizes enrollments, average event-hour load impacts, and reference loads for each event day and the typical event day. There was a slight decrease in large customer enrollments over the course of the season. Aggregate load impacts range from -1.3 MWh/hour on the weekend event (July 10th) to 10.3 MWh/hour on July 28th. The estimated load reduction for the typical event day is 5.3 MWh/hour, which is a 2.2 percent load reduction.

Table 3.2: Average Event-Hour Load Impacts by Event, *PG&E Large*

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
6/17/2021	1,256	247	1.4	196.5	1.1	0.6%	100.0
7/8/2021	1,241	243	2.7	195.8	2.1	1.1%	100.5
7/9/2021	1,241	241	6.7	193.8	5.4	2.8%	104.0
7/10/2021	1,245	210	-1.3	168.5	-1.0	-0.6%	104.7
7/28/2021	1,237	241	10.3	194.8	8.3	4.3%	97.2
7/29/2021	1,237	241	3.8	194.7	3.0	1.6%	98.3
8/12/2021	1,234	238	3.2	192.5	2.6	1.3%	95.4
8/16/2021	1,233	237	2.8	192.1	2.3	1.2%	96.3
9/8/2021	1,218	236	7.5	194.1	6.2	3.2%	97.3
Typical Event Day	**1,235**	**239**	**5.3**	**193.7**	**4.3**	**2.2%**	**98.4**

Figure 3.3 shows the aggregate hourly reference loads, observed loads, and estimated load impacts on the typical event day. Table 3.3 contains the hourly typical event day results in the manner required by the Protocols, including hourly temperatures and uncertainty adjusted load impacts. Notice that the highest load impact during the event hours occurs in the second hour of the event (6:00 to 7:00 p.m.). The hourly load impact estimates do not show evidence of significant pre-cooling or post-event snapback, which would appear as load increases in the hours surrounding the event. Rather, there are load impacts of approximately 6.3 MWh/hour in the hour immediately preceding (4:00 to 5:00 p.m.) and 3.8 MWh/hour in the hour following (8:00 to 9:00 p.m.) the event. Overall, these results do not suggest that large customers are responding to events by shifting event-hour loads to hours outside the event window.

Figure 3.3: Typical Event Day Reference Loads and Load Profile, *PG&E Large*

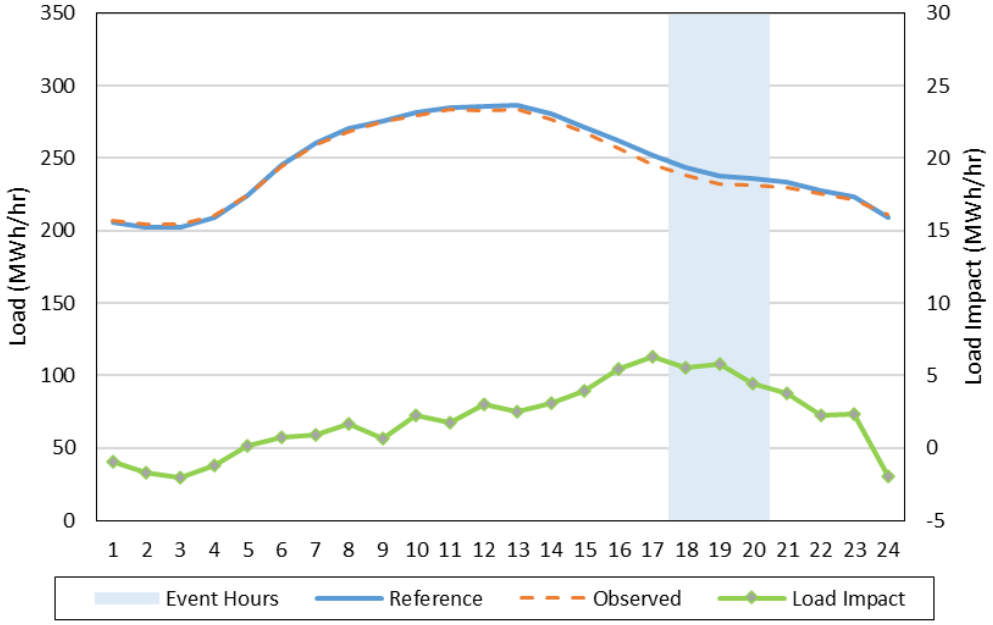


Table 3.3: Typical Event Day Load Impacts and Uncertainty Adjusted Estimates by hour, *PG&E Large*

Hour Ending	Estimated Reference Load (MW)	Observed Event Day Load (MW)	Estimated Load Impact (MW)	Load Impact (%)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact - Percentiles				
						10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	205.8	206.7	-0.9	-0.4%	81.0	-2.0	-1.3	-0.9	-0.5	0.2
2	202.6	204.2	-1.7	-0.8%	79.4	-2.7	-2.1	-1.7	-1.2	-0.6
3	202.2	204.2	-2.0	-1.0%	78.0	-3.0	-2.4	-2.0	-1.7	-1.1
4	209.2	210.4	-1.2	-0.6%	76.7	-2.0	-1.5	-1.2	-0.8	-0.4
5	224.6	224.4	0.2	0.1%	75.3	-0.6	-0.1	0.2	0.5	0.9
6	245.1	244.3	0.8	0.3%	74.0	-0.1	0.4	0.8	1.1	1.7
7	260.1	259.2	0.9	0.3%	73.2	0.1	0.6	0.9	1.2	1.7
8	270.2	268.5	1.7	0.6%	74.7	0.8	1.3	1.7	2.1	2.6
9	275.5	274.9	0.6	0.2%	78.3	-0.5	0.2	0.6	1.1	1.7
10	281.3	279.0	2.2	0.8%	82.5	1.0	1.7	2.2	2.8	3.5
11	285.0	283.3	1.7	0.6%	86.4	0.4	1.2	1.7	2.3	3.1
12	286.0	282.9	3.0	1.1%	90.0	1.7	2.5	3.0	3.6	4.3
13	286.3	283.8	2.5	0.9%	93.1	1.2	2.0	2.5	3.1	3.9
14	280.3	277.3	3.1	1.1%	95.8	1.6	2.5	3.1	3.7	4.5
15	271.7	267.8	3.9	1.4%	98.0	2.5	3.3	3.9	4.5	5.3
16	262.1	256.6	5.5	2.1%	99.7	4.0	4.9	5.5	6.1	6.9
17	252.2	245.9	6.3	2.5%	100.4	4.9	5.7	6.3	6.9	7.8
18	243.7	238.1	5.5	2.3%	100.2	4.1	4.9	5.5	6.1	6.9
19	237.9	232.1	5.8	2.4%	98.8	4.5	5.3	5.8	6.4	7.2
20	236.2	231.7	4.4	1.9%	96.1	3.0	3.9	4.4	5.0	5.9
21	233.3	229.5	3.8	1.6%	92.5	2.2	3.2	3.8	4.5	5.4
22	227.3	225.1	2.2	1.0%	89.7	0.7	1.6	2.2	2.9	3.8
23	223.1	220.8	2.3	1.0%	87.1	0.6	1.6	2.3	3.0	4.0
24	209.1	211.0	-1.9	-0.9%	84.5	-3.1	-2.4	-1.9	-1.5	-0.8
Daily	**5,910.7**	**5,861.8**	**48.9**	**0.8%**	**86.9**	**35.3**	**43.3**	**48.9**	**54.4**	**62.4**

Next, we look at PG&E large customer estimates by industry group. Table 3.4 summarizes aggregate event-hour results for the typical event day for eight industry groups, including the number of enrolled customers, the reference and observed loads, and the estimated load impacts (in MWh/hour and as a percentage of reference loads). Enrollments and loads are concentrated in the Agriculture, Mining & Construction; Manufacturing; Wholesale, Transportation & Utilities; and Offices, Hotels, Health & Services industry groups, which represent a combined 87 percent of large customers and reference loads. Agriculture, Mining & Construction has the highest aggregate load impact (2.82 MWh/hour), but Manufacturing has the highest percentage load impact (4.4 percent). Besides these two industries, the rest of the industries achieve less than 1 MWh/hour of load reduction; Retail Stores and Offices, Hotels, Health & Services have negative load impacts.

Table 3.4: Typical Event Day Event-Hour Load Impacts by Industry Group, *PG&E Large*

Industry Group	# of Service Accounts	Estimated Reference Load (MWh/hour)	Observed Load (MWh/hour)	Estimated Load Impact (MWh/hour)	% LI
1.Agriculture, Mining, Construction	590	85	82	2.82	3.3%
2.Manufacturing	152	44	42	1.92	4.4%
3.Wholesale, Transportation, Utilities	179	41	40	0.95	2.3%
4.Retail Stores	28	6	6	-0.02	-0.3%
5.Offices, Hotels, Health, Services	151	37	38	-0.51	-1.4%
6.Schools	54	6	6	0.003	0.1%
7.Institutional/Government					
8.Other					

To better understand the distribution of results across industries, we look at the shares of estimated load impacts, reference loads, and enrollments by industry group in Figure 3.4. The load impacts for large customers are mainly driven by three industry groups (Agriculture, Mining & Construction; Manufacturing and Wholesale, Transport & Utilities), which represent 96 percent of load impacts.

Figure 3.4: Typical Event Day Event-Hour Load Impacts by Industry Group, *PG&E Large*

[redacted]

Table 3.5 and Figure 3.5 provide the summaries like those above, by LCA. Large customers are concentrated in the Greater Fresno Area and Other LCA, which have reference loads of 82 MWh/hour and 84 MWh/hour, respectively. These two LCAs also account for most of the typical event day load impacts with a 1.08 MWh/hour (1.3 percent) load reduction for Greater Fresno Area and a 4.14 MWh/hour (4.9 percent) load reduction for Other LCA. Figure 3.5 reflects the prominence of these two LCAs, although Greater Fresno Area has a lower share of the load impacts compared to the share of customers while Other LCAs has a greater share.

Table 3.5: Typical Event Day Event-Hour Load Impacts by LCA, *PG&E Large*

LCA	# of Service Accounts	Estimated Reference Load (MWh/hour)	Observed Load (MWh/hour)	Estimated Load Impact (MWh/hour)	% LI
Greater Bay Area	[redacted]				
Greater Fresno Area	450	82	81	1.08	1.3%
Humboldt	[redacted]				
Kern	108	23	23	0.36	1.6%
Northern Coast	26	3	3	-0.04	-1.2%
Other	410	84	80	4.14	4.9%
Sierra	88	13	13	-0.05	-0.4%
Stockton	96	20	20	0.07	0.3%

Figure 3.5: Typical Event Day Event-Hour Load Impacts by LCA, *PG&E Large*

[redacted]

3.1.3 Medium Customers

This section summarizes results for all medium PG&E customers, defined as customers with maximum demand between 20 and 199.99 kW. The presented results include: the average event-hour load impact by event day; the hourly load impact for the typical event day; and load impacts by industry group and LCA for the average event hour. Summaries of load impacts for dually enrolled customers, AutoDR customers, NEM customers, customers receiving event notifications, customers assigned Business Energy Support (BES/CRS), and for agricultural and commercial rate classes are presented in subsequent sub-sections.

The ex-post load impacts for PG&E's medium PDP customers are summarized for all 9 events in Figure 3.6. Medium customers have statistically significant load reductions on 3 out of 9 event days (July 9, August 12 and 16). The load impact for the typical event day is positive but not statistically significant. There is no evidence of positive relationship between load impacts and average event temperature as two of the events with significant load reductions have the coolest average temperatures. The event with the lowest temperature has the second highest load impact.

Figure 3.6: Average Event-Hour Load Impacts by Event, *PG&E Medium*

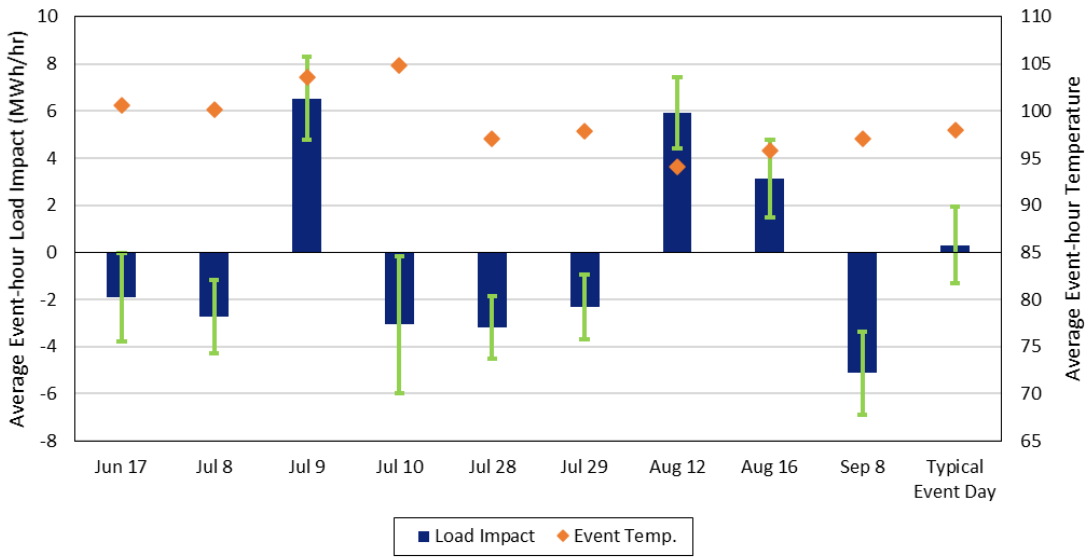


Table 3.6 summarizes enrollments, estimated load impacts, and reference loads for medium customers on each event day as well as for the typical event day. Enrollments decreased slightly over the season for medium customers. The load impacts are a small share of reference loads for medium customers with 0.1 percent on the typical event day.

Table 3.6: Average Event-Hour Load Impacts by Event, *PG&E Medium*

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Ave. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
6/17/2021	16,568	367	-1.9	22.2	-0.12	-0.5%	100.6
7/8/2021	16,474	364	-2.7	22.1	-0.17	-0.8%	100.2
7/9/2021	16,473	389	6.5	23.6	0.40	1.7%	103.6
7/10/2021	16,473	371	-3.1	22.5	-0.19	-0.8%	104.9
7/28/2021	16,420	360	-3.2	21.9	-0.19	-0.9%	97.1
7/29/2021	16,419	369	-2.3	22.5	-0.14	-0.6%	97.9
8/12/2021	16,370	360	5.9	22.0	0.36	1.6%	94.1
8/16/2021	16,360	360	3.1	22.0	0.19	0.9%	95.8
9/8/2021	16,296	361	-5.1	22.1	-0.31	-1.4%	97.1
Typical Event Day	**16,402**	**366**	**0.3**	**22.3**	**0.02**	**0.1%**	**97.9**

Figure 3.7 plots aggregate loads for medium customers for the typical event day. There are load reductions during the first two event hours, but load impacts become negative during the third event hour. There is load reduction in the pre-event hour (4:00 to 5:00 p.m.), similar to the large customers, however there is post-event snapback after the event. Moreover, the pre-event load reduction is higher in magnitude than the event-hour load reductions. We note that the event hours shifted from 2 to 6 p.m. (HE15 to 18) in PY2020 to 5 to 8 p.m. (HE18 to 20) in 2021. These results suggest that medium customers may not be fully aware of the change in event hours as the load impacts during the old event hours are larger on average than the load impacts during the new event hours.

Figure 3.7: Typical Event Day Reference Loads and Load Profile, *PG&E Medium*

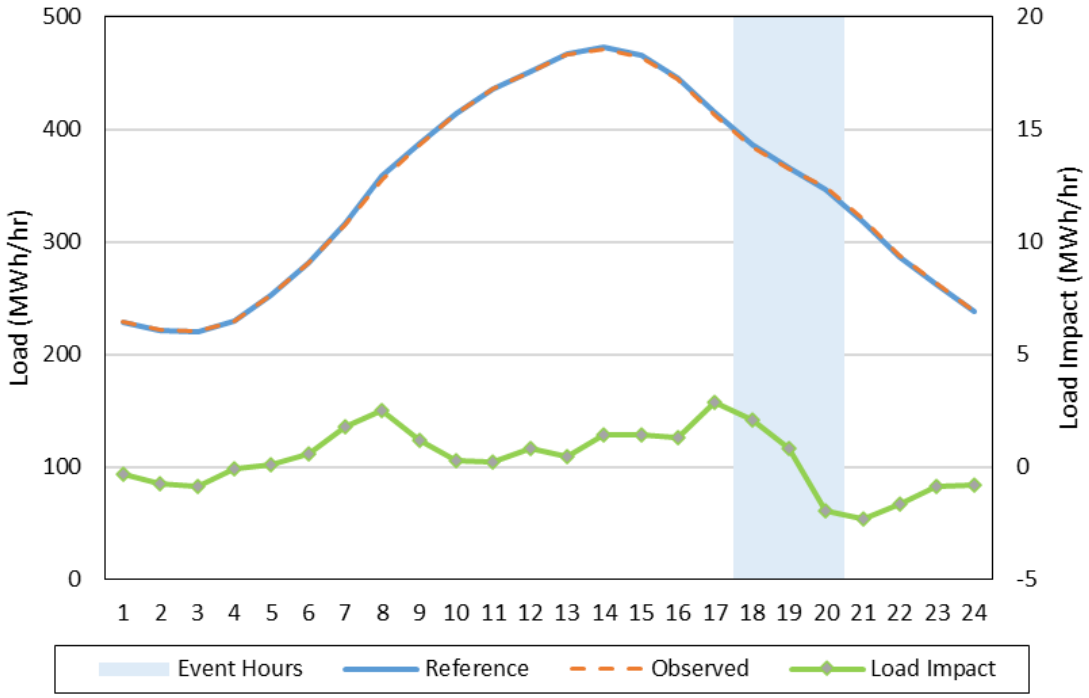


Table 3.7 includes hourly observed loads, estimated load impacts, reference loads, hourly temperatures, and uncertainty adjusted load impacts for the typical event day for medium customers. The load impacts for medium customers range from -1.9 MWh/hour in the third event hour to 2.1 MWh/hour in the first.

Table 3.7: Typical Event Day Load Impacts and Uncertainty Adjusted Estimates by hour, *PG&E Medium*

Hour Ending	Estimated Reference Load (MW)	Observed Event Day Load (MW)	Estimated Load Impact (MW)	Load Impact (%)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact - Percentiles				
						10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	228.7	229.0	-0.3	-0.1%	79.6	-1.0	-0.6	-0.3	0.0	0.3
2	221.3	222.1	-0.7	-0.3%	78.0	-1.2	-0.9	-0.7	-0.5	-0.2
3	219.7	220.5	-0.8	-0.4%	76.6	-1.3	-1.0	-0.8	-0.6	-0.4
4	229.3	229.3	-0.1	0.0%	75.3	-0.4	-0.2	-0.1	0.1	0.3
5	253.1	253.0	0.1	0.0%	74.0	-0.3	-0.1	0.1	0.2	0.5
6	281.4	280.8	0.6	0.2%	72.8	-0.1	0.3	0.6	0.9	1.4
7	316.4	314.6	1.8	0.6%	72.2	0.9	1.4	1.8	2.2	2.7
8	358.1	355.5	2.5	0.7%	74.1	1.3	2.0	2.5	3.0	3.8
9	387.4	386.2	1.2	0.3%	78.0	0.2	0.8	1.2	1.6	2.2
10	414.1	413.8	0.3	0.1%	82.5	-0.5	0.0	0.3	0.6	1.1
11	436.0	435.8	0.2	0.1%	86.7	-0.4	0.0	0.2	0.5	0.9
12	451.4	450.5	0.9	0.2%	90.4	0.4	0.7	0.9	1.1	1.3
13	467.1	466.6	0.5	0.1%	93.6	-0.2	0.2	0.5	0.8	1.2
14	472.6	471.1	1.5	0.3%	96.4	0.3	1.0	1.5	2.0	2.7
15	465.7	464.2	1.5	0.3%	98.7	0.0	0.8	1.5	2.1	2.9
16	445.7	444.4	1.3	0.3%	100.2	-0.3	0.6	1.3	2.0	3.0
17	415.0	412.1	2.9	0.7%	100.8	1.3	2.3	2.9	3.5	4.5
18	386.4	384.4	2.1	0.5%	100.2	0.6	1.5	2.1	2.7	3.5
19	365.4	364.6	0.8	0.2%	98.4	-0.5	0.3	0.8	1.4	2.2
20	346.3	348.2	-1.9	-0.6%	95.2	-3.1	-2.4	-1.9	-1.5	-0.8
21	317.8	320.1	-2.3	-0.7%	91.2	-3.4	-2.8	-2.3	-1.9	-1.2
22	286.4	288.0	-1.6	-0.6%	88.2	-2.8	-2.1	-1.6	-1.1	-0.5
23	262.3	263.2	-0.8	-0.3%	85.7	-2.1	-1.3	-0.8	-0.3	0.4
24	237.8	238.6	-0.8	-0.3%	83.3	-1.7	-1.2	-0.8	-0.4	0.1
Daily	**8,265.5**	**8,256.8**	**8.7**	**0.1%**	**86.3**	**-4.3**	**3.4**	**8.7**	**14.0**	**21.6**

Table 3.8 summarizes aggregate event-hour results for the typical event day for eight industry groups, including the number of enrolled customers, the reference and observed loads, and the estimated load impacts (in MWh/hour and as a percentage of reference loads). Enrollments are highest in the Offices, Hotel, Health & Services industry group, which accounts for 37 percent of enrollments and 160 MWh of reference load. However, this industry group only contributes 1 percent of the aggregate load reduction. Figure 3.8 illustrates the shares of enrollments, reference loads, and load impacts by industry group. Wholesale, Transportation & Utilities accounts for more than half of the load reduction, while Manufacturing has the second highest contribution with 25 percent of the load reduction, and Agriculture, Mining & Construction contributes 18 percent of the load reduction. In total, the three groups contribute 96 percent of the total load reduction.

Table 3.8: Typical Event Day Event-Hour Load Impacts by Industry Group, *PG&E Medium*

Industry Group	# of Service Accounts	Estimated Reference Load (MWh/hour)	Observed Load (MWh/hour)	Estimated Load Impact (MWh/hour)	% LI
1.Agriculture, Mining, Construction	713	14	13	0.30	2.22%
2.Manufacturing	1,045	15	15	0.42	2.74%
3.Wholesale, Transportation, Utilities	2,161	41	41	0.93	2.24%
4.Retail Stores	2,403	68	68	-0.12	-0.18%
5.Offices, Hotels, Health, Services	6,110	160	160	0.03	0.02%
6.Schools	706	16	16	-0.01	-0.07%
7. Institutional/Government	2,963	46	47	-0.70	-1.52%
8.Other	301	5	5	0.04	0.87%

Figure 3.8: Typical Event Day Event-Hour Load Impacts by Industry Group, *PG&E Medium*

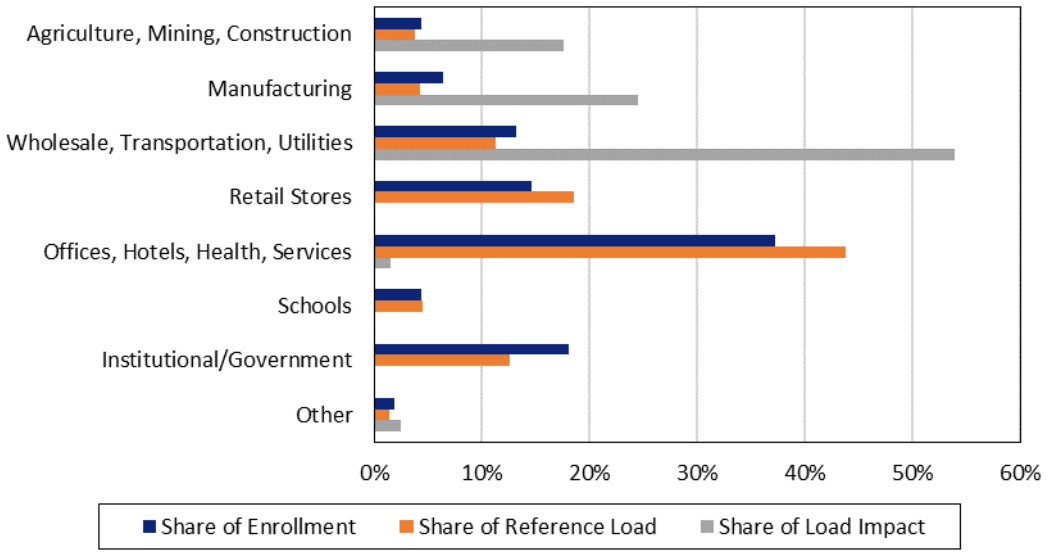
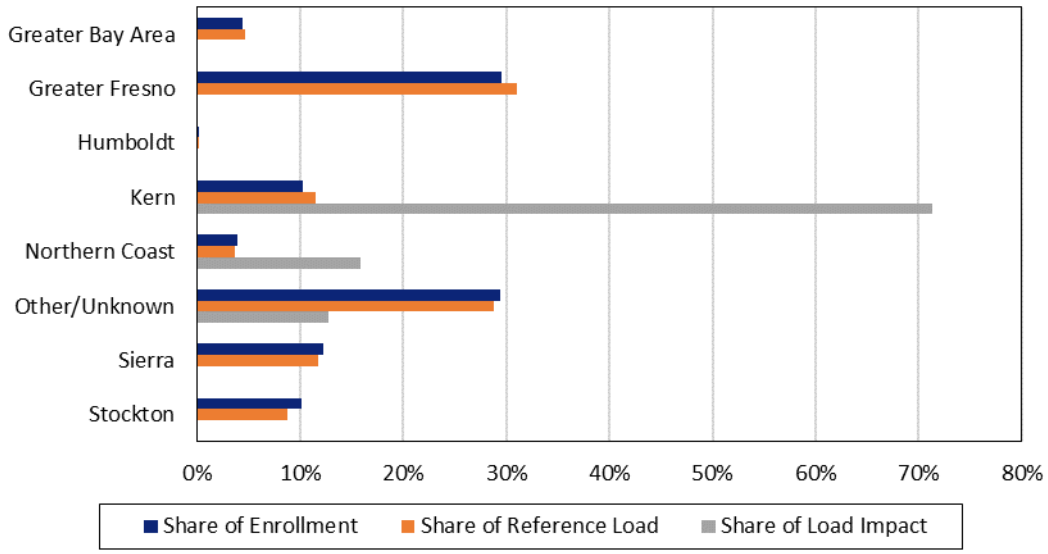


Table 3.9 and Figure 3.9 summarize the results by LCA for medium customers. As with the large customers, enrollments are concentrated in the Greater Fresno Area and Other LCAs, which together contain nearly 60 percent of medium customers and account for almost 220 MWh/hour of loads. However, load impacts for medium customers are largely driven by Kern, which accounts for over 70 percent of the load impacts despite having only 10 percent of customers and 11 percent of reference loads. Estimated load impacts are negative for Greater Fresno Area, while Other LCAs contributes to around 10 percent of the load impacts. Figure 3.9 shows that Kern and Northern Coast have larger share of load reduction compared to the share of enrollments or reference loads.

Table 3.9: Typical Event Day Event-Hour Load Impacts by LCA, *PG&E Medium*

LCA	# of Service Accounts	Estimated Reference Load (MWh/hour)	Observed Load (MWh/hour)	Estimated Load Impact (MWh/hour)	% LI
Greater Bay Area	723	17	17	-0.15	-0.9%
Greater Fresno Area	4,837	114	114	-0.20	-0.2%
Humboldt	35	0.42	0.43	-0.01	-1.3%
Kern	1,676	42	41	0.76	1.8%
Northern Coast	647	13	13	0.17	1.3%
Other	4,822	105	105	0.14	0.1%
Sierra	2,004	43	43	-0.08	-0.2%
Stockton	1,657	32	32	-0.32	-1.0%

Figure 3.9: Typical Event Day Event-Hour Load Impacts by LCA, *PG&E Medium*



3.1.4 Small Customers

This section summarizes results for all small PG&E customers, defined as customers with maximum demand below 20 kW. The presented results include: the average event-hour load impact by event day; the hourly load impact for the typical event day; and load impacts by industry group and LCA for the average event hour. Summaries of load impacts for dually enrolled customers, AutoDR customers, NEM customers, customers receiving event notifications, customers assigned Business Energy Support (BES/CRS), and for agricultural and commercial rate classes are presented in subsequent sub-sections.

The ex-post load impacts for PG&E's small PDP customers are summarized for all 9 events in Figure 3.10. The small customers have statistically significant positive load impacts on 3 out of 9 event days (July 9, August 12 and 16)—the same events as the medium customers. The load impact for the typical event day is positive but not statistically significant. There is no evidence of a positive relationship between load impacts and average temperatures, in fact the highest load impact is associated with the lowest event temperatures.

Figure 3.10: Average Event-Hour Load Impacts by Event, *PG&E Small*

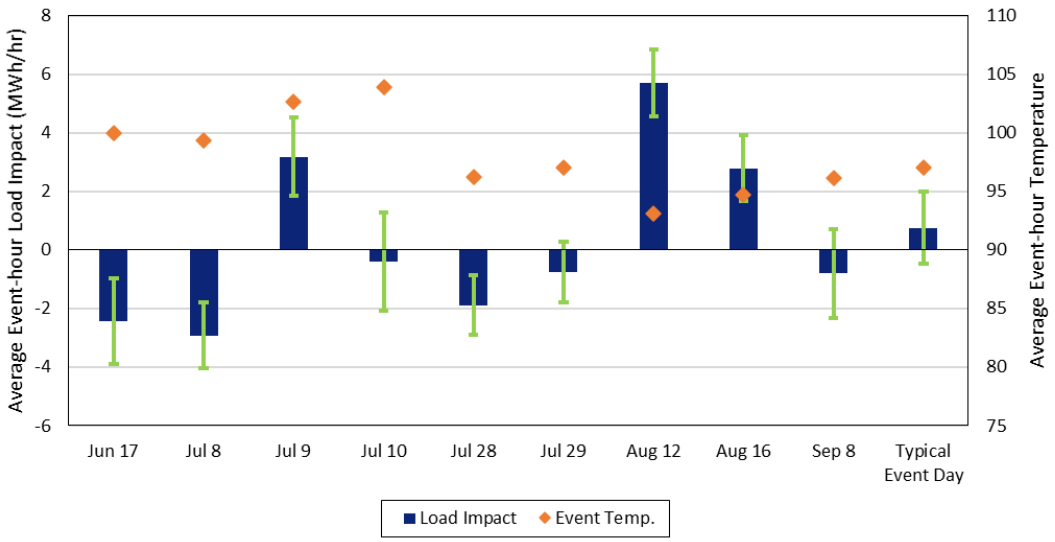


Table 3.10 summarizes enrollments, estimated load impacts, and reference loads for small customers on each event day as well as for the typical event day. Small customer enrollments decreased by more than 2,000 customers across the events in 2021. The aggregate load impact for the typical event day is 0.8 MWh/hour—0.4 percent of reference loads, which is slightly higher than the percentage load impact for medium customers.

Table 3.10: Average Event-Hour Load Impacts by Event, *PG&E Small*

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Ave. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
6/17/2021	91,045	172.1	-2.4	1.89	-0.03	-1.4%	99.9
7/8/2021	90,452	171.4	-2.9	1.89	-0.03	-1.7%	99.3
7/9/2021	90,436	186.6	3.2	2.06	0.04	1.7%	102.6
7/10/2021	90,431	180.0	-0.4	1.99	0.00	-0.2%	103.9
7/28/2021	89,866	168.9	-1.9	1.88	-0.02	-1.1%	96.2
7/29/2021	89,846	175.1	-0.8	1.95	-0.01	-0.4%	97.0
8/12/2021	89,541	170.5	5.7	1.90	0.06	3.3%	93.1
8/16/2021	89,502	168.9	2.8	1.89	0.03	1.7%	94.8
9/8/2021	88,997	171.4	-0.8	1.93	-0.01	-0.5%	96.1
Typical Event Day	**89,806**	**173.2**	**0.8**	**1.93**	**0.008**	**0.4%**	**97.0**

Figure 3.11 plots aggregate loads for small customers for the typical event day. There is a load reduction in the pre-event hour (4 to 5 p.m.), similar to medium and large customers. As with the medium customers, the load impacts for the third event hour are negative. While the load impact reflects some post-event snapback, the uncertainty-adjusted impacts show that it is not statistically significantly different from zero. It also appears that small customers may not be aware of the event window shift, as load impacts are higher during the old event hours than the new event hours on average.

Figure 3.11: Typical Event Day Reference Loads and Load Profile, *PG&E Small*

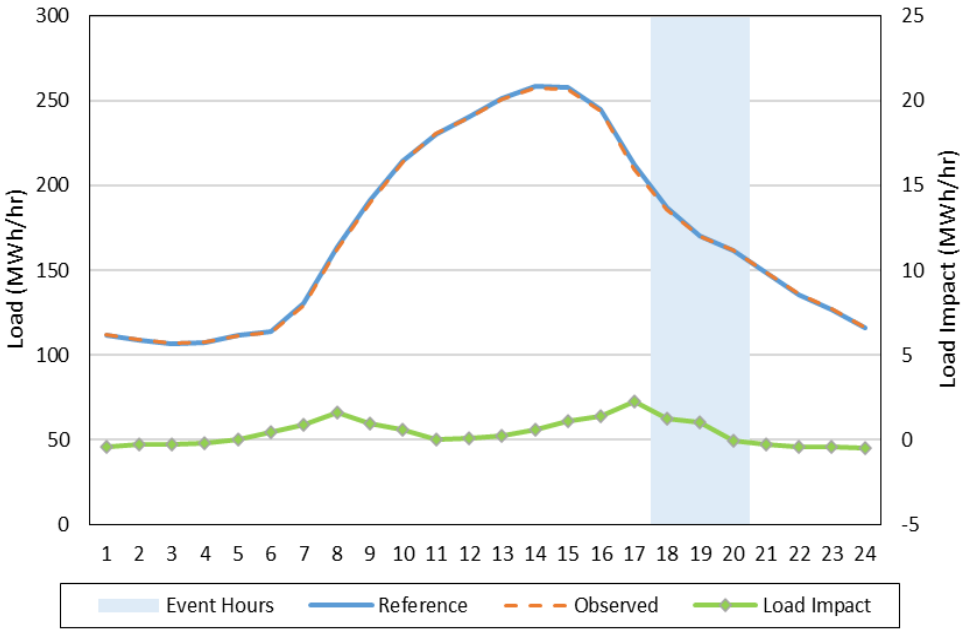


Table 3.11 includes hourly observed loads, estimated load impacts, reference loads, hourly temperatures, and uncertainty adjusted load impacts for the typical event day for small customers. The load impacts during the event window from 5 to 8 p.m. for small customers range from -0.1 MWh/hour during the third hour to 1.3 MWh/hour in the first hour.

Table 3.11: Typical Event Day Load Impacts and Uncertainty Adjusted Estimates by hour, *PG&E Small*

Hour Ending	Estimated Reference Load (MW)	Observed Event Day Load (MW)	Estimated Load Impact (MW)	Load Impact (%)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact - Percentiles				
						10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	111.8	112.2	-0.4	-0.3%	78.7	-0.7	-0.5	-0.4	-0.3	-0.1
2	108.7	109.0	-0.2	-0.2%	77.1	-0.5	-0.3	-0.2	-0.2	0.0
3	106.8	107.1	-0.3	-0.3%	75.7	-0.4	-0.3	-0.3	-0.2	-0.1
4	107.5	107.7	-0.2	-0.2%	74.5	-0.3	-0.2	-0.2	-0.1	0.0
5	111.7	111.7	0.1	0.0%	73.2	-0.2	0.0	0.1	0.1	0.3
6	113.7	113.2	0.5	0.4%	72.1	0.1	0.3	0.5	0.6	0.9
7	130.6	129.7	0.9	0.7%	71.7	0.4	0.7	0.9	1.1	1.3
8	163.7	162.1	1.6	1.0%	73.7	1.0	1.4	1.6	1.9	2.2
9	191.3	190.3	1.0	0.5%	77.8	0.3	0.7	1.0	1.3	1.6
10	214.4	213.8	0.6	0.3%	82.4	0.1	0.4	0.6	0.9	1.2
11	230.7	230.6	0.1	0.0%	86.6	-0.3	-0.1	0.1	0.2	0.4
12	240.5	240.4	0.1	0.1%	90.3	-0.1	0.0	0.1	0.2	0.4
13	251.1	250.9	0.3	0.1%	93.5	-0.1	0.1	0.3	0.4	0.6
14	258.2	257.5	0.6	0.2%	96.2	-0.1	0.3	0.6	0.9	1.4
15	257.7	256.5	1.1	0.4%	98.4	0.1	0.7	1.1	1.6	2.2
16	244.9	243.5	1.4	0.6%	99.7	0.2	0.9	1.4	1.9	2.6
17	212.3	210.1	2.2	1.1%	100.2	1.1	1.8	2.2	2.7	3.3
18	187.2	185.9	1.3	0.7%	99.5	0.2	0.9	1.3	1.7	2.4
19	170.7	169.6	1.0	0.6%	97.5	0.0	0.6	1.0	1.5	2.1
20	161.9	162.0	-0.1	0.0%	94.1	-0.9	-0.4	-0.1	0.3	0.8
21	148.9	149.2	-0.3	-0.2%	90.0	-1.0	-0.6	-0.3	0.0	0.4
22	135.6	136.0	-0.4	-0.3%	87.0	-1.1	-0.7	-0.4	-0.1	0.3
23	126.6	127.0	-0.4	-0.3%	84.5	-1.1	-0.7	-0.4	-0.1	0.3
24	116.1	116.6	-0.5	-0.4%	82.2	-0.9	-0.7	-0.5	-0.3	-0.1
Daily	**4,102.5**	**4,092.4**	**10.1**	**0.2%**	**85.7**	**2.1**	**6.9**	**10.1**	**13.4**	**18.2**

Table 3.12 summarizes aggregate event-hour results for the typical event day for eight industry groups, including the number of enrolled customers, the reference and observed loads, and the estimated load impacts (in MWh/hour and as a percentage of reference loads). Enrollments are highest in the Offices, Hotel, Health & Services industry group, which accounts for 36 percent of enrollments and 76 MWh of reference loads, but does not contribute to load reductions. The Wholesale, Transportation & Utility group has the highest load impact (0.19 MWh/hour). Figure 3.12 illustrates the shares of enrollment, reference load, and load impact by industry group. Wholesale, Transportation & Utilities has the highest contribution to load reduction at 45 percent, while Agriculture, Mining, and Construction contributes 37 percent. Both industry groups contribute a higher share of load impacts than their share of enrollments or reference loads. Retail stores also contributes more to load impacts compared to their share of enrollments.

Table 3.12: Typical Event Day Event-Hour Load Impacts by Industry Group, *PG&E Small*

Industry Group	# of Service Accounts	Estimated Reference Load (MWh/hour)	Observed Load (MWh/hour)	Estimated Load Impact (MWh/hour)	% LI
1.Agriculture, Mining, Construction	6,264	9	9	0.16	1.6%
2.Manufacturing	2,750	5	5	-0.02	-0.5%
3.Wholesale, Transportation, Utilities	15,284	17	17	0.19	1.1%
4.Retail Stores	8,624	26	26	0.06	0.2%
5.Offices, Hotels, Health, Services	31,914	76	77	-0.06	-0.1%
6.Schools	1,292	3	3	0.00	-0.2%
7. Institutional/Government	18,139	28	28	-0.22	-0.8%
8.Other	5,539	7	7	0.02	0.3%

Figure 3.12: Typical Event Day Event-Hour Load Impacts by Industry Group, *PG&E Small*

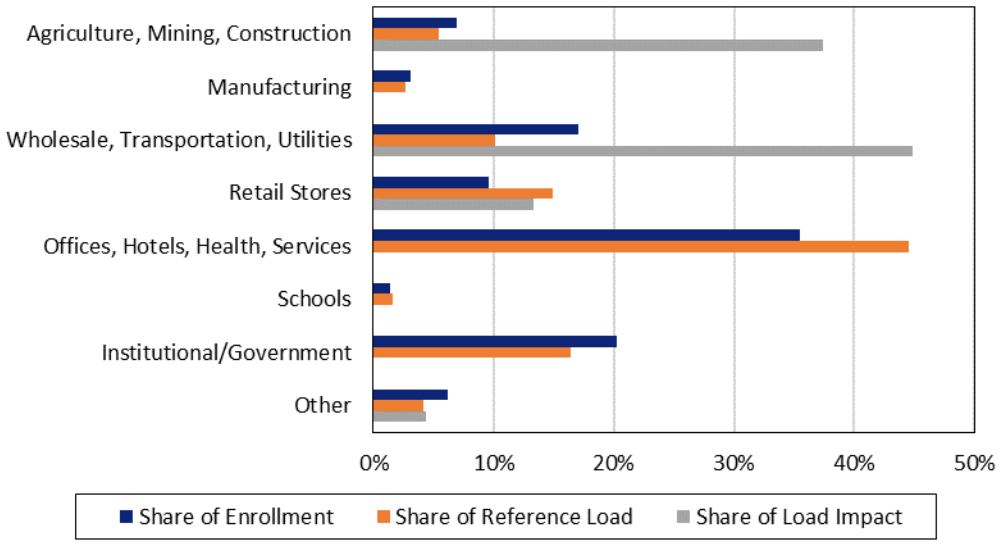
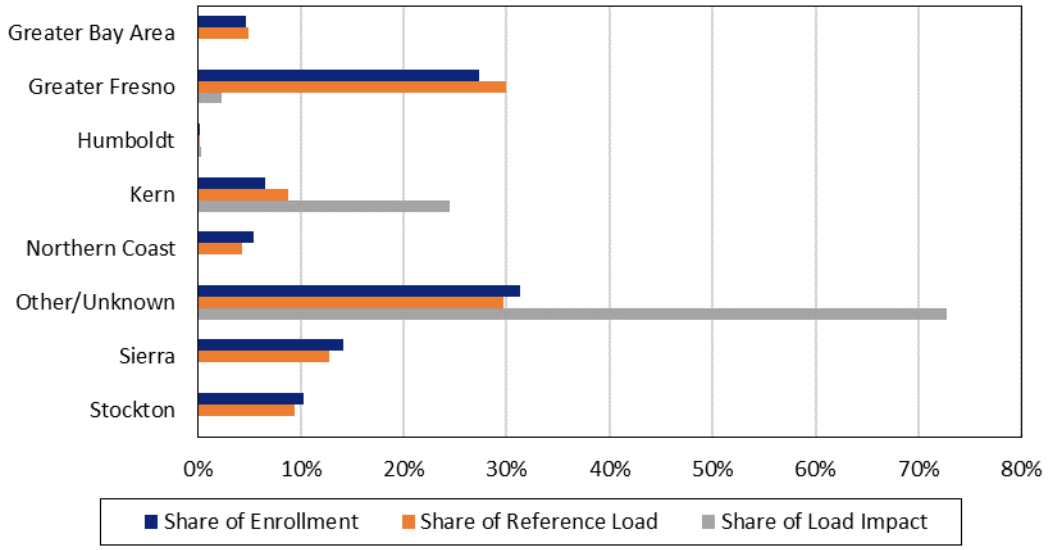


Table 3.13 and Figure 3.13 summarize the results by LCA for small customers. As with the large and medium customers, enrollments are concentrated in the Greater Fresno Area and Other LCAs, which together contain nearly 60 percent of small customers and account for 103 MWh/hour of load. The 0.024 MWh/hour load reduction for Greater Fresno Area only amounts to 0.05 percent of the reference load. Figure 3.13 shows that Greater Fresno Area have a much smaller share of load reduction than the share of enrollments or reference loads. Kern and Other LCA have higher share of load reduction than the share of enrollments or reference loads. Other LCAs contributes 73 percent of the load reduction despite having only 31 percent of customers and 30 percent of reference loads. Other LCAs and Kern also both have at least a one percent load reduction.

Table 3.13: Typical Event Day Load Event-Hour Load Impacts by LCA, *PG&E Small*

LCA	# of Service Accounts	Estimated Reference Load (MWh/hour)	Observed Load (MWh/hour)	Estimated Load Impact (MWh/hour)	% LI
Greater Bay Area	4,196	9	9	-0.064	-0.75%
Greater Fresno Area	24,565	52	52	0.024	0.05%
Humboldt	218	0.41	0.40	0.004	0.96%
Kern	5,885	15	15	0.245	1.62%
Northern Coast	4,923	7	7	-0.010	-0.14%
Other	28,104	51	51	0.728	1.42%
Sierra	12,721	22	22	-0.084	-0.38%
Stockton	9,194	16	16	-0.086	-0.53%

Figure 3.13: Typical Event Day Event-Hour Load Impacts by LCA, *PG&E Small*



3.1.5 Dually Enrolled Customers

This section summarizes results for customers who are dually enrolled in PDP and BIP. We present results for the average event-hour for each event day and the typical event day. Additional results for these customers can be found in electronic form in Protocol table generators provided along with this report.

Table 3.14 summarizes average event-hour results for each event-day as well as the typical event day for customers who are dually enrolled in BIP and PDP, including the number of enrolled customers, the reference and observed loads, and the estimated load impacts (in MWh/hour and as a percentage of reference loads). There are no reported results on July 9th because it is a dual event day—all load impacts for dually enrolled customers are attributed to BIP. [redacted]

[redacted]

Table 3.14: Average Event-Hour Load Impacts for PDP+BIP customers by Event, *PG&E*

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
6/17/2021	[redacted]						
7/8/2021							
7/9/2021							
7/10/2021							
7/28/2021							
7/29/2021							
8/12/2021							
8/16/2021							
9/8/2021							
Typical Event Day							

3.1.6 AutoDR Customers

This section summarizes results for all PDP customers who participated in the Automated Demand Response (AutoDR) program, which provides customers incentives to invest in energy management technologies that will enable their equipment or facilities to reduce demand automatically in response to a physical signal sent from the utility. It encourages customers to expand their energy management capabilities by participating in DR programs using automated electric controls and management strategies. When a DR event is called, a communications signal from the utility enables the execution of a sequence of load shed strategies without participant intervention.

We present results for the average event hour for each event day as well as for the typical event day. Additional results for these customers can be found in electronic form in Protocol table generators provided along with this report.

Table 3.15 summarizes aggregate event-hour results for each event day as well as the typical event day for PDP customers who participate in AutoDR, including the number of enrolled customers, the reference and observed loads, and the estimated load impacts (in MWh/hour and as a percentage of reference loads). One customer de-enrolled from AutoDR after the first event on June 17th. Enrollments remain constant for the rest of season, with 23 customers enrolled in AutoDR. [redacted]

Table 3.15: Average Event-Hour Load Impacts for AutoDR Customers by Event, *PG&E*

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
6/17/2021	[redacted]						
7/8/2021							
7/9/2021							
7/10/2021							
7/28/2021							
7/29/2021							
8/12/2021							
8/16/2021							
9/8/2021							
Typical Event Day							

3.1.7 Notified vs. Non-Notified Customers

This section compares customers who receive notifications versus customers who do not receive notifications. Notifications are sent a day ahead of each event either by email, fax, phone, or SMS. We contrast average load impacts for the typical event day for customers that successfully receive notifications compared to those who do not by size group. Additional results for these customers can be found in electronic form in Protocol table generators provided along with this report.

Table 3.16 summarizes aggregate event-hour results for the typical event day, including the number of enrolled customers, the reference and observed loads, and the estimated load impacts (in MWh/hour and as a percentage of reference loads). 82 percent of customers successfully receive notifications, but these customers generate 98 percent of the aggregate load impacts. Customers who receive notifications have higher per-customer load impacts across all sizes. In fact, small and medium customers that do not receive notifications do not have load reductions on the typical event day.

Table 3.16: Average Event-Hour Load Impacts on Typical Event Day by Size and Notification Status, PG&E

Notified	Size	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
			Ref. Load	Load Impact	Ref. Load	Load Impact		
No	Large	122	19	0.3	154.7	2.39	1.5%	98.3
	Medium	2,627	56	-0.1	21.2	-0.03	-0.1%	98.8
	Small	16,463	29	-0.2	1.7	-0.010	-0.6%	97.7
	All	**19,212**	**103**	**0.1**	**5.4**	**0.00**	**0.1%**	**98.4**
Yes	Large	1,114	221	5.0	198.7	4.49	2.3%	98.3
	Medium	13,775	310	0.4	22.5	0.03	0.1%	97.8
	Small	73,343	143	0.9	1.9	0.01	0.6%	96.8
	All	**88,231**	**674**	**6.2**	**7.6**	**0.07**	**0.9%**	**97.7**

3.1.8 Other Subgroup Results

This section summarizes the average load impacts for customers in the agricultural and commercial rate classes, customers who received Business Energy Support (BES/CRS), and NEM customers. We present results for the average event-hour for the typical event day by size group. Additional results for these customers can be found in electronic form in Protocol table generators provided along with this report.

Table 3.17 summarizes aggregate event-hour results for the typical event day for PDP customers of different subgroups, including the number of enrolled customers, the reference and observed loads, and the estimated load impacts (in MWh/hour and as a percentage of reference loads).

The results for the two major rate classes show that most customers (97 percent) are on a commercial/industrial rate class, however a much higher share of large customers are on an agricultural rate class (42 percent). Large agricultural and commercial/industrial customers have comparable aggregate load impacts of 2.7 and 2.6 MWh/hour, respectively. The percentage load impacts for large agricultural customers are 3.6 percent of reference loads—larger than for the average large customer (2.2 percent). Small and medium agricultural customers have even higher percentage load impacts of 3.8 and 8.6 percent, respectively.

The results for BES/CRS show that the customer support is highly targeted towards large customers: 61 percent of large customers have BES/CRS compared to 25 percent of medium customers and 15 percent of small customers (17 percent of all customers). BES/CRS customers also represent an even larger share of loads for large and medium customers than enrollments. Customers receiving this support generate 72 percent of aggregate load impacts with 4.6 MWh/hour of load reduction.

The results for NEM customers suggest that across all sizes, NEM customers do not make load reductions during PDP events. Just 1 percent of PDP customers are NEM customers (4 percent of large customers).

Table 3.17: Average Event-Hour Load Impacts on Typical Event Day by Size and Subgroup, *PG&E*

Subgroup	Size	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
			Ref. Load	Load Impact	Ref. Load	Load Impact		
Agricultural Rate Class	Large	515	74.5	2.7	144.65	5.21	3.6%	102.3
	Medium	191	7.4	0.6	38.64	3.32	8.6%	101.3
	Small	1,023	2.0	0.1	1.95	0.07	3.8%	99.5
	All	**1,729**	**83.9**	**3.4**	**48.51**	**1.96**	**4.0%**	**102.2**
Commercial/ Industrial Rate Class	Large	708	157.5	2.6	222.32	3.65	1.6%	97.3
	Medium	16,018	354.8	-0.3	22.15	-0.02	-0.1%	97.9
	Small	87,831	169.4	0.7	1.93	0.01	0.4%	97.0
	All	**104,557**	**681.7**	**3.0**	**6.52**	**0.03**	**0.4%**	**97.5**
BES/CRS	Large	759	175.3	4.1	230.93	5.38	2.3%	97.7
	Medium	4,053	128.7	0.4	31.76	0.09	0.3%	97.9
	Small	13,168	25.1	0.1	1.91	0.01	0.5%	95.9
	All	**17,980**	**329.2**	**4.6**	**18.31**	**0.26**	**1.4%**	**97.7**
NEM	Large	45	12.1	-0.2	268.58	-3.88	-1.4%	99.5
	Medium	423	10.9	-0.3	25.79	-0.70	-2.7%	96.4
	Small	634	2.0	-0.03	3.10	-0.05	-1.5%	96.4
	All	**1,102**	**25.0**	**-0.5**	**22.65**	**-0.45**	**-2.0%**	**97.9**
All Customers	Large	1,235	239.2	5.3	193.65	4.26	2.2%	98.4
	Medium	16,402	366.1	0.3	22.32	0.02	0.1%	97.9
	Small	89,806	173.2	0.8	1.93	0.01	0.4%	97.0
	All	**107,443**	**778.5**	**6.3**	**7.25**	**0.06**	**0.8%**	**97.9**

3.2 PG&E Ex-Ante Load Impacts

This section provides the ex-ante PDP load impact forecasts based on an enrollment forecast provided by PG&E. Results are presented by size group. Within each size group, we present the following: a summary of the enrollment forecast provided by PG&E; a figure showing the hourly reference loads and load impacts on a typical event day; a figure showing the share of load impacts by LCA; a figure showing the seasonal pattern of load impacts; and a figure summarizing annual load impacts by weather scenario. Detailed results for each hour, weather scenario, month, and forecast year are available in electronic form in Protocol table generators provided along with this report.

As described in Section 2.2, *per-customer load impacts* are derived from analysis of current and previous ex-post load impacts. We investigated the effect of weather on

estimated load impacts (and percentage load impacts) and found that there was not a strong relationship between load impacts and weather conditions for most customer groups. Therefore, we simulate ex-ante load impacts by multiplying forecasted reference loads and ex-post percentage load impacts (by size, LCA, and hour of the day).

Beginning on March 1, 2022, PG&E will change its PDP event hours, moving the event window from 5 to 8 p.m. (HE 18 to 20) to align with the RA window from 4 to 9 p.m. (HE 17 to 21). To apply load impacts that correspond to the updated PDP event hours, we first categorize each hour of the day with respect to the old and updated PDP event hours. Table 3.18 summarizes our categorization of each hour of the day, with the "Previous Event Window" column representing the current event hours and the "Ex-ante Event Window" column representing the new PDP event window.[9] The PY2021 ex-post reference loads and load impacts are averaged over these periods to obtain average percentage load impacts, which are then applied to ex-ante reference load estimates during the corresponding period category to calculate the ex-ante load impacts for PY2021. For example, the PY2021 ex-post percentage load impact for the hour before the previous event window (HE 17) is applied to the ex-ante reference loads for the hour before the ex-ante event window (HE 16) to extend the load impacts one hour earlier than in 2021.

Table 3.18: PG&E Hourly Categorization of Periods Relating to Change in PDP Event Window

Hour	*Previous Event Window*	*Ex-Ante Event Window*
1	Beginning of Event Day	Beginning of Event Day
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		Pre-event hour
17	Pre-event hour	Beginning of Event
18	Beginning of Event	
19	Middle of Event	Middle of Event
20	End of Event	
21	Post-event hour	End of Event
22	Remainder of Event Day	Post-event hour
23		Remainder of Event Day
24		

[9]While the new event hours do not begin until March 2022, the ex-ante forecast applies this adjustment to results for January and February 2022 for simplicity.

3.2.1 All Customers

Figure 3.14 summarizes the overall trend of PG&E's enrollment forecast. PG&E anticipates a 12 percent decrease in total enrollment from 2021 to 2022 followed by a 9 percent increase in 2023. After 2023, an annual attrition of 6 percent is expected.

Figure 3.14: PDP Enrollments, *PG&E All*

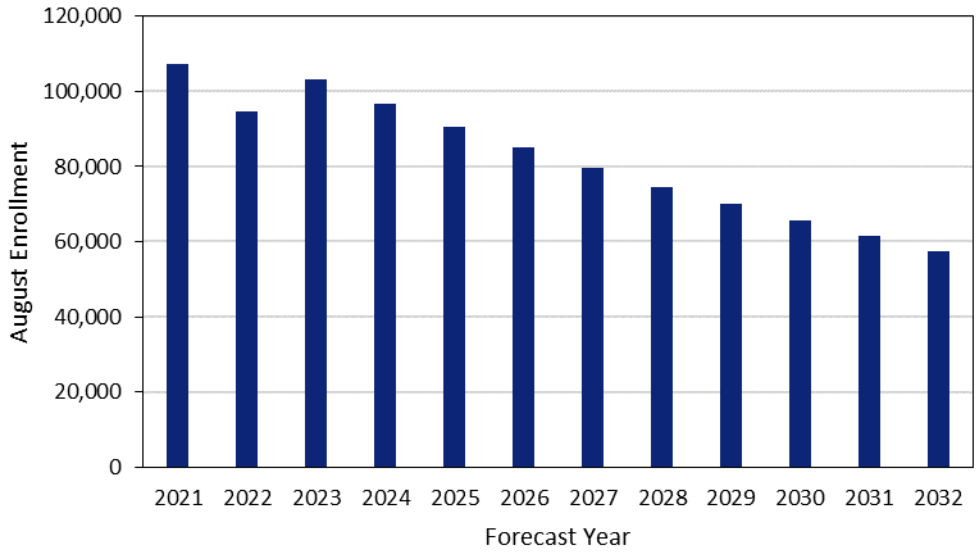


Figure 3.15 shows the change in aggregate load impacts of all customers over time and across weather scenarios. Each bar is the average aggregate load impact during the RA window of the typical event day. There is a small increase in aggregate load impact of about 0.18 MWh/hour from 2022 to 2023 due to increased enrollments. Load impacts decline after 2023 due to program attrition. There are relatively minor differences between forecasted load impacts across the weather scenarios over the forecast period. The highest load impacts for each year occur under PG&E 1-in-10 weather conditions. Additional results of load impacts are presented by customer size.

Figure 3.15: Aggregate Load Impacts for the Typical Event Day by Year and Weather Scenario over RA Window, *PG&E All*

3.2.2 Large Customers

Figure 3.16 summarizes PG&E's enrollment forecast for large customers. PG&E anticipates a 12 percent increase in large customer enrollments from 2021 to 2022 followed by an additional 15 percent increase in 2023. After 2023, an annual attrition of 6 percent is expected.

Figure 3.16: PDP Enrollments, *PG&E Large*

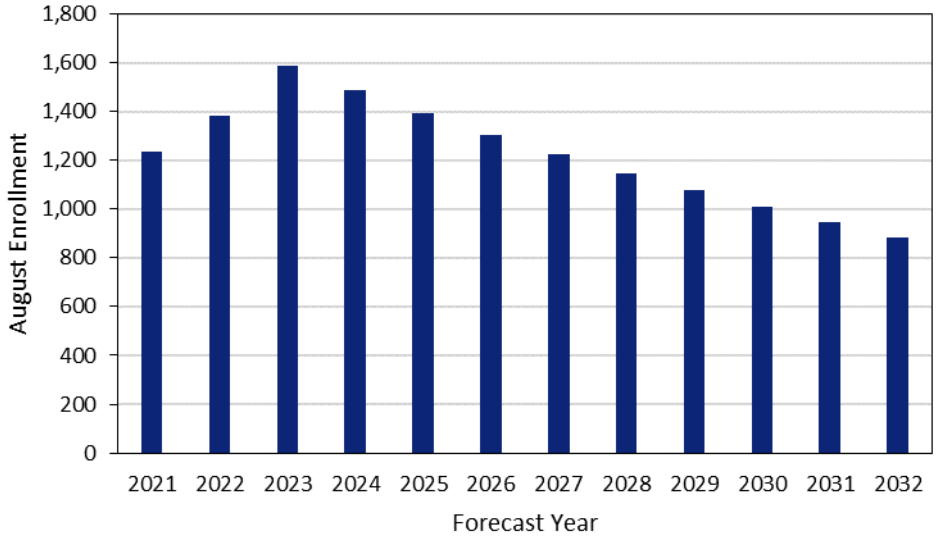


Figure 3.17 illustrates the aggregate reference loads, observed loads, and load impacts for large customers on the typical event day in 2023 for the PG&E 1-in-2 weather scenario. The magnitudes of the load impacts are larger than the ex-post results in Figure 3.3 due to higher enrollment. The average event-hour load impact is 6.2 MWh/hour, or 2.0 percent of the reference load. The shape of the load impacts is flatter during the event hours due to the change from three-hour event in the ex-post results to five-hour event in the ex-ante forecast.

Figure 3.17: Aggregate Hourly Loads and Load Impacts in 2023 for *PG&E 1-in-2 Typical Event Day, PG&E Large*

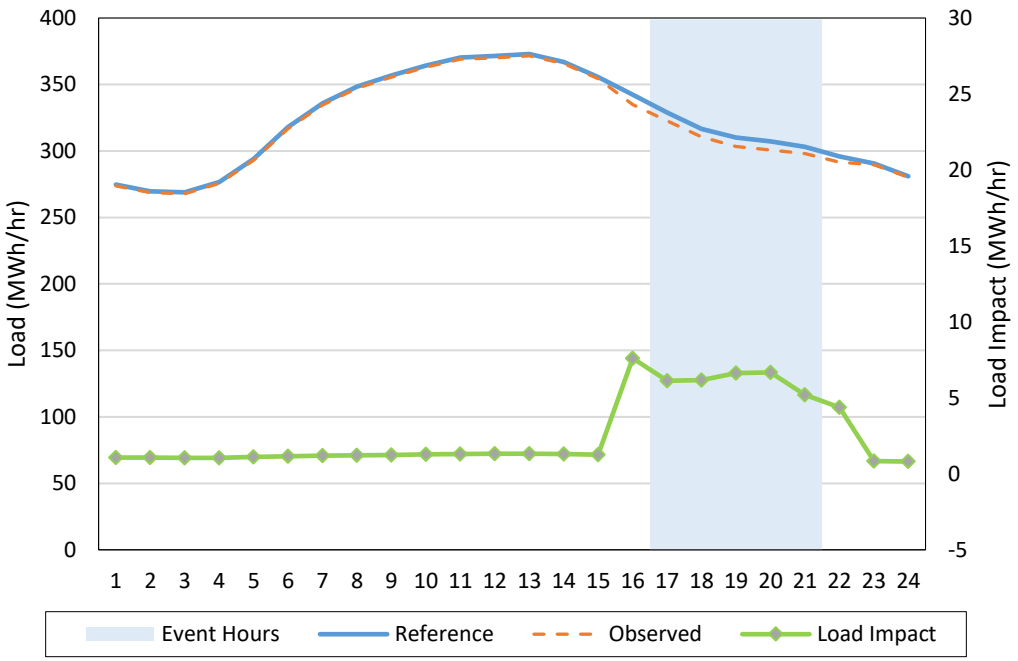


Figure 3.18 shows the forecasted share of load impacts by LCA during the average event hour on the typical event day in 2023 under PG&E's 1-in-2 weather scenario. Other LCA has the largest share of load impacts. Greater Fresno Area and Kern have the second and third largest shares of load impacts. In total, the three LCAs contribute 99 percent of load impacts in the forecast. The top three LCAs in terms of the share of load impacts are the same as the ex-post results presented in Figure 3.5, and the shares of the three LCAs are similar for ex-ante and ex-post. The share of Other LCA decreases by less than 3 percent, and the share of Kern increases by 2 percent, based on the enrollment forecast for these LCAs.

Figure 3.18: Share of Load Impacts by LCA in 2023 for *PG&E 1-in-2 Typical Event Day, PG&E Large*

Figure 3.19 illustrates the seasonality in the forecasted load impacts by comparing aggregate load impacts for the average hour in the Resource Adequacy (RA) window in 2023 across months for PG&E's 1-in-2 peak day weather scenario. The RA window is 4 to 9 p.m. each day. The load impact is highest in June (6.4 MWh/hour) and lowest in February (3.9 MWh/hour). The load impacts are lower from November to March because the reference loads are lower in those months.

Figure 3.19: Aggregate Load Impacts by Month over RA Window in 2023 for *PG&E 1-in-2 Peak Day, PG&E Large*

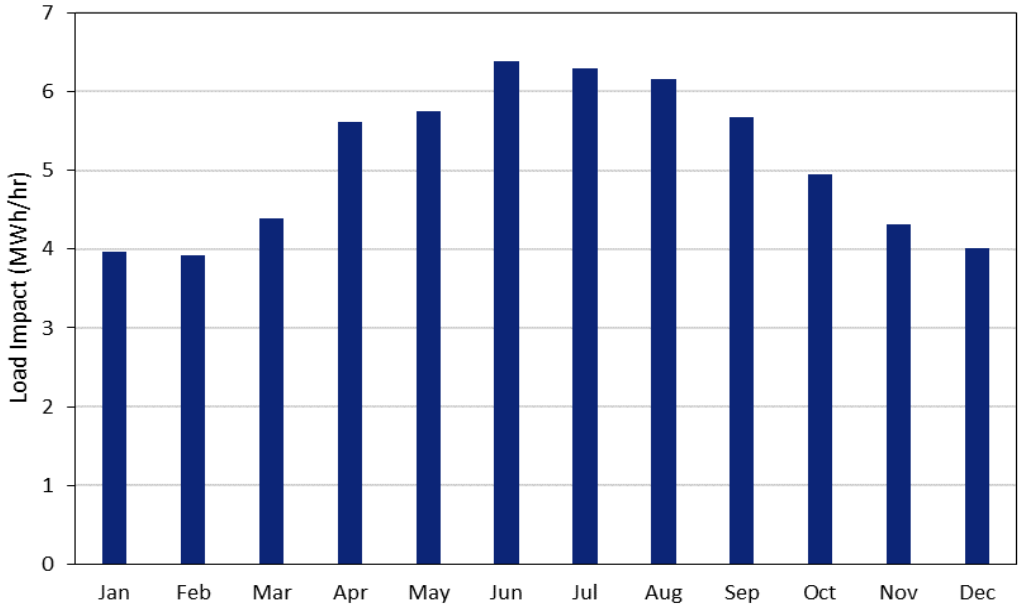
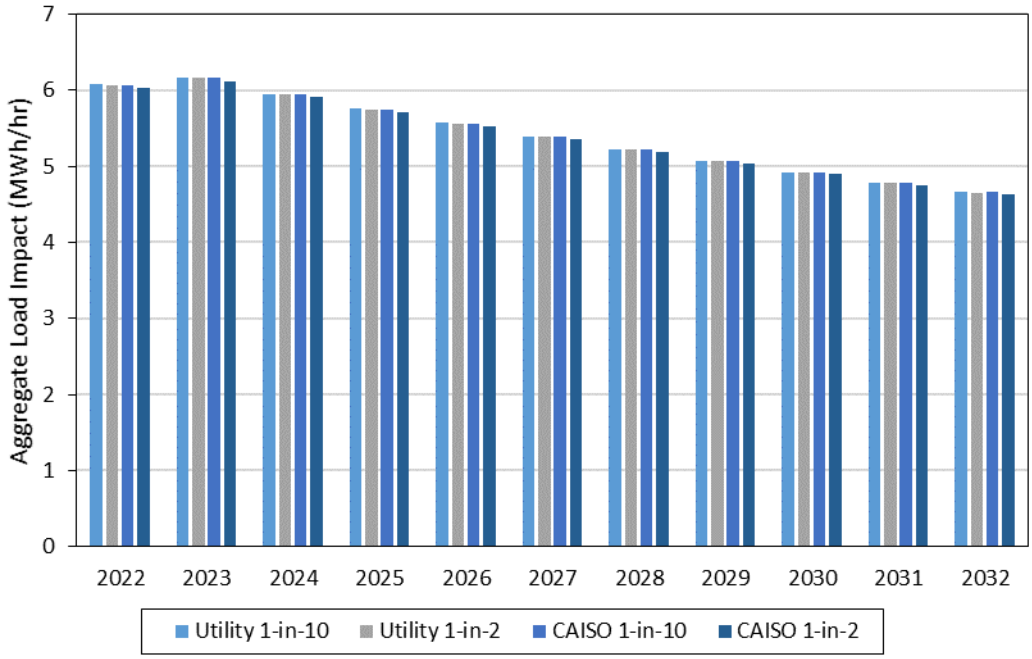


Figure 3.20 shows the change in load impacts over time and across weather scenarios. Each bar is the average aggregate load impact during the RA window of the typical event day. There is a small increase in aggregate load impact of about 0.1 MWh/hour from 2022 to 2023 due to increased enrollments. Load impacts decline after 2023 due to program attrition. There are relatively minor differences between forecasted load impacts across the weather scenarios over the forecast period. The highest load impacts for each year occur under PG&E 1-in-10 weather conditions.

Figure 3.20: Aggregate Load Impacts for the Typical Event Day by Year and Weather Scenario over RA Window, *PG&E Large*



3.2.3 Medium Customers

Figure 3.21 summarizes PG&E's enrollment forecast for medium customers. PG&E anticipates a 12 percent decrease in medium customer enrollments from 2021 to 2022. Enrollments are expected to increase by 8 percent in 2023. From 2024 onward, medium customer enrollments are expected to decline by 6 percent per year.

Figure 3.21: PDP Enrollments, *PG&E Medium*

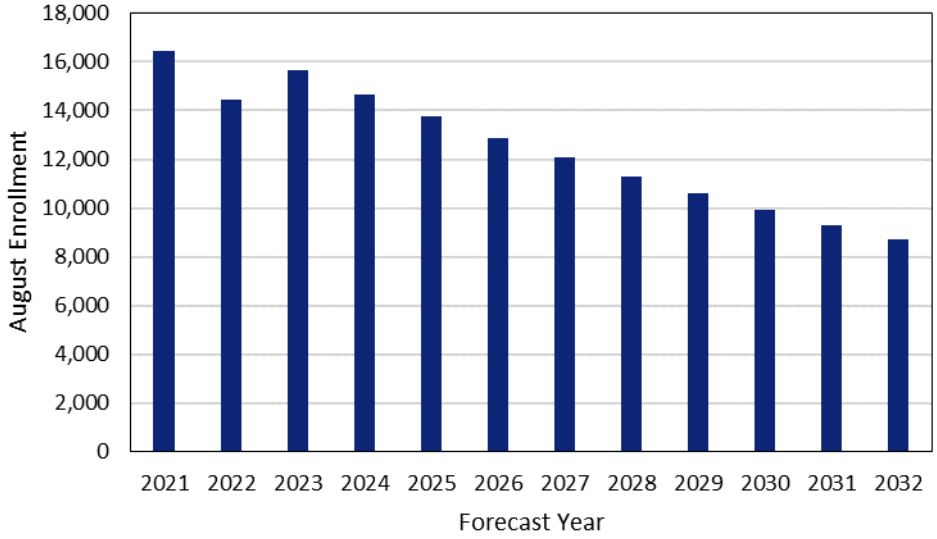


Figure 3.22 illustrates the aggregate reference loads, observed loads, and load impacts for medium customers on the typical event day in 2023 for the PG&E 1-in-2 weather scenario. The shape of the load impacts is flatter during the event hours due to the change from three-hour event in the ex-post results as shown in Figure 3.7 to five-hour events in the ex-ante forecast. The forecast predicts an average load impact of 0.58 MWh/hour, or 0.2 percent of the reference loads.

Figure 3.22: Aggregate Hourly Loads and Load Impacts in 2023 for *PG&E 1-in-2 Typical Event Day, PG&E Medium*

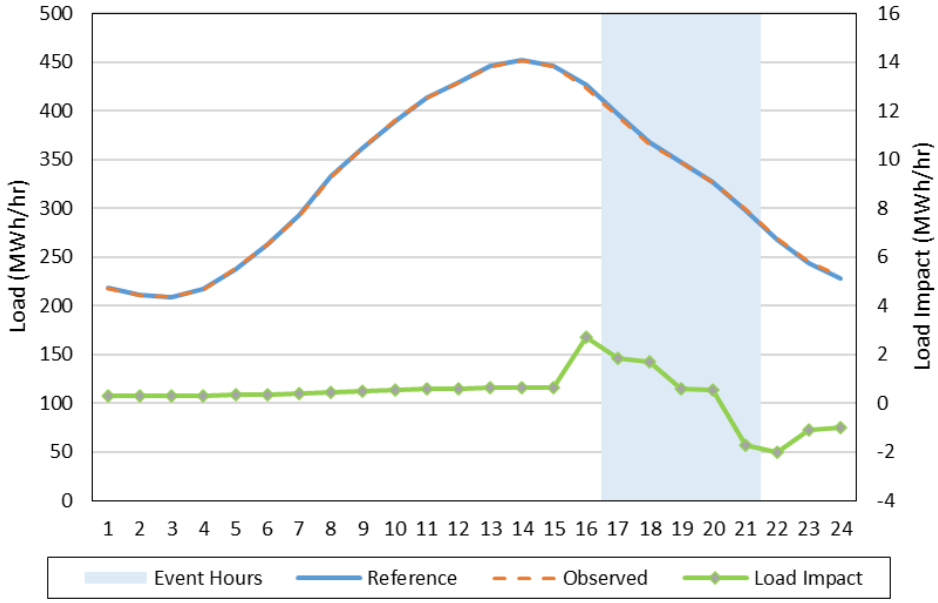


Figure 3.23 shows the forecasted share of load impacts for medium customers by LCA, based on the average event-hour load impact on the typical event day in 2023 under PG&E's 1-in-2 weather scenario. Kern, Northern Coast and Other LCA are the three LCAs contributing to medium customer load reduction, similar to the ex-post results. Compared to the ex-post estimates presented in Figure 3.9, Kern's share of aggregate load impacts declines by 7 percent, while Other LCAs gains 10 percent. These changes are due to the change of event hours in the forecast rather than due to enrollment changes. As shown in Table 3.18, the ex-post percent load impacts in the first and second event hours are given twice the weight in the ex-ante forecast as the third hour. LCAs with higher load impacts in the first two hours or lower load impacts in the third hour will have higher load impacts in the ex-ante forecast.

Figure 3.23: Share of Load Impacts by LCA in 2023 for *PG&E 1-in-2 Typical Event Day, PG&E Medium*

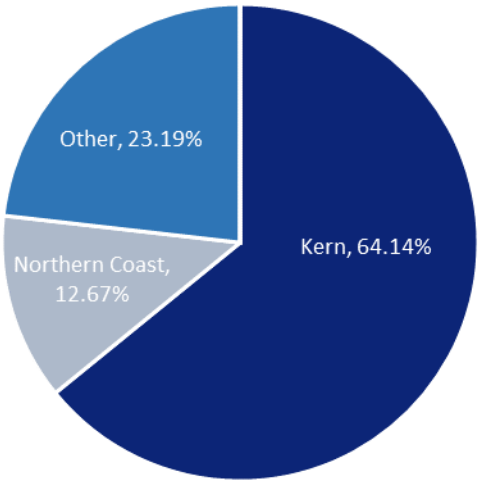


Figure 3.24 shows the seasonality of the forecasted load impacts for medium customers based on the 2023 aggregate load impacts for the average hour in the RA window for PG&E's 1-in-2 weather scenario. The load impact is highest in July (0.60 MWh/hour) and lowest in December (0.28 MWh/hour). The load impacts are lower from November to March because reference loads are lower in those months.

Figure 3.24: Aggregate Load Impacts by Month over RA Window in 2023 for *PG&E 1-in-2 Peak Day, PG&E Medium*

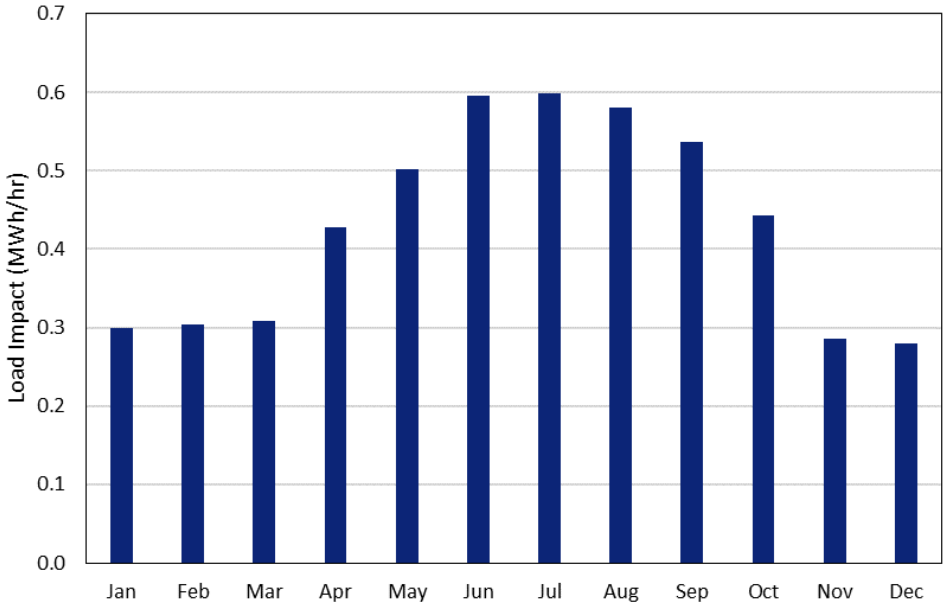
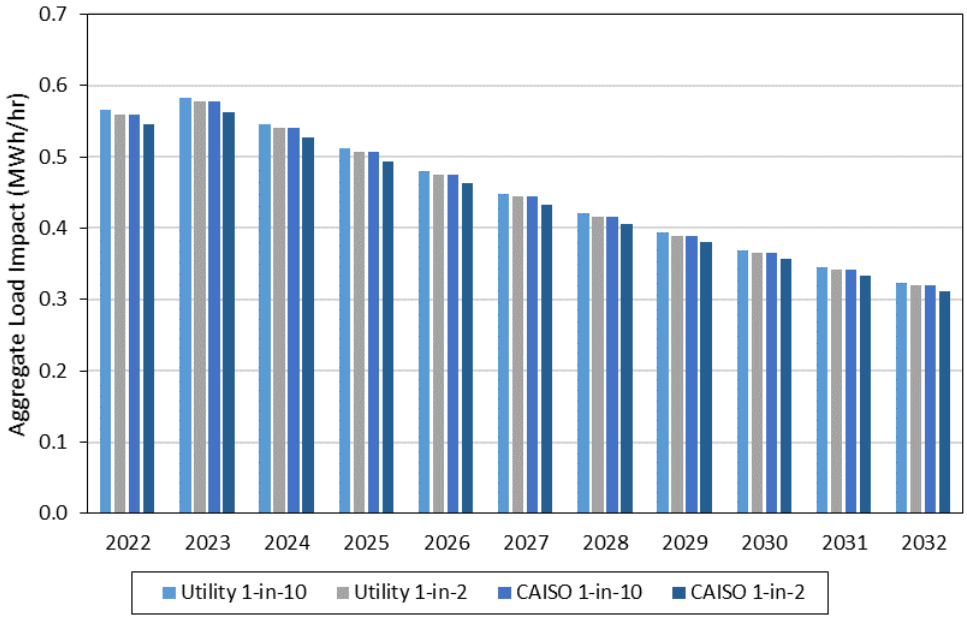


Figure 3.25 shows the change in load impacts over time and across weather scenarios. Each value is the aggregate load impact during the RA window of the typical event day. Load impacts increase by about 0.02 MWh/hour for all weather scenarios from 2022 to 2023 due to increasing enrollments. There are relatively minor differences between the forecasted load impacts for the alternative weather scenarios over the forecast period. The load impacts are highest for PG&E 1-in-10 scenario.

Figure 3.25: Aggregate Load Impacts for the Typical Event Day by Year and Weather Scenario over RA Window, *PG&E Medium*



3.2.4 Small Customers

Figure 3.26 summarizes PG&E's enrollment forecast for small customers. PG&E anticipates a 12 percent decrease in medium customer enrollments from 2021 to 2022. Enrollments are expected to increase by 9 percent in 2023. From 2024 onwards, enrollments decrease by 6 percent annually due to attrition.

Figure 3.26: PDP Enrollments, *PG&E Small*

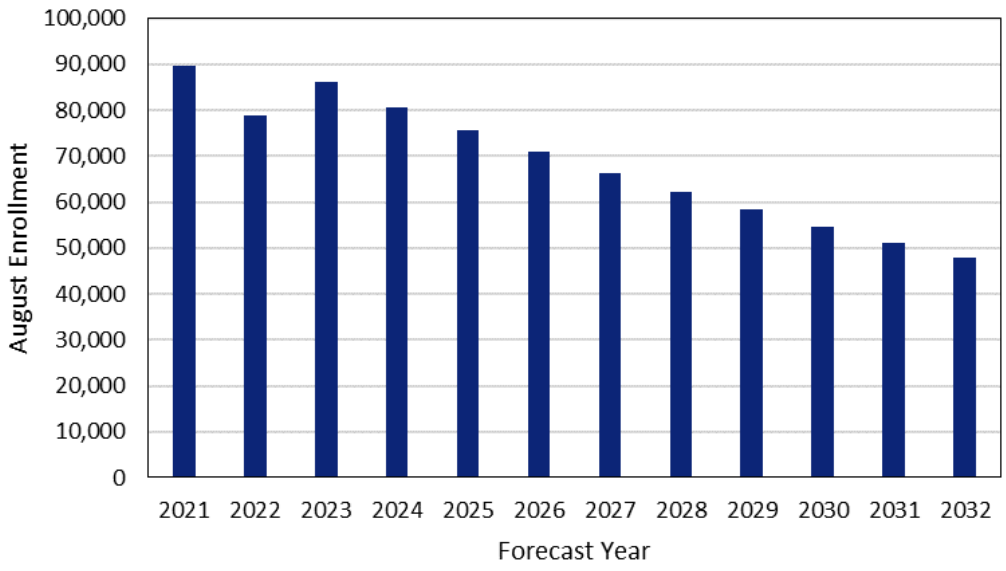


Figure 3.27 illustrates the aggregate reference loads, observed loads, and load impacts for small customers on the typical event day in 2023 for the PG&E 1-in-2 weather scenario. The shape of the load impacts is flatter during the event hours due to the change from a three-hour event in the ex-post to a five-hour event in the ex-ante forecast. The forecast predicts an average load impact of 0.83 MWh/hour, or 0.5 percent of reference loads.

Figure 3.27: Aggregate Hourly Loads and Load Impacts in 2023 for *PG&E 1-in-2 Typical Event Day, PG&E Small*

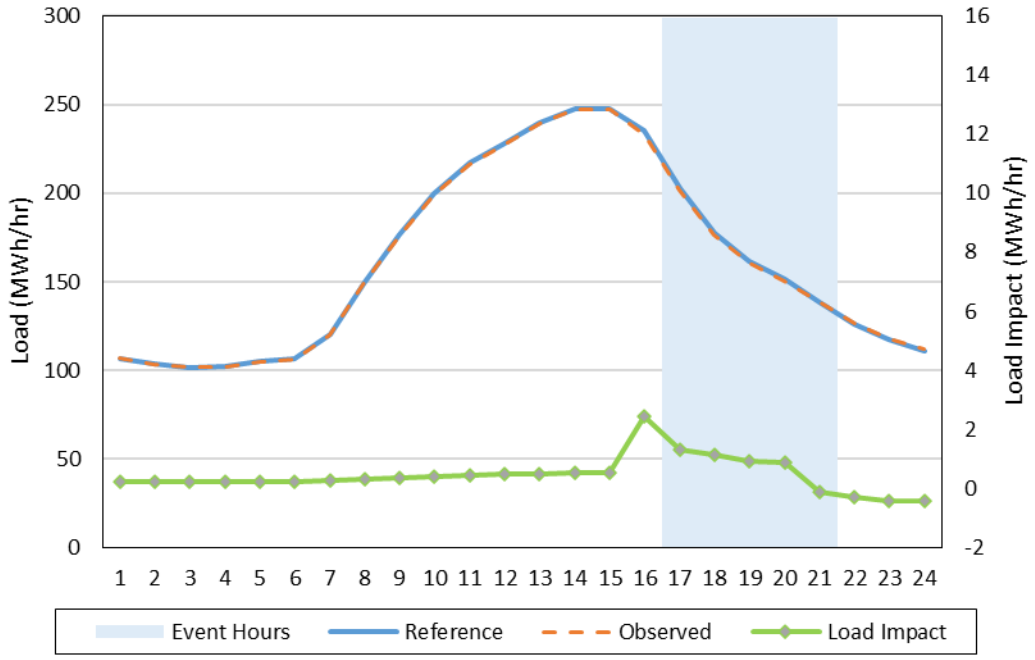


Figure 3.28 shows the forecasted share of load impacts for small customers by LCA, based on the average event-hour load impact on the typical event day in 2023 under PG&E's 1-in-2 weather scenario. Other LCA, Kern and Greater Fresno Area contribute most of the aggregate load reduction. Compared to the ex-post estimates presented in Figure 3.13, Other LCA's share of load impacts declines by 8 percent. Conversely, Greater Fresno Area's share of load impacts increases from 2 percent to 8 percent. These changes are primarily due to the change in event window between ex-post and ex-ante as discussed in Section 3.2.3.

Figure 3.28: Share of Load Impacts by LCA in 2023 for *PG&E 1-in-2 Typical Event Day, PG&E Small*

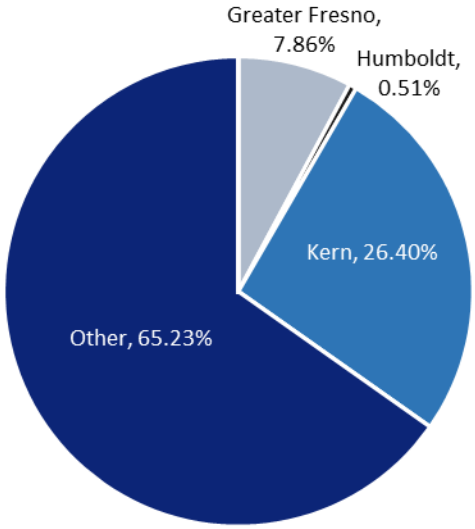


Figure 3.29 shows the seasonality of the forecasted load impacts for small customers based on the 2023 aggregate load impacts for the average hour in the RA window for PG&E's 1-in-2 weather scenario. The load impact is highest in July (0.86 MWh/hour) and lowest in November (0.49 MWh/hour). Load impacts are lower from November to March because the reference loads are lower in those months.

Figure 3.29: Aggregate Load Impacts by Month over RA Window in 2023 for *PG&E 1-in-2 Peak Day, PG&E Small*

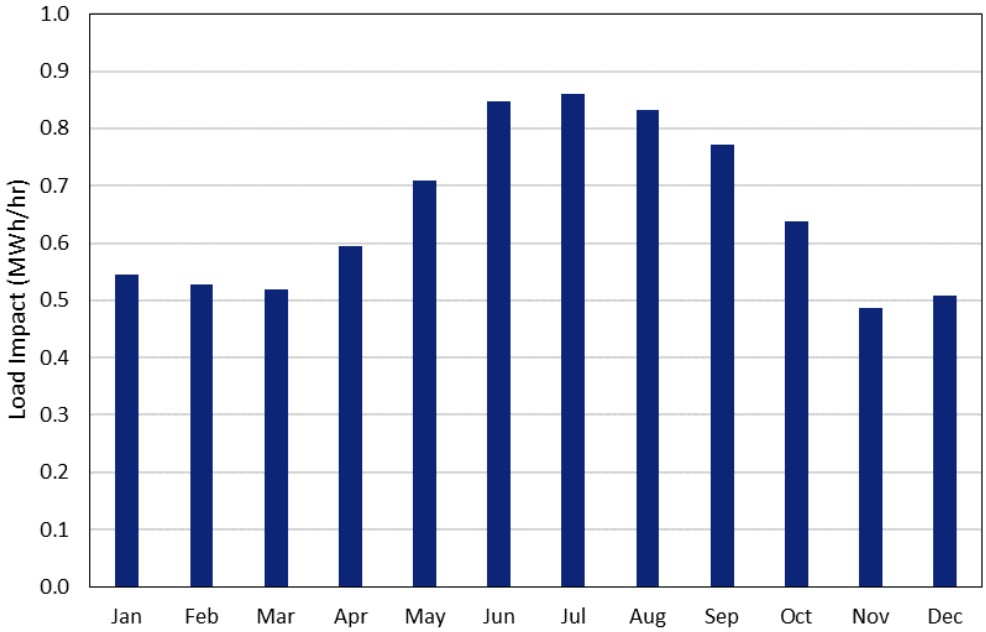
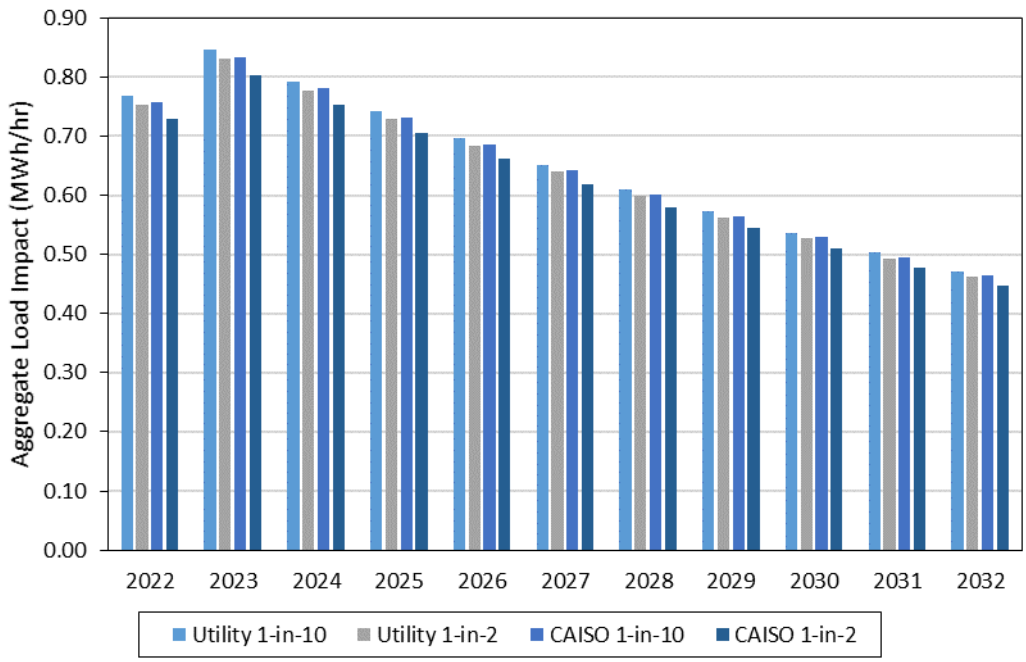


Figure 3.30 shows the change in load impacts over time and across weather scenarios. Each value is the aggregate load impact during the RA window of the typical event day. Load impacts increase by about 0.07 MWh/hour for all weather scenarios from 2022 to 2023 due to increasing enrollment, and decline afterwards due to program attrition. There are relatively minor differences between the forecasted load impacts for the alternative weather scenarios over the forecast period. The load impacts are highest for PG&E 1-in-10 scenario.

Figure 3.30: Aggregate Load Impacts for the Typical Event Day by Year and Weather Scenario over RA Window, *PG&E Small*



3.3 PG&E Load Impact Reconciliations

In a continuing effort to clarify the relationships between ex-post and ex-ante results, this section compares several sets of estimated load impacts for PDP, including the following:

- Ex-post load impacts from the current and previous studies;
- Ex-ante load impacts from the current and previous studies;
- Current ex-post and previous ex-ante load impacts; and
- Current ex-post and ex-ante load impacts.

The term “current” refers to the present study, which includes ex-post and ex-ante results for PY2021. The term “previous” refers to findings from the PY2020 evaluation. In the final comparison above, we illustrate the linkage between the PY2021 ex-post load impacts and the ex-ante forecast (of the 1-in-2 August peak day) for 2021.

3.3.1 Large Customers

Previous vs. Current Ex-Post

Table 3.19 shows the average event-hour reference loads and load impacts for the typical event day during the current and previous program years. Enrollments increased in PY2021 by 370 customers, while at the same time per-customer load impacts decreased by more than half between PY2020 and PY2021. Per-customer reference loads are also lower in PY2021 despite higher event temperatures. Some of the difference may be due to the change in event hours from 2 to 6 p.m. in 2020 to 5 to 8 p.m. in 2021. Loads are lower during the later event hours and load impacts may be lower as a result. As previously mentioned, some of the drop in load impacts may be due to low customer awareness of the change in event hours. Load impacts are also lower in percentage terms, decreasing by 1.3 percentage points from PY2020. These results are more in line with the PY2019 percent load impacts of 2.9 percent. Aggregate load impacts are 31 percent lower in PY2021 despite increased enrollments.

Table 3.19: Previous vs. Current Ex-Post Load Impacts for the Typical Event Day, *PG&E Large*

Level	Outcome	Ex-post Previous Study	Ex-post Current Study
Total	# SAIDs	865	1,235
	Reference (MW)	220	239
	Load Impact (MW)	7.7	5.3
	Avg. Temp.	96.4	98.4
Per SAID	Reference (kW)	254.6	193.7
	Load Impact (kW)	8.9	4.3
	% Load Impact	3.5%	2.2%

Previous vs. Current Ex-Ante

In this sub-section, we compare the PY2020 ex-ante forecast to the ex-ante forecast contained in the current study. Table 3.20 reports the RA window average load impacts for the typical event day under utility-specific 1-in-2 weather conditions in 2023. The aggregate load impact forecast decreases by half between PY2020 and PY2021. Some of this difference is due to a lower enrollment forecast from PG&E as well as a composition of customers with lower per-customer loads and load impacts. The percentage load impacts are more comparable between the two forecasts—2 percent in PY2021 compared to 2.6 percent in PY2020.

Table 3.20: Previous vs. Current Ex-Ante Load Impacts, *Utility 1-in-2 Typical Event Day, PG&E Large*

Level	Outcome	Ex-ante for 2023 Typical Event Day, Previous Study	Ex-ante for 2023 Typical Event Day, Current Study
Total	# SAIDs	1,653	1,587
	Reference (MW)	484	313
	Load Impact (MW)	12.6	6.2
	Avg. Temp.	95.6	96.6
Per SAID	Reference (kW)	293.0	197.4
	Load Impact (kW)	7.65	3.88
	% Load Impact	2.6%	2.0%

Previous Ex-Ante vs. Current Ex-Post

Table 3.21 provides a comparison of the average event-hour load impacts from the PY2020 ex-ante forecast of 2021 and the ex-post load impacts estimated as part of this study. The ex-ante forecast shown in the table represents the typical event day during a utility-specific 1-in-2 weather year. The ex-post load impacts are based on the typical event day. The PY2020 load impact forecast is in line with the ex-post results in the current study in terms of per-customer load impacts which are 4.3 kWh/customer/hour compared to 4.9 kWh/customer/hour in the forecast. Reference loads are lower than forecasted leading to percentage load impacts in 2021 that are slightly higher than forecasted—2.2 compared to 1.7 percent of reference loads. Actual enrollments fall considerably short of the enrollment forecast, leading to aggregate load impacts in 2021 that are half the magnitude of the PY2020 forecast.

Table 3.21: Previous Ex-Ante vs. Current Ex-Post Load Impacts, *PG&E Large*

Level	Outcome	Ex-ante for 2021 Typical Event Day, Previous Study	Ex-post Typical Event Day, Current Study
Total	# SAIDs	2,106	1,235
	Reference (MW)	592	239
	Load Impact (MW)	10.3	5.3
	Avg. Temp.	96.5	98.4
Per SAID	Reference (kW)	281	194
	Load Impact (kW)	4.9	4.3
	% Load Impact	1.7%	2.2%

Current Ex-Post vs. Current Ex-Ante

Table 3.22 compares the ex-post and ex-ante load impacts from the current study. The average RA window ex-ante load impacts in the table represent the 2023 typical event day under utility-specific 1-in-2 weather conditions. The ex-post load impacts are for the average event hour on the typical event day. Aggregate load impacts are forecasted to increase from 5.3 MWh/hour in 2021 to 6.2 MWh/hour in 2023, due to an increase in enrollments. Per-customer load impacts are actually lower in 2023 at 3.9 kWh/customer/hour down from 4.3 kWh/customer/hour.

Table 3.22: Current Ex-Post vs. Current Ex-Ante Load Impacts, *PG&E Large*

Level	Outcome	Ex-Post Typical Event Day, Current Study	Ex-ante for 2023 Typical Event Day, Current Study
Total	# SAIDs	1,235	1,587
	Reference (MW)	239	313
	Load Impact (MW)	5.3	6.2
	Avg. Temp.	98.4	96.6
Per SAID	Reference (kW)	193.7	197.4
	Load Impact (kW)	4.3	3.9
	% Load Impact	2.2%	2.0%

Table 3.23 documents the various potential sources of differences between the ex-post and ex-ante load impacts. The two biggest drivers of differences are the 29 percent increase in customer enrollments (which scales the aggregate load impact up by a commensurate amount) and a shift in the distribution of enrollments across LCAs towards LCAs that had lower percent load impacts in the ex-post analysis, which causes a slight reduction in the percentage load impacts from 2.2 to 2 percent.

Table 3.23: Comparison of Ex-Post and Ex-Ante Factors, *PG&E Large*

Factor	Ex-Post	Ex-Ante	Expected Impact
Weather	Average event-hour temperature of 98.4 °F during the typical event day.	Average event-hour temperature of 96.6 °F during the PG&E 1-in-2 Typical Event Day.	Slightly higher ex-post temperatures may have increased the per-customer load impact (ceteris paribus).
Event window	HE18 – HE 20.	RA window (HE17-HE21).	None.
% of resource dispatched	100 percent	100 percent	None.
Enrollment	1,235 service accounts.	1,587 service accounts.	Higher ex-ante enrollments lead to higher aggregate load impacts. The ex-ante distribution of enrollments across LCAs leads to a slight decrease in percentage load impacts.
Methodology	Large individual customer models and panel models by LCA with fixed customer effects.	Simulated reference loads by LCA for all customers and applied percentage load impacts derived from the ex-post Typical Event Day.	The method is not expected to produce differences between the ex-post and ex-ante impacts.

3.3.2 Medium Customers

Previous vs. Current Ex-Post

Table 3.24 shows the average event-hour reference loads and load impacts for the typical event day during the current and previous program years. Enrollments also increased for medium customers in PY2021 by 2,488 customers. There was a sharp decline in per-customer load impacts from 0.33 to 0.02 kWh/customer/hour, leading aggregate load impacts to decrease from 4.6 to 0.3 MWh/hour despite the higher enrollments. The change in event hours and low customer awareness of this change may be factors in the lower 2021 load impacts. If we compare the results during the only overlapping event hour between 2020 and 2021, HE18, per-customer load impacts only decline by 28 percent and percent load impacts are only 0.2 percent lower. Moreover, these results are consistent with the PY2019 per-customer load impacts of -0.01 kWh/customer/hour, which suggests that the findings in 2020 may have been an outlier.

Table 3.24: Previous vs. Current Ex-Post Load Impacts for the Typical Event Day, *PG&E Medium*

Level	Outcome	Ex-post Previous Study	Ex-post Current Study
Total	# SAIDs	13,914	16,402
	Reference (MW)	383	366
	Load Impact (MW)	4.6	0.3
	Avg. Temp.	95.9	97.9
Per SAID	Reference (kW)	27.5	22.3
	Load Impact (kW)	0.33	0.02
	% Load Impact	1.2%	0.1%

Previous vs. Current Ex-Ante

In this sub-section, we compare the PY2020 and PY2021 ex-ante forecasts. Table 3.25 reports the RA window average load impacts for the typical event day under utility-specific 1-in-2 weather conditions in 2023. The aggregate load impact forecast decreases dramatically between PY2020 and PY2021 from 4.1 to 0.6 MWh/hour, despite an enrollment increase of almost 500 customers. This decline is consistent with the comparison of ex-post load impacts presented in the previous section. The current forecast is in line with the PY2019 forecast in per-customer terms. The percent load impacts decrease by 80 percent from PY2020 to PY2021.

Table 3.25: Previous vs. Current Ex-Ante Load Impacts, *Utility 1-in-2 Typical Event Day*, *PG&E Medium*

Level	Outcome	Ex-ante for 2023 Typical Event Day, Previous Study	Ex-ante for 2023 Typical Event Day, Current Study
Total	# SAIDs	15,159	15,649
	Reference (MW)	410	347
	Load Impact (MW)	4.1	0.6
	Avg. Temp.	95.6	97.0
Per SAID	Reference (kW)	27.0	22.2
	Load Impact (kW)	0.27	0.04
	% Load Impact	1.0%	0.2%

Previous Ex-Ante vs. Current Ex-Post

Table 3.26 provides a comparison of the average event-hour load impacts from the PY2020 ex-ante forecast of 2021 and the ex-post load impacts estimated as part of this study. The ex-ante forecast shown in the table represents the typical event day during a utility-specific 1-in-2 weather year. The ex-post load impacts are based on the typical event day. The ex-post load impacts are 92 percent lower than forecast in PY2020. Enrollments that are lower than forecasted explain some of the difference, but a decline

in per-customer load impacts is a major factor. Percent load impacts decline from 0.8 to 0.1 percent of reference loads.

Table 3.26: Previous Ex-Ante vs. Current Ex-Post Load Impacts, *PG&E Medium*

Level	Outcome	Ex-ante for 2021 Typical Event Day, Previous Study	Ex-post Typical Event Day, Current Study
Total	# SAIDs	19,352	16,402
	Reference (MW)	476	366
	Load Impact (MW)	3.8	0.3
	Avg. Temp.	96.5	97.9
Per SAID	Reference (kW)	24.6	22.3
	Load Impact (kW)	0.20	0.02
	% Load Impact	0.8%	0.1%

Current Ex-Post vs. Current Ex-Ante

Table 3.27 compares the ex-post and ex-ante load impacts from the current study. The average RA window ex-ante load impacts in the table represent the 2023 typical event day under utility-specific 1-in-2 weather conditions. The ex-post load impacts are for the average event hour on the typical event day. Aggregate load impacts are forecasted to increase from 0.3 MWh/hour in 2021 to 0.6 MWh/hour in 2023, despite a decrease in the forecasted enrollments. This is due to an increase in percentage load impacts from 0.1 to 0.2 percent of reference loads that reflects the re-mapping of ex-post impacts from the HE18-20 to the HE17-21 event window.

Table 3.27: Current Ex-Post vs. Current Ex-Ante Load Impacts, *PG&E Medium*

Level	Outcome	Ex-Post Typical Event Day, Current Study	Ex-ante for 2023 Typical Event Day, Current Study
Total	# SAIDs	16,402	15,649
	Reference (MW)	366	347
	Load Impact (MW)	0.3	0.6
	Avg. Temp.	97.9	97.0
Per SAID	Reference (kW)	22.3	22.2
	Load Impact (kW)	0.02	0.04
	% Load Impact	0.1%	0.2%

Table 3.28 documents the various potential sources of differences between the ex-post and ex-ante load impacts. The decreased enrollment is offset by a slightly higher percentage load impact.

Table 3.28: Comparison of Ex-Post and Ex-Ante Factors, *PG&E Medium*

Factor	Ex-Post	Ex-Ante	Expected Impact
Weather	Average event-hour temperature of 97.9 °F during the typical event day.	Average event-hour temperature of 97.0 °F during the PG&E 1-in-2 Typical Event Day.	Would not have increased per-customer load impacts.
Event window	HE18 – HE 20.	RA window (HE17-HE21).	Increases %impact because of how old window's impacts are mapped into the new window.
% of resource dispatched	100 percent	100 percent	None.
Enrollment	16,402 service accounts.	15,649 service accounts.	Lower ex-ante enrollments lead to lower aggregate load impacts.
Methodology	Panel models by LCA with fixed customer effects.	Simulated reference loads by LCA for all customers and applied percentage load impacts derived from the ex-post Typical Event Day.	The method is not expected to produce differences between the ex-post and ex-ante impacts.

3.3.3 Small Customers

Previous vs. Current Ex-Post

Table 3.29 shows the average event-hour reference loads and load impacts for the typical event day during the current and previous program years. Enrollments also increased for small customers in PY2021 by 2,956 customers and, similar to medium customers, there was a sharp decline in per-customer load impacts from 0.043 to 0.008 kWh/customer/hour. As a result, aggregate load impacts decrease from 3.8 to 0.8 MWh/hour despite the higher enrollments. The change in event hours and low customer awareness of this change may be factors in the decreased load impacts of small customers in PY2021. The PY2021 load impacts are consistent with the PY2019 per-customer estimate of 0.01 kWh/customer/hour. If we compare the results during the only overlapping event hour between 2020 and 2021, HE18, per-customer load impacts decline by 61 percent instead of the 81 percent decline across all event hours. Aggregate reference loads are lower in PY2021 despite the increase in enrollments and higher event temperatures. Percentage load impacts decrease from 1.8 to 0.4 percent of reference loads.

Table 3.29: Previous vs. Current Ex-Post Load Impacts for the Typical Event Day, *PG&E Small*

Level	Outcome	Ex-post Previous Study	Ex-post Current Study
Total	# SAIDs	86,850	89,806
	Reference (MW)	204	173
	Load Impact (MW)	3.8	0.8
	Avg. Temp.	92.5	97.0
Per SAID	Reference (kW)	2.35	1.93
	Load Impact (kW)	0.043	0.008
	% Load Impact	1.8%	0.4%

Previous vs. Current Ex-Ante

In this sub-section, we compare the PY2020 and PY2021 ex-ante forecasts. Table 3.30 reports the RA window average load impacts for the typical event day under utility-specific 1-in-2 weather conditions in 2023. The aggregate load impact forecast decreases dramatically between PY2020 and PY2021 from 2.9 to 0.8 MWh/hour, despite an enrollment increase of almost 4,000 customers. This decline is consistent with the comparison of ex-post load impacts presented in the previous section. The current forecast is an improvement from the -0.5 MWh/hour from the PY2019 forecast. The percent load impacts decrease by 67 percent from PY2020 to PY2021.

Table 3.30: Previous vs. Current Ex-Ante Load Impacts, *Utility 1-in-2 Typical Event Day*, *PG&E Small*

Level	Outcome	Ex-ante for 2023 Typical Event Day, Previous Study	Ex-ante for 2023 Typical Event Day, Current Study
Total	# SAIDs	82,313	86,125
	Reference (MW)	188	166
	Load Impact (MW)	2.9	0.8
	Avg. Temp.	93.7	96.3
Per SAID	Reference (kW)	2.29	1.93
	Load Impact (kW)	0.04	0.01
	% Load Impact	1.5%	0.5%

Previous Ex-Ante vs. Current Ex-Post

Table 3.31 provides a comparison of the average event-hour load impacts from the PY2020 ex-ante forecast of 2021 and the ex-post load impacts estimated as part of this study. The ex-ante forecast shown in the table represents the typical event day during a utility-specific 1-in-2 weather year. The ex-post load impacts are based on the typical event day. The ex-post load impacts are 64 percent lower than forecast in PY2020, primarily due to enrollments being much lower than forecasted. Another factor is a

decline in per-customer load impacts from 0.2 to 0.1 kWh/customer/hour. Percent load impacts decline from 1 to 0.4 percent of reference loads.

Table 3.31: Previous Ex-Ante vs. Current Ex-Post Load Impacts, *PG&E Small*

Level	Outcome	Ex-ante for 2021 Typical Event Day, Previous Study	Ex-post Typical Event Day, Current Study
Total	# SAIDs	105,124	89,806
	Reference (MW)	209	173
	Load Impact (MW)	2.2	0.8
	Avg. Temp.	94.6	97.0
Per SAID	Reference (kW)	1.99	1.93
	Load Impact (kW)	0.021	0.008
	% Load Impact	1.0%	0.4%

Current Ex-Post vs. Current Ex-Ante

Table 3.32 compares the ex-post and ex-ante load impacts from the current study. The average RA window ex-ante load impacts in the table represent the 2023 typical event day under utility-specific 1-in-2 weather conditions. The ex-post load impacts are for the average event hour on the typical event day. Aggregate load impacts are forecasted to be the same in 2023 as in 2021, despite a decrease in enrollments. This is due to an increase in percentage load impacts from 0.4 to 0.5 percent of reference loads that reflects the re-mapping of ex-post impacts from the HE18-20 to the HE17-21 event window.

Table 3.32: Current Ex-Post vs. Current Ex-Ante Load Impacts, *PG&E Small*

Level	Outcome	Ex-Post Typical Event Day, Current Study	Ex-ante for 2023 Typical Event Day, Current Study
Total	# SAIDs	89,806	86,125
	Reference (MW)	173	166
	Load Impact (MW)	0.8	0.8
	Avg. Temp.	97.0	96.3
Per SAID	Reference (kW)	1.93	1.93
	Load Impact (kW)	0.008	0.010
	% Load Impact	0.4%	0.5%

Table 3.33 documents the various potential sources of differences between the ex-post and ex-ante load impacts. The decreased enrollment is offset by a slightly higher percentage load impact.

Table 3.33: Comparison of Ex-Post and Ex-Ante Factors, *PG&E Small*

Factor	Ex-Post	Ex-Ante	Expected Impact
Weather	Average event-hour temperature of 97.0 °F during the typical event day.	Average event-hour temperature of 96.3 °F during the PG&E 1-in-2 Typical Event Day.	Would not have increased per-customer load impacts.
Event window	HE18 – HE 20.	RA window (HE17-HE21).	Increases %impact because of how old window's impacts are mapped into the new window.
% of resource dispatched	100 percent	100 percent	None.
Enrollment	89,806 service accounts.	86,125 service accounts.	Lower ex-ante enrollments lead to lower aggregate load impacts.
Methodology	Panel models by LCA with fixed customer effects.	Simulated reference loads by LCA for all customers and applied percentage load impacts derived from the ex-post Typical Event Day.	The method is not expected to produce differences between the ex-post and ex-ante impacts.

4. SCE

4.1 SCE Ex-Post Load Impacts

This section documents the findings from the ex-post load impact analysis for SCE. The primary load impact results include estimates of average event-hour load impacts, in aggregate and per-customer, for the typical event day as well as for each individual event. Results for all hours for the typical event day are also illustrated in figures and presented in data tables. Detailed results for each hour for each event are available in electronic form in Protocol table generators provided along with this report.

As described in Section 2.1.3, all results presented in this section are derived from either customer specific or panel fixed-effects regression analyses of hourly data for CPP customers. The estimated model is described in Section 2.1.4, with the SCE model including the variables that account for morning load and temperature variations. Furthermore, we control for concurrent events that are called for other programs (e.g., BIP, CBP) by including indicators for customers who are dually enrolled and who are called for a given event that occurs during an event or non-event day. The evaluation of model specification selection is presented in the appendix.

4.1.1 All Customers

This section summarizes results for all SCE customers. The average ex-post load impacts are summarized for all 12 events in Figure 4.1. The blue bars indicate the magnitude of the aggregate load impact (in MWh/hour). The green bands correspond to 90 percent confidence intervals around these estimates (using the same methods to create the uncertainty-adjusted load impacts scenarios in the protocol tables). The orange diamond icons represent the average temperatures experienced by the customers during the event hours.

SCE customers have statistically significant load reductions on 10 out of 12 event days. The highest load reduction is 43 MWh/hour on August 11th. The load impact averaged 16 MWh/hour across all event days. Figure 4.1 does not provide evidence of a relationship between load impact and event temperature. The event on June 16th has the second highest load impact and the lowest temperature. June 15th is the only event day with temperature over 90°F, but the load reduction only ranks the fourth highest.

Figure 4.1: Average Event-Hour Load Impacts by Event, *SCE All*

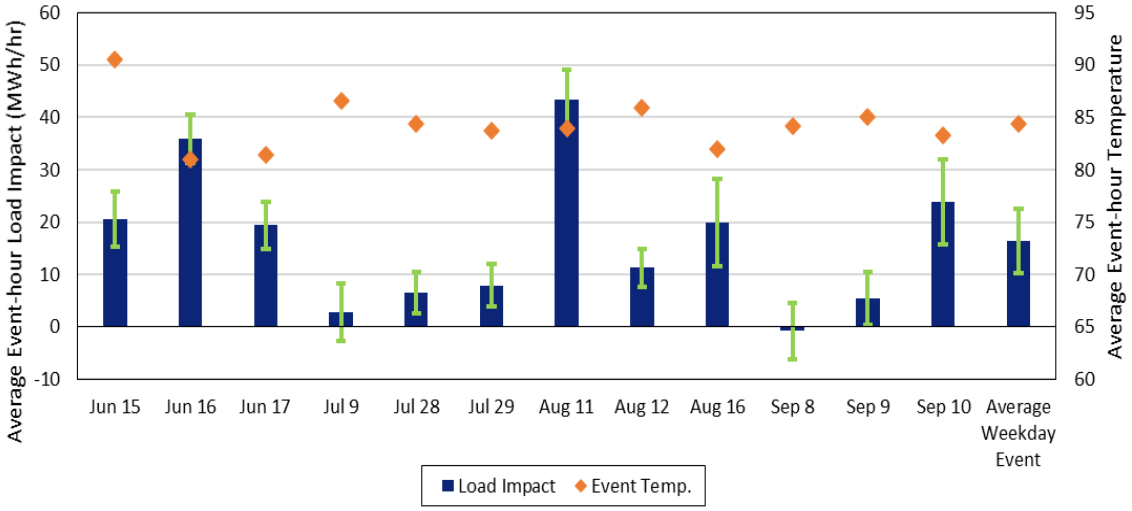


Table 4.1 summarizes enrollments, average event-hour load impacts, and reference loads for each event day and the average event for all SCE customers. Estimated load impacts averaged 0.06 kWh/hour per customer across event days, which amounts to a 1.1 percent load reduction. Detailed results by hour, industry group and LCA are presented in subsequent subsections by customer size.

Table 4.1: Average Event-Hour Load Impacts by Event, *SCE All*

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
6/15/2021	258,995	1,512	20.6	5.8	0.08	1.4%	90.6
6/16/2021	258,995	1,457	35.8	5.6	0.14	2.5%	81.0
6/17/2021	258,995	1,445	19.4	5.6	0.07	1.3%	81.5
7/9/2021	258,995	1,468	2.8	5.7	0.01	0.2%	86.6
7/28/2021	258,996	1,474	6.4	5.7	0.02	0.4%	84.4
7/29/2021	258,996	1,471	7.9	5.7	0.03	0.5%	83.8
8/11/2021	259,001	1,483	43.4	5.7	0.17	2.9%	84.0
8/12/2021	259,001	1,506	11.2	5.8	0.04	0.7%	86.0
8/16/2021	259,001	1,487	19.9	5.7	0.08	1.3%	82.0
9/8/2021	259,003	1,489	-0.8	5.8	0.00	-0.1%	84.1
9/9/2021	259,003	1,526	5.4	5.9	0.02	0.4%	85.0
9/10/2021	259,003	1,481	23.9	5.7	0.09	1.6%	83.3
Typical Event Day	**259,000**	**1,483**	**16.3**	**5.7**	**0.06**	**1.1%**	**84.3**

4.1.2 Large Customers

This section summarizes results for all large SCE customers, defined as customers with maximum demand over 200 kW.[10] The presented results include: the average event-hour load impact by event day; the hourly load impact for the average event day; and load impacts by industry group and LCA for the average event hour. Summaries of load impacts for dually enrolled, AutoDR, and notified versus non-notified customers are presented in successive sub-sections.

The ex-post load impacts for SCE's large CPP customers are summarized for all 12 events in Figure 4.2. The blue bars indicate the magnitude of the aggregate load impact (in MWh/hour). The green bands correspond to 90 percent confidence intervals around these estimates (using the same methods to create the uncertainty-adjusted load impacts scenarios in the protocol tables). The orange diamond icons represent the average temperatures experienced by the customers during the event hours.

These results indicate that large customers had statistically significant load reductions on each of the 12 event days, ranging from 6 to 21 MWh/hour. The load impact averaged 11 MWh/hour across all event days. Figure 4.2 doesn't provide evidence of a relationship between load impacts and average temperatures. The three events with

[10] Large CPP customers were identified using rate codes provided by SCE. The majority (96 percent) of Large CPP customers are on rates TOU-8-D, TOU-GS-3D, TOU-PA-3-D.

the largest load impacts (June 15th, June 16th, and June 17th) experienced both the highest and lowest event temperatures (91 °F on June 15th and around 81 °F on June 16th and 17th).

Figure 4.2: Average Event-Hour Load Impacts by Event, *SCE Large*

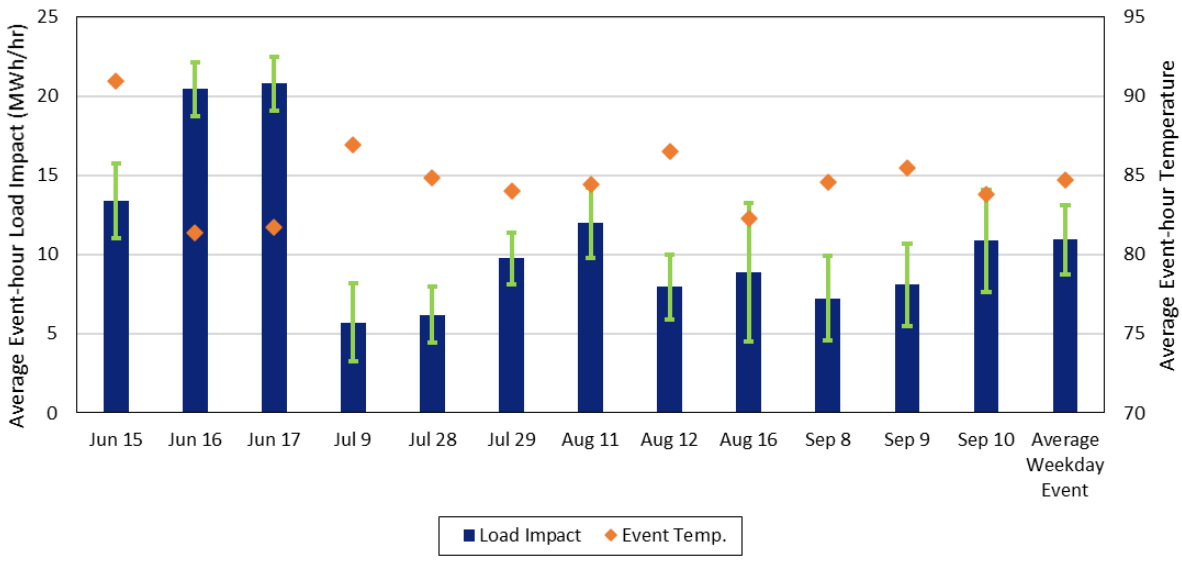


Table 4.2 summarizes enrollments, average event-hour load impacts, and reference loads for each event day and the average event. Estimated load reductions averaged 5.7 kWh/hour per customer across event days, which amounts to a 2.6 percent load reduction.

Table 4.2: Average Event-Hour Load Impacts by Event, *SCE Large*

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
6/15/2021	1,914	424	13.4	221.6	7.0	3.2%	90.9
6/16/2021	1,914	419	20.5	219.1	10.7	4.9%	81.4
6/17/2021	1,914	421	20.8	219.9	10.9	4.9%	81.7
7/9/2021	1,914	410	5.7	214.2	3.0	1.4%	86.9
7/28/2021	1,914	423	6.2	220.8	3.2	1.5%	84.8
7/29/2021	1,914	421	9.7	220.1	5.1	2.3%	84.0
8/11/2021	1,915	426	12.0	222.2	6.3	2.8%	84.4
8/12/2021	1,915	426	7.9	222.5	4.1	1.9%	86.5
8/16/2021	1,915	427	8.9	223.2	4.6	2.1%	82.2
9/8/2021	1,915	435	7.2	227.4	3.8	1.7%	84.6
9/9/2021	1,915	441	8.1	230.4	4.2	1.8%	85.5
9/10/2021	1,915	424	10.9	221.2	5.7	2.6%	83.8
Typical Event Day	**1,915**	**425**	**10.9**	**221.8**	**5.7**	**2.6%**	**84.7**

Figure 4.3 shows the aggregate hourly reference loads, observed loads, and estimated load impacts on the typical event day. Table 4.3 contains the hourly typical event day results in the manner required by the Protocols, including hourly temperatures and uncertainty adjusted load impacts. Notice that the highest load impact tends to occur in the second hour of the event (5 to 6 p.m.). The hourly load impact estimates do not show evidence of significant pre-cooling or post-event snapback, which would appear as load increases in the hours surrounding the event. Rather, there are smaller load impacts in the hours immediately preceding (4.4 MWh from 3 to 4 p.m.) and following (3.9 MWh from 9 to 10 p.m.) the event. Overall, these results do not suggest that large customers are responding to events by shifting event-hour loads to hours outside the event window.

Figure 4.3: Typical Event Day Reference Loads and Load Profile, SCE *Large*

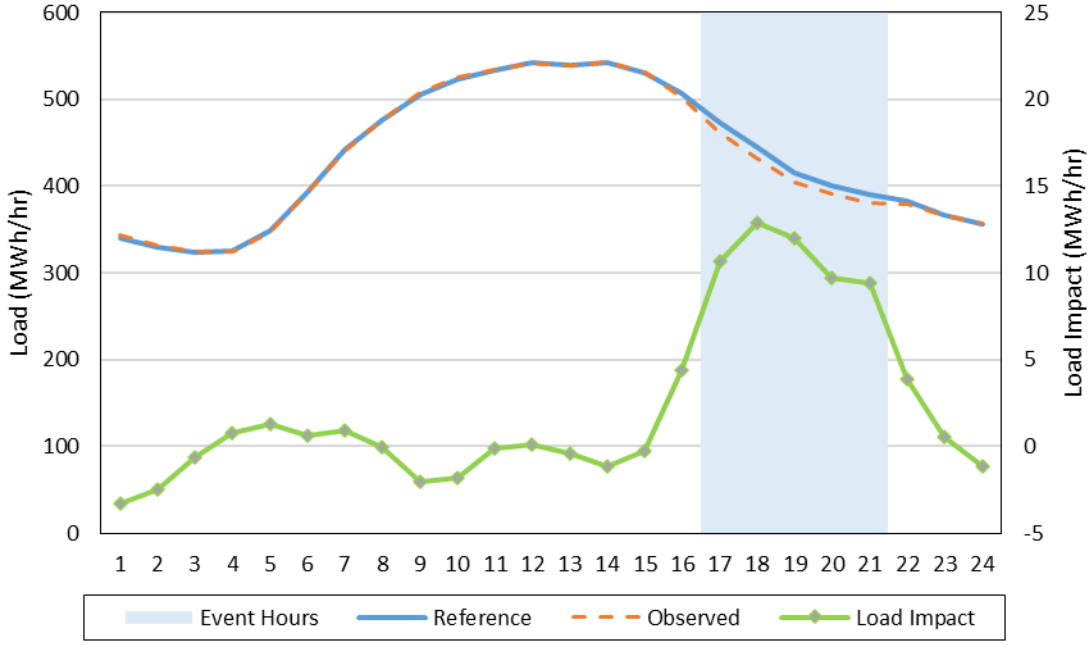


Table 4.3: Typical Event Day Load Impacts and Uncertainty Adjusted Estimates by hour, *SCE Large*

Hour Ending	Estimated Reference Load (MW)	Observed Event Day Load (MW)	Estimated Load Impact (MW)	Load Impact (%)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact - Percentiles				
						10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	339.6	342.9	-3.3	-1.0%	73.2	-5.6	-4.2	-3.3	-2.3	-1.0
2	329.9	332.4	-2.5	-0.7%	72.4	-4.0	-3.1	-2.5	-1.8	-0.9
3	323.4	324.1	-0.6	-0.2%	71.6	-1.7	-1.1	-0.6	-0.2	0.5
4	324.8	324.0	0.8	0.2%	71.0	-0.2	0.4	0.8	1.1	1.7
5	348.4	347.1	1.3	0.4%	70.5	0.0	0.8	1.3	1.8	2.5
6	393.5	392.9	0.6	0.2%	70.1	-1.1	-0.1	0.6	1.4	2.4
7	441.3	440.3	0.9	0.2%	70.2	-1.4	0.0	0.9	1.9	3.3
8	475.8	475.9	0.0	0.0%	72.4	-2.3	-0.9	0.0	0.9	2.2
9	505.2	507.2	-2.0	-0.4%	76.0	-3.9	-2.8	-2.0	-1.3	-0.2
10	523.6	525.4	-1.8	-0.3%	79.6	-3.7	-2.6	-1.8	-1.0	0.1
11	534.1	534.2	-0.1	0.0%	83.3	-1.5	-0.7	-0.1	0.5	1.3
12	541.5	541.4	0.1	0.0%	86.1	-1.3	-0.5	0.1	0.7	1.5
13	538.7	539.1	-0.4	-0.1%	88.0	-2.2	-1.1	-0.4	0.3	1.4
14	541.9	543.1	-1.2	-0.2%	89.4	-3.2	-2.0	-1.2	-0.3	0.9
15	530.6	530.9	-0.3	-0.1%	90.0	-2.6	-1.2	-0.3	0.7	2.0
16	506.4	502.0	4.4	0.9%	90.1	1.6	3.2	4.4	5.5	7.1
17	472.3	461.6	10.7	2.3%	89.3	8.1	9.6	10.7	11.8	13.3
18	445.4	432.5	12.9	2.9%	87.6	10.3	11.8	12.9	13.9	15.5
19	415.9	403.9	12.0	2.9%	85.5	9.4	10.9	12.0	13.1	14.6
20	400.1	390.4	9.7	2.4%	82.2	7.2	8.7	9.7	10.8	12.3
21	390.2	380.8	9.4	2.4%	79.1	7.0	8.4	9.4	10.4	11.8
22	382.9	379.1	3.9	1.0%	77.0	1.5	2.9	3.9	4.9	6.3
23	366.0	365.5	0.5	0.1%	75.5	-1.7	-0.4	0.5	1.5	2.8
24	356.0	357.1	-1.1	-0.3%	74.3	-3.8	-2.2	-1.1	0.0	1.5
Daily	**10,428**	**10,374**	**54**	**0.5%**	**79.3**	**39.3**	**47.9**	**53.9**	**59.9**	**68.5**

Next, we look at SCE large customer estimate by industry group. Table 4.4 summarizes aggregate event-hour results for the typical event day for eight industry groups, including the number of enrolled customers, the reference and observed loads, and the estimated load impacts (in MWh/hour and as a percentage of reference loads). Enrollments have 69 percent concentration in three industry groups: Manufacturing; Offices, Hotels, Health, & Services; and Wholesale, Transportation, & Utilities. The estimated reference loads are 112, 97, and 97 MWh/hour for these groups, respectively. The load impact is more concentrated with 79 percent (8.6 MW) of the total load impact coming from the Manufacturing and Wholesale, Transportation, & Utilities industry groups.

Table 4.4: Typical Event Day Event-Hour Load Impacts by Industry Group, *SCE Large*

Industry Group	# of Service Accounts	Estimated Reference Load (MWh/hour)	Observed Load (MWh/hour)	Estimated Load Impact (MWh/hour)	% LI
1.Agriculture, Mining, Construction	143	26	25	0.63	2.5%
2.Manufacturing	522	112	105	6.42	5.7%
3.Wholesale, Transportation, Utilities	377	97	95	2.16	2.2%
4.Retail Stores	125	33	32	0.23	0.7%
5.Offices, Hotels, Health, Services	415	97	96	0.68	0.7%
6.Schools	140	23	22	0.77	3.4%
7. Institutional/Government	128	27	26	0.81	3.0%
8.Other	65	12	12	0.08	0.7%

To better understand the distribution of results across industries, we look at the shares of estimated load impacts, reference loads, and enrollments by industry group in Figure 4.4. Since Manufacturing represents such a large share of the load impact, all the other industry groups (with the exception of Institutional/Government) have lower shares of the load impact than the shares of enrolled customers.

Figure 4.4: Typical Event Day Event-Hour Load Impacts by Industry Group, *SCE Large*

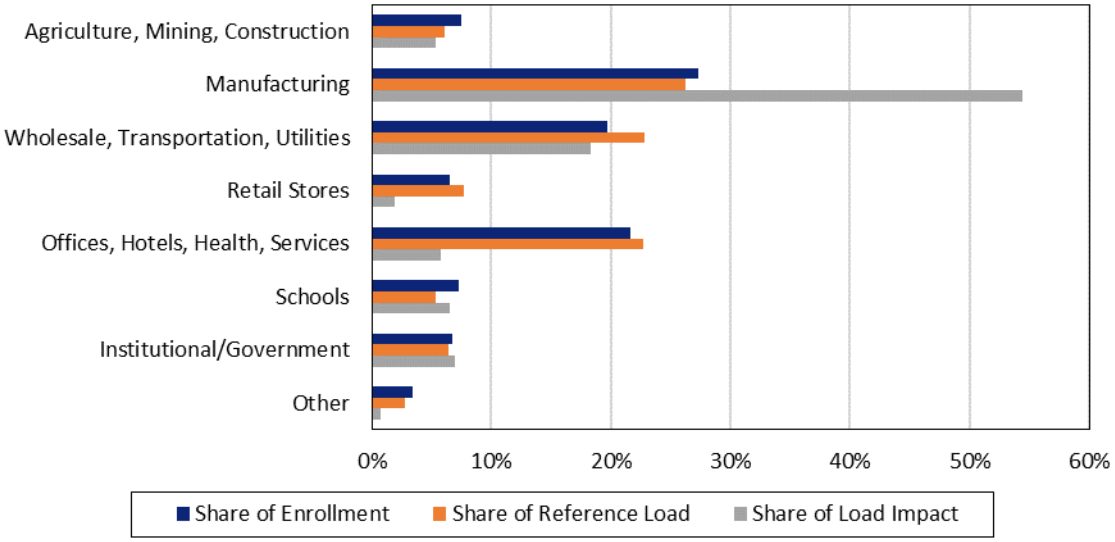
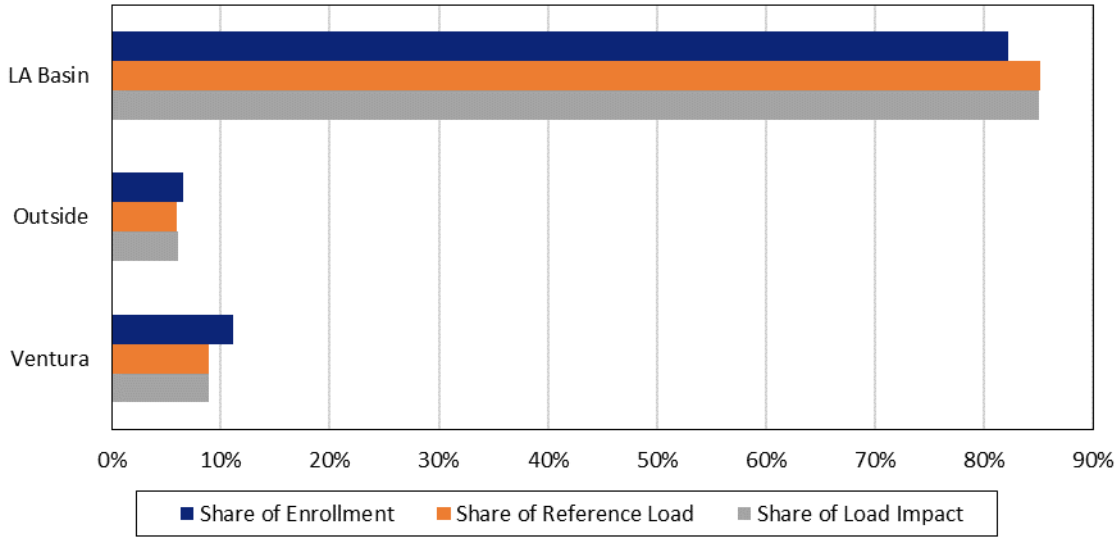


Table 4.5 and Figure 4.5 provide the same summaries as above by LCA. SCE's large CPP customers are concentrated in the LA Basin, which has a combined reference load of 362 MWh/hour. This LCA also accounts for the largest load impact of 9.8 MWh/hour. We can see in Figure 4.5 that the LA Basin's share of customers, reference loads, and load impacts all exceed 80 percent.

Table 4.5: Typical Event Day Event-Hour Load Impacts by LCA, *SCE Large*

LCA	# of Service Accounts	Estimated Reference Load (MW)	Observed Load (MW)	Estimated Load Impact (MW)	% LI
LA Basin	1,575	362	352	9.78	2.7%
Outside Basin	126	25	25	0.22	0.9%
Ventura	214	38	37	0.94	2.5%

Figure 4.5: Typical Event Day Event-Hour Load Impacts by LCA, *SCE Large*



4.1.3 Medium Customers

This section summarizes results for all Medium SCE customers, defined as customers with maximum demand between 20 and 199.99 kW.[11] The presented results include: the average event-hour load impact by event day; the hourly load impact for the average event day; and load impacts by industry group and LCA for the average event hour. Summaries of load impacts for dually enrolled, AutoDR, and notified versus non-notified customers presented in successive sub-sections.

The ex-post load impacts for SCE's Medium CPP customers are summarized for all 12 events in Figure 4.6. In contrast to large customers, the load impacts are not statistically significant on each event day. Five of the events days (June 15th, 16th, 17th, July 28th, and August 11th) have estimated load reductions that are statistically significant. The average event day load impact of 4.6 MWh/hour is also statistically significant. The Medium customers do not show a relationship between load impacts and temperature.

[11] Medium CPP customers were identified using rate codes provided by SCE. The majority (99.7 percent) of Medium CPP customers are on rate TOU-GS-2-D.

Figure 4.6: Average Event-Hour Load Impacts by Event, SC*E Medium*

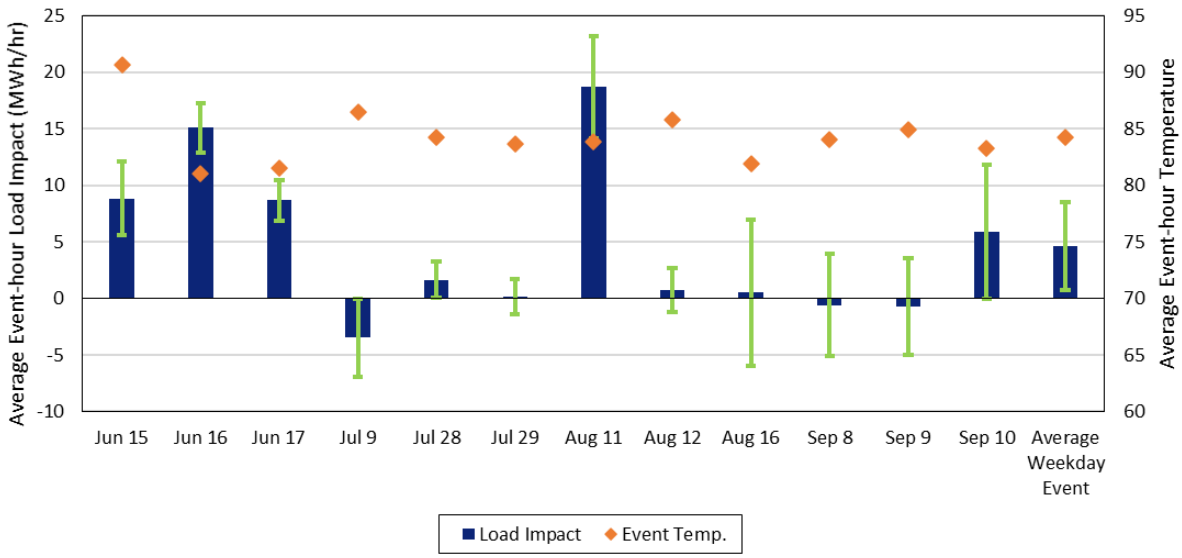


Table 4.6 summarizes enrollments, average event-hour load impacts, and reference loads for each event day and the average event. Overall, Medium customers had an aggregate load impact of 4.6 MWh/hour, which is 0.2 kWh/hour per customer on average, or about a 0.6 percent load reduction.

Table 4.6: Average Event-Hour Load Impacts by Event, *SCE Medium*

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
6/15/2021	27,503	738	8.8	26.8	0.3	1.2%	90.7
6/16/2021	27,503	704	15.1	25.6	0.5	2.1%	81.0
6/17/2021	27,503	697	8.7	25.4	0.3	1.2%	81.5
7/9/2021	27,503	720	-3.5	26.2	-0.1	-0.5%	86.4
7/28/2021	27,503	720	1.6	26.2	0.1	0.2%	84.3
7/29/2021	27,503	717	0.1	26.1	0.0	0.0%	83.6
8/11/2021	27,503	719	18.7	26.2	0.7	2.6%	83.9
8/12/2021	27,503	734	0.7	26.7	0.0	0.1%	85.8
8/16/2021	27,503	718	0.5	26.1	0.0	0.1%	81.9
9/8/2021	27,503	725	-0.6	26.4	0.0	-0.1%	84.0
9/9/2021	27,503	740	-0.7	26.9	0.0	-0.1%	84.9
9/10/2021	27,503	720	5.9	26.2	0.2	0.8%	83.2
Typical Event Day	**27,503**	**721**	**4.6**	**26.2**	**0.2**	**0.6%**	**84.3**

Figure 4.7 shows the aggregate hourly reference loads, observed loads, and estimated load impacts on the typical event day for medium customers. Table 4.7 contains the hourly typical event day results in the manner required by the Protocols, including hourly temperatures and uncertainty adjusted load impacts. Similar to large customers, the highest load impacts of 5.84 MWh/hour occurred in the second hour of the event (5 to 6 p.m.). There is no evidence of pre-cooling or post-event snapback, and in fact, there are load impacts of 3.7 MWh/hour in the hour directly preceding and 2.3 MWh/hour in the hour directly following the event. Overall, these results do not suggest that Medium CPP customers respond to events by shifting event-hour loads to hours outside the event window.

Figure 4.7: Typical Event Day Reference Loads and Load Profile, SCE *Medium*

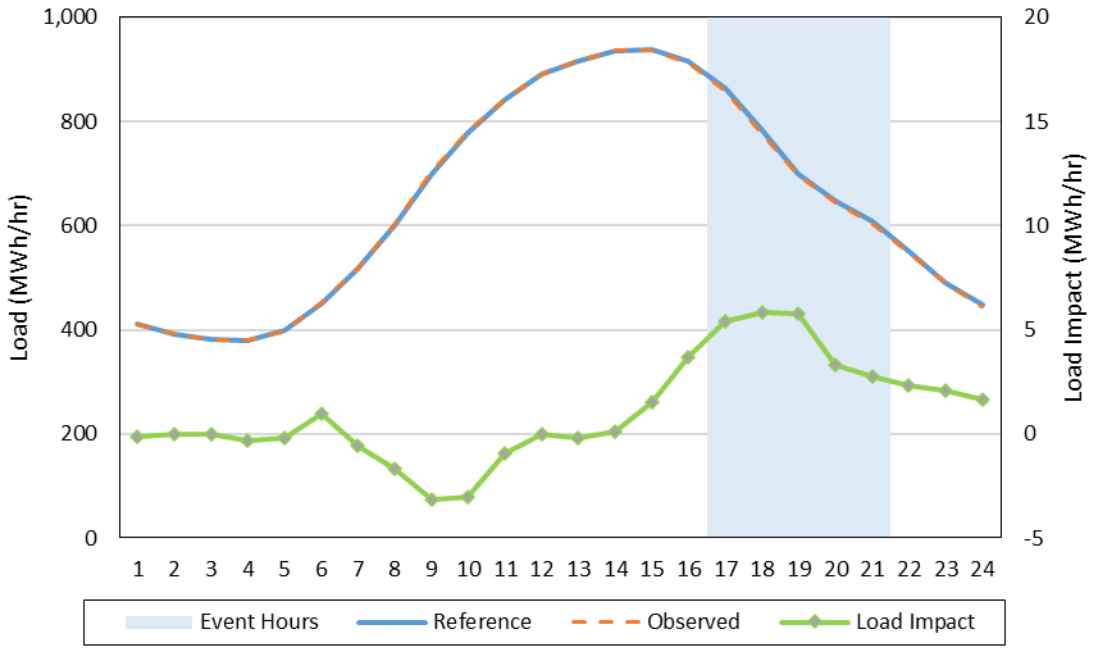


Table 4.7: Typical Event Day Load Impacts and Uncertainty Adjusted Estimates by hour, *SCE Medium*

Hour Ending	Estimated Reference Load (MW)	Observed Event Day Load (MW)	Estimated Load Impact (MW)	Load Impact (%)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact - Percentiles				
						10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	410.5	410.6	-0.1	0.0%	72.8	-1.8	-0.8	-0.1	0.6	1.6
2	391.9	391.9	0.0	0.0%	72.0	-1.0	-0.4	0.0	0.4	1.1
3	381.3	381.3	0.0	0.0%	71.3	-0.6	-0.3	0.0	0.2	0.6
4	379.4	379.7	-0.3	-0.1%	70.7	-0.7	-0.5	-0.3	-0.2	0.0
5	398.2	398.4	-0.2	-0.1%	70.3	-0.6	-0.4	-0.2	0.0	0.2
6	451.5	450.6	0.9	0.2%	69.9	0.1	0.6	0.9	1.3	1.8
7	517.9	518.5	-0.5	-0.1%	70.1	-1.9	-1.1	-0.5	0.0	0.8
8	601.8	603.5	-1.7	-0.3%	72.4	-3.4	-2.4	-1.7	-0.9	0.1
9	699.8	703.0	-3.2	-0.5%	75.9	-5.5	-4.1	-3.2	-2.2	-0.8
10	778.0	781.1	-3.1	-0.4%	79.4	-5.2	-3.9	-3.1	-2.2	-0.9
11	843.2	844.1	-0.9	-0.1%	83.1	-2.4	-1.5	-0.9	-0.3	0.5
12	890.4	890.4	0.0	0.0%	85.9	-1.0	-0.4	0.0	0.4	1.0
13	916.3	916.5	-0.2	0.0%	87.7	-1.6	-0.8	-0.2	0.4	1.3
14	936.4	936.3	0.1	0.0%	89.0	-2.0	-0.8	0.1	1.0	2.3
15	937.9	936.4	1.5	0.2%	89.6	-0.8	0.6	1.5	2.5	3.8
16	915.2	911.5	3.7	0.4%	89.7	0.8	2.5	3.7	4.9	6.6
17	864.7	859.3	5.4	0.6%	88.9	1.6	3.8	5.4	6.9	9.2
18	783.9	778.0	5.8	0.7%	87.2	2.3	4.4	5.8	7.3	9.3
19	700.5	694.7	5.8	0.8%	85.0	2.2	4.3	5.8	7.2	9.3
20	648.1	644.7	3.3	0.5%	81.6	0.8	2.3	3.3	4.4	5.8
21	608.1	605.4	2.8	0.5%	78.5	0.3	1.8	2.8	3.8	5.2
22	550.4	548.1	2.3	0.4%	76.4	-0.3	1.3	2.3	3.4	4.9
23	491.0	489.0	2.1	0.4%	75.0	-0.3	1.1	2.1	3.0	4.4
24	447.2	445.5	1.7	0.4%	73.8	-0.8	0.7	1.7	2.7	4.1
Daily	**15,544**	**15,519**	**25**	**0.2%**	**79.0**	**-2.6**	**13.8**	**25.2**	**36.6**	**53.1**

Next, we look at SCE Medium customer estimates by industry group. Table 4.8 summarizes the aggregate average event-hour results for the typical event day for eight industry groups, including the number of enrolled customers, the reference and observed loads, and the estimated load impacts (in MWh/hour and as a percentage of reference loads). Offices, Hotels, Health, & Services has the largest number of enrollments, reference load and load impacts (2.6 MW). The schools industry group has the largest percentage load impact of 1.2 percent.

Table 4.8: Typical Event Day Event-Hour Load Impacts by Industry Group, *SCE Medium*

Industry Group	# of Service Accounts	Estimated Reference Load (MWh/hour)	Observed Load (MWh/hour)	Estimated Load Impact (MWh/hour)	% LI
1.Agriculture, Mining, Construction	807	15	15	0.09	0.6%
2.Manufacturing	2,816	66	65	0.29	0.4%
3.Wholesale, Transportation, Utilities	2,715	63	62	0.59	0.9%
4.Retail Stores	3,676	114	114	0.69	0.6%
5.Offices, Hotels, Health, Services	13,079	360	358	2.58	0.7%
6.Schools	729	19	18	0.22	1.2%
7. Institutional/Government	2,614	58	58	0.13	0.2%
8.Other	1,067	27	27	0.21	0.8%

Figure 4.8 shows the shares of enrollments, reference loads, and load impacts by industry group. The load impacts are concentrated in Offices, Hotels, Health, & Services, which realizes 54 percent of the total load impact.

Figure 4.8: Typical event Day Event-Hour Load Impacts by Industry Group, *SCE Medium*

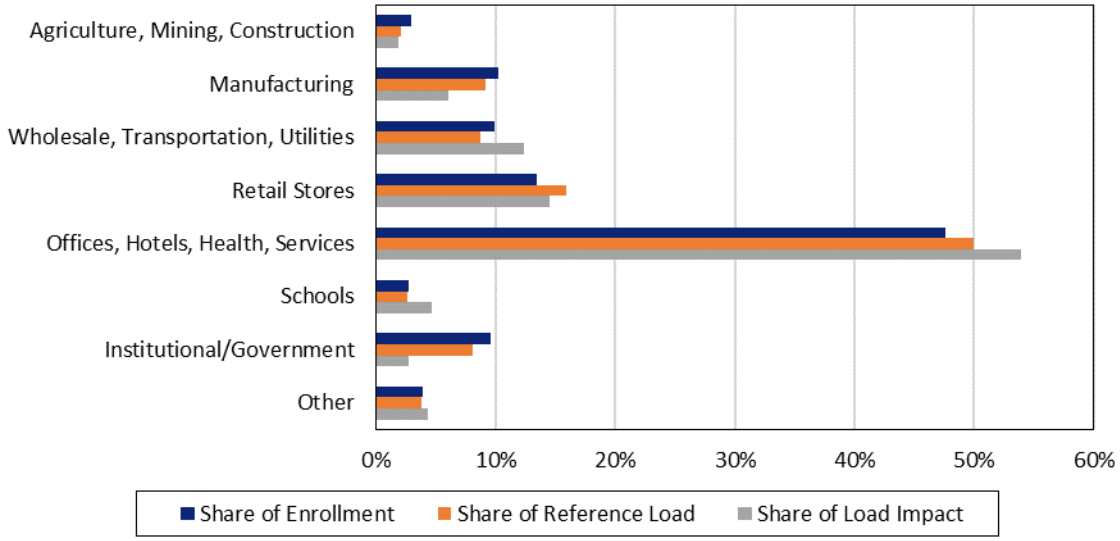
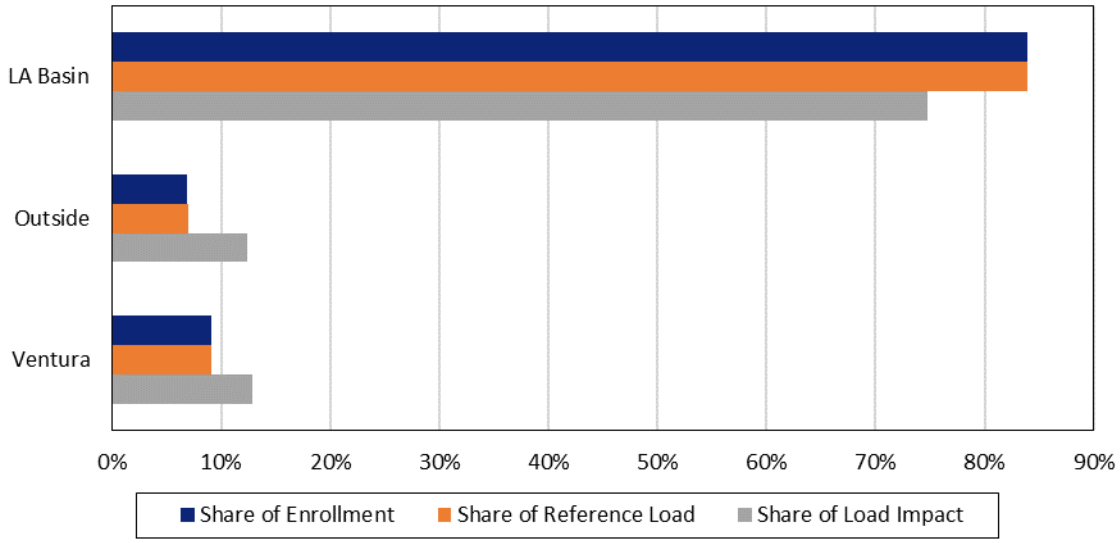


Table 4.9 and Figure 4.9 provide the same summaries as above but by LCA instead of industry group. Enrollments and reference loads are highly concentrated in LA Basin, with over 80 percent of Medium CPP enrollment and 75 percent of Medium CPP customer load impacts.

Table 4.9 Typical Event Day Event-Hour Load Impacts by LCA, *SCE Medium*

LCA	# of Service Accounts	Estimated Reference Load (MWh/hour)	Observed Load (MWh/hour)	Estimated Load Impact (MWh/hour)	% LI
LA Basin	23,089	605	601	3.45	0.6%
Outside Basin	1,905	51	50	0.57	1.1%
Ventura	2,509	66	65	0.59	0.9%

Figure 4.9: Typical Event Day Event-Hour Load Impacts by LCA, *SCE Medium*



4.1.4 Small Customers

This section summarizes results for SCE Small CPP customers, defined as customers with maximum demand less than 20 kW.[12] The presented results include: the average event-hour load impact by event day; the hourly load impact for the average event day; and load impacts by industry group and LCA for the average event hour. Summaries of load impacts for dually enrolled, AutoDR, and notified versus non-notified customers are presented in successive sub-sections.

The ex-post load impacts for SCE's Small CPP customers are summarized for all 12 events in Figure 4.10. Seven of the twelve events have statistically significant load impacts at the 90 percent confidence level (represented by the green bars). However, only four events exhibit reductions in usage that are statistically significant (August 11th, 12th, 16th, and September 10th). The average weekday event of 0.8 MWh/hour (0.2 percent) is not statistically significant. The Small CPP customers do not show a relationship between load impacts and temperature.

[12] Small CPP customers were identified using rate codes provided by SCE. The majority (99.96 percent) of Small CPP customers are on rate TOU-GS-1-E.

Figure 4.10: Average Event-Hour Load Impacts by Event, *SCE Small*

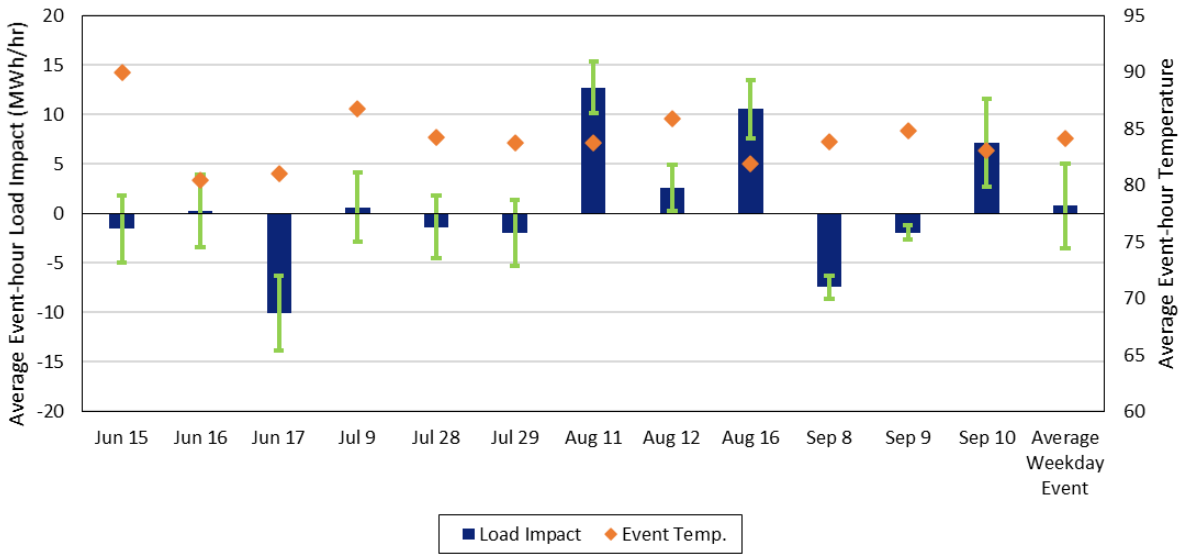


Table 4.10 summarizes enrollments, average event-hour load impacts, and reference loads for each event day and the average event. Enrollment of Small customers in CPP were fairly consistent over the course of the season. Overall, Small CPP customers had an aggregate load impact of 0.8 MWh/hour, which is 0.003 kWh/hour per customer on average, or about a 0.2 percent load reduction.

Table 4.10: Average Event-Hour Load Impacts by Event, *SCE Small*

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
6/15/2021	229,578	350	-1.6	1.5	-0.01	-0.4%	90.0
6/16/2021	229,578	334	0.3	1.5	0.00	0.1%	80.4
6/17/2021	229,578	327	-10.1	1.4	-0.04	-3.1%	81.1
7/9/2021	229,578	338	0.6	1.5	0.00	0.2%	86.8
7/28/2021	229,579	331	-1.4	1.4	-0.01	-0.4%	84.2
7/29/2021	229,579	332	-2.0	1.4	-0.01	-0.6%	83.8
8/11/2021	229,583	338	12.7	1.5	0.06	3.8%	83.7
8/12/2021	229,583	346	2.5	1.5	0.01	0.7%	85.9
8/16/2021	229,583	342	10.5	1.5	0.05	3.1%	81.9
9/8/2021	229,585	329	-7.5	1.4	-0.03	-2.3%	83.8
9/9/2021	229,585	344	-1.9	1.5	-0.01	-0.6%	84.8
9/10/2021	229,585	337	7.1	1.5	0.03	2.1%	83.1
Typical Event Day	**229,582**	**337**	**0.8**	**1.5**	**0.003**	**0.2%**	**84.1**

Figure 4.11 shows the aggregate hourly reference loads, observed loads, and estimated load impacts on the typical event day for Small CPP customers. Table 4.11 contains the hourly typical event day results, including hourly temperatures and uncertainty adjusted load impacts. The largest load impact of 2.4 MWh/hour occurred during the first event hour.

Figure 4.11: Typical Event Day Reference Loads and Load Profile, SCE *Small*

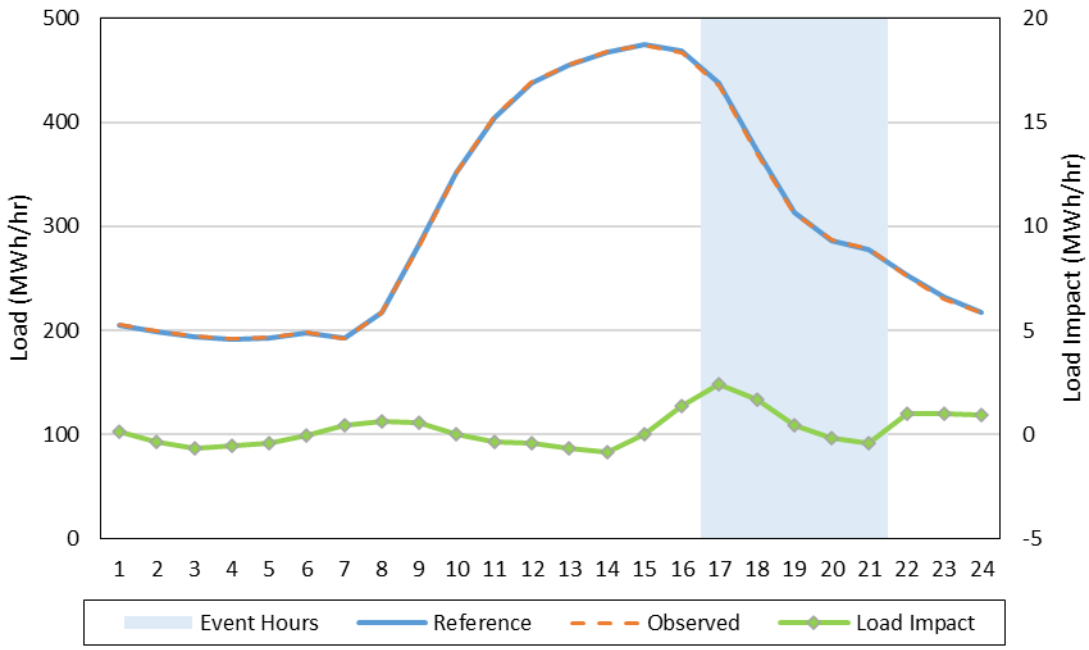


Table 4.11: Typical Event Day Load Impacts and Uncertainty Adjusted Estimates by hour, *SCE Small*

Hour Ending	Estimated Reference Load (MW)	Observed Event Day Load (MW)	Estimated Load Impact (MW)	Load Impact (%)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact - Percentiles				
						10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	205.4	205.3	0.1	0.1%	72.7	-0.6	-0.2	0.1	0.4	0.8
2	198.7	199.1	-0.4	-0.2%	71.9	-0.7	-0.5	-0.4	-0.2	0.0
3	193.9	194.6	-0.6	-0.3%	71.2	-1.0	-0.8	-0.6	-0.5	-0.3
4	191.4	192.0	-0.5	-0.3%	70.6	-0.8	-0.6	-0.5	-0.4	-0.3
5	192.3	192.7	-0.4	-0.2%	70.2	-0.6	-0.5	-0.4	-0.3	-0.2
6	197.6	197.6	0.0	0.0%	69.9	-0.3	-0.1	0.0	0.1	0.3
7	192.8	192.4	0.4	0.2%	70.1	-0.4	0.1	0.4	0.8	1.3
8	217.2	216.6	0.6	0.3%	72.4	-0.4	0.2	0.6	1.1	1.7
9	282.8	282.2	0.6	0.2%	75.9	-0.4	0.2	0.6	1.0	1.6
10	351.5	351.5	0.0	0.0%	79.5	-1.1	-0.4	0.0	0.4	1.1
11	404.5	404.9	-0.4	-0.1%	83.1	-1.3	-0.7	-0.4	0.0	0.5
12	438.2	438.6	-0.4	-0.1%	85.8	-1.0	-0.6	-0.4	-0.2	0.2
13	454.5	455.2	-0.7	-0.1%	87.6	-1.6	-1.1	-0.7	-0.3	0.3
14	466.8	467.7	-0.9	-0.2%	88.9	-2.9	-1.7	-0.9	0.0	1.2
15	474.5	474.5	0.0	0.0%	89.5	-2.9	-1.2	0.0	1.2	3.0
16	467.9	466.5	1.4	0.3%	89.7	-2.3	-0.2	1.4	2.9	5.0
17	437.3	434.9	2.4	0.6%	88.9	-1.6	0.8	2.4	4.0	6.4
18	372.4	370.7	1.7	0.5%	87.1	-2.3	0.1	1.7	3.4	5.7
19	313.7	313.2	0.4	0.1%	84.8	-3.1	-1.0	0.4	1.9	4.0
20	286.5	286.7	-0.2	-0.1%	81.4	-3.1	-1.4	-0.2	1.0	2.7
21	277.2	277.6	-0.4	-0.2%	78.2	-2.8	-1.4	-0.4	0.5	1.9
22	253.3	252.4	1.0	0.4%	76.2	-1.0	0.2	1.0	1.8	2.9
23	231.4	230.4	1.0	0.4%	74.8	-0.7	0.3	1.0	1.7	2.7
24	217.2	216.3	0.9	0.4%	73.7	-0.4	0.4	0.9	1.5	2.3
Daily	**7,319**	**7,314**	**6**	**0.1%**	**78.9**	**-23.1**	**-6.1**	**5.7**	**17.5**	**34.5**

Next, we look at SCE Small CPP customer estimates by industry group. Table 4.12 summarizes the aggregate event-hour results for the typical event day for each industry group, including the number of enrolled customers, the reference and observed loads, and the estimated load impacts (in MWh/hour and as a percentage of reference loads). About 47 percent of enrollments come from the Offices, Hotels, Health, & Services industry group, which also account for 36 percent of the load impact with 0.3 MWh/hour.

Table 4.12: Typical Event Day Event-Hour Load Impacts by Industry Group, *SCE Small*

Industry Group	# of Service Accounts	Estimated Reference Load (MWh/hour)	Observed Load (MWh/hour)	Estimated Load Impact (MWh/hour)	% LI
1.Agriculture, Mining, Construction	10,219	14	14	0.09	0.7%
2.Manufacturing	8,240	12	12	0.17	1.4%
3.Wholesale, Transportation, Utilities	13,139	18	18	0.16	0.9%
4.Retail Stores	17,058	45	45	0.12	0.3%
5.Offices, Hotels, Health, Services	108,186	158	158	0.30	0.2%
6.Schools	2,801	6	6	-0.01	-0.2%
7. Institutional/Government	32,594	52	52	-0.05	-0.1%
8.Other	37,344	33	33	0.00	0.0%

Figure 4.12 shows the shares of enrollments, reference loads, and load impacts by industry group. The first four industry groups provide a larger share of load impacts than their enrollments.

Figure 4.12 Typical Event Day Event-Hour Load Impacts by Industry Group, *SCE Small*

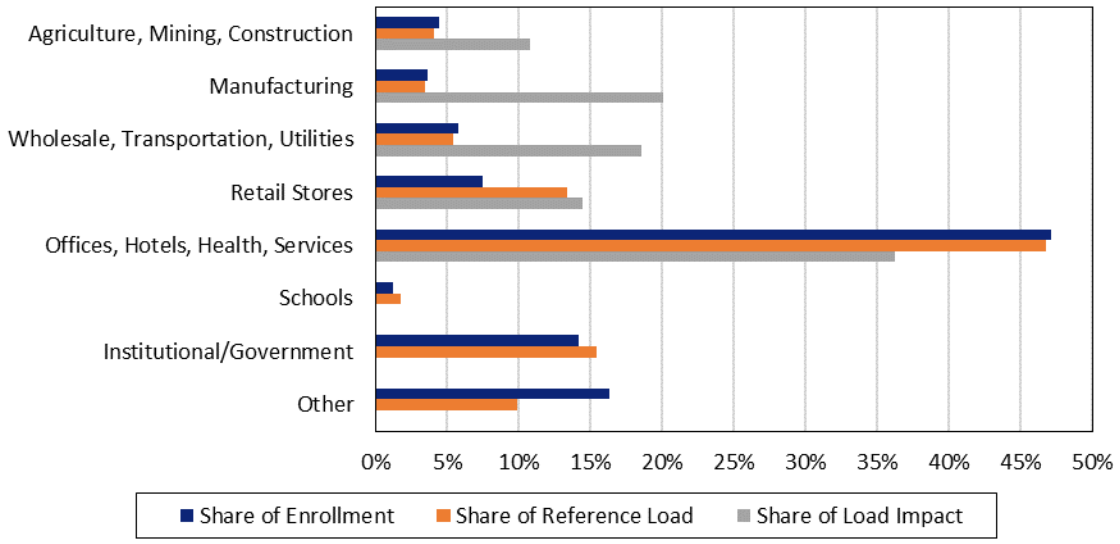
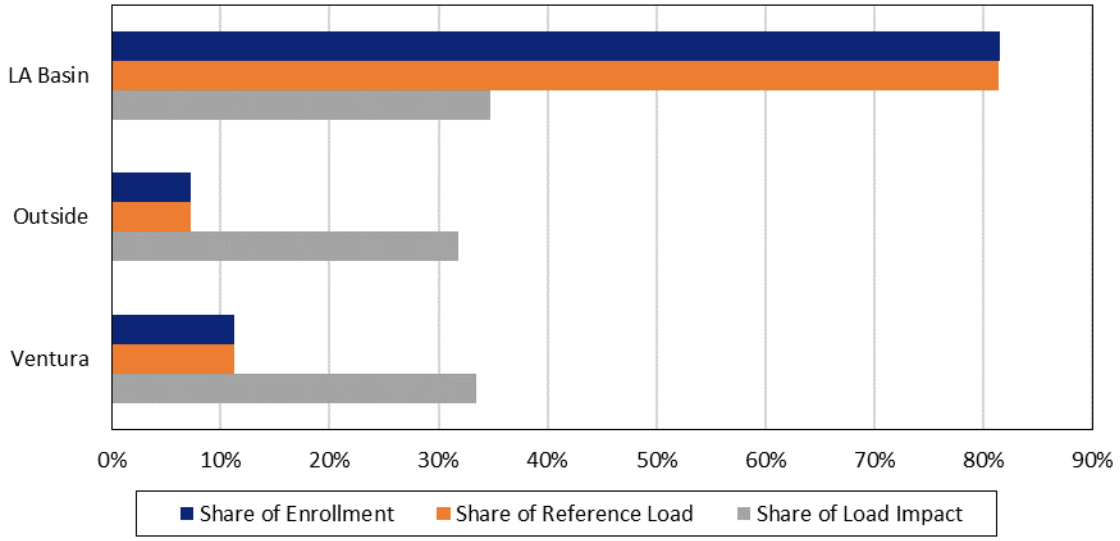


Table 4.13 and Figure 4.13 provide the same summaries as above but by LCA instead of industry group. Enrollments and reference loads are highly concentrated in LA Basin, accounting for over 80 percent of Small CPP customers. The load impact, however, is distributed fairly evenly across the LCAs.

Table 4.13: Typical Event Day Event-Hour Load Impacts by LCA, *SCE Small*

LCA	# of Service Accounts	Estimated Reference Load (MWh/hour)	Observed Load (MWh/hour)	Estimated Load Impact (MWh/hour)	% LI
LA Basin	187,120	275	274	0.27	0.1%
Outside Basin	16,637	25	24	0.25	1.0%
Ventura	25,825	38	38	0.26	0.7%

Figure 4.13 Typical Event Day Event-Hour Load Impacts by LCA, *SCE Small*



4.1.5 Dually Enrolled Customers

This section summarizes results for customers who are enrolled in CPP as well as another SCE demand response program. Customers that were dually enrolled prior to Decision 18-11-029 could remain grandfathered for dual participation. The other programs in which SCE customers can enroll along with CPP include Base Interruptible Program (BIP) and Capacity Bidding Program (CBP). We present results for the average event-hour for each event day and the average event. Additional results for these customers can be found in electronic form in Protocol table generators provided along with this report.

Table 4.14 summarizes enrollments, average event-hour load impacts, and reference loads for each event day and the average event for customers who are dually enrolled in CPP. The July 9th CPP event was also a BIP event day; as a result, load impacts are not counted for these customers because they are accounted for in the BIP evaluation. The load impact presented for July 9th is for a single non-BIP dually enrolled customer. The Typical Event Day excludes July 9th when calculating averages. The average dually enrolled customer has a reference load of 260.1 kWh/hour. Dually enrolled customers provided a 2.1 MW load impact, or 40.7 percent.

Table 4.14: Average Event-Hour Load Impacts for Dually Enrolled Customers by Event, SC*E*

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
6/15/2021	20	5.1	2.2	254.4	110.3	43.4%	89.8
6/16/2021	20	5.2	2.3	262.1	116.9	44.6%	77.1
6/17/2021	20	5.3	2.4	265.3	119.4	45.0%	77.2
7/9/2021							
7/28/2021	20	5.5	1.8	273.4	90.2	33.0%	83.3
7/29/2021	20	5.2	1.2	259.6	61.2	23.6%	82.4
8/11/2021	20	5.2	1.9	260.2	96.8	37.2%	83.7
8/12/2021	20	5.3	2.1	265.9	105.1	39.5%	86.1
8/16/2021	20	5.1	2.2	256.2	111.7	43.6%	79.9
9/8/2021	20	5.5	2.5	276.7	123.2	44.5%	82.5
9/9/2021	20	5.6	2.3	282.0	114.3	40.5%	85.3
9/10/2021	20	4.8	2.5	241.5	122.8	50.9%	82.4
Typical Event Day	**20**	**5.2**	**2.1**	**260.1**	**105.9**	**40.7%**	**82.9**

4.1.6 AutoDR Customers

This section summarizes results for CPP customers who participated in Automated Demand Response (AutoDR) programs. The AutoDR program provides customers incentives to invest in energy management technologies that will enable their equipment or facilities to reduce demand automatically in response to a physical signal sent from the utility. It encourages customers to expand their energy management capabilities by participating in DR programs using automated electric controls and management strategies. When a DR event is called, a communications signal from the utility enables the execution of a sequence of load shed strategies without participant intervention. We present results for the average event-hour for each event day and for the average event. Additional results for these customers can be found in electronic form in Protocol table generators provided along with this report.

Table 4.15 summarizes enrollments, average event-hour load impacts, and reference loads for each event day and the average event for customers who participated in the AutoDR program. There were 105 SCE CPP customers enrolled in AutoDR. Their combined load impact was 1.2 MW (7.1 percent) for the average event day.

Table 4.15: Average Event-Hour Load Impacts for AutoDR Customers by Event, SC*E*

Event Date	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Avg. Event Temp.
		Ref. Load	Load Impact	Ref. Load	Load Impact		
6/15/2021	105	16.4	1.6	156.5	15.16	9.7%	89.9
6/16/2021	105	16.0	1.6	152.8	15.29	10.0%	80.7
6/17/2021	105	16.1	2.1	153.6	19.54	12.7%	81.6
7/9/2021	105	16.3	0.1	154.8	0.93	0.6%	87.4
7/28/2021	105	16.8	1.1	160.3	10.04	6.3%	85.9
7/29/2021	105	17.0	1.4	161.4	13.48	8.4%	85.4
8/11/2021	105	17.2	1.3	163.4	12.37	7.6%	85.5
8/12/2021	105	17.3	1.1	165.2	10.41	6.3%	87.3
8/16/2021	105	17.4	0.6	165.7	6.12	3.7%	83.5
9/8/2021	105	17.1	1.0	162.6	9.33	5.7%	86.0
9/9/2021	105	17.5	1.0	166.5	9.52	5.7%	87.3
9/10/2021	105	17.0	1.5	161.5	13.92	8.6%	84.4
Typical Event Day	**105**	**16.8**	**1.2**	**160.4**	**11.34**	**7.1%**	**85.3**

4.1.7 Notified vs. Non-Notified Customers

SCE customers can elect to receive day-ahead notification of CPP events by phone, email, or text message. This section summarizes results for CPP customers by notification status. Additional results for these customers can be found in electronic form in Protocol table generators provided along with this report.

Table 4.16 summarizes enrollments, average event-hour load impacts, and reference loads for the average event day by size and notification status. About 69 percent of all customers were notified during events. Large CPP customers have the greatest proportion of notified customers with 80 percent of enrollments. Additionally, Large CPP customers exhibited the largest difference in percentage load impacts between notified and non-notified customers, 2.9 percent and 1.3 percent, respectively.

Table 4.16: Average Event-Hour Load Impacts on Typical Event Day by Size and Notification Status, SC*E*

Notified	Size	# Enrolled	Aggregate (MWh/hour)		Per-Customer (kWh/hour)		% Load Impact	Ave. Event Temp.
			Ref. Load	Load Impact	Ref. Load	Load Impact		
No	Large	389	94	1.3	241.0	3.22	1.3%	84.9
	Medium	7,529	196	1.3	26.0	0.17	0.6%	83.8
	Small	73,548	107	0.0	1.5	0.00	0.0%	83.7
	All	**81,466**	**396**	**2.5**	**4.9**	**0.03**	**0.6%**	**84.0**
Yes	Large	1,526	331	9.6	217.0	6.29	2.9%	84.6
	Medium	19,975	525	3.4	26.3	0.17	0.6%	84.4
	Small	156,033	231	0.7	1.5	0.00	0.3%	84.3
	All	**177,534**	**1,087**	**13.7**	**6.1**	**0.08**	**1.3%**	**84.5**

4.2 SCE Ex-Ante Load Impacts

This section provides the ex-ante CPP load impact forecast based on an enrollment forecast provided by SCE. Results are presented by size group. Within each size group, we present the following: a summary of the enrollment forecast provided by SCE; a figure showing the hourly reference load and load impact on a typical event day; a figure showing the share of load impacts by LCA; a figure showing the seasonal pattern of load impacts; and a figure summarizing annual load impacts by weather scenario. Detailed results for each hour, weather scenario, month, and forecast year are available in electronic form in Protocol table generators provided along with this report.

As described in Section 2.2, *per-customer load impacts* are derived from analysis of current and previous ex-post load impacts. We investigated the effect of weather on estimated load impacts and found that the results were not reasonable for most customer groups. Therefore, the ex-ante load impacts are simulated by multiplying forecast reference loads by the ex-post percentage load impacts (by size, LCA, and hour of the day).

Another assumption made in these forecasts is that the share of enrollments by LCA within each size group remains constant over time. This was necessary to produce

forecasts at the LCA level from SCE's enrollment forecasts, which vary by size group but not by LCA.

4.2.1 All Customers

Figure 4.14 summarizes the overall trend of SCE's enrollment forecast. SCE anticipates that the total number of CPP customers decreases in 2023 by 0.8 percent and then grows by 0.4 percent each year until 2026, where it will remain constant at 241,775 customers.

Figure 4.14: CPP Enrollments, *SCE All*

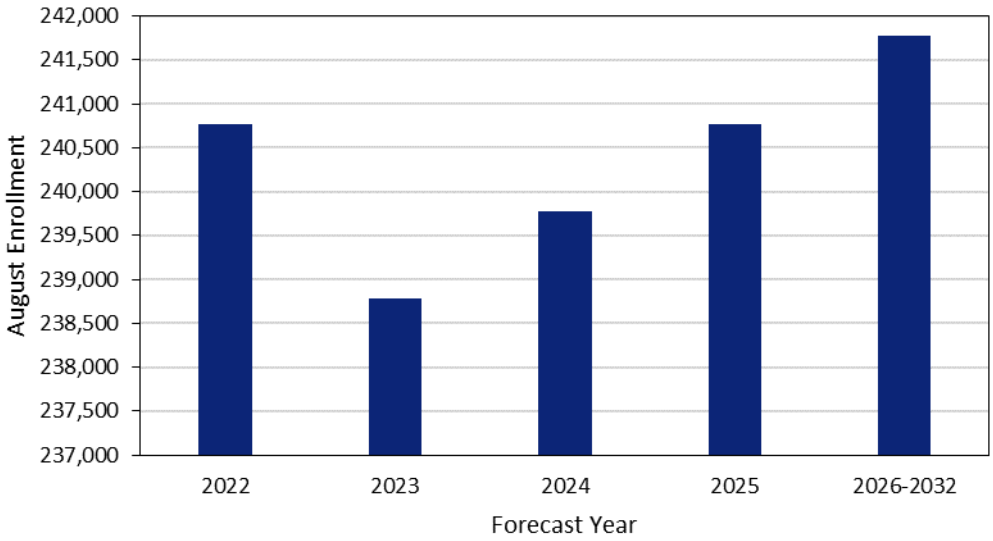
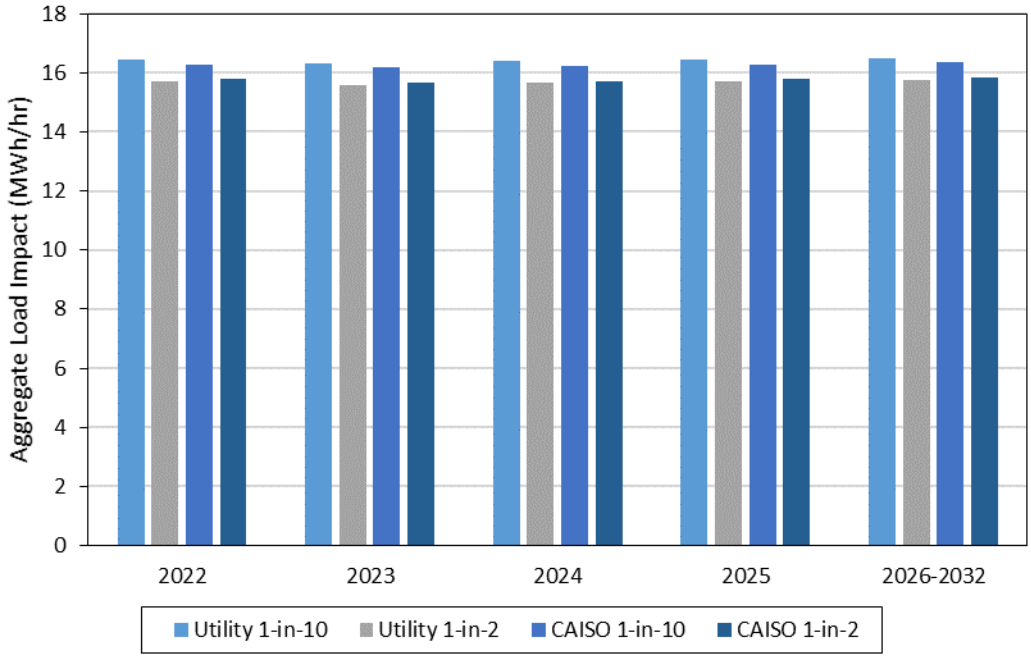


Figure 4.15 shows the change in aggregate load impacts over time and across weather scenarios for all customers. Each value is the aggregate load impact during the RA window of the typical event day. Load impacts are similar across the years because there are only small changes in forecasted total enrollment. The load impacts for 1-in-10 scenarios are higher than 1-in-2 scenarios, and the largest difference of load impacts between 1-in-10 and 1-in-2 scenarios is about 0.7 MWh/hour. The highest load impacts for each year occur under utility-specific 1-in-10 weather conditions. Additional results of ex-ante load impacts are presented in the subsequent sections by customer size.

Figure 4.15: Aggregate Load Impacts for Typical Event Day by Year and Weather Scenario over RA Window, *SCE All*



4.2.2 Large Customers

Figure 4.16 summarizes SCE's enrollment forecast for Large CPP customers. SCE anticipates that Large CPP customer enrollment decreases in 2023 and then grows by 0.4 percent each year until 2026, where it will remain constant at 1,815 customers.

Figure 4.16: CPP Enrollments, *SCE Large*

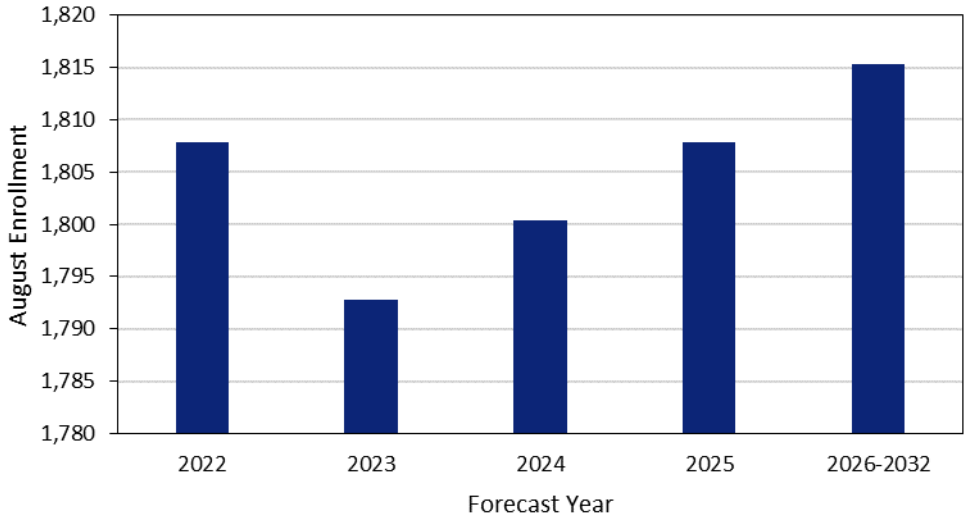


Figure 4.17 illustrates the aggregate reference load, observed load, and load impact for large customers on the typical event day in 2023 for the SCE 1-in-2 weather scenario. The average event-hour load impact is 10.7 MWh/hour, or 2.6 percent of the reference load. The shape of the ex-ante loads and load impacts is similar to the ex-post results in Figure 4.3.

Figure 4.17: Aggregate Hourly Loads and Load Impacts in 2023 for *SCE 1-in-2 Typical Event Day, SCE Large*

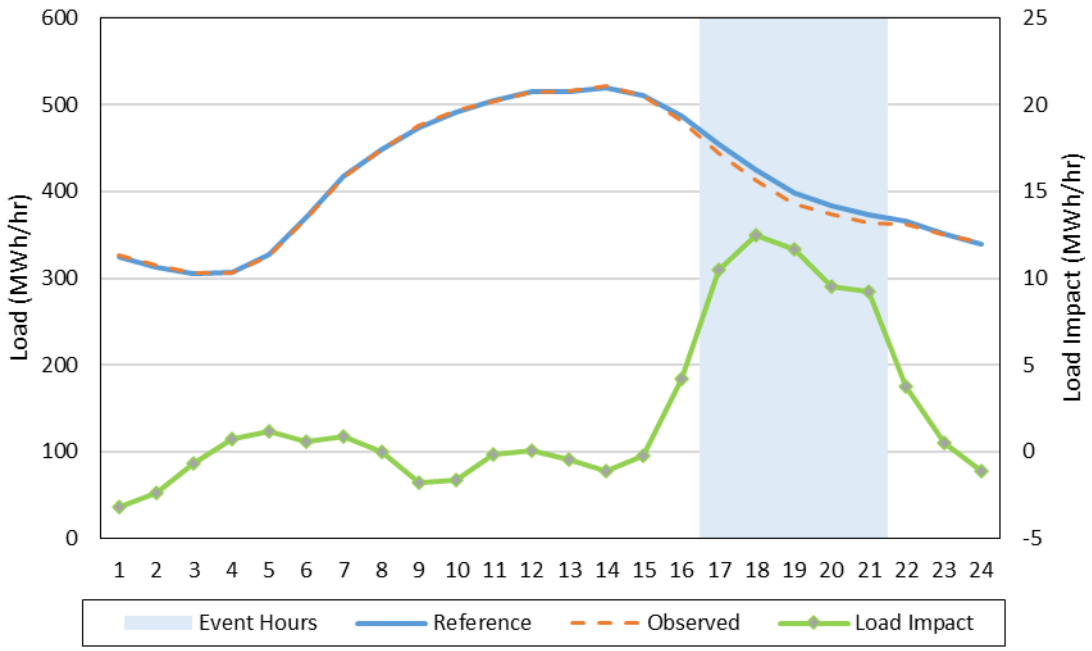


Figure 4.18 shows the forecasted share of large customer load impacts by LCA during the average event hour on the typical event day in 2023 under SCE's 1-in-2 weather scenario. As expected, the LA Basin accounts for 91 percent of the total load impact.

Figure 4.18: Share of Load Impacts by LCA in 2023 for *SCE 1-in-2 Typical Event Day, SCE Large*

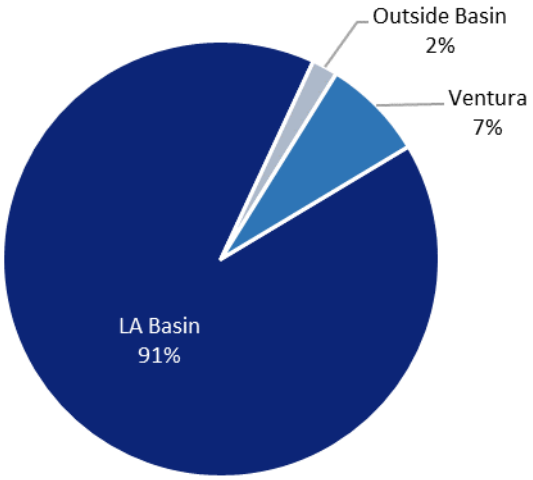


Figure 4.19 illustrates the seasonality in the forecasted load impacts by comparing aggregate load impacts for the average hour in the Resource Adequacy (RA) window in 2023 across months for SCE's 1-in-2 peak day weather scenario. The RA window is 4 to 9 p.m. for all months of the year. The load impact is highest in August (10.8 MWh/hour) and lowest in January (7.7 MWh/hour) as a result of reference loads being the highest and lowest during these months.

Figure 4.19: Aggregate Load Impacts by Month over RA Window in 2023 for *SCE 1-in-2 Peak Day*, *SCE Large*

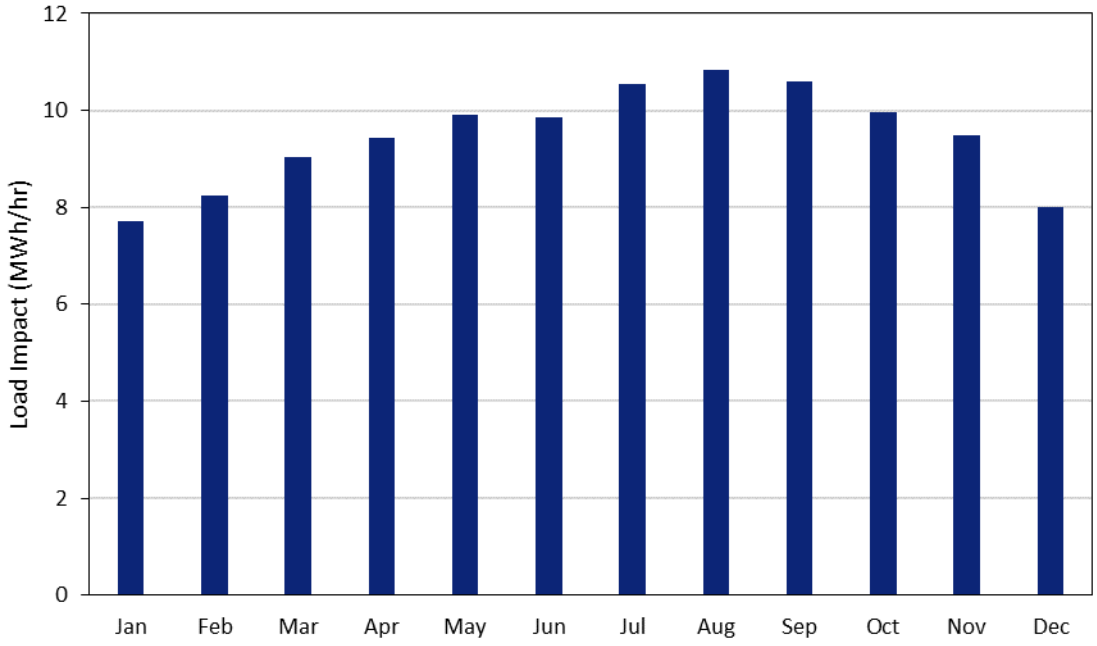
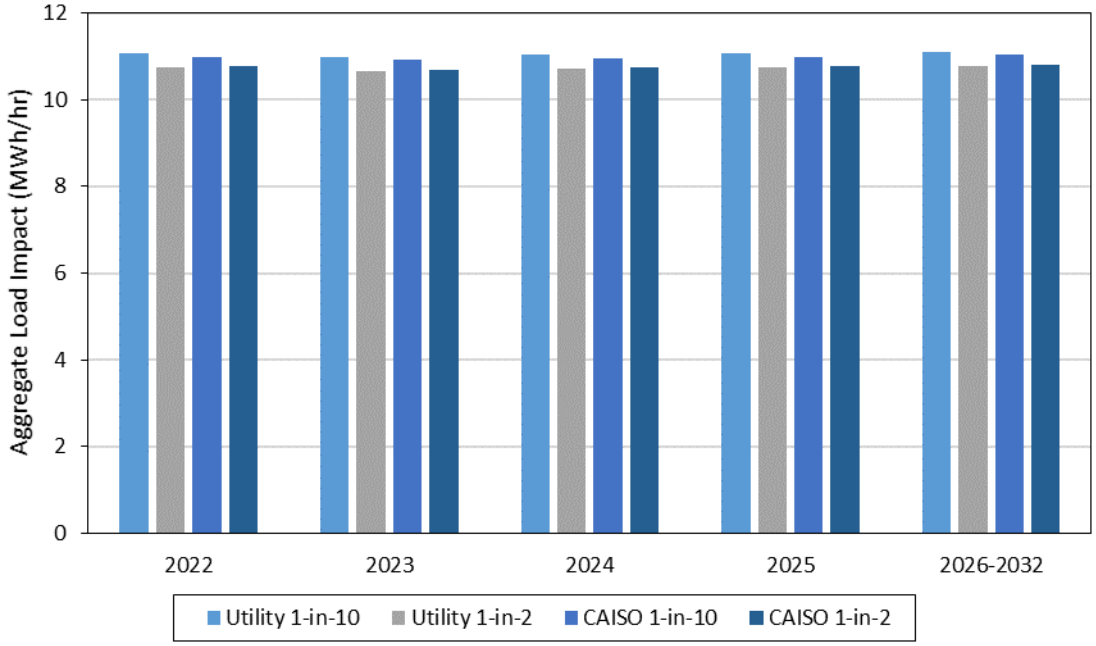


Figure 4.20 shows the change in load impacts over time and across weather scenarios. Each value is the aggregate load impact during the RA window of the typical event day. There is little forecast growth in load impacts because SCE forecasts a correspondingly small change in large customer CPP enrollments. There are relatively minor differences between the forecast load impacts for the alternative weather scenarios over the forecast period. The highest load impacts for each year occur under utility-specific 1-in-10 weather conditions.

Figure 4.20: Aggregate Load Impacts for Typical Event Day by Year and Weather Scenario over RA Window, *SCE Large*



4.2.3 Medium Customers

Figure 4.21 summarizes SCE's enrollment forecast for Medium CPP customers. SCE anticipates that Medium CPP customer enrollment decreases in 2023 and then grows by 0.4 percent each year until 2026, where it will remain constant at 24,868 customers.

Figure 4.21: CPP Enrollments, *SCE Medium*

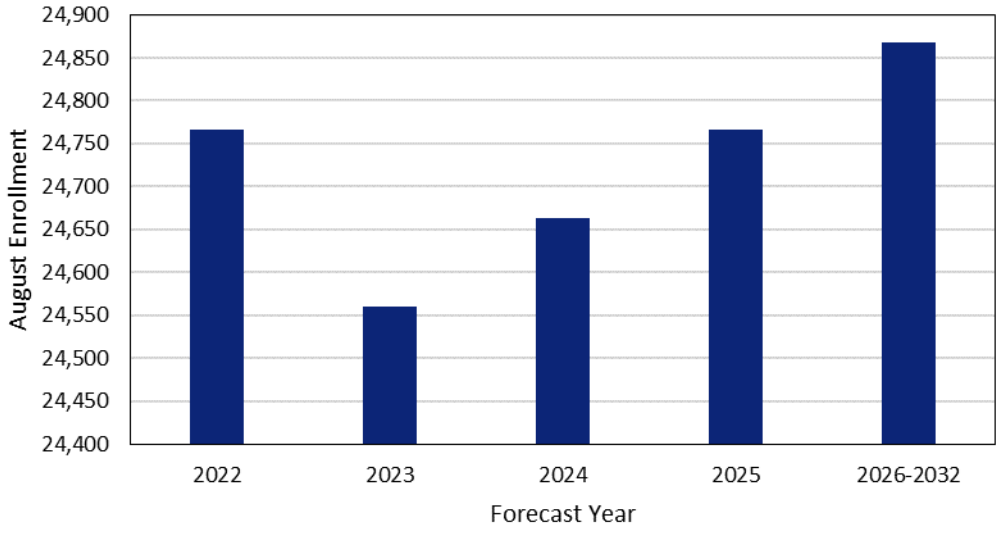


Figure 4.22 illustrates the aggregate reference loads, observed loads, and load impacts for medium customers on the typical event day in August in 2023 for the SCE 1-in-2 weather scenario. The forecast predicts an average load impact of 4.2 MWh/hour for Medium CPP customers on the typical event day in 2023, which is a 0.6 percent reduction in reference loads.

Figure 4.22: Aggregate Hourly Loads and Load Impacts in 2023 for *SCE 1-in-2 Typical Event Day, SCE Medium*

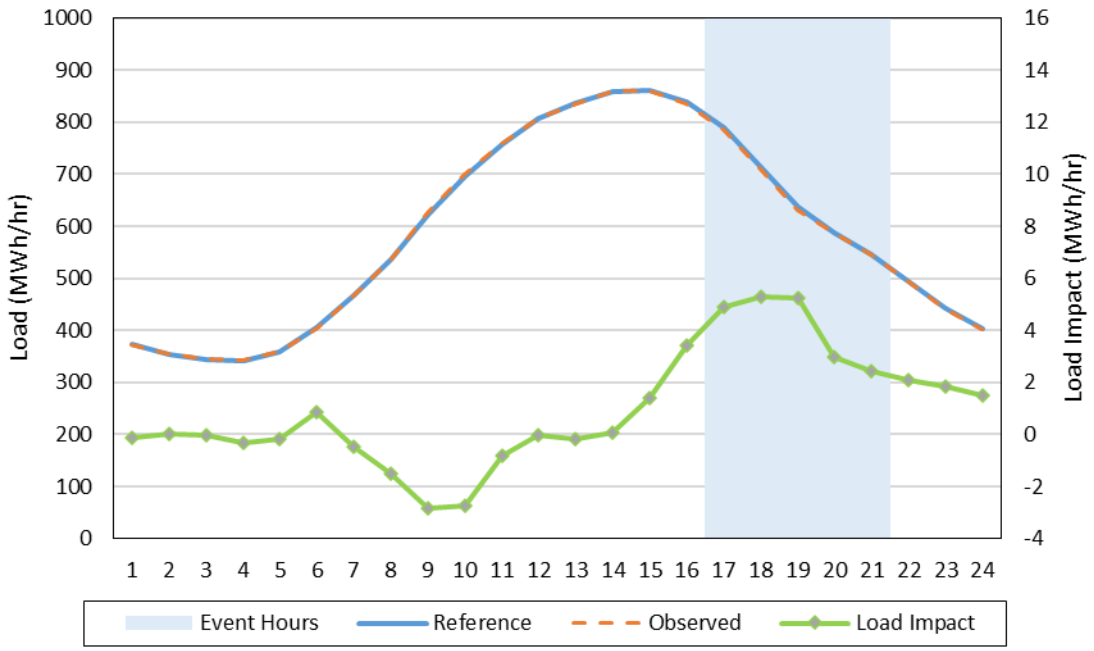


Figure 4.23 shows the forecasted share of load impacts for medium customers by LCA, based on the average event-hour load impact on the typical event day in 2023 under SCE's 1-in-2 weather scenario. LA Basin is expected to have the largest share of load impacts at 75 percent, followed by Ventura at 13 percent, then Outside Basin at 12 percent.

Figure 4.23: Share of Load Impacts by LCA in 2023 for *SCE 1-in-2 Typical Event Day, SCE Medium*

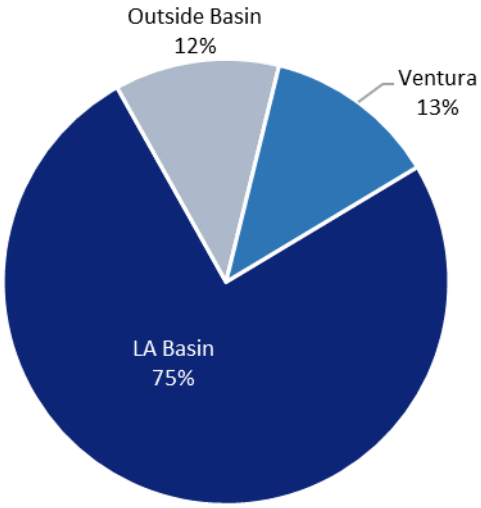


Figure 4.24 shows the seasonality of the forecasted load impacts for Medium CPP customers based on the 2023 aggregate load impacts for the average hour in the RA window for SCE's 1-in-2 weather scenario. The load impact is highest in August (4.4 MWh/hour) and lowest in December (2.7 MWh/hour).

Figure 4.24: Aggregate Load Impacts by Month over RA Window in 2023 for *SCE 1-in-2 Peak Day, SCE Medium*

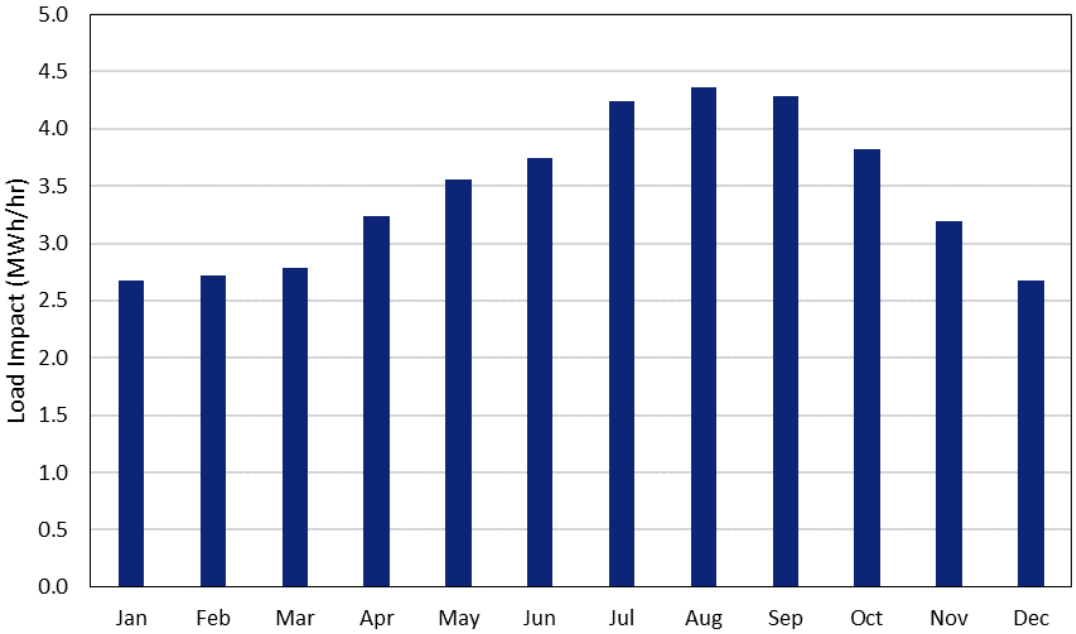
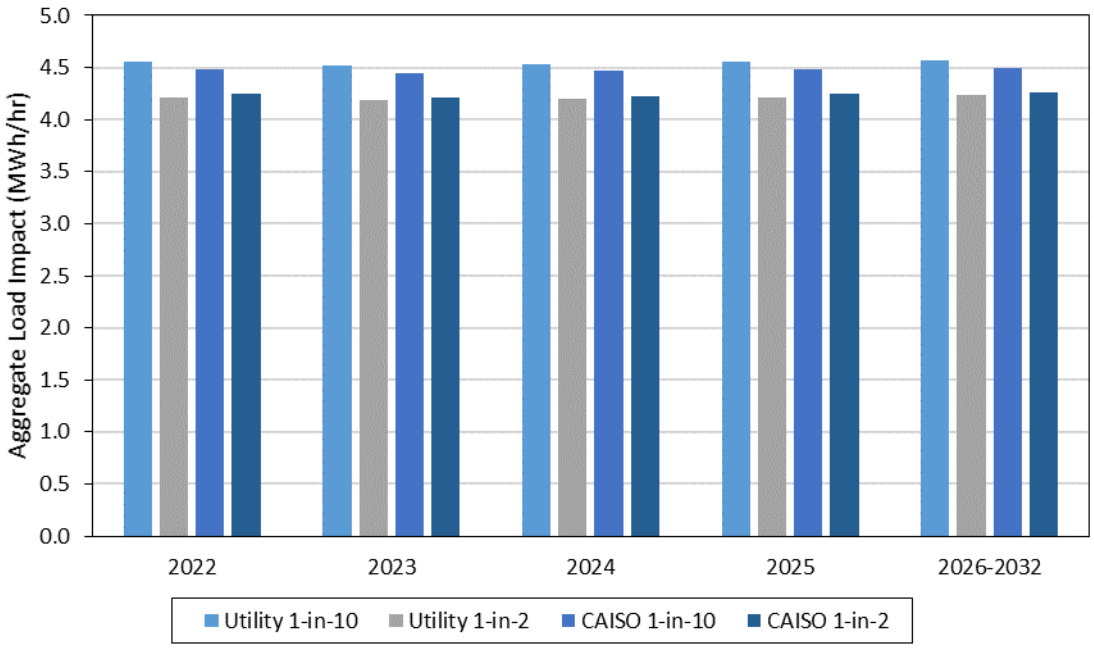


Figure 4.25 shows the change in load impacts over time and across weather scenarios. Each value is the aggregate load impact during the RA window of the typical event day. The range of load impacts between alternative weather scenarios is relatively minor at 0.3 MWh/hour. The largest load impacts occur during the Utility 1-in-10 weather scenario at 4.5 MWh/hour.

Figure 4.25: Aggregate Load Impacts for Typical Event Day by Year and Weather Scenario over RA Window, *SCE Medium*



4.2.4 Small Customers

Figure 4.26 summarizes SCE's enrollment forecast for Small CPP customers. SCE anticipates that Small CPP customer enrollment decreases in 2023 and then grows by 0.4 percent each year until 2026, where it will remain constant at 215,091 customers.

Figure 4.26: CPP Enrollments, *SCE Small*

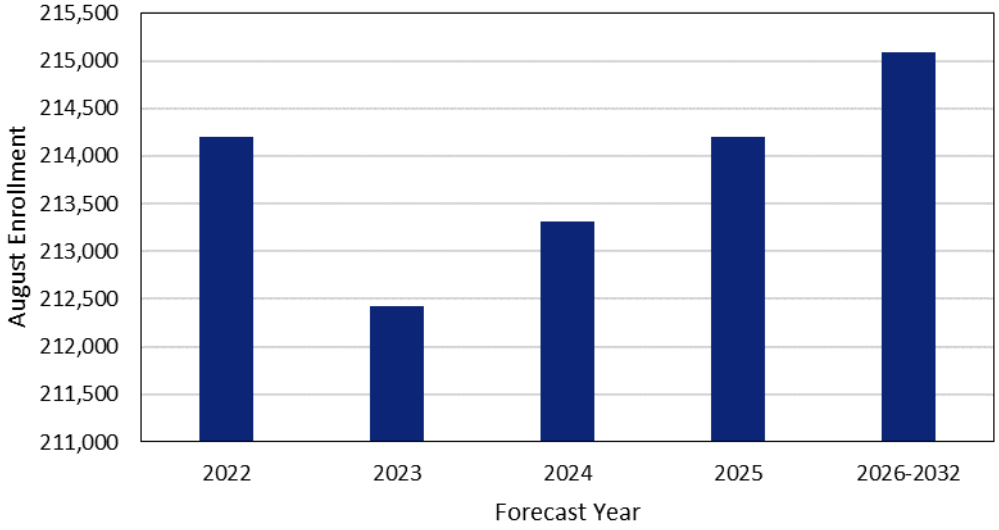


Figure 4.27 illustrates the aggregate reference loads, observed loads, and load impacts for Small CPP customers on the typical event day in August in 2023 for the SCE 1-in-2 weather scenario. The forecast predicts an average load impact of 0.7 MWh/hour for Small CPP customers on the typical event day in 2023 for the SCE 1-in-2 weather scenario, which is a 0.2 percent reduction in reference loads.

Figure 4.27: Aggregate Hourly Loads and Load Impacts in 2023 for *SCE 1-in-2 Typical Event Day, SCE Small*

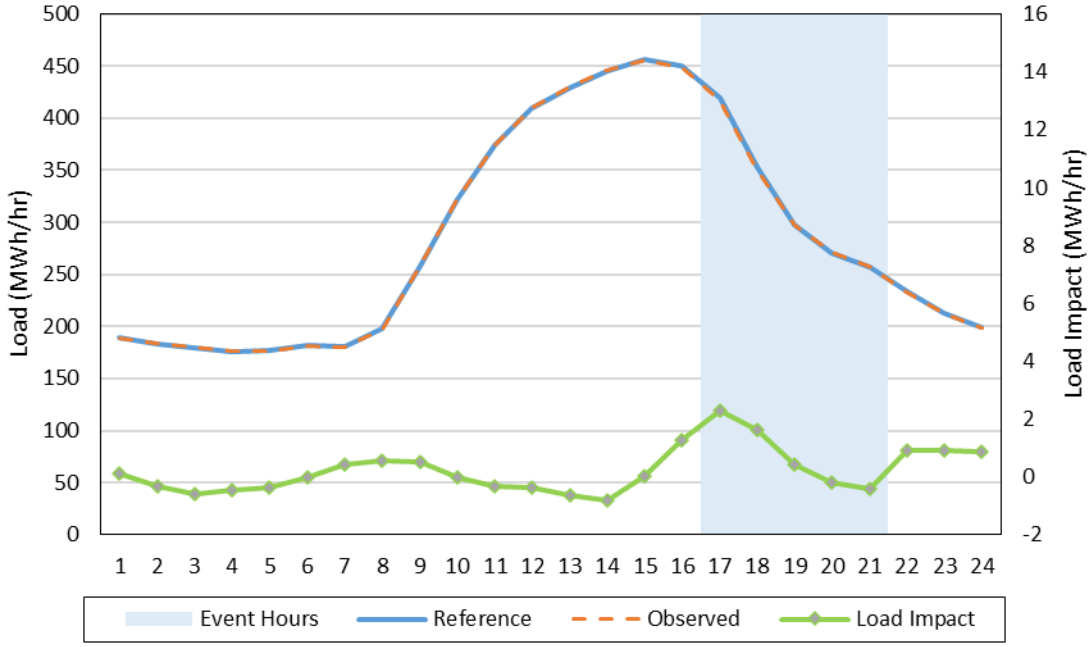


Figure 4.28 shows the forecasted share of load impacts for small customers by LCA, based on the average event-hour load impact on the typical event day in 2023 under SCE's 1-in-2 weather scenario. The share of load impacts is similar between LCAs. LA Basin is expected to have the largest share of load impacts at 36 percent, followed by Ventura at 33 percent, then Outside Basin at 31 percent.

Figure 4.28: Share of Load Impacts by LCA in 2023 for *SCE 1-in-2 Typical Event Day, SCE Small*

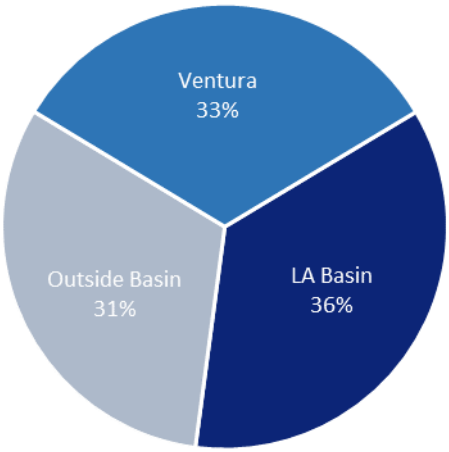


Figure 4.29 shows the seasonality of the forecasted load impacts for Small CPP customers based on the 2023 aggregate load impacts for the average hour in the RA window for SCE's 1-in-2 weather scenario. The load impact is highest in August (0.78 MWh/hour) and lowest in March (0.43 MWh/hour).

Figure 4.29: Aggregate Load Impacts by Month over RA Window in 2023 for *SCE 1-in-2 Peak Day*, *SCE Small*

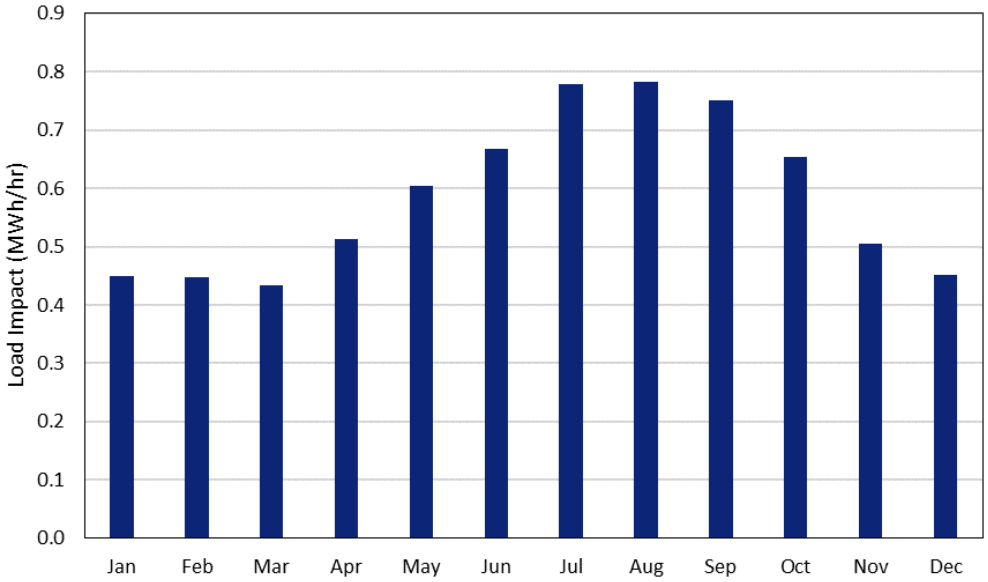
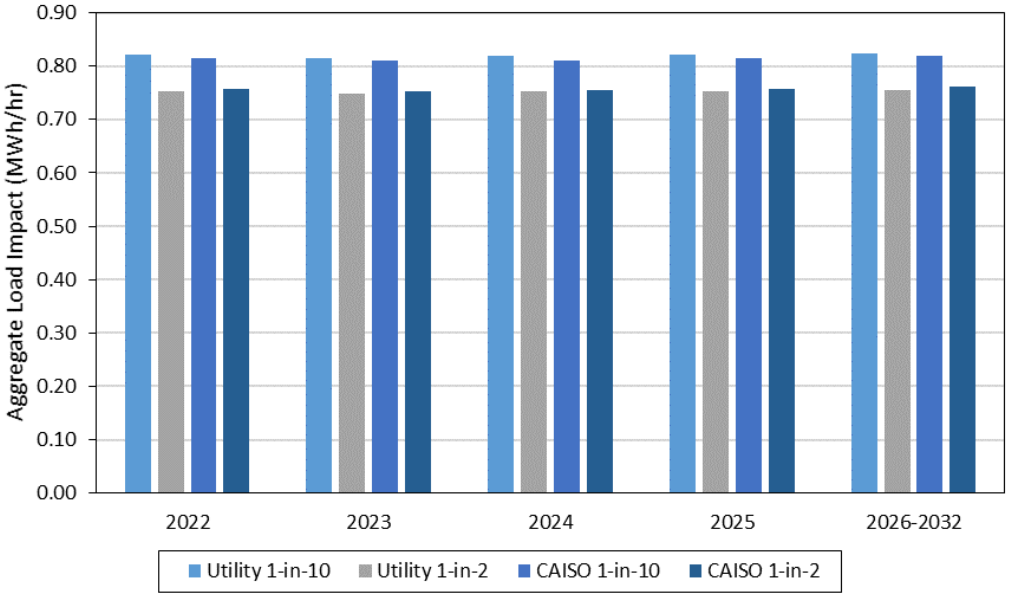


Figure 4.30 shows the change in load impacts over time and across weather scenarios. Each value is the aggregate load impact during the RA window of the typical event day. There are relatively minor differences between the forecasted load impacts for the alternative weather scenarios over the forecast period. The largest load impact occurs during the Utility 1-in-10 weather scenario at 0.82 MWh/hour.

Figure 4.30: Aggregate Load Impacts for Typical Event Day by Year and Weather Scenario over RA Window, *SCE Small*



4.3 SCE Load Impact Reconciliations

In a continuing effort to clarify the relationships between ex-post and ex-ante results, this section compares several sets of estimated load impacts for CPP, including the following:

- Ex-post load impacts from the current and previous studies;
- Ex-ante load impacts from the current and previous studies;
- Current ex-post and previous ex-ante load impacts; and
- Current ex-post and ex-ante load impacts.

The term "current" refers to the present study, which includes ex-post and ex-ante results for PY2021. The term "previous" refers to findings in reports for PY2020.

4.3.1 Large Customers

Previous vs. Current Ex-Post

Table 4.17 shows the average event-hour reference loads and load impacts for the typical event day during the current and previous program years. The total load impact is somewhat larger in the current study (10.9 MWh/hour vs. 8.3 MWh/hour in the previous study). This is due to a combination of higher enrollments and larger per-customer reference loads. The per-customer reference load increased from 174 kWh/hour to 222 kWh/hour. It is likely that the increase is a result the COVID-19 impact lessening. COIVD-19 had the initial effect of reducing the reference loads for commercial and industrial customers. The increase is indication of customers moving closer to pre-COVID levels. Composition changes can also affect the per-customer reference load, but this seems unlikely since the enrollment counts were similar between years.

Table 4.17: Previous vs. Current Ex-Post Load Impacts for the Typical Event Day, *SCE Large*

Level	Outcome	Ex-post Previous Study	Ex-post Current Study
Total	# SAIDs	1,895	1,915
	Reference (MW)	330	425
	Load Impact (MW)	8.3	10.9
	Avg. Temp.	89.6	84.7
Per SAID	Reference (kW)	174.1	221.8
	Load Impact (kW)	4.4	5.7
	% Load Impact	2.5%	2.6%

Previous vs. Current Ex-Ante

In this sub-section, we compare the ex-ante forecast prepared following PY2020 (the "previous study") to the ex-ante forecast contained in this study (the "current study"). Table 4.18 reports the average event-hour load impacts for the 2023 typical event day under utility-specific 1-in-2 weather conditions. The forecast load impact is higher in the

current study (10.7 MWh/hour vs. 9.6 MWh/hour in the previous study) despite having lower forecast enrollments. This is due to per-customer reference loads being higher in the current study. Which, as mentioned above, is likely due to customers moving closer to pre-COVID levels. The percentage load impact is the same between studies.

Table 4.18: Previous vs. Current Ex-Ante Load Impacts, *Utility 1-in-2 Typical Event Day, SCE Large*

Level	Outcome	Ex-ante for 2023 Typical Event Day, Previous Study	Ex-ante for 2023 Typical Event Day, Current Study
Total	# SAIDs	1,905	1,793
	Reference (MW)	366	407
	Load Impact (MW)	9.6	10.7
	Avg. Temp.	87.8	87.7
Per SAID	Reference (kW)	192.4	226.9
	Load Impact (kW)	5.0	5.9
	% Load Impact	2.6%	2.6%

Previous Ex-Ante vs. Current Ex-Post

Table 4.19 provides a comparison of the ex-ante forecast of 2021 load impacts prepared following PY2020 and the PY2021 load impacts estimated as part of this study. The ex-ante forecast shown in the table represents the typical event day during a utility-specific 1-in-2 weather year. The ex-post load impacts are based on the average event day. The ex-ante forecast in the previous study predicted slightly lower per-customer reference loads and load impacts than we estimated in the current study. However, the percentage load impact and enrollment numbers are similar between years.

Table 4.19: Previous Ex-Ante vs. Current Ex-Post Load Impacts, *SCE Large*

Level	Outcome	Ex-Ante for 2021 Typical Event Day Previous Study	Ex-Post Typical Event Day Current Study
Total	# SAIDs	1,905	1,915
	Reference (MW)	366	425
	Load Impact (MW)	9.6	10.9
	Avg. Temp.	87.8	84.7
Per SAID	Reference (kW)	192	222
	Load Impact (kW)	5.0	5.7
	% Load Impact	2.6%	2.6%

Current Ex-Post vs. Current Ex-Ante

Table 4.20 compares the ex-post and ex-ante load impacts from this study. The ex-ante load impacts in the table represent the 2023 August typical event day with utility-specific 1-in-2 weather conditions. The percentage load impacts are identical by design of the method of applying ex-post percentage load impacts to ex-ante reference loads. The ex-ante per-customer reference loads are higher in ex ante because of higher event-

hour temperatures. The larger per-customer reference loads and load impacts in ex-ante results in slightly higher aggregate load impact, even with lower enrollments.

Table 4.20: Current Ex-Post vs. Current Ex-Ante Load Impacts, *SCE Large*

Level	Outcome	Ex-Post Typical Event Day Current Study	Ex-Ante for 2023 Typical Event Day Current Study
Total	# SAIDs	1,915	1,793
	Reference (MW)	425	407
	Load Impact (MW)	10.9	10.7
	Avg. Temp.	84.7	87.7
Per SAID	Reference (kW)	222	227
	Load Impact (kW)	5.7	5.9
	% Load Impact	2.6%	2.6%

Table 4.21 documents the various potential sources of differences between the ex-post and ex-ante load impacts. As explained above, the difference in enrollments and weather-related reference loads is the driving force behind the forecast increase in load impacts.

Table 4.21: Comparison of Ex-Post and Ex-Ante Factors, *SCE Large*

Factor	Ex-Post	Ex-Ante	Expected Impact
Weather	Average event-hour temperature of 84.7 °F during the average event day.	Average event-hour temperature of 87.7 °F during the SCE 1-in-2 August peak day.	Higher ex-ante temperatures increase the per-customer reference load and load impact.
Event window	Hours-ending 17 through 21.	Hours-ending 17 through 21.	None, though ex-post event window aligns with the ex-ante event and RA window.
% of resource dispatched	100 percent	100 percent	None.
Enrollment	1,915 service accounts.	1,793 service accounts.	Lower ex-ante enrollment leads to a lower aggregate load impact (*ceteris paribus*).
Methodology	Panel models by LCA with fixed customer effects and controls for day type (e.g., month, day of week) and weather.	Panel models by LCA with fixed customer effects and controls for day type (e.g., month, day of week) and weather.	The method is not expected to consistently produce differences between the ex-post and ex-ante impacts.

4.3.2 Medium Customers

Previous vs. Current Ex-Post

Table 4.22 shows the average event-hour reference loads and load impacts for the typical event day during the current and previous program years. The aggregate load impact is larger in the current study (4.6 MWh/hour vs. 3.4 MWh/hour in the previous study). Per-customer reference loads and load impacts are larger in the current study. However, the percentage load impact is only slightly higher in the current study (0.6 versus 0.5 percent). The larger per-customer reference loads are likely a result of customers moving closer to pre-COVID-19 levels (since COVID-19 had the average effect of reducing commercial and industrial customer loads).

Table 4.22: Previous vs. Current Ex-Post Load Impacts for the Typical Event Day, *SCE Medium*

Level	Outcome	Ex-post Previous Study	Ex-post Current Study
Total	# SAIDs	29,581	27,503
	Reference (MW)	669	721
	Load Impact (MW)	3.4	4.6
	Avg. Temp.	86.6	84.3
Per SAID	Reference (kW)	22.6	26.2
	Load Impact (kW)	0.11	0.17
	% Load Impact	0.5%	0.6%

Previous vs. Current Ex-Ante

In this sub-section, we compare the ex-ante forecast prepared following PY2020 (the "previous study") to the ex-ante forecast contained in this study (the "current study"). Table 4.23 reports the average event-hour load impacts for the 2023 typical event day under utility-specific 1-in-2 weather conditions. The per-customer reference load is larger in the current study, combined with a larger load impact percentage, results in larger per-customer load impacts. The aggregate result is a 4.2 MWh/hour load impacts, which is larger than the previous study 3.8 MWh/hour load impact, even with decreased enrollment numbers.

Table 4.23: Previous vs. Current Ex-Ante Load Impacts, *Utility 1-in-2 August Typical Event Day, SCE Medium*

Level	Outcome	Ex-ante for 2023 Typical Event Day, Previous Study	Ex-ante for 2023 Typical Event Day, Current Study
Total	# SAIDs	29,901	24,560
	Reference (MW)	749	655
	Load Impact (MW)	3.8	4.2
	Avg. Temp.	87.5	87.6
Per SAID	Reference (kW)	25.0	26.7
	Load Impact (kW)	0.13	0.17
	% Load Impact	0.5%	0.6%

Previous Ex-Ante vs. Current Ex-Post

Table 4.24 provides a comparison of the ex-ante forecast of 2021 load impacts prepared following PY2020 and the PY2021 load impacts estimated as part of this study. The ex-ante forecast shown in the table represents the typical event day during a utility-specific 1-in-2 weather year. The ex-post load impacts are based on the average event day. The total load impact is somewhat higher in the current ex-post study due to larger average customer reference loads (offset by lower enrollments).

Table 4.24: Previous Ex-Ante vs. Current Ex-Post Load Impacts, *SCE Medium*

Level	Outcome	Ex-Ante for 2021 Typical Event Day Previous Study	Ex-Post Typical Event Day Current Study
Total	# SAIDs	28,560	27,503
	Reference (MW)	702	721
	Load Impact (MW)	3.7	4.6
	Avg. Temp.	87.5	84.3
Per SAID	Reference (kW)	24.6	26.2
	Load Impact (kW)	0.13	0.17
	% Load Impact	0.5%	0.6%

Current Ex-Post vs. Current Ex-Ante

Table 4.25 compares the ex-post and ex-ante load impacts from this study. The ex-ante load impacts in the table represent the 2023 August typical event day with utility-specific 1-in-2 weather conditions. The percentage load impacts between ex-post and ex-ante are identical because of the methodological design of applying ex-post load impact percentages to ex-ante reference loads. The per-customer reference loads are slightly higher in ex-ante due to hotter event hour temperatures (87.6 °F versus 84.3 °F). The aggregate reference loads and load impacts (4.2 MWh/hour), however, are slightly lower in ex-ante due to the decreased enrollments.

Table 4.25: Current Ex-Post vs. Current Ex-Ante Load Impacts, *SCE Medium*

Level	Outcome	Ex-Post Typical Event Day Current Study	Ex-Ante for 2023 Typical Event Day Current Study
Total	# SAIDs	27,503	24,560
	Reference (MW)	721	655
	Load Impact (MW)	4.6	4.2
	Avg. Temp.	84.3	87.6
Per SAID	Reference (kW)	26.2	26.7
	Load Impact (kW)	0.17	0.17
	% Load Impact	0.6%	0.6%

Table 4.26 documents the various potential sources of differences between the ex-post and ex-ante load impacts. The difference between enrollments is the main driving force for the reduced load impact forecast.

Table 4.26: Comparison of Ex-Post and Ex-Ante Factors, *SCE Medium*

Factor	Ex-Post	Ex-Ante	Expected Impact
Weather	Average event-hour temperature of 84.3 °F during the average event day.	Average event-hour temperature of 87.6 °F during the SCE 1-in-2 August peak day.	Higher temperatures result in larger reference loads which leads to larger load impacts.
Event window	Hours-ending 17 through 21.	Hours-ending 17 through 21.	None, though ex-post event window aligns with the ex-ante event and RA window.
% of resource dispatched	100 percent	100 percent	None.
Enrollment	27,503 service accounts.	24,560 service accounts.	Lower ex-ante enrollment leads to a lower aggregate load impact (*ceteris paribus*).
Methodology	Panel models by LCA with fixed customer effects and controls for day type (e.g., month, day of week) and weather.	Panel models by LCA with fixed customer effects and controls for day type (e.g., month, day of week) and weather.	The method is not expected to consistently produce differences between the ex-post and ex-ante impacts.

4.3.3 Small Customers

Previous vs. Current Ex-Post

Table 4.27 shows the average event-hour reference loads and load impacts for the typical event day during the current and previous program years. The aggregate load

impact is 0.8 MWh/hour in the previous and current study. However, the enrollment number increased in the current study but was offset by lower per-customer load impacts. Higher per-customer reference loads in the current study are likely a factor of customers returning closer to pre-COVID-19 usage levels.

Table 4.27: Previous vs. Current Ex-Post Load Impacts for the Typical Event Day, *SCE Small*

Level	Outcome	Ex-post Previous Study	Ex-post Current Study
Total	# SAIDs	212,615	229,582
	Reference (MW)	284	337
	Load Impact (MW)	0.8	0.8
	Avg. Temp.	83.3	84.1
Per SAID	Reference (kW)	1.34	1.47
	Load Impact (kW)	0.004	0.003
	% Load Impact	0.3%	0.2%

Previous vs. Current Ex-Ante

In this sub-section, we compare the ex-ante forecast prepared following PY2020 (the "previous study") to the ex-ante forecast contained in this study (the "current study"). Table 4.28 reports the average event-hour load impacts for the 2023 typical event day under utility-specific 1-in-2 weather conditions. The previous and current study have similar aggregate, per-customer, and percentage load impacts. Enrollments are lower in the current forecast.

Table 4.28: Previous vs. Current Ex-Ante Load Impacts, *Utility 1-in-2 Typical Event Day*, *SCE Small*

Level	Outcome	Ex-ante for 2023 Typical Event Day, Previous Study	Ex-ante for 2023 Typical Event Day, Current Study
Total	# SAIDs	235,661	212,422
	Reference (MW)	381	320
	Load Impact (MW)	0.7	0.7
	Avg. Temp.	87.1	87.3
Per SAID	Reference (kW)	1.62	1.51
	Load Impact (kW)	0.003	0.004
	% Load Impact	0.2%	0.2%

Previous Ex-Ante vs. Current Ex-Post

Table 4.29 provides a comparison of the ex-ante forecast of 2021 load impacts prepared following PY2020 and the PY2021 load impacts estimated as part of this study. The ex-ante forecast shown in the table represents the typical event day during a utility-specific 1-in-2 weather year. The ex-post load impacts are based on the average event day. The

total load impact is somewhat higher in the current ex-post study due to larger average customer reference loads and enrollments (offset by lower percentage load impacts).

Table 4.29: Previous Ex-Ante vs. Current Ex-Post Load Impacts, *SCE Small*

Level	Outcome	Ex-Ante for 2021 Typical Event Day Previous Study	Ex-Post Typical Event Day Current Study
Total	# SAIDs	225,092	229,582
	Reference (MW)	358	337
	Load Impact (MW)	0.7	0.8
	Avg. Temp.	87.1	84.1
Per SAID	Reference (kW)	1.59	1.47
	Load Impact (kW)	0.003	0.003
	% Load Impact	0.2%	0.2%

Current Ex-Post vs. Current Ex-Ante

Table 4.30 compares the ex-post and ex-ante load impacts from this study. The ex-ante load impacts in the table represent the 2023 August typical event day with utility-specific 1-in-2 weather conditions. The ex-post percentage load impacts were applied to ex-ante reference loads, resulting in equivalent percentage load impacts. The per-customer ex-ante reference loads are higher due to hotter event hour-temperatures. The aggregate reference load and load impact is lower in ex-ante due to decreased enrollment numbers.

Table 4.30: Current Ex-Post vs. Current Ex-Ante Load Impacts, *SCE Small*

Level	Outcome	Ex-Post Typical Event Day Current Study	Ex-Ante for 2023 Typical Event Day Current Study
Total	# SAIDs	229,582	212,422
	Reference (MW)	337	320
	Load Impact (MW)	0.8	0.7
	Avg. Temp.	84.1	87.3
Per SAID	Reference (kW)	1.47	1.51
	Load Impact (kW)	0.003	0.004
	% Load Impact	0.2%	0.2%

Table 4.31 documents the various potential sources of differences between the ex-post and ex-ante load impacts. The difference between enrollments is the main driving force for the reduced load impact forecast.

Table 4.31: Comparison of Ex-Post and Ex-Ante Factors, *SCE Small*

Factor	Ex-Post	Ex-Ante	Expected Impact
Weather	Average event-hour temperature of 84.1 °F during the average event day.	Average event-hour temperature of 87.3 °F during the SCE 1-in-2 August peak day.	Higher ex-ante temperatures increase the per-customer reference load and load impact.
Event window	Hours-ending 17 through 21.	Hours-ending 17 through 21.	None, though ex-post event window aligns with the ex-ante event and RA window.
% of resource dispatched	100 percent	100 percent	None.
Enrollment	229,582 service accounts.	212,422 service accounts.	Lower ex-ante enrollment leads to a lower aggregate load impact (*ceteris paribus*).
Methodology	Panel models by LCA with fixed customer effects and controls for day type (e.g., month, day of week) and weather.	Panel models by LCA with fixed customer effects and controls for day type (e.g., month, day of week) and weather.	The method is not expected to consistently produce differences between the ex-post and ex-ante impacts.

5. SDG&E

5.1 SDG&E Ex-Ante Load Impacts

This section provides the ex-ante CPP load impact forecasts based on an enrollment forecast provided by SDG&E. Results are presented by size group. First, the enrollment forecast provided by SDG&E is summarized in figures on an annual basis. Second, results for all hours for the average weekday event in 2023 are illustrated in figures to convey the shape of ex-ante reference loads. Finally, forecasted ex-ante load impacts are summarized in figures by month and forecast year. Detailed results for each hour, weather scenario, month, and forecast year are available in electronic form in Protocol table generators provided along with this report.

As described in Section 2.2, *per-customer load impacts* are derived from the ex-ante load impacts provided in the previous PY2020 analysis since no events were called in 2021. The PY2020 ex-ante percentage load impacts are applied to the PY2021 ex-ante reference loads to produce ex-ante load impacts that vary by weather scenario and month. Beginning on June 1, 2022, will change its CPP event hours, moving the event window of 2 to 6 p.m. (HE 15 to 18) to align with the RA window of 4 to 9 pm (HE 17 to 21). To apply load impacts that correspond to the updated CPP event hours, we first

categorize each hour of the day with respect to the old and updated CPP event hours. Table 5.1 summarizes our categorization of each hour, with the "Previous Event Window" column representing the current event hours and the "Ex-ante Event Window" column representing the new CPP event window starting in June 2022.[13] The PY2020 ex-ante reference loads and load impacts are averaged over these periods to obtain percentage load impacts, which are then applied to PY2021 ex-ante reference loads during the corresponding categorized period to calculate the ex-ante load impacts. For example, the PY2020 ex-ante percentage load impact for the hour before the previous event window (HE 14) is applied to the PY2021 ex-ante reference load for the hour before the ex-ante event window (HE 16).

Table 5.1: SDG&E Hourly Categorization of Periods Relating to Change in CPP Event Window

Hour	*Previous Event Window*	*Ex-Ante Event Window*
1	Beginning of Event Day	Beginning of Event Day
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14	Pre-event hour	
15	Beginning of Event	
16	Middle of Event	Pre-event hour
17		Beginning of Event
18	End of Event	
19	Post-event hour	Middle of Event
20	Remainder of Event Day	
21		End of Event
22		Post-event hour
23		Remainder of Event Day
24		

[13] PY2020 ex-ante percentage load impacts are applied to PY2021 reference loads on an hourly basis for the period before SDG&E changes the event window; specifically, January 2022 through May 2022.

5.1.1 All Customers

Figure 5.1 summarizes the trend of SDG&E's enrollment forecast for medium and large customers combined. The enrollments exclude any customers dually enrolled in AC Saver Day-ahead.[14] SDG&E anticipates the total number of customers decreases about 12 percent per year.

Figure 5.1: CPP Enrollments, *SDG&E All*

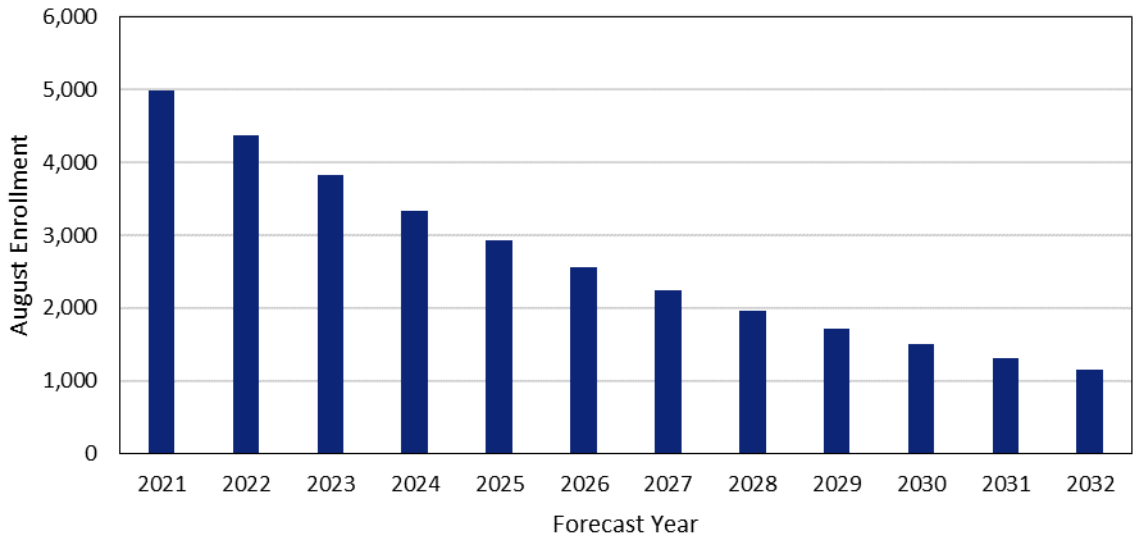
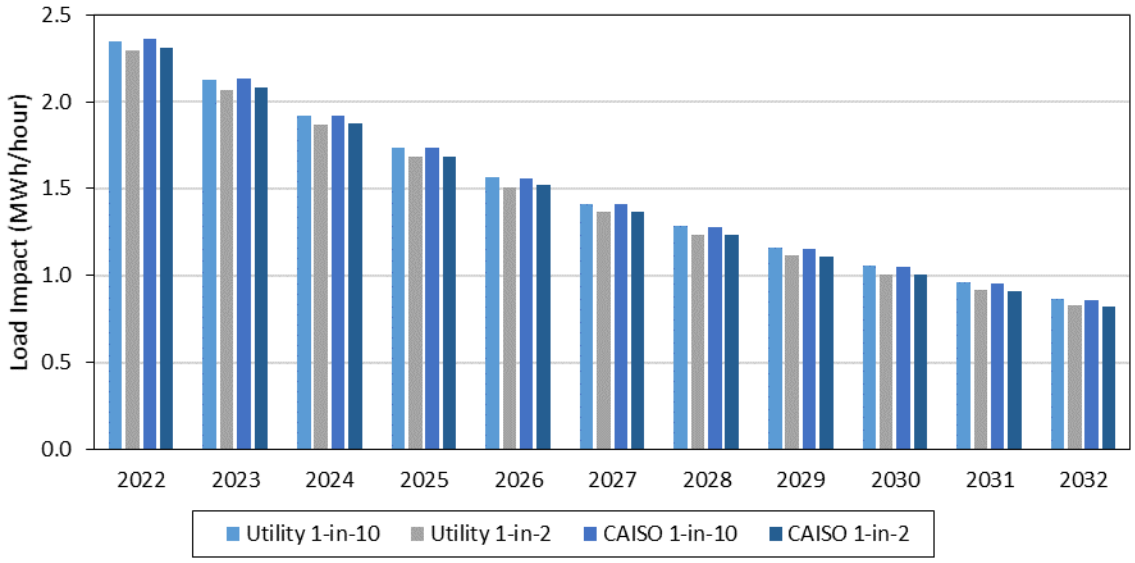


Figure 5.2 shows the change in aggregate load impacts over time and across weather scenarios for all customers. Each value is the aggregate load impact during the RA window of the typical event day. Load impacts decrease after 2022 because of reductions in enrollments. The load impacts of the 1-in-10 scenarios are higher than 1-in-2 scenarios, but the difference is only about 0.05 MWh/hour. Additional results of ex-ante load impacts are presented in the subsequent sections by customer size.

[14] AC Saver Day-ahead is also referred to as Technology Deployment (TD).

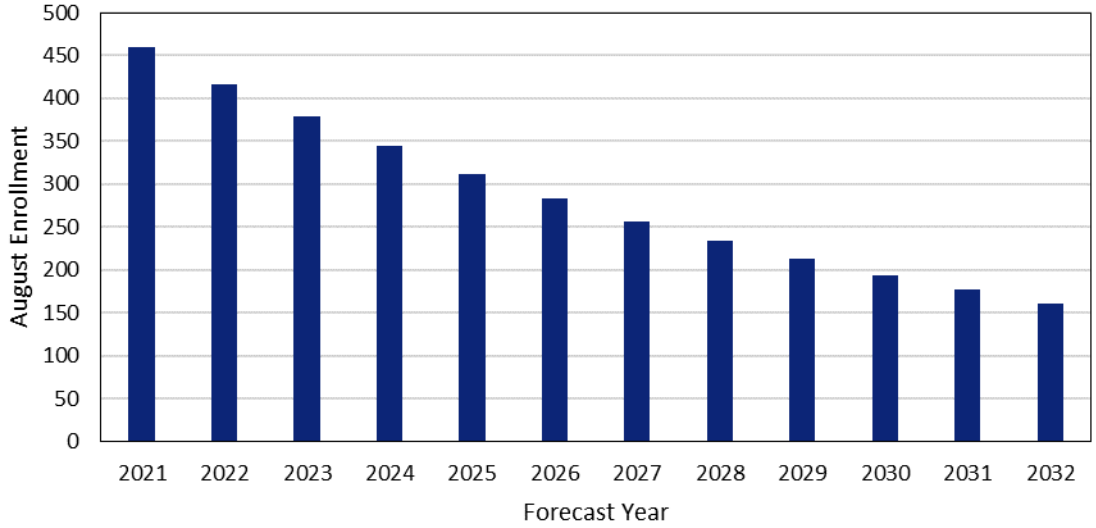
Figure 5.2: Aggregate Load Impacts for Typical Event Day by Year and Weather Scenario over RA Window, *SDG&E All*



5.1.2 Large Customers

Figure 5.3 summarizes SDG&E's enrollment forecast for large customers. The enrollments exclude any customers dually enrolled in AC Saver Day-ahead.[15] SDG&E anticipates an average decrease in large customers of about 9 percent per year.

Figure 5.3: CPP Enrollments, *SDG&E Large*



[15] AC Saver Day-ahead is also referred to as Technology Deployment (TD).

Figure 5.4 illustrates the aggregate reference loads, observed loads, and load impacts for large customers on the typical event day in August of 2023 for the SDG&E 1-in-2 weather scenario. The shape of the load impact is concentrated around the event hours due the applying the previous PY2021 ex-ante percentage load impacts to specific periods (which reduces the amount of variation between hours). The event window has been shifted to the 4 to 9 p.m. (as opposed to the previous 2 to 6 p.m. event window). The forecast predicts an average load impact of 1.7 MWh/hour for large customers on the average weekday event in 2023 for the SDG&E 1-in-2 weather scenario, which is a 1.9 percent reduction in reference loads.

Figure 5.4: Aggregate Hourly Loads and Load Impacts in 2023 for *SDG&E 1-in-2 Typical Event Day, SDG&E Large*

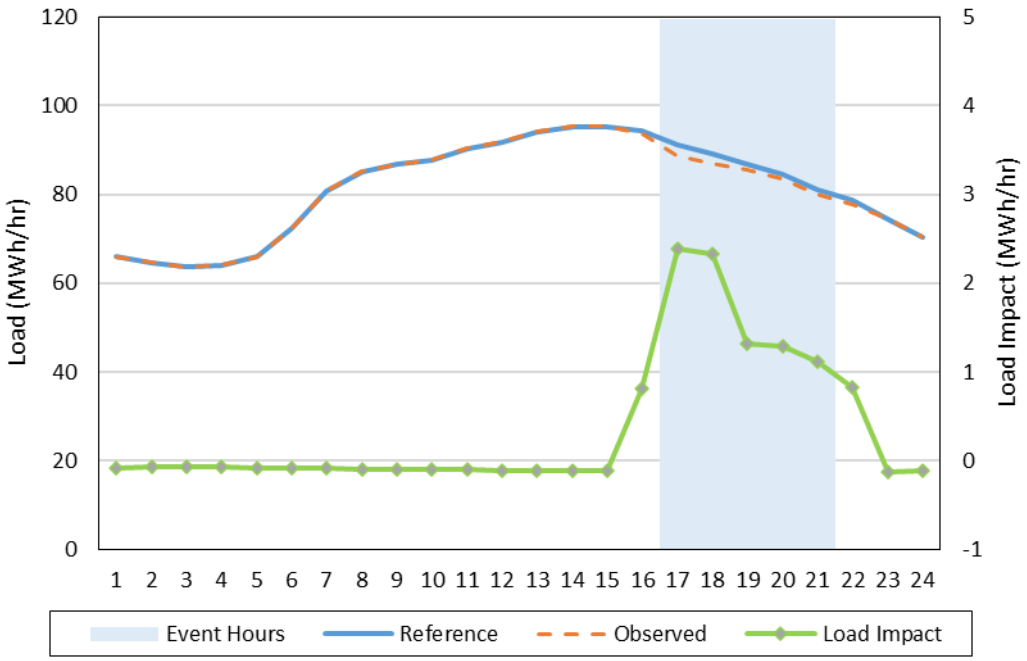


Figure 5.5 illustrates the seasonality in the forecasted load impacts by comparing aggregate load impacts for the average hour in the Resource Adequacy (RA) window in 2023 across months for SDG&E's 1-in-2 peak day weather scenario. The RA window is 4 to 9 p.m. The load impact is highest in September (1.8 MWh/hour) and lowest in December (1.1 MWh/hour).

Figure 5.5: Aggregate Load Impacts by Month over RA Window in 2023 for *SDG&E 1-in-2 Peak Day, SDG&E Large*

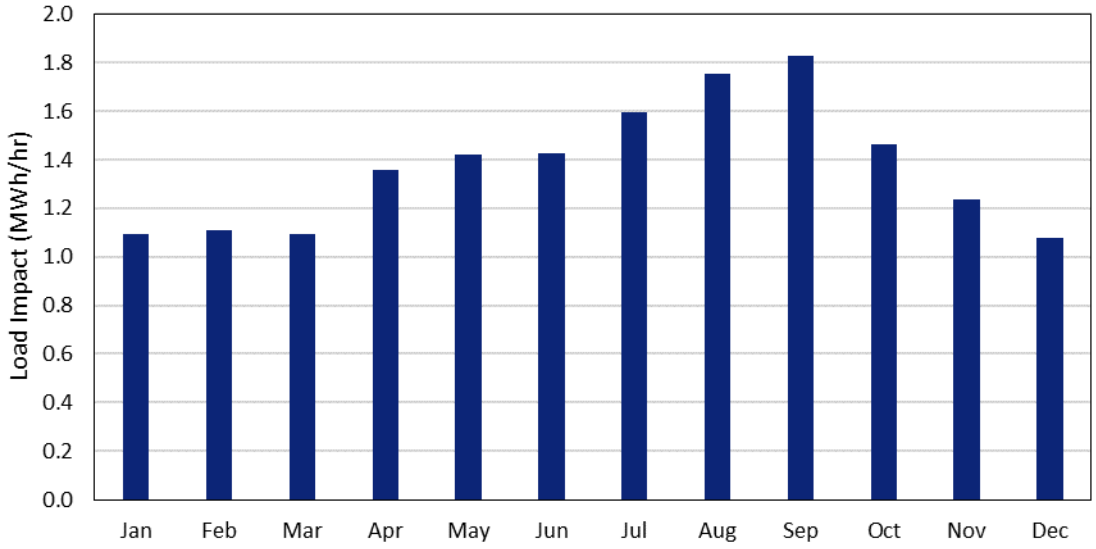
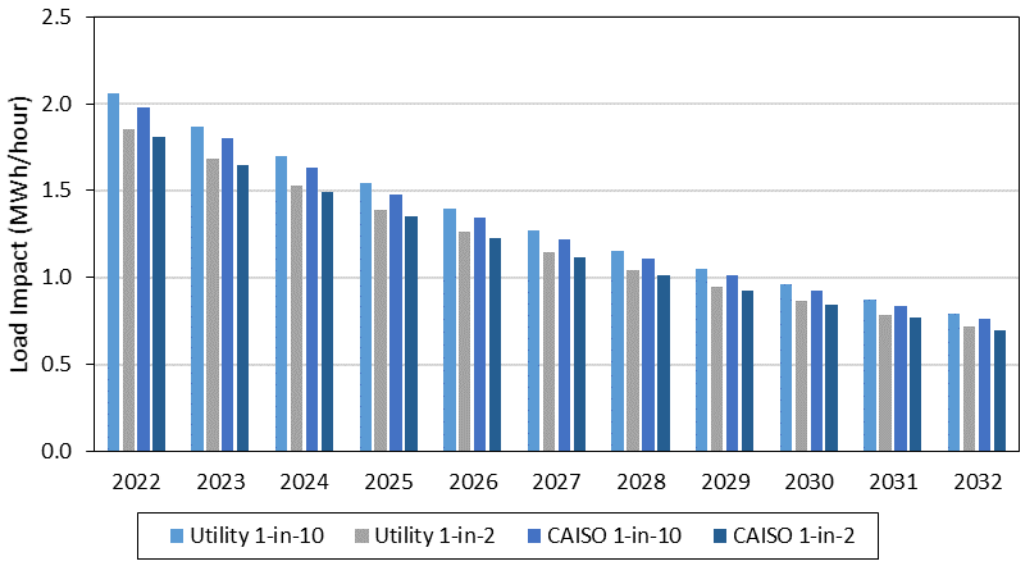


Figure 5.6 shows the change in load impacts over time and across weather scenarios. Each value is the aggregate load impact during the RA window of the typical event day. Load impacts decrease after 2022 because of reductions in enrollments. As expected, the largest load impacts occur for the SDG&E 1-in-10 weather year while the lowest load impacts occur during the CAISO 1-in-2 weather year. Nonetheless, the range of difference in load impacts between weather scenarios is about 0.2 MWh/hour.

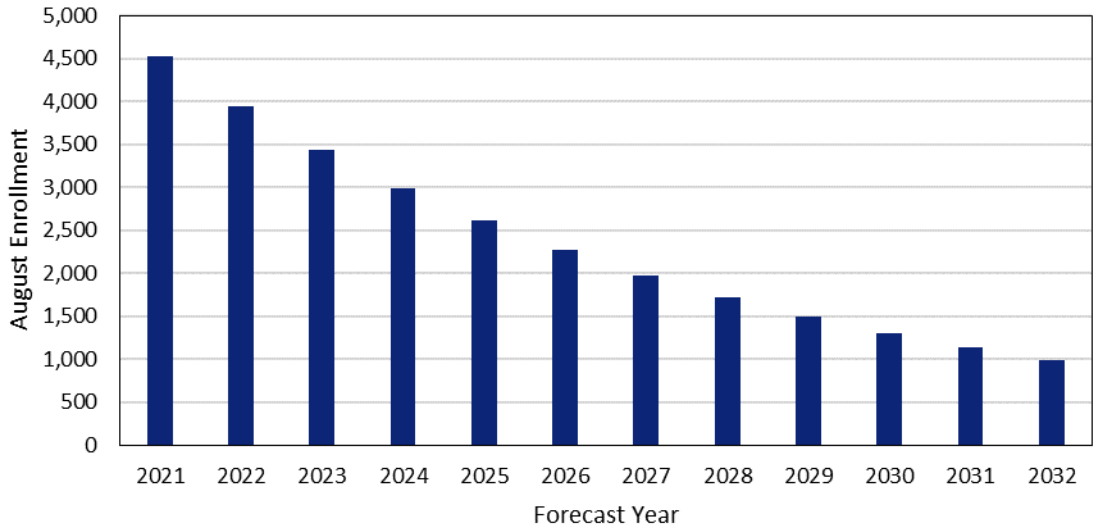
Figure 5.6: Aggregate Load Impacts for Typical Event Day by Year and Weather Scenario over RA Window, *SDG&E Large*



5.1.3 Medium Customers

Figure 5.7 summarizes SDG&E's enrollment forecast for medium customers. The enrollments exclude any customers dually enrolled in AC Saver Day-ahead. [16] SDG&E anticipates an average decrease in medium customers of 13 percent per year.

Figure 5.7: CPP Enrollments, *SDG&E Medium*



[16] AC Saver Day-ahead is also referred to as Technology Deployment (TD).

Figure 5.8 illustrates the aggregate reference loads, observed loads, and load impacts for medium customers on the typical event day in August of 2023 for the SDG&E 1-in-2 weather scenario. The shape of the load impact is concentrated around the event hours due the applying the previous PY2021 ex-ante percentage load impacts to specific periods (which reduces the amount of variation between hours). The event window has been shifted to the 4 to 9 p.m. (as opposed to the previous 2 to 6 p.m. event window). The forecast predicts an average load impact of 0.4 MWh/hour, or 0.4 percent of the reference load.

Figure 5.8: Aggregate Hourly Loads and Load Impacts in 2023 for *SDG&E 1-in-2 Typical Event Day, SDG&E Medium*

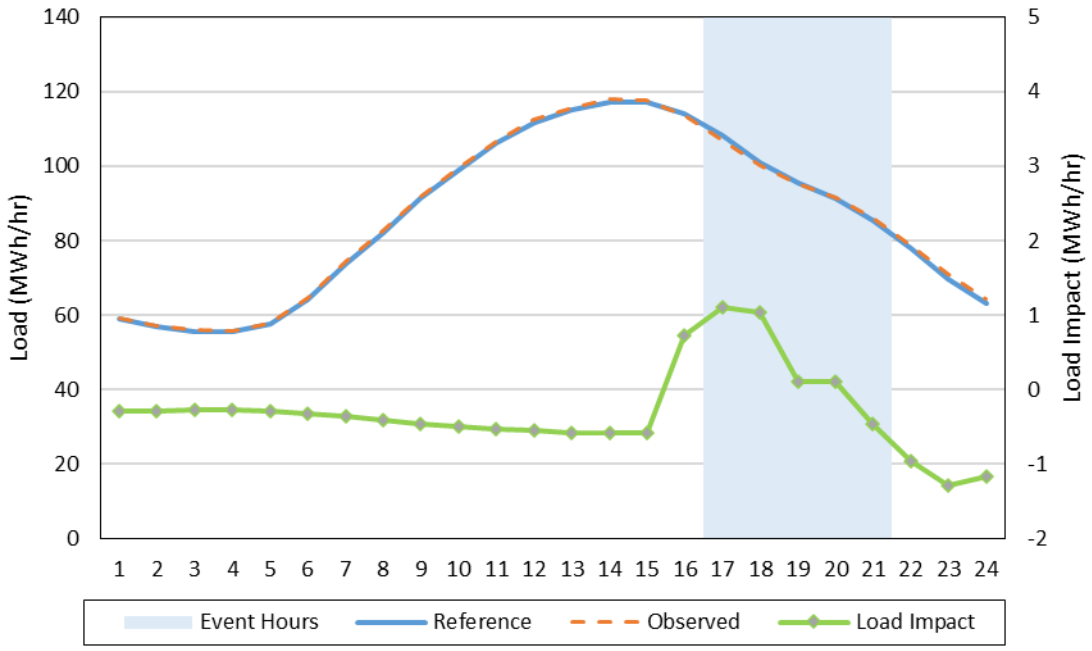


Figure 5.9 shows the seasonality of the forecasted load impacts for medium customers based on the 2023 aggregate load impacts for the average hour in the RA window for SDG&E's 1-in-2 weather scenario. As with the large customers, the load impacts follow the seasonal pattern of reference loads over the RA window of 4 to 9 p.m. Additionally percentage load impacts are slightly higher during the summer months. The load impact is highest in September (0.4 MWh/hour) and lowest in December (0.25 MWh/hour).

Figure 5.9: Aggregate Load Impacts by Month over RA Window in 2023 for *SDG&E 1-in-2 Peak Day, SDG&E Medium*

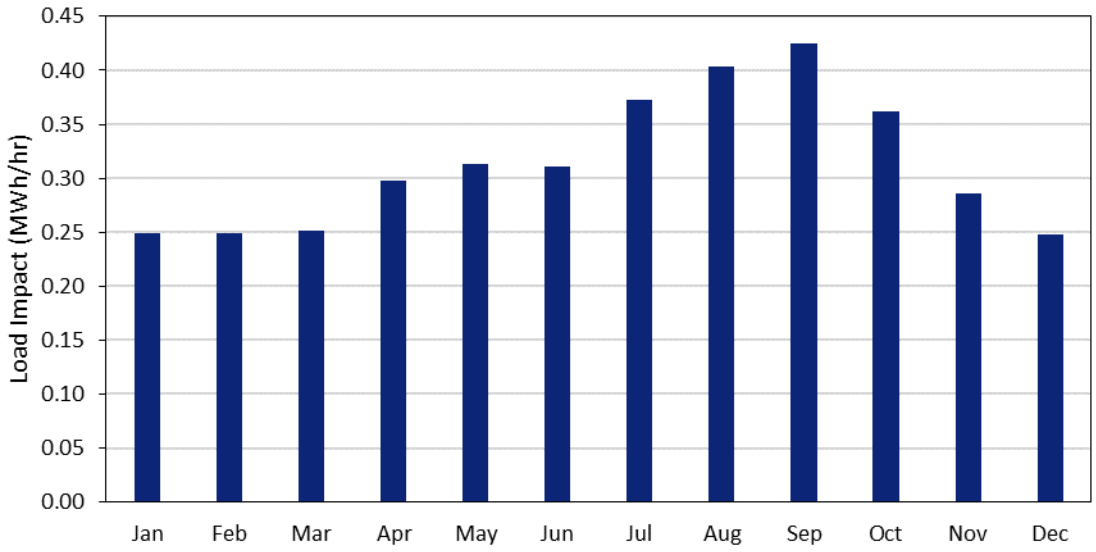
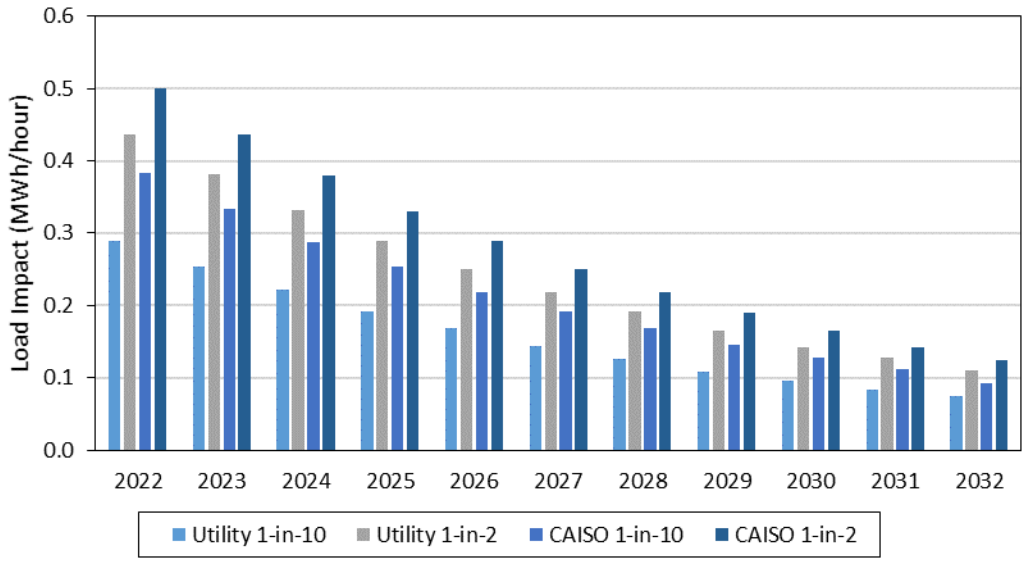


Figure 5.10 shows the change in load impacts over time and across weather scenarios. Each value is the aggregate load impact during the RA window of the typical event day. Load impacts decrease over time because of the reduction in forecast enrollments. Reference loads are largest for the SDG&E 1-in-10 and CAISO 1-in-2 weather scenarios; however, PY2020 ex-ante percentage load impacts are also lowest during these scenarios, resulting in lower load impacts for the 1-in-10 scenarios relative to 1-in-2 scenarios. The range of difference in load impacts between weather scenarios is about 0.12 MWh/hour.

Figure 5.10: Aggregate Load Impacts for Typical Event Day by Year and Weather Scenario over RA Window, *SDG&E Medium*



5.2 SDG&E Load Impact Reconciliations

In a continuing effort to clarify the relationships between ex-post and ex-ante results, this section compares findings from this study to those of the previous study. Because there SDG&E did not call any CPP events during this program year, we cannot conduct our usual comparisons of ex-post impacts. Therefore, we focus on a comparison of ex-ante impacts across program years. In the text below, the term "current" refers to the present study while the term "previous" refers to findings from PY2020.

5.2.1 Large Customers

Previous vs. Current Ex-Ante

In this sub-section, we compare the ex-ante forecast prepared following PY2020 (the "previous study") to the ex-ante forecast contained in this study (the "current study"). Table 5.2 reports the average weekday event-hour load impacts for the August 2023 typical event day under utility-specific 1-in-2 weather conditions. Results for the RA window and Event window are provided for the previous study since the event window did not previously align with the RA window. As a result, the load impact during the RA window was 0.8 percent, lower than the 1.8 percent load impact during the event window. The current study results indicate a load impact of 1.9 percent during the RA window, which now overlaps completely with the event window. The number of enrollments decreased slightly from the previous study, resulting in slightly lower aggregate load impacts of 1.7 MWh/hour when compared to the previous study event window load impacts of 1.8 MWh/hour.

Table 5.2: Previous vs. Current Ex-Ante Load Impacts, *Utility 1-in-2*
2023 Typical Event Day, SDG&E Large

Level	Outcome	Previous Study RA Window	Previous Study Event Window	Current Study RA Window
Total	# SAIDs	425	425	379
	Reference (MW)	93	102	87
	Load Impact (MW)	0.8	1.8	1.7
	Avg. Temp.	80.9	85.1	81.5
Per SAID	Reference (kW)	218.3	240.2	228.5
	Load Impact (kW)	1.82	4.26	4.45
	% Load Impact	0.8%	1.8%	1.9%

5.2.2 Medium Customers

Previous vs. Current Ex-Ante

In this sub-section, we compare the ex-ante forecast prepared following PY2020 (the "previous study") to the ex-ante forecast contained in this study (the "current study"). Table 5.3 reports the average weekday event-hour load impacts for the typical event day in 2023 under utility-specific 1-in-2 weather conditions. Results for the RA window and Event window are provided for the previous study since the event window did not previously align with the RA window. As a result, the load impact during the RA window was -1.1 percent, lower than the 0.2 percent load impact during the event window. The current study results indicate a load impact of 0.4 percent during the RA window, which now overlaps completely with the event window. The current study load impact is slightly higher than the previous study's event window results because period-specific load impact percentages are applied (as shown in Table 5.1). The number of enrollments decreased from the previous study; however, the load impact of 0.4 MWh/hour is slightly higher as a result of the higher percentage load impact.

Table 5.3: Previous vs. Current Ex-Ante Load Impacts, *Utility 1-in-2*
2023 Typical Event Day, SDG&E Medium

Level	Outcome	Previous Study RA Window	Previous Study Event Window	Current Study RA Window
Total	# SAIDs	4,359	4,359	3,440
	Reference (MW)	121	139	96
	Load Impact (MW)	-1.3	0.3	0.4
	Avg. Temp.	80.7	84.7	81.3
Per SAID	Reference (kW)	27.74	31.78	28.00
	Load Impact (kW)	-0.31	0.06	0.11
	% Load Impact	-1.1%	0.2%	0.4%

6. Recommendations

In 2021, SDG&E didn't call any events. Calling events will improve the understanding of customer response to the program.

For PG&E, we note that PDP load impacts are largely driven by customers dually enrolled in BIP. Recruiting and retaining more BIP customers may improve PDP load impacts.

Appendices

The following Appendices accompany this report. Appendix A presents the matching quality associated with our ex-post load impact evaluation. The additional appendices consist of Excel files that can produce the tables required by the Protocols.

Appendix B	PDP PG&E Ex-post Load Impact Tables
Appendix C	PDP PG&E Ex-ante Load Impact Tables
Appendix D	CPP SCE Ex-post Load Impact Tables
Appendix E	CPP SCE Ex-ante Load Impact Tables
Appendix F	CPP SDG&E Ex-post Load Impact Tables
Appendix G	CPP SDG&E Ex-ante Load Impact Tables

Appendix A. Model Validity Assessment

This appendix presents additional details regarding our model validation process to determine which regression specifications are used in our ex-post analysis.

A.1 Selection of Event-Like Non-Event Days

To select event-like non-event days, we create an average weather profile using the load-weighted average temperature across customers, each of which is associated with a weather station.

We select days according to the average event-hours, omitting holidays, weekends (for SCE and SDG&E), event days for programs in which customers are dually enrolled (e.g., BIP), Flex Alert days, and Public Safety Power Shutoff days. For the most part, the selection involved selecting the hottest qualifying days. Table A.1 lists the event-like non-event days selected, separated by weekday and weekend for PG&E.

Table A.1: List of Event-Like Non-Event Days by IOU

PG&E		SCE
Weekday	Weekend	Weekday
6/16/2021	6/19/2021	6/28/2021
6/28/2021	7/11/2021	7/1/2021
6/29/2021	7/17/2021	7/2/2021
7/1/2021	7/18/2021	7/6/2021
7/2/2021	7/25/2021	7/7/2021
7/19/2021	7/31/2021	7/8/2021
7/23/2021	8/14/2021	7/14/2021
7/26/2021	8/15/2021	7/16/2021
7/27/2021	8/28/2021	7/19/2021
7/30/2021	8/29/2021	7/20/2021
8/6/2021		7/21/2021
8/9/2021		7/22/2021
8/10/2021		8/2/2021
8/11/2021		8/3/2021
8/13/2021		8/4/2021
8/26/2021		8/5/2021
8/27/2021		8/9/2021
8/30/2021		8/10/2021
9/7/2021		8/13/2021
9/21/2021		8/26/2021
		8/27/2021
		9/7/2021

A.2 Model Specification Tests

Customer-Specific Models

We test a range of model specifications before arriving at the model used in the ex-post load impact analysis of customer specific models. The tests are conducted using average-customer data by industry group and weather-sensitivity classification. Model variations include 17 combinations of weather-related variables for weather-sensitive customers and 5 different specifications of non-weather-related variables for non-weather sensitive customers.

The basic structure of the model for weather-sensitive customers is shown in Section 2.1.4. The weather variables include: temperature-humidity index (THI)[17]; heat index

[17] THI = $T - 0.55 \times (1 - HUM) \times (T - 58)$ if T>=58 or THI = T if T<58, where T = ambient dry-bulb temperature in degrees Fahrenheit and HUM = relative humidity (where 10 percent is expressed as "0.10").

(HI)[18]; cooling degree hours (CDH)[19], including both a 60 and 65 degree Fahrenheit threshold; the 3-hour moving average of CDH; cooling degree days (CDD)[20], including both a 60 and 65 degree Fahrenheit threshold; the one-day lag of cooling degree days, and the average of the temperatures in degrees Fahrenheit during the first 17 hours of the day (Mean17). A list of the combinations of these variables that we test for weather-sensitive customers is provided in Table A.2, including 17 specifications for the individual customer ex-post analysis.[21]

Table A.2: Weather Variables Included in the Tested Specifications for Weather Sensitive Customers, *Customer-Specific Models*

Model Number	Weather Variables
1	THI
2	HI
3	CDH60
4	CDH65
5	CDD60
6	CDD65
7	Mean 17
8	CDH60_MA3
9	CDH65_MA3
10	THI Lag_CDD60
11	HI, Lag_CDD60
12	CDH60, Lag_CDD60
13	CDH65, Lag_CDD60
14	CDH60_MA3, Lag_CDD60
15	CDH65_MA3, Lag_CDD60
16	CDH60, Mean17
17	CDH65, Mean17

The model specifications for non-weather sensitive customers do not include any weather variables but have different combinations of non-weather-related variables. The variables include combinations of indicator variables and interactions of month, hour, Monday, Friday, and morning load. A list of the five combinations of these variables is shown in Table A.3, where an "X" between two variables represents the

[18] HI = $c_1 + c_2T + c_3R + c_4TR + c_5T^2 + c_6R^2 + c_7T^2R + c_8TR^2 + c_9T^2R^2 + c_{10}T^3 + c_{11}R^3 + c_{12}T^3R + c_{13}TR^3 + c_{14}T^3R^2 + c_{15}T^2R^3 + c_{16}T^3R^3$, where T = ambient dry-bulb temperature in degrees Fahrenheit and R = relative humidity (where 10 percent is expressed as "10"). The values for the various c's may be found here: http://en.wikipedia.org/wiki/Heat_index.

[19] Cooling degree hours (CDH) was defined as MAX[0, Temperature – Threshold], where Temperature is the hourly temperature in degrees Fahrenheit and Threshold is either 60 or 65 degrees Fahrenheit. Customer-specific CDH values are calculated using data from the most appropriate weather station.

[20] Cooling degree days (CDD) are defined as MAX[0, (Max Temp + Min Temp) / 2 – 60], where Max Temp is the daily maximum temperature in degrees Fahrenheit and Min Temp is the daily minimum temperature. Customer-specific CDD values are calculated using data from the most appropriate weather station.

[21] Humidity data for PG&E was not available in PY2021. Therefore, the set of specifications we test for PG&E excludes the entries that require humidity.

interaction of these two variables. Each specification includes the following variables in common: hour indicators, day type indicators, and events interacted with hour indicators. For the ex-ante analysis, we exclude the specifications with the morning load variable.

Table A.3: Variables Included in the Tested Specifications for Non-Weather Sensitive Customers, *Customer-Specific Models*

Model Number	Included Non-Weather-Related Variables
1	Month X Hour
2	Month X Hour, Monday X Hour, Friday X Hour
3	Month, Monday X Hour, Friday X Hour, Morningload X Hour
4	Month X Hour, Morningload X Hour
5	Month X Hour, Monday X Hour, Friday X Hour, Morningload X Hour

Panel Models

Similar to the customer-specific model specification search described above, a range of models are tested before determining which variables are included in the ex-post panel regression models. For each size category, model validation tests are conducted using average per-customer event-hour usage over days including events and selected event-like non-event days selected (see Table A.1).[22] Panel models follow the basic structure provided in Section 2.1.4, including day type and weather variables. The day type variable includes controls for events (both CPP and other demand response programs), day of week (e.g., Monday, Friday), month, and morning load patterns. Table A.4 provides the 11 weather specifications that were tested. Variables that include lags or moving averages are excluded from the model search because the panel days only include event-days and event-like non-event days, unlike the customer-specific models.

Table A.4: Weather Variables Included in Tested Specifications, *Panel Models*

Model Number	Weather Variables
1	THI
2	HI
3	CDH60
4	CDH65
5	CDD60
6	CDD65
7	Mean 17
8	CDH60, Mean17
9	CDH65, Mean17
10	CDD60, Mean17
11	CDD65, Mean17

[22] The model validation event hours are hours-ending 18-20 for PG&E and 17-21 for SCE. Model validation did not occur for SDG&E since no events were called.

Validation Test

For both the customer-specific and panel models, the model variations are evaluated according to the ability to predict usage on event-like *non-event days*. Specifically, we identify a set of days that are similar to event days, but were not called as event days (i.e., "test days"). The use of non-event test days allows us to test model performance against known "reference loads," or customer usage in the absence of an event. We estimate the model excluding one of the test days and use the estimates to make out-of-sample predictions of customer loads on that day. The process is repeated for all of the test days. The model fit (i.e., the difference between the actual and predicted loads on the test days, during afternoon hours in which events are typically called) is evaluated using mean absolute percentage error (MAPE) as a measure of accuracy, and mean percentage error (MPE) as a measure of bias.

A.3 Results from Tests of Alternative Weather Specifications

For customer-specific models, we test 17 different sets of weather variables for weather sensitive customers and 5 different specifications for non-weather sensitive customers. For panel models, we test 11 different sets of weather variables. The aggregate load used in conducting these tests was constructed separately for each industry group and weather sensitivity categorization in the customer-specific models. In contrast, the aggregate load profiles were constructed separately by size group for the panel models. Only customers who were called on at least one event day are included.

The tests are conducted by estimating one model for every group (i.e., industry and weather sensitivity for customer specific models; and size for panel models), specification (17 for weather sensitive customers, 5 for non-weather sensitive customers, 11 for panel model customers), and event-like day. Each model excludes one event-like day from the estimation model and uses the estimated parameters to predict the usage for that day. The MPE and MAPE are calculated across the event windows of the withheld days. The MPE and MAPE values are also calculated across the entire day for the panel model results.

Tables A.5 through A.8 summarize for each utility the mean percentage error (MPE), mean absolute percentage error (MAPE), and number of customers in the sub-group for both customer the customer-specific and panel models. Tables A.5 and A.6 for PG&E bifurcates the results by weekday and weekend.

Table A.5: Specification Test Results for Customer-Specific Models, PG&E

Weekday

Group	Industry Type	Selected Specification	Event-Hour		All-Day		Number of Customers
			MPE	MAPE	MPE	MAPE	
Weather Sensitive	1. Agriculture, Mining, Construction	5	-0.2%	6.6%	0.1%	6.1%	5
	2. Manufacturing	7	0.7%	3.4%	0.4%	3.0%	9
	3. Wholesale, Transportation, Utilities	6	0.0%	2.6%	0.0%	2.1%	11
	4. Retail	N/A	N/A	N/A	N/A	N/A	N/A
	5. Offices, Hotels, Health, Services	15	-0.3%	1.9%	0.0%	1.2%	9
	6. Schools	N/A	N/A	N/A	N/A	N/A	N/A
	7. Entertainment, Other Services, Government	17	-0.1%	2.7%	0.0%	2.4%	4
	8. Other or unknown	N/A	N/A	N/A	N/A	N/A	N/A
Non-Weather Sensitive	1. Agriculture, Mining, Construction	5	2.5%	12.8%	0.8%	10.7%	8
	2. Manufacturing	5	1.0%	5.8%	0.1%	4.0%	15
	3. Wholesale, Transportation, Utilities	3	-1.5%	3.4%	-0.3%	3.7%	6
	4. Retail	N/A	N/A	N/A	N/A	N/A	N/A
	5. Offices, Hotels, Health, Services	N/A	N/A	N/A	N/A	N/A	N/A
	6. Schools	N/A	N/A	N/A	N/A	N/A	N/A
	7. Entertainment, Other Services, Government	2	0.1%	12.9%	0.3%	8.2%	3
	8. Other or unknown	N/A	N/A	N/A	N/A	N/A	N/A

Weekend

Group	Industry Type	Selected Specification	Event-Hour		All-Day		Number of Customers
			MPE	MAPE	MPE	MAPE	
Weather Sensitive	1. Agriculture, Mining, Construction	17	0.8%	8.2%	1.4%	7.2%	4
	2. Manufacturing	3	1.8%	5.4%	-0.2%	4.4%	3
	3. Wholesale, Transportation, Utilities	15	-1.3%	4.4%	-0.3%	3.3%	11
	4. Retail	N/A	N/A	N/A	N/A	N/A	N/A
	5. Offices, Hotels, Health, Services	16	0.0%	1.0%	0.0%	0.9%	11
	6. Schools	N/A	N/A	N/A	N/A	N/A	N/A
	7. Entertainment, Other Services, Government	12	-0.7%	1.4%	-0.2%	2.0%	4
	8. Other or unknown	N/A	N/A	N/A	N/A	N/A	N/A
Non-Weather Sensitive	1. Agriculture, Mining, Construction	5	-1.1%	8.9%	-0.4%	6.4%	10
	2. Manufacturing	5	-0.9%	6.2%	0.1%	4.1%	15
	3. Wholesale, Transportation, Utilities	3	6.1%	8.3%	3.3%	6.3%	7
	4. Retail	3	0.2%	2.3%	0.0%	2.2%	1
	5. Offices, Hotels, Health, Services	3	13.2%	25.9%	12.9%	29.3%	1
	6. Schools	N/A	N/A	N/A	N/A	N/A	N/A
	7. Entertainment, Other Services, Government	1	0.7%	13.9%	0.4%	10.7%	3
	8. Other or unknown	5	-0.8%	2.2%	-0.8%	2.5%	1

Table A.6: Specification Test Results for Panel Models, PG&E

Day Type	Size	Selected Specification	Event-Hour		All-Day		Number of Customers
			MPE	MAPE	MPE	MAPE	
Weekdays	Large	4	0.1%	1.6%	0.0%	1.3%	1,174
	Medium	4	0.1%	0.7%	0.0%	0.8%	16,532
	Small	4	0.1%	1.0%	0.0%	1.1%	86,186
Weekends	Large	6	-0.3%	2.3%	-0.1%	1.9%	1,173
	Medium	4	0.0%	1.2%	0.1%	1.0%	16,531
	Small	4	0.0%	1.3%	0.0%	1.3%	86,172

Table A.7: Specification Test Results for Customer-Specific Models, SCE

Group	Industry Type	Selected Specification	MPE	MAPE	Number of Customers
Weather Sensitive	1. Agriculture, Mining, Construction	4	-0.5%	3.4%	3
	2. Manufacturing	3	-0.7%	1.8%	10
	3. Wholesale, Transportation, Utilities	1	0.0%	5.7%	13
	4. Retail	2	1.2%	4.1%	3
	5. Offices, Hotels, Health, Services	15	-0.5%	1.9%	12
	6. Schools	11	0.6%	5.8%	3
	7. Entertainment, Other Services, Government	9	0.0%	2.9%	3
	8. Other or unknown	n/a	n/a	n/a	n/a
Non-Weather Sensitive	1. Agriculture, Mining, Construction	5	9.5%	28.0%	2
	2. Manufacturing	3	-1.3%	4.8%	19
	3. Wholesale, Transportation, Utilities	3	-0.4%	7.5%	9
	4. Retail	n/a	n/a	n/a	n/a
	5. Offices, Hotels, Health, Services	3	-1.4%	11.4%	3
	6. Schools	n/a	n/a	n/a	n/a
	7. Entertainment, Other Services, Government	3	1.4%	9.7%	2
	8. Other or unknown	5	8.3%	15.6%	1

Table A.8: Specification Test Results for Panel Models, SCE

Size	Selected Specification	Event-Hour		All-Day		Number of Customers
		MPE	MAPE	MPE	MAPE	
Large	10	0.00%	1.15%	0.02%	1.34%	1,459
Medium	8	0.00%	0.64%	0.00%	0.62%	30,016
Small	2	0.02%	0.79%	0.01%	0.64%	227,807

A.4 Comparison of Predicted and Observed Loads on Event-like Days

The model specification tests are based on the ability of the model to predict program load on event-like non-event days. Figures A.1 through A.6 illustrate each utility's average predicted and observed loads across the event-like days using the specification chosen for each customer or group. In each figure, the solid line represents the observed load and the dashed line represents the load predicted by the statistical model. Figures A.1 and A.2 provide weekday load profiles for PG&E while figures A.3 and A.4 provide weekend load profiles. Figures A.1, A.3 (PG&E), and A.5 (SCE), provides loads for large customers, separating the results between the customer-specific and panel models. Figures A.2, A.4 (PG&E), and A.6 (SCE) provides predicted and observed loads separately for small and medium customers, both of which were estimated using panel models. These figures show that the predicted loads are quite close to the observed loads for the event-like non-event days.

Figure A.1: Average Observed & Predicted Loads on Weekday Event-Like Days, Large Customers, *PG&E*

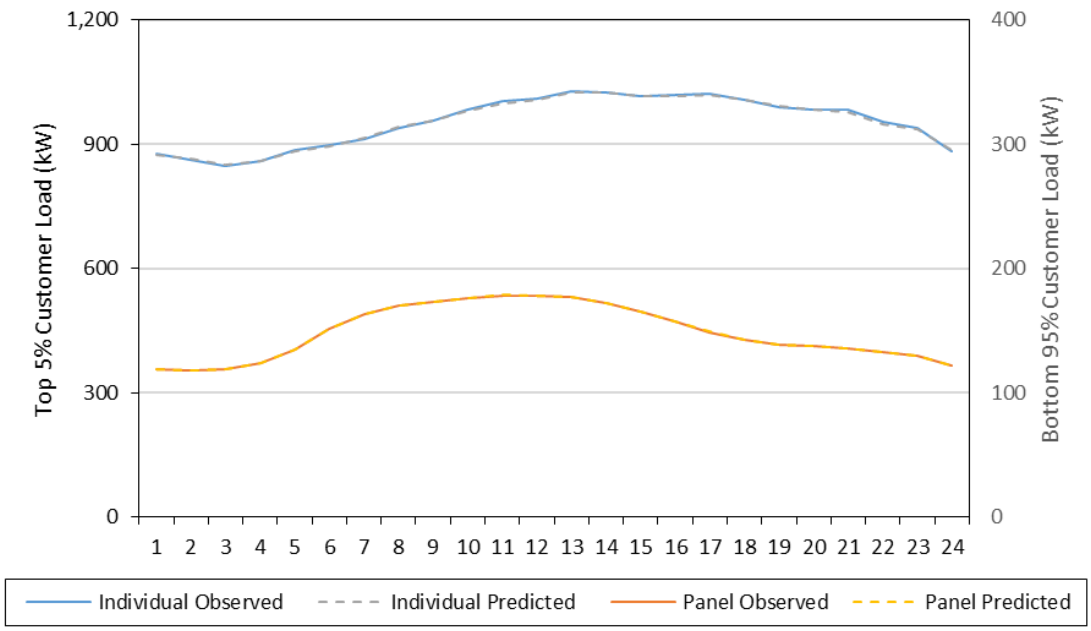


Figure A.2: Average Observed & Predicted Loads on Weekday Event-Like Days, Small and Medium Customers, *PG&E*

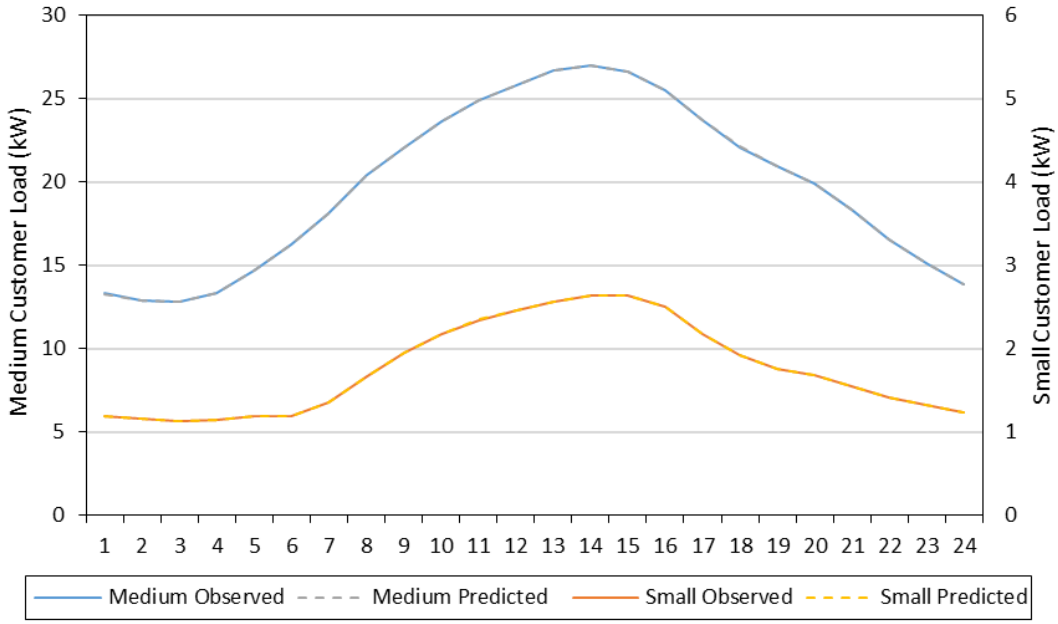


Figure A.3: Average Observed & Predicted Loads on Weekend Event-Like Days, Large Customers, *PG&E*

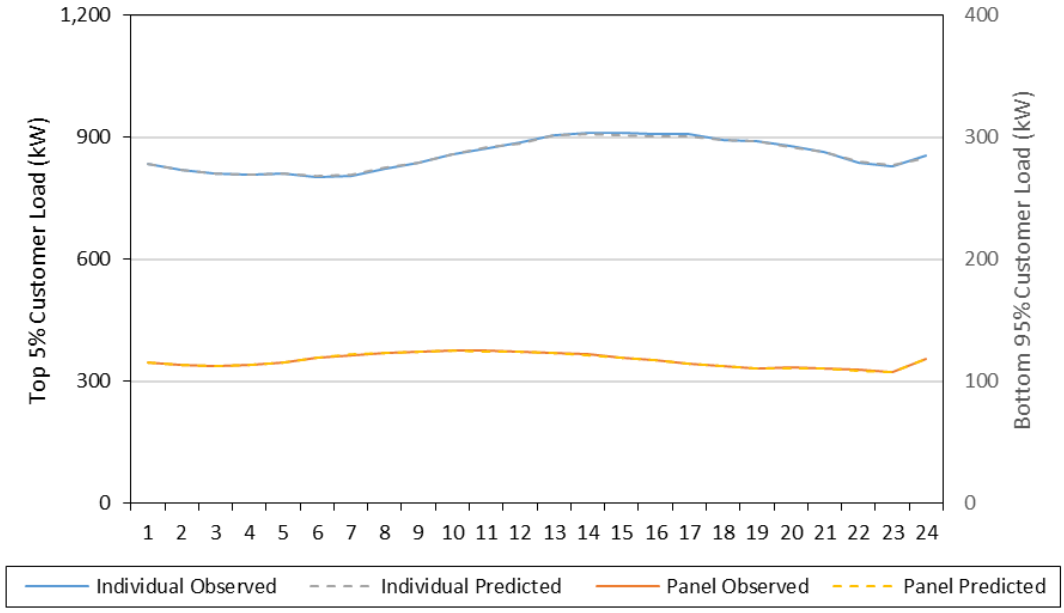


Figure A.4: Average Observed & Predicted Loads on Weekend Event-Like Days, Small and Medium Customers, *PG&E*

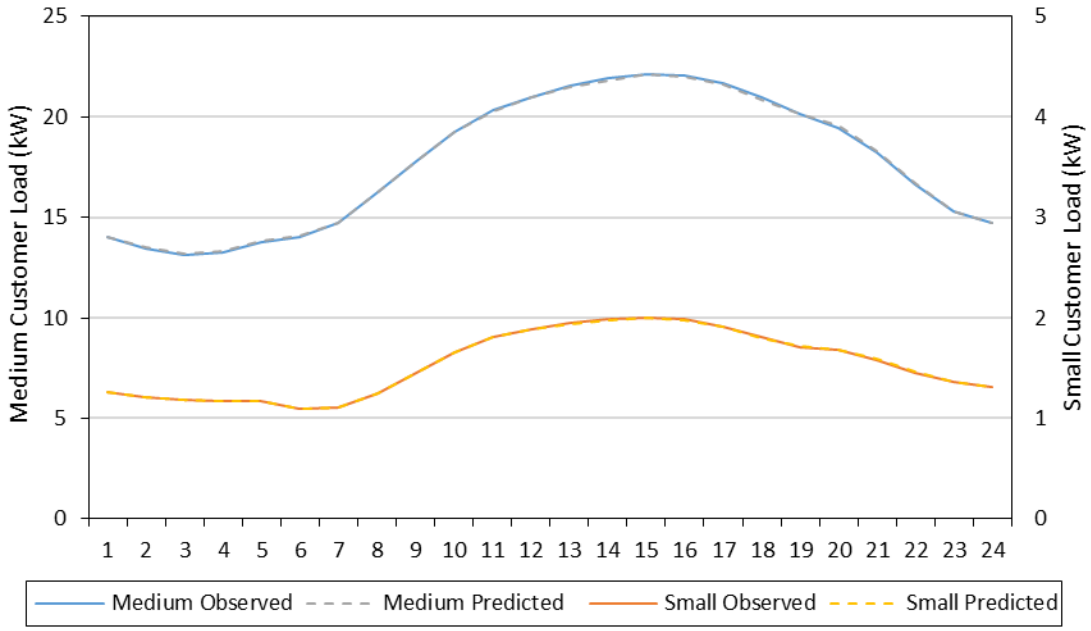


Figure A.5: Average Observed & Predicted Loads on Weekday Event-Like Days, Large Customers, *SCE*

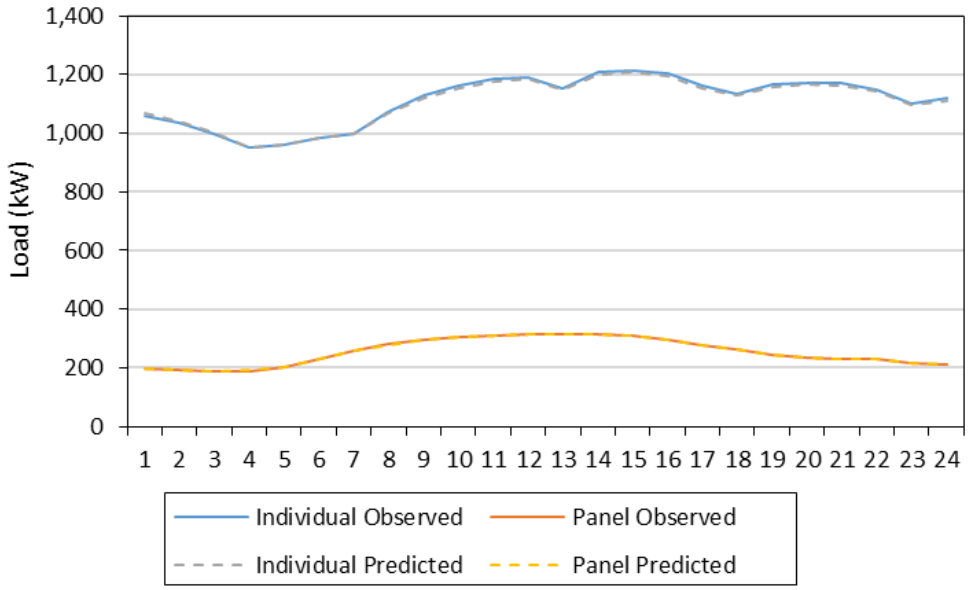
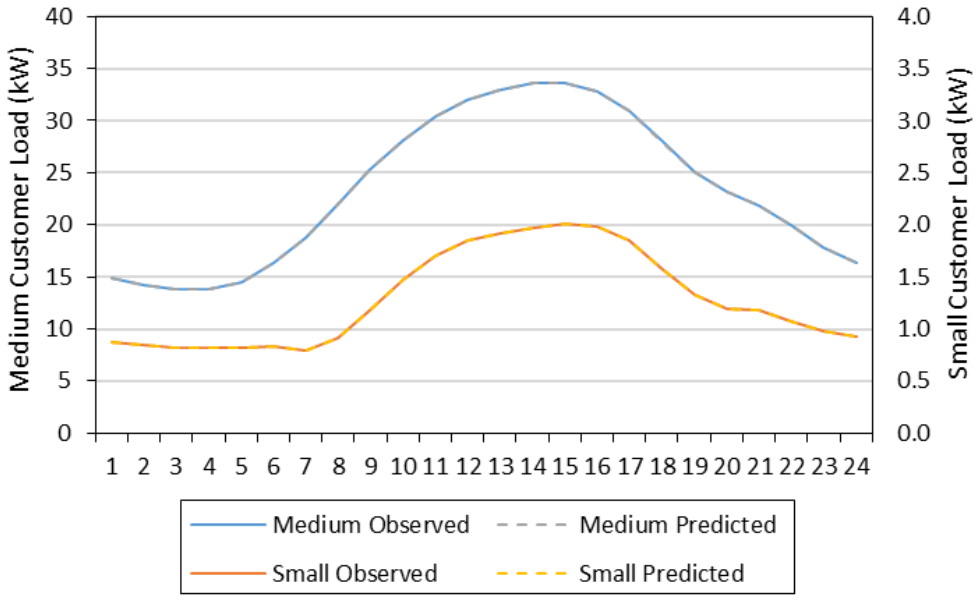



Figure A.6: Average Observed & Predicted Loads on Weekday Event-Like Days, Small and Medium Customers, *SCE*