**2017 Statewide Load Impact Evaluation of Non-Residential Critical Peak Pricing (CPP) Rates**

This document contains Pacific Gas and Electric Company’s CONFIDENTIAL information described in Declaration of Franklin Fuchs dated March 30, 2018.

Public Version. Redactions in “2017 Statewide Load Impact Evaluation of Non-Residential Critical Peak Pricing (CPP) Rates” and appendices.

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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 2017. The evaluation produces estimates of the *ex-post* load impacts for each hour of each of the utilities’ CPP events called in 2017, and it develops *ex-ante* load impact forecasts of the programs through 2028.

## 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). All CPP tariffs are designed for bundled service customers. 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.

The three utilities began defaulting their large commercial and industrial customer accounts onto CPP rates in 2008 (SDG&E) and 2010 (PG&E and SCE). The utilities have also begun defaulting (or plan to default) small and medium business (SMB) customers onto CPP rates. (SMB customers have been able to participate on a voluntary basis since 2014.) SCE’s medium and small customers are the last groups to be defaulted, which is scheduled for 2019. 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 2017;
2. Estimate *ex-post* load impacts for 2017 for each of the utilities’ Technical Assistance and Technology Incentives (TA/TI) and Automated Demand Response (AutoDR) programs for those customers enrolled in those programs;
3. Produce *ex-ante* load impact forecasts for the CPP rates for 2018-2028; and
4. Estimate the incremental CPP load impacts due to technology or dual participation in other programs.

Secondary goals include estimating the effect of PG&E’s in-season support (*e.g.*, text notifications and performance feedback) on load impacts; and estimating non-event day load impacts for PG&E’s newly enrolled customers.

## ES.2 Evaluation Methodologies

In this evaluation, we estimate load impacts using quasi-experimental matched control groups, such that load impacts for CPP participants are estimated by comparing their loads to the control group loads on event days, accounting for differences in their loads on non-event days. The eligible control-group customers consist of customers who opted to leave CPP for a TOU-only rate.

Matched control-group customers are selected based on both available *customer characteristics* (*e.g.*, LCA, industry group, size category) and *usage patterns* on non-event days that are similar to event days. We then estimate event-day load impacts using a regression-based difference-in-differences (D-in-D) method, which produce estimates of standard errors, and thus confidence intervals around the estimated event-hour or event-day usage reductions. The analysis also accounts for (*i.e.*, adjust for) differences in usage between the two groups on event-like non-event days, thus representing a D-in-D evaluation approach.

## 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 an 80 percent confidence interval (corresponding to the 10th and 90th percentile uncertainty-adjusted load impacts) for PG&E’s large PDP customers. These customers had statistically significant load reductions on each of the 15 event days, ranging from 12 to 34 MWh/hour. The load impact averaged 22 MWh/hour, with 80 percent of the event days having a load impact in excess of 20 MWh/hour.

Figure ES.1: Average Event-Hour Load Impacts by Event, *PG&E Large*

Figure ES.2 presents the same information for PG&E’s small and medium business (SMB) customers. Their aggregate load impact ranged from 4 MWh/hour to 30 MWh/hour. The standard deviation of the load impact across event days was 9 MWh/hour, which is somewhat high relative to the average load impact of 15 MWh/hour. The low load impact on September 2nd may be attributable to the fact that it was the lone weekend event. These load impacts are quite small in percentage terms, ranging from 0.3 to 2.1 percent of the reference load. When load impacts are relatively low, a very high degree of precision is required of the modeling (including the matching and subsequent regression) in order to identify the “true” load impact. We suspect that the variability in our estimated load impacts for SMB customers partly captures “noise” in the data, perhaps due to omitted variables. We would encourage caution in forecasting load impacts for this customer group.

Figure ES.2: Average Event-Hour Load Impacts by Event, *PG&E SMB*

In addition to these “primary” analyses, we also studied whether newly enrolled PDP customers had load impacts on non-event days; and whether customers who signed up for Enhanced In-Season Support (ISS) had different load impacts from those who did not. (Enhanced ISS provides customers with additional event notifications and a post-event summary of their performance.) We found little evidence of non-event-day load impacts among newly enrolled customers. In addition, we found that customers receiving Enhanced ISS had higher load impacts than those who did not. Our analysis cannot determine whether the higher load impact is due to the information provided under Enhanced ISS or because high-responding customers tended to sign up for the service.

### ES.3.2 SCE

Figure ES.3 shows the estimates of the average event-hour load impacts by event day, along with an 80 percent confidence interval (corresponding to the 10th and 90th percentile uncertainty-adjusted load impacts) for SCE’s large CPP customers. These customers had statistically significant load reductions on each of the 12 event days, ranging from 16 to 29 MWh/hour. The load impact averaged 22 MWh/hour, with 67 percent of the event days having a load impact in excess of 20 MWh/hour.

Figure ES.3: Average Event-Hour Load Impacts by Event, *SCE Large*

Figure ES.4 presents the same information for SCE’s SMB customers. In contrast to SCE’s large customers, the load impacts are not statistically significant for every event day. Five events days (July 27th, August 1st, August 28th, August 31st, and September 5th) have small estimated load reductions or increases in load. However, on the remaining seven event days, there are significant load impacts that range between 0.7 and 1.4 MWh/hour with an average of 0.9 MWh/hour (1.5 percent).

Figure ES.4: Average Event-Hour Load Impacts by Event, SC*E SMB*

For SCE, we placed net energy metered (NEM) customers in a separate group. Their estimated load impacts are highly variable across event days and rarely statistically significantly different from zero.

### ES.3.3 SDG&E

Figure ES.5 shows the estimates of the average event-hour load impacts by event day, along with an 80 percent confidence interval (corresponding to the 10th and 90th percentile uncertainty-adjusted load impacts) for SDG&E’s large CPP customers. The results indicate that SDG&E’s large customers had statistically significant load reductions on each of the three event days, ranging from 9 to 19 MWh/hour. The load impact averaged 15 MWh/hour over the three days or 18 MWh/hour for the average weekday event (August 31st and September 1st).

Figure ES.5: Average Event-Hour Load Impacts by Event, *SDG&E Large*

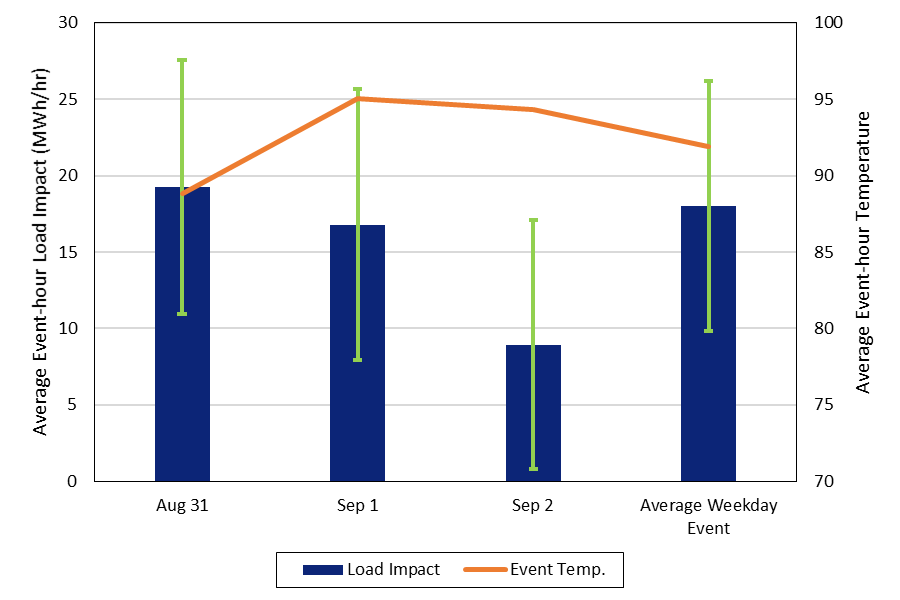
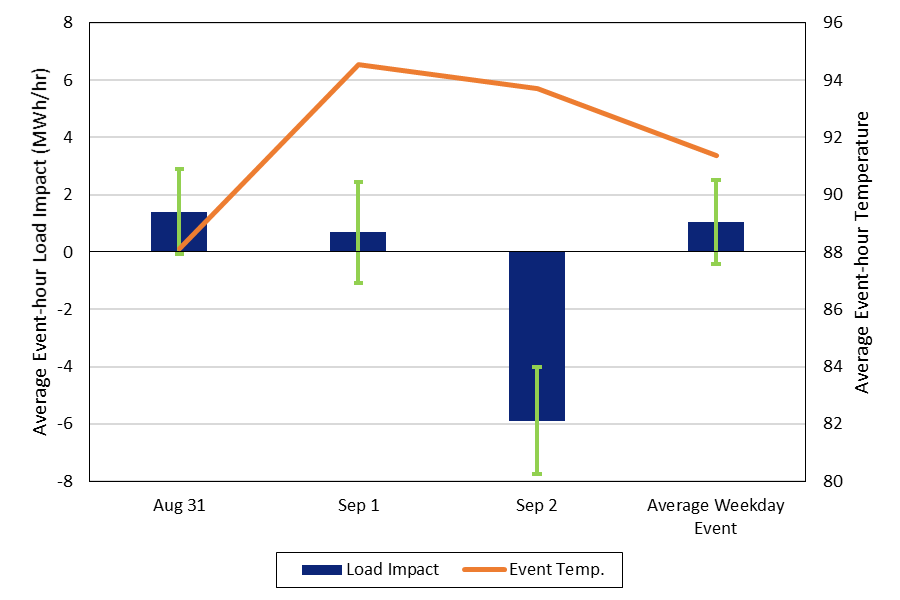


Figure ES.6 presents the same information for SDG&E’s medium-sized CPP customers. In contrast to large customers, the load impacts are only statistically significant for the weekend event day (September 2nd) which also indicates an *increase* in usage.

Figure ES.6: Average Event-Hour Load Impacts by Event, *SDG&E Medium*



## 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 requires three key pieces of information:

1. Utility-provided *enrollment forecasts* for relevant components of the program, which consists of forecasts of the number of customers by required type of customer;
2. *Reference loads* by customer type, simulated from regression models plus utility-provided *ex-ante* weather conditions;
3. A forecast of *load impacts per customer*, again by relevant customer type, based on the estimates in the *ex-post* evaluation.

We conducted this process for each utility and size group, with the exception of SCE’s SMB customers. For those customers, who are to be defaulted onto CPP in 2019, we relied on the per-customer forecasts from the previous study, re-scaled using SCE’s current enrollment forecast.

### ES.4.1 *Ex-ante* load impacts – PG&E

Figures ES.7 through ES.9 summarize the *ex-ante* load impacts for PG&E’s Large, Medium, and Small PDP customers, respectively. In each case, the results reflect the Typical Event Day load impacts during the Resource Adequacy (RA) window at August enrollments. The RA window is from 1 to 6 p.m. during August, which includes one non-event hour (thus diluting the average load impact compared to an average event-hour summary). 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.

Our forecast calls for an increase in load impacts over time for all three size groups. In each case, the highest load impact within a year is associated with the utility-specific 1-in-10 weather conditions. This is expected, as those weather conditions tend to correspond to the hottest days.

Figure ES.7: Aggregate Load Impacts for the Typical Event Day by Year and Weather Scenario over RA Window, *PG&E Large*

Figure ES.8: Aggregate Load Impacts for the Typical Event Day by Year and Weather Scenario over RA Window, *PG&E Medium*

Figure ES.9: Aggregate Load Impacts for the Typical Event Day by Year and Weather Scenario over RA Window, *PG&E Small*

### ES.4.2 *Ex-Ante* load impacts – SCE

Figures ES.10 through ES.12 summarize the *ex-ante* load impacts for SCE’s Large, Medium, and Small CPP customers, respectively. In each case, the results reflect the Typical Event Day load impacts during the Resource Adequacy (RA) window at August enrollments. The RA window is from 1 to 6 p.m. during August, which includes one non-event hour (thus diluting the average load impact compared to an average event-hour summary). 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.

SCE intends to default its SMB customers onto CPP in 2019, so there are no load impacts for 2018 (*i.e.*, enrollment is zero in that year). For these customers, the 2019 load impacts are quite high, but drop off in 2020 (and thereafter) as customers are assumed to opt-out of CPP following the end of their bill protection. SCE’s large customer load impacts are quite stable over the course of the forecast period.

Figure ES.10: Aggregate Load Impacts for Typical Event Day by Year and Weather Scenario over RA Window, *SCE Large*

Figure ES.11: Aggregate Load Impacts for Typical Event Day by Year and Weather Scenario over RA Window, *SCE Medium*

Figure ES.12: Aggregate Load Impacts for Typical Event Day by Year and Weather Scenario over RA Window, *SCE Small*

### ES.4.3 *Ex-Ante* load impacts – SDG&E

SDG&E has modified the CPP event hours, reducing the event window of 11 a.m. to 6 p.m. (HE 12 to 18) to an event widow of 2 to 6 p.m. (HE 15 to 18). Figures ES.13 and ES.14 summarize the *ex-ante* load impacts for SDG&E’s Large and Medium CPP customers, respectively. In each case, the results reflect the average weekday event load impacts during the Resource Adequacy (RA) window at August enrollments. The RA window is from 1 to 6 p.m. during August, which includes one non-event hour (thus diluting the average load impact compared to an average event-hour summary). 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.

SDG&E forecasts an increase in large CPP customer enrollment that has a corresponding effect on the forecast load impacts, which increase from approximately 15 MWh/hour to approximately 20 MWh/hour from 2018 through 2028. Conversely, the medium customer enrollment and load impacts are forecast to decline somewhat over time. Note that the small customer forecast (under 20 kW maximum demand) are included in a separate study. Also, customers participating in Small Customer Technology Deployment (SCTD) are excluded from our analysis and are included in the same study as the small CPP customers.

Figure ES.13: Aggregate Load Impacts for Average Weekday Event by Year and Weather Scenario over RA Window, *SDG&E Large*

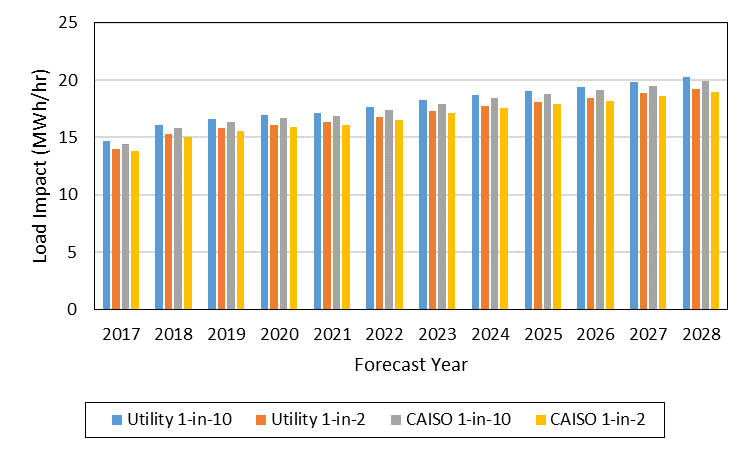
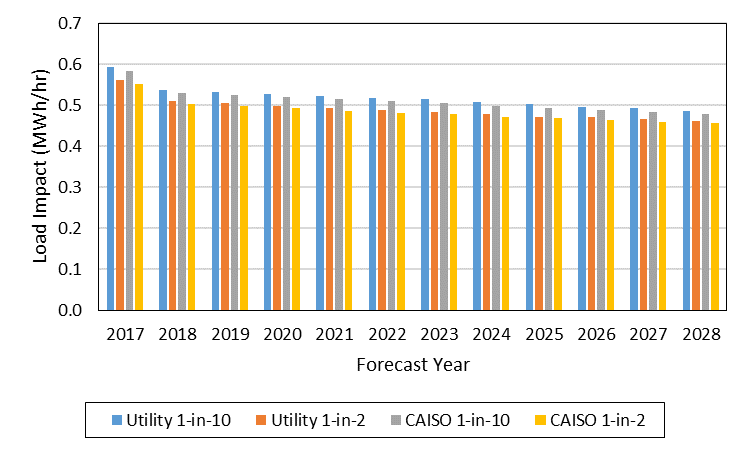


Figure ES.14: Aggregate Load Impacts for Average Weekday Event by Year and Weather Scenario over RA Window, *SDG&E Medium*



# 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 2017. The evaluation produces estimates of the *ex-post* load impacts for each hour of each of the utilities’ CPP events called in 2017, and it develops *ex-ante* load impact forecasts of the programs through 2028.

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. Customers benefit financially from the longer periods of the lower rates for electricity consumed outside of the CPP periods. New customers on the program may also be eligible for bill protection for an initial period, such as 12 months, so that their energy costs on CPP do not exceed their pre-CPP costs while they learn how to respond.

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). All CPP tariffs are designed for bundled service customers. 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 (AutoDR) programs. 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.

The three utilities began defaulting their large commercial and industrial customer accounts onto CPP rates in 2008 (SDG&E) and 2010 (PG&E and SCE).[[1]](#footnote-1) The utilities have also begun defaulting (or plan to default) small and medium business (SMB) customers onto CPP rates. (SMB customers have been able to participate on a voluntary basis since 2014.) SCE’s medium and small customers are the last groups to be defaulted, which is scheduled for 2019. The table below summarizes the groups of customers included in the *ex-post* and *ex-ante* portions of this study. Note that the analysis of SDG&E’s small CPP customers will be carried out in a different study.

Table .: Analyses Included in the Study

|  |  |  |  |
| --- | --- | --- | --- |
| **Size Group** | **PG&E** | **SCE** | **SDG&E** |
| Large (Over 200kW) | *Ex-post* and *ex-ante* | *Ex-post* and *ex-ante* | *Ex-post* and *ex-ante* |
| Medium (20 to 199kW) | *Ex-post* and *ex-ante* | *Ex-ante only* | *Ex-post* and *ex-ante* |
| Small (Under 20kW) | *Ex-post* and *ex-ante* | *Ex-ante only* | Excluded |

The CPP event hours and number of allowed events vary across utilities, as shown in the table below. SDG&E’s program will change beginning in December 2017, with the event period shortened to match that of the other utilities (2 to 6 p.m.).

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

|  |  |  |  |
| --- | --- | --- | --- |
| **Program Characteristic** | **PG&E** | **SCE** | **SDG&E** |
| Event hours | 2 to 6 p.m. | 2 to 6 p.m. | Historical: 11 a.m. to 6 p.m.  Beginning Dec. 2017: 2 to 6 p.m. |
| Events / year | 9 to 15 | 12 | Maximum of 18 |

Newly enrolled customers receive bill protection for the first 12 months. Most of the largest customers at all three utilities have the option of reserving a level of generation capacity (a capacity reservation level, or CRL) to protect a portion of their load on CPP event days.

## 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 2017;
2. Estimate *ex-post* load impacts for 2017 for each of the utilities’ Technical Assistance and Technology Incentives (TA/TI) and Automated Demand Response (AutoDR) programs for those customers enrolled in those programs;
3. Produce *ex-ante* load impact forecasts for the CPP rates for 2018-2028;[[2]](#footnote-2) and
4. Estimate the incremental CPP load impacts due to technology or dual participation in other programs.

Secondary goals include estimating the effect of PG&E’s in-season support (*e.g.*, text notifications and performance feedback) on load impacts; and estimating non-event day load impacts for PG&E’s newly enrolled customers. Finally, the study compares current and previous *ex-post* and *ex-ante* load impacts, as an aid in understanding reasons for variability in the *ex-post* load impacts, and the link between *ex-post* and *ex-ante* load impacts. The evaluation conforms to the Load Impact Protocols adopted by the California Public Utilities Commission (CPUC) in April 2008 (D.08-04-050).

## PY2017 Event Days

The table below summarizes the CPP events for each utility as of the Project Initiation meeting. PG&E and SCE called the maximum number of allowed events, while SDG&E had called three events.

Table .: PY2017 CPP Event Dates by Utility

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| **Date** | **Day of Week** | **PG&E** | **SCE** | **SDG&E** |
| 6/16/2017 | Friday | X |  |  |
| 6/19/2017 | Monday | X | X |  |
| 6/20/2017 | Tuesday | X | X |  |
| 6/22/2017 | Thursday | X |  |  |
| 6/23/2017 | Friday | X |  |  |
| 7/6/2017 | Thursday |  | X |  |
| 7/7/2017 | Friday | X | X |  |
| 7/27/2017 | Thursday | X | X |  |
| 7/31/2017 | Monday | X | X |  |
| 8/1/2017 | Tuesday | X | X |  |
| 8/2/2017 | Wednesday | X |  |  |
| 8/28/2017 | Monday | X | X |  |
| 8/29/2017 | Tuesday | X | X |  |
| 8/31/2017 | Thursday | X | X | X |
| 9/1/2017 | Friday | X |  | X |
| 9/2/2017 | Saturday | X |  | X |
| 9/5/2017 | Tuesday |  | X |  |
| 9/12/2017 | Tuesday |  | X |  |

While most of the events occurred on a non-holiday weekday, the Saturday, September 2 event at PG&E and SDG&E is the exception. In addition to the events listed above, a statewide Flex Alert (which calls for voluntary reductions in customer usage) was declared for September 1, 2017.

## 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. Section 6 provides recommendations. Appendices describe the results of our control-group matching process and contain electronic versions of the required Protocol table generators.

# Study Methodology

*Overview*

In this evaluation, we estimate load impacts using quasi-experimental matched control groups, such that load impacts for CPP participants are estimated by comparing their loads to the control group loads on event days, accounting for differences in their loads on non-event days. The eligible control-group customers consist of customers who opted to leave CPP for a TOU-only rate.

Matched control-group customers are selected based on both available *customer characteristics* (*e.g.*, LCA, industry group, size category) and *usage patterns* on non-event days that are similar to event days. We then estimate event-day load impacts using a regression-based difference-in-differences (D-in-D) method, which produce estimates of standard errors, and thus confidence intervals around the estimated event-hour or event-day usage reductions. The analysis also accounts for (*i.e.*, adjust for) differences in usage between the two groups on event-like non-event days, thus representing a D-in-D evaluation approach.[[3]](#footnote-3)

*Control group selection*

The objective in selecting a quasi-experimental matched control group is to identify a group of customers that are as comparable as possible to the treatment customers, particularly in the level and hourly load profile of their usage patterns. The matching process is based on hourly load data for non-event days that are as similar as possible to the actual event days in terms of temperatures and day-type.[[4]](#footnote-4) The event-like non-event days were selected using a Euclidean distance matching method, comparing daily CDD, event-hour temperature, and event-hour relative humidity. The three nearest neighbors were selected for each event day, with the final list trimmed to include only the most relevant days.

The matching is conducted in one or two stages, depending on the ratio of the number of eligible control customers to the number of treatment customers. In most cases (all but SCE’s small and medium customers), the pool of eligible control-group customers was relatively small (*i.e.*, most customers were on the CPP rate) so we conducted a one-stage match using hourly profile data. The matches were selected using the Euclidean distance method applied to average hourly load profiles on the event-like non-event days. Two 24-hour profiles were used, one for the hottest days and another for the remainder of the event-like days.[[5]](#footnote-5) To improve the efficiency of the search for comparable customers, we first segment CPP customers into groups defined by observable characteristics (*e.g.*, utility, size group, climate zone, and industry group).[[6]](#footnote-6)

For the two cases in which a large pool of eligible control-group customers was available (SCE’s small and medium customers), we conducted a two-stage process. The first stage applied Euclidean distance matching to annual usage per day and maximum demand, with matches segmented by size and LCA. The ten nearest neighbors were selected, for which we requested hourly interval data. The second matching stage applies only to these customers, and matches the one-stage process described above. Descriptions of the match quality are provided in the Appendix A. The load impacts are estimated using a differences-in-differences method described in detail below.

## 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.

### Data

Analysis that addresses each of the load impact objectives listed in Section 1.1 requires the following types of data:

* *Customer* information for the CPP customers and potential control-group customers (*e.g*., industry group, weather station, LCA, size group);
* Billing-based *interval load data on event days and event-like non-event days* (*i.e.*, hourly loads for each treatment and potential control group customers);
* *Weather* *data* (*i.e.*, hourly temperatures and other variables for the relevant time period, by weather station);
* *Program event data* (*i.e.*, dates and hours of CPP events and any programs in which CPP customers are dually enrolled).

### Analysis Methods

Load impacts are estimated from panel models estimated separately for each hour of the day and customer sub-group, with the model taking the following form:

*kW*c,d = β0 + ΣEvts(i) (β1,i x *CPP*c,d x *Evt*i,d) + *Cc* + *Dd* + εc,d

The variables and coefficients in the equation are described in the following table:

Table .: Panel Model Terms

|  |  |
| --- | --- |
| **Symbol** | **Description** |
| *kW*c,d | Load during a given hour for customer *c* on day *d* |
| *CPPc,d* | Variable indicating whether customer *c* is a CPP (1) or Control (0) customer |
| *Evti,d* | Variable indicating that day *d* is the *i*th event day (1) or not (0) |
| β0 | Estimated constant coefficient |
| β 1,i | Estimated load impact for event *i* |
| *Cc* | Customer fixed effects |
| *Dd* | Date fixed effects |
| εc,d | Error term (correlated at the customer level) |

The model includes date and customer fixed effects to account for factors that commonly affect all customers over time such as weather and time-invariant customer characteristics (such as establishment size). In addition, the model can include additional variables, including indicators for other program events in which treatment customers are dually enrolled; weather variables such as the mean temperature across the first 17 hours of the day[[7]](#footnote-7); and a “morning load” variable, which is the average usage during the first 10 hours the day.[[8]](#footnote-8) The *1,i* coefficients represent the estimated load impacts for each hour of every event day.

This model is estimated separately for each hour of the day using only event and event-like non-event days, and is estimated for all required sub-groups.

*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 and TA/TI 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*

To assess the validity of the control-group matching processes, we compare the characteristics and non-event-day load profiles of the matched control-group and treatment customers. In addition, we perform various consistency checks of the panel model estimated load impacts compared to: 1) simple difference-in-differences calculations (*i.e.*, from means of data rather than regression analyses), 2) program-level day matching comparisons (*i.e.*, by comparing event-day program loads to event-like non-event day program loads), and 3) estimates from prior evaluations.

## Developing 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 requires three key pieces of information:

1. An *enrollment forecast* for relevant components of the program, which consists of forecasts of the number of customers by required type of customer;
2. *Reference loads* by customer type;
3. 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 developed for the following subgroups of customers:

1. Utility;
2. Size group;
3. LCA;
4. Busbar (by November 1, 2018); and
5. Program vs. portfolio load impacts based on dual enrollment status.

The load impacts are also provided for the years 2018 through 2028,[[9]](#footnote-9) for a number of day types, and weather scenarios, including the following:

* Estimates are provided for a typical event day under the four 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 scenarios.

The utilities provided the enrollment forecasts and *ex-ante* weather conditions for each required scenario. 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, accounting for weather and seasonal usage patterns. The reference load regression models require 8760 load profile data (as opposed to the *ex-post* regression models, which include only event and event-like days), which we requested for either all CPP customers or a representative sample of treatment customers (where the number of customers is high, such as PG&E’s small customers). 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 month.

The *per-customer load impacts* are derived from an analysis of the current and previous *ex-post* load impact evaluations, with a focus on the effect, if any, of weather on the estimated load impacts. The resulting per-customer load impacts are then applied to the appropriate reference loads to develop the forecast load impacts and (by extension) event-day reference load profiles. CPP load impacts must be forecast for both winter and summer months. Because we don’t observe winter event days, we assume that winter percentage load impacts are equal to the summer percentage load impacts.

In practice, the *ex-ante* percentage load impacts are based on regressions of the group-level percentage load impact as a function of a constant term and a weekend indicator variable, as follows (where *evt* indexes event days and *h* indexes hours):

*PctImpactevt,h* = *a* + *b* x *Weekendevt,h* + e*evt,h*

Separate models are estimated by customer group (*e.g.*, by size and LCA for PG&E), and hour of the day. The estimated constant term (*a*) is average weekday percentage load impact for the modeled customer group and hour of the day. The standard error of the constant is the basis for the uncertainty-adjusted load impacts.

For SCE and PG&E, we tested an alternate specification that modeled the relationship between the load impact and weather conditions:

*Impactevt,h* = *a* + *bWE* x *Weekendevt,h* + *bCDD* x *CDD60evt,h* + e*evt,h*

This version of the model uses the per-customer load impact (in kWh/hour/customer) rather than the percentage load impact and included cooling degree days as an explanatory variable. We concluded that the relationship between weather and load impacts was not reliable, and therefore adopted the average percentage load impact approach described above.

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 2017 and the temperatures in the various weather scenarios). We will also compare current and previous *ex-post* load impacts, and current and previous *ex-ante* load impacts.

SCE will be defaulting SMB customers in 2019. For these customer groups, the *ex-ante* forecast uses the reference loads and load impacts developed as part of the PY2016 evaluation (in which percentage load impacts were adapted from *ex-post* studies of PG&E’s SMB customers). In this evaluation, we re-scaled the per-customer forecasts from the PY2016 evaluation to the current *ex-ante* enrollment forecast provided by SCE.

# PG&E

## 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, all results presented in this section are derived from panel fixed-effects regression analyses of hourly data for PDP customers and a matched control group. The evaluation of match quality and a discussion thereof is presented in the appendix. The estimated model is described in Section 2.1.2, including the morning load variable. Furthermore, we control for concurrent events that are called for other programs, including BIP and CBP, by including indicators for customers who are dually enrolled and who are called (or in the case of CBP, nominated when their aggregator is called) for a given event that occurs during an event or non-event day.

### 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 average event day; and load impacts by industry group and LCA for the average event hour. Summaries of load impacts for dually enrolled customers and AutoDR customers are presented in subsequent sub-sections.

The *ex-post* load impacts for PG&E’s large PDP customers are summarized for all 15 events in Figure 3.1. The blue bars indicate the magnitude of the aggregate load impact (in MWh/hour). The green bands correspond to 80 percent confidence intervals around these estimates (*i.e.*, the 10th and 90th percentile scenarios from the uncertainty-adjusted load impacts). The orange line represents 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 15 event days, ranging from 12 to 34 MWh/hour. The load impact averaged 22 MWh/hour, with 80 percent of the event days having a load impact in excess of 20 MWh/hour. Figure 3.1 shows some evidence of a relationship between load impacts and average temperatures. The two events with the lowest load impacts (July 31st and August 29th) experienced lower average temperatures (approximately 88 °F on both dates), while the event with the highest load impact (September 1st), had a much higher average temperature of 103 °F. Note that September 2nd was the lone weekend event, which may explain the relatively low estimated load impact despite being the hottest event day.

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

Table 3.1 summarizes enrollments, average event-hour load impacts, and reference loads for each event day and the average event. There was a slight decrease in the number of enrolled large customers over the course of the season, which may explain some of the lower aggregate load impacts in the second half of the season. Estimated load reductions averaged 11 kWh/hour/customer across event days, which amounts to a 4 percent load reduction.

Table .: 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** |
| 6/16/2017 | 2,023 | 521.1 | 26.8 | 257.6 | 13.3 | 5.1% | 87.2 |
| 6/19/2017 | 2,018 | 551.4 | 20.9 | 273.2 | 10.4 | 3.8% | 92.9 |
| 6/20/2017 | 2,016 | 542.0 | 23.8 | 268.8 | 11.8 | 4.4% | 90.5 |
| 6/22/2017 | 2,012 | 555.0 | 27.7 | 275.9 | 13.8 | 5.0% | 93.3 |
| 6/23/2017 | 2,005 | 517.6 | 25.4 | 258.2 | 12.7 | 4.9% | 87.2 |
| 7/7/2017 | 1,976 | 517.5 | 27.9 | 261.9 | 14.1 | 5.4% | 93.5 |
| 7/27/2017 | 1,969 | 516.9 | 23.4 | 262.5 | 11.9 | 4.5% | 89.4 |
| 7/31/2017 | 1,969 | 501.7 | 12.7 | 254.8 | 6.4 | 2.5% | 87.3 |
| 8/1/2017 | 1,968 | 524.2 | 20.8 | 266.4 | 10.6 | 4.0% | 90.7 |
| 8/2/2017 | 1,968 | 544.9 | 20.1 | 276.9 | 10.2 | 3.7% | 91.9 |
| 8/28/2017 | 1,965 | 551.0 | 18.3 | 280.4 | 9.3 | 3.3% | 93.1 |
| 8/29/2017 | 1,966 | 528.7 | 11.8 | 268.9 | 6.0 | 2.2% | 87.6 |
| 8/31/2017 | 1,960 | 550.5 | 22.2 | 280.9 | 11.3 | 4.0% | 94.2 |
| 9/1/2017 | 1,957 | 566.6 | 33.6 | 289.5 | 17.2 | 5.9% | 102.8 |
| 9/2/2017 | 1,957 | 438.5 | 20.6 | 224.0 | 10.5 | 4.7% | 104.0 |
| **Typical Event Day** | **1,982** | **528.5** | **22.4** | **266.7** | **11.3** | **4.2%** | **92.4** |

Figure 3.2 shows the aggregate hourly reference loads, observed loads, and estimated load impacts on the typical event day. Table 3.2 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 third hour of the event (4:00 to 5:00 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 smaller load impacts of approximately 9 MWh/hour in the hour immediately preceding (1:00 to 2:00 p.m.) and 8 MWh/hour in the hour following (6:00 to 7:00 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 .: Typical Event Day Reference Loads and Load Profile, *PG&E Large*

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



Next, we look at PG&E large customer estimates by industry group. Table 3.3 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 the reference load). Enrollments are concentrated in the Agriculture, Mining, & Construction and Offices, Hotels, Health & Services groups, which represent a combined --- percent of large customers. These two groups also have the largest estimated reference loads of ‑‑‑‑ MWh/hour and 154 MWh/hour, respectively. However, despite the high loads of these industry groups, the estimated *load impacts* are largest for the Manufacturing and Wholesale, Transportation & Other Utilities groups, which have estimated loads impact of 9 MWh/hour (9 percent) and 7 MWh/hour (11 percent), respectively. There are four industry groups that achieve less than 1 MWh/hour of load reduction, including Agriculture, Mining, & Construction; Retail Stores; Schools (which notably has a small but statistically insignificant *increase* in load); and Entertainment, Other Services, Government.

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Table .: Typical Event Day 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** |
| Agriculture, Mining, & Construction |  |  |  |  |  |
| Manufacturing | 299 | 98.0 | 89.2 | 8.76 | 8.9% |
| Wholesale, Transportation, & Other Utilities | 313 | 60.7 | 54.1 | 6.52 | 10.7% |
| Retail Stores | 76 | 19.1 | 18.5 | 0.52 | 2.7% |
| Offices, Hotels, Health, Services | 459 | 153.5 | 149.1 | 4.42 | 2.9% |
| Schools |  |  |  |  |  |
| Entertainment, Other Services, Government | 139 | 34.8 | 34.4 | 0.42 | 1.2% |
| Other or unknown | 107 | 29.9 | 28.5 | 1.44 | 4.8% |

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 3.3. The load impacts for large customers are mainly driven by three industry groups (Manufacturing; Wholesale, Transport & Other Utilities; and Other or Unknown), which have a higher share of load impacts than of enrollments or reference loads. All other industries have a lower share of load impact than share of enrollments or reference loads.

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Figure 3.3: Typical Event Day Event-Hour Load Impacts by Industry Group, *PG&E Large*

Table 3.4 and Figure 3.4 provide the same summaries as above by LCA. Large customers are concentrated in the Greater Bay Area and outside of any LCA (Other LCA), which have average reference loads of 214 MWh/hour and 134 MWh/hour, respectively. These two LCAs also account for the vast majority of the total load impact. The Greater Bay Area achieved a 7 MWh/hour (3 percent) reduction in aggregate loads while the Other LCA realized a 12 MWh/hour (9 percent) load reduction. Figure 3.4 reflects the prominence of these two LCAs.

Table .: 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 | 691 | 214.4 | 207.8 | 6.54 | 3.1% |
| Greater Fresno Area | 289 | 63.4 | 63.3 | 0.16 | 0.2% |
| Humboldt |  |  |  |  |  |
| Kern |  |  |  |  |  |
| Northern Coast | 23 | 4.3 | 4.0 | 0.30 | 6.9% |
| Other | 495 | 133.6 | 122.1 | 11.46 | 8.6% |
| Sierra | 90 | 14.9 | 14.1 | 0.81 | 5.4% |
| Stockton | 151 | 35.2 | 33.2 | 1.96 | 5.6% |

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

### SMB Customers

This section summarizes results for PG&E’s small and medium business (SMB) customers for the average event hour for each event day as well as for the average event day.[[10]](#footnote-10) Results for each hour for the typical event day are presented separately for small and medium customers. Finally, we examine how estimated load impacts are distributed across industry groups and LCAs separately for small and medium customers.

The *ex-post* load impacts for PG&E’s SMB PDP customers are summarized for all 15 events in Figure 3.5. Although there are statistically significant load impacts on each event day, there is much more variation in the load impact across event days for SMB customers than for large customers. The aggregate load impacts range from 4 MWh/hour to 30 MWh/hour. The standard deviation of the load impact across event days was 9 MWh/hour, which is somewhat high relative to the average load impact of 15 MWh/hour. SMB customers are similar to large customers in having a low load impact (especially given the hot temperatures) for the only weekend event (September 2nd) despite overall having a positive relationship between the magnitude of the load impact and the average temperature.

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Figure .: Average Event-Hour Load Impacts by Event, *PG&E SMB*

Table 3.5 summarizes enrollments, estimated load impacts, and reference loads for SMB customers on each event day as well as for the average event. SMB enrollment in PDP decreased over the season by more than 4,000 customers. SMB customers also had much smaller percentage load reductions (ranging from 0.3 to 2.1 percent) than the large customers (which ranged from 2.2 to 5.9 percent).

*Investigation of SMB Load Impact Variability*

In order to better understand the variability of SMB load impacts, we conducted a detailed analysis of one customer sub-group: medium-sized customers in the offices, hotels, health, and services industry group, of which there are approximately 17,700. This group was selected for three reasons: we expect their loads to predictable relative to other industry groups; the estimated load impact was highly variable across event days; and some of the load impact differences could not be explained by temperatures or the day of week. The average event-hour load impact for this group was 1.9 MWh/hour, while the standard deviation across event days was 2.4 MWh/hour.

In our investigation, we found that the control group was a good match for the treatment group, with an event-hour mean absolute percentage error (MAPE) of 1.1 percent on non-event days.[[11]](#footnote-11) In addition, we did not find evidence that a small number of outlier customers were driving the differences in load impacts across event days.[[12]](#footnote-12) We also found a close correspondence between treatment and control-group customer loads across days, with a correlation of average event-hour load across event days of 0.99.

The explanation appears to be that the estimated load impacts are very low in percentage terms, averaging 0.5 percent and ranging from -0.3 percent to 1.7 percent across the 15 event days. When load impacts are relatively low (which we would expect for this group relative to, say, manufacturing customers), a very high degree of precision is required of the modeling (including the matching and subsequent regression) in order to identify the “true” load impact. We suspect that the variability in our estimated load impacts for this group partly capture “noise” in the data, perhaps due to omitted variables. We would encourage caution in forecasting load impacts from groups such as these (with low expected percentage load impacts and high variability across event days).

Table .: Average Event-Hour Load Impacts by Event, *PG&E SMB*

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
| **Event Date** | **# Enrolled** | **Aggregate (MWh/hour)** | | **Per-Customer (kWh/hour)** | | **% Load Impact** | **Ave. Event Temp.** |
| **Ref. Load** | **Load Impact** | **Ref. Load** | **Load Impact** |
| 6/16/2017 | 205,362 | 1,233.9 | 11.3 | 6.0 | 0.1 | 0.9% | 88.9 |
| 6/19/2017 | 205,288 | 1,390.1 | 28.4 | 6.8 | 0.1 | 2.0% | 95.5 |
| 6/20/2017 | 205,225 | 1,376.9 | 23.0 | 6.7 | 0.1 | 1.7% | 93.4 |
| 6/22/2017 | 205,061 | 1,409.5 | 26.9 | 6.9 | 0.1 | 1.9% | 95.8 |
| 6/23/2017 | 204,993 | 1,283.9 | 4.3 | 6.3 | 0.0 | 0.3% | 89.9 |
| 7/7/2017 | 203,963 | 1,315.8 | 14.1 | 6.5 | 0.1 | 1.1% | 96.0 |
| 7/27/2017 | 203,037 | 1,277.1 | 4.7 | 6.3 | 0.0 | 0.4% | 91.5 |
| 7/31/2017 | 202,851 | 1,241.4 | 12.7 | 6.1 | 0.1 | 1.0% | 89.6 |
| 8/1/2017 | 202,629 | 1,312.9 | 12.3 | 6.5 | 0.1 | 0.9% | 93.1 |
| 8/2/2017 | 202,563 | 1,346.8 | 6.1 | 6.6 | 0.0 | 0.4% | 93.2 |
| 8/28/2017 | 201,555 | 1,383.3 | 25.5 | 6.9 | 0.1 | 1.8% | 95.8 |
| 8/29/2017 | 201,521 | 1,306.0 | 8.1 | 6.5 | 0.0 | 0.6% | 89.8 |
| 8/31/2017 | 201,360 | 1,337.1 | 12.9 | 6.6 | 0.1 | 1.0% | 95.1 |
| 9/1/2017 | 201,172 | 1,413.9 | 30.2 | 7.0 | 0.1 | 2.1% | 103.2 |
| 9/2/2017 | 201,167 | 1,145.8 | 4.0 | 5.7 | 0.0 | 0.3% | 104.3 |
| **Typical Event Day** | **203,183** | **1,318.3** | **15.0** | **6.5** | **0.1** | **1.1%** | **94.3** |

Figure 3.6 and Figure 3.7 plot aggregate loads for medium and small customers, respectively, for the typical event day. There are much different patterns of load reduction for these two groups as compared with the large customers. Medium customers begin ramping up load reductions several hours in advance of the event window beginning at 8 a.m. Aggregate load impacts reach a peak of 15.7 MWh/hour (1.5 percent) between 3 and 4 p.m. Small customers have a similar, but choppier pattern of load impacts, with much smaller total load reductions. The irregular pattern of load impacts may be indicative of the potential “noise” captured by the load impact estimates, as described above. These customers also have small load reductions beginning at 8 a.m., but the reductions sharply fall in the hour preceding the event and then peak at 3.2 MWh/hour (0.9 percent) between 3 and 4 p.m.

Table 3.6 and Table 3.7 include hourly observed loads, estimated load impacts, reference loads, hourly temperatures, and uncertainty adjusted load impacts for the typical event day for medium and small customers. The load impacts for medium customers range from 9.5 to 15.7 MWh/hour during the event window from 2 to 6 p.m., while small-customer load impacts range from 2.0 to 3.2 MWh/hour.

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

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

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



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



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 the reference load). Enrollments are highest in the Offices, Hotel, Health & Services group, which accounts for almost 40 percent of enrollments and 412 MWh of reference load. By contrast the load reductions are much more evenly distributed across industry groups. Figure 3.8 illustrates the shares of enrollment, reference load, and load impact by industry group. The Retail Stores group has the highest contribution to load reduction at 21 percent, while the Offices, Hotel, Health & Services group contributes just 15 percent of the total load reduction despite accounting for over 40 percent of the load. All other industry groups except Other or Unknown contribute a higher share of load than the share of enrollments or reference loads.

Table .: Typical Event Day 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** |
| Agriculture, Mining, & Construction | 1,017 | 20.2 | 19.5 | 0.7 | 3.3% |
| Manufacturing | 2,207 | 50.9 | 49.9 | 0.9 | 1.9% |
| Wholesale, Transportation, & Other Utilities | 3,978 | 77.9 | 76.4 | 1.5 | 2.0% |
| Retail Stores | 6,152 | 162.8 | 160.3 | 2.6 | 1.6% |
| Offices, Hotels, Health, Services | 17,493 | 412.4 | 410.5 | 1.9 | 0.5% |
| Schools | 1,845 | 60.2 | 58.3 | 1.9 | 3.2% |
| Entertainment, Other Services, Government | 6,359 | 104.6 | 102.7 | 1.9 | 1.8% |
| Other or unknown | 6,126 | 99.7 | 98.6 | 1.1 | 1.1% |

Figure .: Typical Event Day Event-Hour Load Impacts by Industry Group,

*PG&E Medium*

Table 3.9 and Figure 3.9 summarize the small customer results by industry group. For small customers, enrollments are highest in the Offices, Hotel, Health & Services and Other or Unknown groups, which together account for 59 percent of enrollments and almost 194 MWh/hour of load. While the Offices, Hotels, Health, & Services group accounts for a significant share of the customers and enrolled load, its average event-day load impact indicates that this industry group actually *increases* loads by 0.3 MWh/hour during the average event (which likely reflects omitted variable bias or noise rather than the actual program-induced customer response). Figure 3.9 shows that the Institutional/Government and Other or Unknown industry groups have the highest shares of load impacts of 25 percent and 27, respectively.

Table .: Typical Event Day 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** |
| Agriculture, Mining, & Construction | 5,708 | 9.7 | 9.5 | 0.2 | 1.6% |
| Manufacturing | 3,467 | 8.6 | 8.4 | 0.2 | 1.8% |
| Wholesale, Transportation, & Other Utilities | 17,270 | 23.5 | 23.0 | 0.5 | 2.0% |
| Retail Stores | 10,821 | 37.7 | 37.2 | 0.5 | 1.4% |
| Offices, Hotels, Health, Services | 49,040 | 117.9 | 118.2 | -0.3 | -0.3% |
| Schools | 2,147 | 5.4 | 5.4 | 0.0 | 0.6% |
| Entertainment, Other Services, Government | 25,756 | 51.3 | 50.6 | 0.7 | 1.3% |
| Other or unknown | 43,797 | 75.7 | 74.9 | 0.8 | 1.0% |

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

Table 3.10 and Figure 3.10 summarize the results by LCA for medium-sized customers. As with the large customers, enrollments are concentrated in the Greater Bay Area and Other LCA, which together contain nearly 70 percent of medium customers and account for almost 630 MWh/hour of load. The 3.9 MWh/hour load reduction for the Greater Bay Area only amounts to a 1.1 percent of the reference load. Figure 3.10 shows that the Greater Bay Area, Greater Fresno Area, and Northern Coast LCAs have a smaller share of load reduction than the share of enrollment or reference loads. Stockton has the largest positive difference between its share of load impacts and enrollment, with 17 percent of total load reduction despite having only 7 percent of customers and 8 percent of reference load.

Table .: Typical Event Day 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 | 17,221 | 366.7 | 362.8 | 3.9 | 1.1% |
| Greater Fresno Area | 5,085 | 119.8 | 119.6 | 0.2 | 0.2% |
| Humboldt | 394 | 7.2 | 7.0 | 0.2 | 3.1% |
| Kern | 3,168 | 77.8 | 76.2 | 1.6 | 2.1% |
| Northern Coast | 768 | 15.1 | 15.1 | 0.1 | 0.4% |
| Other | 12,578 | 260.7 | 256.6 | 4.0 | 1.6% |
| Sierra | 2,780 | 64.7 | 63.7 | 1.0 | 1.5% |
| Stockton | 3,184 | 77.8 | 75.5 | 2.3 | 3.0% |

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

Table 3.11 and Figure 3.11 summarize the results by LCA for small customers. Once again, customers are concentrated in the Greater Bay Area and Other LCA which have a combined 66 percent of customers and 210 MWh/hour of load. However, Figure 3.11 clearly demonstrates that the load impact is highly concentrated in the Other LCA, which accounts for over 45 percent of the total load impact. As with the medium customer results, Stockton provides a disproportionate share of load impacts.

Table .: Typical Event Day 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 | 51,684 | 111.0 | 110.7 | 0.3 | 0.3% |
| Greater Fresno Area | 15,309 | 38.7 | 38.7 | 0.0 | 0.1% |
| Humboldt | 2,142 | 3.5 | 3.4 | 0.1 | 3.8% |
| Kern | 8,353 | 22.2 | 22.1 | 0.1 | 0.6% |
| Northern Coast | 3,305 | 5.7 | 5.8 | -0.1 | -1.3% |
| Other | 53,484 | 99.3 | 98.2 | 1.2 | 1.2% |
| Sierra | 12,875 | 27.2 | 27.0 | 0.2 | 0.8% |
| Stockton | 10,854 | 23.3 | 22.8 | 0.5 | 2.3% |

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

### Dually Enrolled Customers

This section summarizes results for customers who are enrolled in PDP as well as another PG&E demand response program. The two programs in which PG&E customers can enroll along with PDP are BIP and CBP. We present results for the average event-hour for each event day and the average event day. Additional results for these customers can be found in electronic form in Protocol table generators provided along with this report.

Table 3.12 summarizes aggregate 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 the reference load). Although there are only 56 customers on average in this group with an aggregate reference load of 27 MWh/hour, they accomplish a reliable weekday reduction of approximately 11 MWh/hour, which is 41 percent load impact. The sole weekend event (on September 2nd) had essentially no load impact and a significantly lower reference load relative to the weekday events.

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

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Event Date** | **# of Service Accounts** | **Estimated Reference Load (MWh/hour)** | **Observed Load (MWh/hour)** | **Estimated Load Impact (MWh/hour)** | **% LI** |
| 6/16/2017 | 55 | 28.2 | 18.7 | 9.5 | 33.6% |
| 6/19/2017 | 55 | 27.2 | 14.2 | 13.0 | 47.8% |
| 6/20/2017 | 55 | 27.0 | 14.8 | 12.1 | 45.0% |
| 6/22/2017 | 55 | 26.7 | 14.1 | 12.6 | 47.2% |
| 6/23/2017 | 55 | 26.9 | 14.0 | 12.8 | 47.8% |
| 7/7/2017 | 57 | 26.5 | 13.4 | 13.1 | 49.4% |
| 7/27/2017 | 57 | 28.0 | 15.6 | 12.4 | 44.3% |
| 7/31/2017 | 56 | 25.5 | 18.3 | 7.1 | 28.0% |
| 8/1/2017 | 56 | 27.9 | 14.5 | 13.4 | 48.0% |
| 8/2/2017 | 56 | 27.0 | 16.1 | 11.0 | 40.6% |
| 8/28/2017 | 56 | 27.5 | 17.2 | 10.3 | 37.4% |
| 8/29/2017 | 56 | 26.6 | 17.5 | 9.0 | 34.0% |
| 8/31/2017 | 57 | 28.2 | 18.4 | 9.8 | 34.7% |
| 9/1/2017 | 58 | 27.7 | 18.3 | 9.3 | 33.7% |
| 9/2/2017 | 58 | 19.1 | 19.2 | -0.1 | -0.3% |
| **Typical Event Day** | **56** | **26.7** | **16.3** | **10.4** | **38.9%** |

Table 3.13 shows the enrollments, observed loads, and estimated reference loads, load reductions and percentage load reductions for all customers who are dually enrolled in CBP and PDP for the average event hour for each event as well as the average event. There are --- customers on average in this group, but the load reduction is much smaller and less consistent than for the BIP+PDP customers, averaging only --- MWh/hour (--- percent). Somewhat surprisingly, the CBP+ PDP customers have their highest load impact on September 2nd (the weekend event day).

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

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Event Date** | **# of Service Accounts** | **Estimated Reference Load (MWh/hour)** | **Observed Load (MWh/hour)** | **Estimated Load Impact (MWh/hour)** | **% LI** |
| 6/16/2017 |  |  |  |  |  |
| 6/19/2017 |  |  |  |  |  |
| 6/20/2017 |  |  |  |  |  |
| 6/22/2017 |  |  |  |  |  |
| 6/23/2017 |  |  |  |  |  |
| 7/7/2017 |  |  |  |  |  |
| 7/27/2017 |  |  |  |  |  |
| 7/31/2017 |  |  |  |  |  |
| 8/1/2017 |  |  |  |  |  |
| 8/2/2017 |  |  |  |  |  |
| 8/28/2017 |  |  |  |  |  |
| 8/29/2017 |  |  |  |  |  |
| 8/31/2017 |  |  |  |  |  |
| 9/1/2017 |  |  |  |  |  |
| 9/2/2017 |  |  |  |  |  |
| **Typical Event Day** |  |  |  |  |  |

### In-season Support Customers

PG&E offers in-season support (ISS) to all enrolled customers with a valid email address or mobile phone number. The support consists of day-ahead and day-of event notifications plus a performance summary after each event day. This enhanced support is offered via email or text message. In this section, we provide comparisons of load impacts for various notification segmentations.

Figure 3.12 summarizes the number of service accounts and average percentage load impacts (in parentheses) for customers receiving enhanced ISS versus customers receiving standard event notifications. Results are shown by size group to reflect the size-based selection into Enhanced ISS. That is, only 29 percent of small customers opt for Enhanced ISS, while 54 percent of large customers do. Within each of these groups, the enrollments and percentage load impacts are further summarized according to whether the customer had been on PDP prior to October 2016 (“Existing PDP”) or was defaulted onto PDP at the end of 2016 (“2016 Default).[[13]](#footnote-13) For the “2016 Default” customers, we further distinguish between early enrollees and defaulted customers. Table 3.14 provides additional detail behind each node of the figure (with the “Diagram Item No.” included to facilitate comparisons), summarized across all size groups combined.

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The results show that Enhanced ISS is associated with higher load impacts for large customers, with the percentage load impact of 5 percent versus 3 percent for standard notification customers. This appears to be driven by the 772 large Existing PDP customers, who have 7 percent load impacts on Enhanced ISS versus 3 percent load impacts from the 571 large customers with standard notification.

One counter-intuitive result in the figure is that Enhanced ISS load impacts are lower than standard-notification load impacts for large early enrollees (item 7 versus item 9, with 3 percent versus 7 percent load impacts).[[14]](#footnote-14) While we don’t know the cause of this difference, we can note some differences between the large ISS and standard customers in these groups:

* The enhanced ISS customers are less likely to be in the Agriculture, Mining, and Construction industry group (42 vs. 67 percent) and more likely to be in the Manufacturing industry group (9 vs. 4 percent).
* The Standard notification customers are more likely to be in the Greater Fresno and Kern LCAs and less likely to be in the Greater Bay Area LCA.
* The enhanced ISS customers have significantly higher reference loads (233 kWh/hour/customer vs. 174 kWh/hour/customer).

Figure 3.12: Number of Service Accounts and Percentage Load Impacts, *PG&E Segmentation 1*

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Table .: Typical Event Day Load Impacts, *PG&E Segmentation 1*

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
| **Diagram Item No.** | **Group** | **# of Service Accts** | **Aggregate Results (MWh/hour)** | | **Per-customer Results (kWh/hour)** | | **% LI** |
| **Estimated Reference Load** | **Estimated Load Impact** | **Estimated Reference Load** | **Estimated Load Impact** |
| 1 | Enhanced ISS,  All | 63,738 | 797 | 22.1 | 12.5 | 0.35 | 2.8% |
| 2 | Standard,  All | 141,212 | 1,053 | 15.8 | 7.5 | 0.11 | 1.5% |
| 3 | ISS,  2016 Default | 16,051 | 308 | 3.1 | 19.2 | 0.19 | 1.0% |
| 4 | ISS,  Existing PDP | 47,687 | 489 | 18.8 | 10.3 | 0.39 | 3.8% |
| 5 | Standard,  2016 Default | 25,856 | 394 | 5.4 | 15.2 | 0.21 | 1.4% |
| 6 | Standard,  Existing PDP | 115,356 | 659 | 10.4 | 5.7 | 0.09 | 1.6% |
| 7 | ISS+2016 Default,  Early Enrollees | 751 | 35 | 0.8 | 46.6 | 1.11 | 2.4% |
| 8 | ISS+2016 Default, Default | 15,300 | 274 | 2.2 | 17.9 | 0.14 | 0.8% |
| 9 | Std.+2016 Default,  Early Enrollees | 828 | 38 | 2.0 | 46.1 | 2.36 | 5.1% |
| 10 | Std.+2016 Default,  Default | 25,028 | 355 | 3.5 | 14.2 | 0.14 | 1.0% |

Figure 3.13 and Table 3.15 show the results for a second segmentation consisting entirely of Enhanced ISS customers. The top branch contains customers who receive text notifications, further divided into customers who received Enhanced versus standard text notifications. The bottom branch of the figure contains the customers who received only Enhanced email notifications (*i.e.*, they don’t receive texts of any kind). (All customers in the figure receive Enhanced email notifications.)

The percentage notifications show that text notifications are associated with higher load impacts than email-only notifications for all size groups. Furthermore, customers who receive Enhanced text notifications have higher percentage load impacts than those who receive only standard text notifications (but Enhanced email notifications).

Figure 3.13: Number of Service Accounts and Percentage Load Impacts, *PG&E Segmentation 2*

Table .: Typical Event Day Load Impacts, *PG&E Segmentation 2*

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
| **Diagram Item No.** | **Group** | **# of Service Accts** | **Aggregate Results (MWh/hour)** | | **Per-customer Results (kWh/hour)** | | **% LI** |
| **Estimated Reference Load** | **Estimated Load Impact** | **Estimated Reference Load** | **Estimated Load Impact** |
| 1 | Text | 2,693 | 55 | 4.5 | 20.4 | 1.7 | 8.2% |
| 2 | Email Only | 61,045 | 742 | 17.7 | 12.2 | 0.3 | 2.4% |
| 3 | Enhanced Text | 693 | 11 | 1.6 | 16.2 | 2.3 | 14.0% |
| 4 | Standard Text, Enhanced Email | 2,000 | 44 | 3.0 | 21.9 | 1.5 | 6.8% |

Taken together, the results indicate that large customers who received Enhanced ISS have significantly higher load impacts than customers who receive standard notifications. There is cause for caution against using these results for policy purposes (*i.e.*, by proposing expanded use of Enhanced ISS) in that the Enhanced ISS customers self-selected into their group. It may be the case that the most responsive customers elected to receive Enhanced ISS and that the benefits of providing Enhanced ISS to more customers (particularly non-volunteers) would be lower than suggested by the results shown here.

### Newly Enrolled Customers

The *ex-post* analyses in this study are designed to estimate incremental event-day load impacts. That is, the load impact that CPP customers provide on event days compared their usage on non-event days within the program year. By matching to control-group customers using non-event days from within the program year, this method prevents us from estimating whether CPP participation is associated with non-event day load impacts. It’s not clear what one should expect from CPP customers on non-event days. Because they receive a discount relative to the otherwise applicable rate (in exchange for facing event days), the pure price incentive might produce load increases on non-event days. Conversely, it’s possible that increased awareness of usage could lead customers to make changes that apply to event and non-event days (*e.g.*, purchasing a smart thermostat or installing more efficient lighting).

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PG&E expressed interest in exploring the non-event-day load impacts for CPP customers. To facilitate this analysis, we focused on newly enrolled customers (those who joined CPP in November or December 2016) so that we have a compact pre-treatment period that may be used to match CPP customers to control-group customers. That is, while our primary *ex-post* study matched customers on event-like non-event days during the 2017 program year, this “new customer” analysis matches customers using loads from 2016, when both the treatment and control-group customers took service under the non-CPP rates. The 2016 dates used in matching and estimation are the CPP event dates from that program year (those days are not yet event days for any customers included in the analysis).

The difference-in-differences regression model is then expanded in a straightforward fashion to estimate the 2017 load impact (which applies to all event and non-event days) and incremental event-day load impact. Specifically, the models use data for 2016 dates, 2017 non-event days, and 2017 event days. The regression model adds a variable indicating treatment customers on 2017 days to the model shown in Section 2.1.2. The model is then estimated by size, industry group, and hour of the day.

The figures below (Figure 3.14 through Figure 3.16) show the hourly incremental event-day load impacts (the blue solid line, calculated by averaging event-specific load impact coefficients) and 2017 “everyday” load impact (the dashed orange line, which applies to both event days and event-like non-event days in 2017) by size group. The load impacts are scaled to the relevant enrollment level and a positive number means the customers reduced usage in that hour (as is the convention throughout the report).

The most important conclusion from this analysis is that the majority of the everyday load impacts are not statistically significantly different from zero. Only 20 percent of the 576 estimated coefficients (24 hours times 3 size groups x 8 industry groups) are statistically significant. The small- and medium-sized customers lean toward load increases on these days (17 percent of the coefficients indicate statistically significant load increases, versus 11 percent that show significant load decreases), while the large customer everyday load impacts are almost entirely lacking in statistical significance (4 percent of the estimates indicate a statistically significant load decrease and none of them indicate a significant load increase).

This analysis does not provide evidence that a failure to account for non-event-day load impacts in our primary *ex-post* study leads to misleading results (*i.e.*, either over- or under-counting total program load impacts).

Figure .: Average Incremental Event-Day and Everyday Load Impacts, *Small Newly Enrolled Customers*

Figure .: Average Incremental Event-Day and Everyday Load Impacts, *Medium Newly Enrolled Customers*

Figure .: Average Incremental Event-Day and Everyday Load Impacts, *Large Newly Enrolled Customers*

### 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. 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 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 the reference load). Enrollments increased by -- customers over the season, with -- customers enrolled in AutoDR on average during the season. The estimated load impact is fairly stable across event days, averaging --- MWh/hour (-- percent of reference loads). This load impact falls short of the ---- MW of approved reduction for the customers in this program.

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

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
| **Event Date** | **# of Service Accounts** | **Estimated Reference Load (MWh/hour)** | **Observed Load (MWh/hour)** | **Estimated Load Impact (MWh/hour)** | **% LI** | **Approved MW** |
| 6/16/2017 |  |  |  |  |  |  |
| 6/19/2017 |  |  |  |  |  |  |
| 6/20/2017 |  |  |  |  |  |  |
| 6/22/2017 |  |  |  |  |  |  |
| 6/23/2017 |  |  |  |  |  |  |
| 7/7/2017 |  |  |  |  |  |  |
| 7/27/2017 |  |  |  |  |  |  |
| 7/31/2017 |  |  |  |  |  |  |
| 8/1/2017 |  |  |  |  |  |  |
| 8/2/2017 |  |  |  |  |  |  |
| 8/28/2017 |  |  |  |  |  |  |
| 8/29/2017 |  |  |  |  |  |  |
| 8/31/2017 |  |  |  |  |  |  |
| 9/1/2017 |  |  |  |  |  |  |
| 9/2/2017 |  |  |  |  |  |  |
| **Typical Event Day** |  |  |  |  |  |  |

## 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, with the small and medium customers combined into an SMB section. Within each size group, we present the following: a summary of the enrollment forecast provided by PG&E; 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, in a manner similar to the approach used in the 2016 evaluation, 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).

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### Large Customers

Figure 3.17 summarizes PG&E’s enrollment forecast for large customers. PG&E anticipates a 22 percent increase in large customer enrollments in 2019 followed by an additional 49 percent increase in 2020. After 2020, there is expected to be a more modest increase of approximately 0.05 percent per year. This enrollment forecast directly translates into the large increases in aggregate load impacts forecasted in 2019 and 2020, and more modest increases in load impacts depicted in Figure 3.21.

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

Figure 3.18 illustrates the aggregate reference load, observed load, and load impact for large customers on the typical event day in August in 2022 for the PG&E 1-in-2 weather scenario. The shape of the *ex-ante* loads and load impacts is similar to the *ex-post* results in Figure 3.2, while the magnitudes are much larger due to higher enrollment. The average event-hour load impact is 46.4 MWh/hour, or 3.0 percent of the reference load.

Figure .: Aggregate Hourly Loads and Load Impacts in 2022 for *PG&E 1-in-2 Typical Event Day, PG&E Large*

Figure 3.19 shows the forecasted share of load impacts by LCA during the average event hour on the typical event day in 2022 under PG&E’s 1-in-2 weather scenario. Several LCAs including the Greater Bay Area, Northern Coast, and Sierra gain larger shares of total load impacts compare to the *ex-post* results presented in Figure 3.4. Notably, customers not in any LCA, who achieved 52 percent of the *ex-post* load impacts, are forecasted to have a lower share of *ex-ante* load impacts of 42 percent.

Figure 3.19: Share of Load Impacts by LCA in 2022 for *PG&E 1-in-2 Typical Event Day, PG&E Large*

Figure 3.20 illustrates the seasonality in the forecastedload impacts by comparing aggregate load impacts for the average hour in the Resource Adequacy (RA) window in 2022 across months for PG&E’s 1-in-2 peak day weather scenario. The RA window is 1 to 6 p.m. from April through October and 4 to 9 p.m. for the remainder of the year. The lower load impacts from November through March are largely due to the fact that the RA window in those months includes three hours that are not PDP event hours, where the summer RA window includes only one such hour. The load impact is highest in September (41 MWh/hour) and lowest in February (16 MWh/hour).

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Figure .: Aggregate Load Impacts by Month over RA Window in 2022 for *PG&E 1-in-2 Peak Day*, *PG&E Large*

Figure 3.21 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. Customers who join PDP in 2019 and 2020 cause forecast load impacts to increase by approximately 4 MWh/hour and 10 MWh/hour, respectively. 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 .: Aggregate Load Impacts for the Typical Event Day by Year and Weather Scenario over RA Window, *PG&E Large*

### SMB Customers

Figure 3.22 summarizes PG&E’s enrollment forecast for SMB customers. PG&E anticipates a 12 percent increase in small customer enrollments and a 14 percent increase in medium customers enrollments in 2019. Enrollments are expected to further increase by 32 percent for small customers and 43 percent for medium customers in 2020. In 2022, an increase of 8 percent is forecast for both groups. The changes in other years are modest in comparison. This pattern is reflected in the load impact forecasts shown in Figure 3.29 and Figure 3.30.

Figure .: PDP Enrollments, *PG&E SMB*

Figure 3.23 illustrates the aggregate reference loads, observed loads, and load impacts for medium customers on the typical event day in August in 2022 for the PG&E 1-in-2 weather scenario. The shape of the *ex-ante* loads and load impacts is similar to the *ex-post* results in Figure 3.6, though the magnitudes are much larger due to higher enrollment. The forecast predicts an average load impact of 21.8 MWh/hour, or 1.1 percent of the reference load.

Figure .: Aggregate Hourly Loads and Load Impacts in 2022 for *PG&E 1-in-2 Typical Event Day, PG&E Medium*

Figure 3.24 illustrates the aggregate reference loads, observed loads, and load impacts for small customers on the typical event day in August in 2022 for the PG&E 1-in-2 weather scenario. There are some slight differences in the shape of the *ex-ante* loads and load impacts compared to the *ex-post* results in Figure 3.7, though the overall pattern is similar. The forecast predicts an average load impact of 3.3 MWh/hour, or 0.6 percent of the reference load.

Figure .: Aggregate Hourly Loads and Load Impacts in 2022 for *PG&E 1-in-2 Typical Event Day, PG&E Small*

Figure 3.25 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 2022 under PG&E’s 1-in-2 weather scenario. Several LCAs including the Greater Bay Area, Northern Coast, and Sierra gain larger shares of total load impacts compare to the *ex-post* estimates presented in Figure 3.10. The Greater Bay Area gains almost 10 percent points of the load impact share. Conversely, customers not in any LCA lose approximately 8 percentage points of the load impact share. These changes are due to differences between *ex-post* and *ex-ante* enrollment shares across LCAs.

Figure .: Share of Load Impacts by LCA in 2022 for *PG&E 1-in-2 Typical Event Day, PG&E Medium*

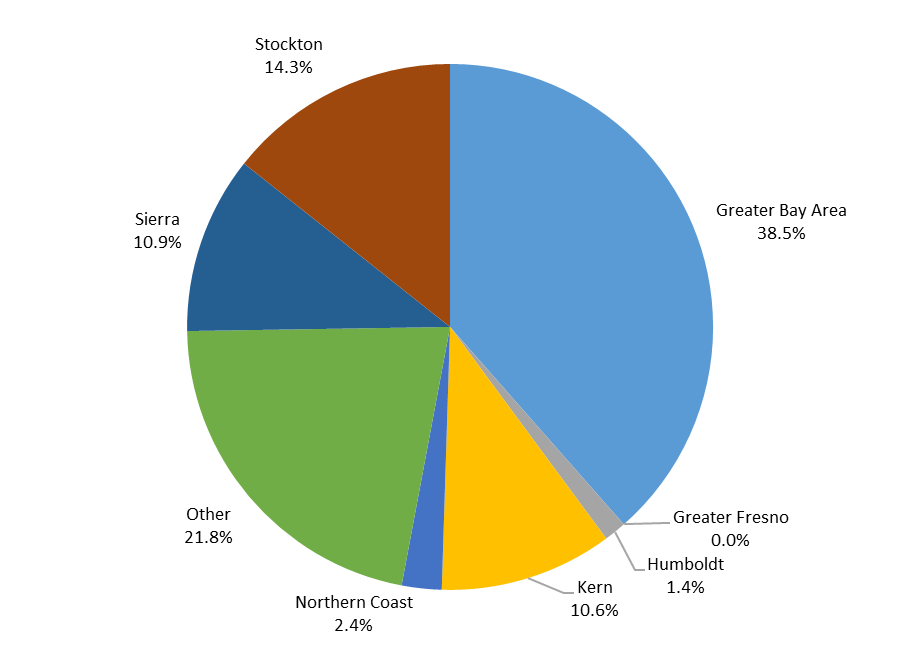


Figure 3.26 shows same shares for small customers. In this case, the customers not in any LCA (“Other”) account for the highest share of the load impacts, followed by customers in Stockton.

Figure .: Share of Load Impacts by LCA in 2022 for *PG&E 1-in-2 Typical Event Day, PG&E Small*

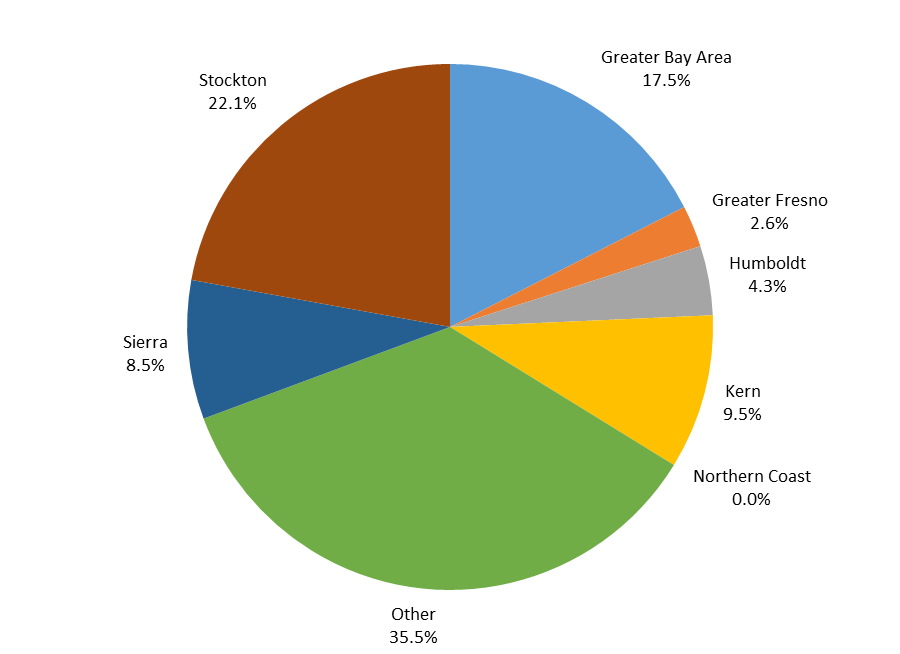


Figure 3.27 shows the seasonality of the forecastedload impacts for medium customers based on the 2022 aggregate load impacts for the average hour in the RA window for PG&E’s 1-in-2 weather scenario. Again, the lower non-summer load impacts of approximately 4 MWh/hour (compared to the 19 MWh/hour load impacts from April through October) are due to differences in the RA window. The load impact is highest in August (20 MWh/hour) and lowest in March (4 MWh/hour).

Figure .: Aggregate Load Impacts by Month over RA Window in 2022 for *PG&E 1-in-2 Peak Day*, *PG&E Medium*

Figure 3.28 illustrates the seasonality in the forecastedload impacts for small customers. The seasonal pattern is similar to that of the medium customers, though perhaps more exaggerated.

Figure .: Aggregate Load Impacts by Month over RA Window in 2022 for *PG&E 1-in-2 Peak Day*, *PG&E Small*

Figure 3.29 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. Customers who join PDP in 2019 and 2020 cause forecasted load impacts to increase by 1.8 MWh/hour and 5.3 MWh/hour, respectively. There are relatively minor differences between the forecasted load impacts for the alternative weather scenarios over the forecast period.

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

Figure 3.30 shows the same information for small customers. As with medium customers, the changes in load impacts reflect changes in enrollments; and the highest load impacts in each year are associated with the utility-specific 1-in-10 weather conditions.

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

## 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 PY2017. The term “previous” refers to findings in reports for PY2016. In the final comparison above, we illustrate the linkage between the PY2017 *ex-post* load impacts and the *ex-ante* forecast (of the 1-in-2 August peak day) for 2018.

### PG&E Large Customer Reconciliations

***Previous vs. Current Ex-Post***

Table 3.17 shows the average event-hour reference loads and load impacts for the average event day during the current and previous program years. Enrollment decreased in PY2017, which appears to have reduced the average usage level. The reference load decreasing from 293 to 267 kWh/hour/customer despite higher event-hour temperatures in PY2017. Percentage load impacts were somewhat lower in PY2017, decreasing from 4.9 to 4.2 percent.

Table .: Current vs. Previous *Ex-Post* Load Impacts for the Average Event

|  |  |  |  |
| --- | --- | --- | --- |
| **Level** | **Outcome** | **PY2016** | **PY2017** |
| **Total** | # SAIDs | 2,118 | 1,982 |
| Reference (MW) | 620 | 528 |
| Load Impact (MW) | 30.5 | 22.4 |
| Avg. Temp. | 89.9 | 92.8 |
| **Per SAID** | Reference (kW) | 293 | 267 |
| Load Impact (kW) | 14.4 | 11.3 |
| % Load Impact | 4.9% | 4.2% |

***Previous versus current ex-ante***

In this sub-section, we compare the *ex-ante* forecast prepared following PY2016 (the “previous study”) to the *ex-ante* forecast contained in this study (the “current study”). Table 3.18 reports the average event-hour load impacts for the August 2018 peak day under utility-specific 1-in-2 weather conditions. The aggregate load impact forecast decreased substantially across years, from 58.2 to 30.1 MWh/hour. This is due to a combination of reduced enrollment, lower-use customers, and lower percentage load impacts.

Table .: Previous vs. Current *Ex-Ante* Load Impacts, *Utility 1-in-2 August 2018 Peak Day*

|  |  |  |  |
| --- | --- | --- | --- |
| **Level** | **Outcome** | **Previous Study** | **Current Study** |
| **Total** | # SAIDs | 3,387 | 3,154 |
| Reference (MW) | 1,001 | 861 |
| Load Impact (MW) | 58.2 | 30.1 |
| Avg. Temp. | 93.9 | 91.9 |
| **Per SAID** | Reference (kW) | 295 | 273 |
| Load Impact (kW) | 17.2 | 9.5 |
| % Load Impact | 5.8% | 3.5% |

***Previous ex-ante versus current ex-post***

Table 3.19 provides a comparison of the *ex-ante* forecast of 2017 load impacts prepared following PY2016 and the PY2017 load impacts estimated as part of this study. The *ex-ante* forecast shown in the table represents the August peak day during a utility-specific 1-in-2 weather year. The *ex-post* load impacts are based on the average event day. The load impact forecast as part of the previous evaluation exceeded the *ex-post* estimated load impact by a substantial margin (45.2 vs. 22.4 MWh/hour). This can be attributed to a combination of fewer, smaller, and less responsive customers than forecast.

Table .: Comparison of Previous *Ex-Ante* and Current *Ex-Post* Impacts

|  |  |  |  |
| --- | --- | --- | --- |
| **Level** | **Outcome** | ***Ex-Ante* for 2017 August Peak Day from PY2016 Study** | ***Ex-Post* for Average Event Day from PY2017 Study** |
| **Total** | # SAIDs | 2,646 | 1,982 |
| Reference (MW) | 782 | 528 |
| Load Impact (MW) | 45.2 | 22.4 |
| Avg. Temp. | 93.9 | 92.8 |
| **Per SAID** | Reference (kW) | 295 | 267 |
| Load Impact (kW) | 17.1 | 11.3 |
| % Load Impact | 5.8% | 4.2% |

***Current ex-post versus current ex-ante***

Table 3.20 compares the *ex-post* and *ex-ante* load impacts from this study. The *ex-ante* load impacts in the table represent the 2018 August peak day with utility-specific 1-in-2 weather conditions. The aggregate load impact is forecast to increase from 22.4 MWh/hour in PY2017 to 30.1 MWh/hour in 2018.

Table .: Comparison of Current *Ex-Post* and *Ex-Ante* Load Impacts

|  |  |  |  |
| --- | --- | --- | --- |
| **Level** | **Outcome** | ***Ex-Post* for Average Event Day from PY2017 Study** | ***Ex-Ante* for 2018 August Peak Day from PY2017 Study** |
| **Total** | # SAIDs | 1,982 | 3,154 |
| Reference (MW) | 528 | 861 |
| Load Impact (MW) | 22.4 | 30.1 |
| Avg. Temp. | 92.8 | 91.9 |
| **Per SAID** | Reference (kW) | 267 | 273 |
| Load Impact (kW) | 11.3 | 9.5 |
| % Load Impact | 4.2% | 3.5% |

Table 3.21 documents the various potential sources of differences between the *ex-post* and *ex-ante* load impacts. The two biggest drivers of differences are the 59 percent increase in customer enrollment (which scales the aggregate load impact up by a commensurate amount) and a shift in the distribution of enrollments across LCAs, which causes a slight reduction in the average percentage load impact (which decreases from 4.2 to 3.5 percent).

Table .: Comparison of *Ex-Post* and *Ex-Ante* Factors

|  |  |  |  |
| --- | --- | --- | --- |
| Factor | *Ex-Post* | *Ex-Ante* | Expected Impact |
| Weather | Average event-hour temperature of 92.8 °F during the average event day. | Average event-hour temperature of 91.9 °F during the PG&E 1-in-2 August peak day. | Slightly higher *ex-post* temperatures may have increased the per-customer load impact (*ceteris paribus*). |
| Event window | Hours-ending 15 through 18. | Hours-ending 15 through 18. | None, though *ex-ante* load impact summaries for the Resource Adequacy window will be lower because they include non-event hours (HE 14 from Apr. to Oct.; HE 19-21 from Nov. to Mar.) |
| % of resource dispatched | 100 percent | 100 percent | None. |
| Enrollment | 1,982 service accounts. | 3,154 service accounts. | Higher *ex-ante* enrollment leads to higher aggregate load impact. The *ex-ante* distribution of enrollments across LCAs leads to a slight decrease in percentage load impacts. |
| Methodology | Panel models by LCA with fixed customer and date effects and a matched control-group of non-participants. | Simulated LCA-specific reference loads by LCA from a representative sample of customers. Then applied percentage load impacts derived from the *ex-post* analysis, excluding the weekend event day. | The method is not expected to consistently produce differences between the *ex-post* and *ex-ante* impacts. |

### PG&E SMB Customer Reconciliations

***Previous vs. Current Ex-Post***

Table 3.22 shows the average event-hour reference loads and load impacts for the average event day during the current and previous program years. Aggregate load impacts were approximately 10 MWh/hour lower in PY2017, which is primarily due to a lower percentage load impact. The higher temperatures in PY2017 contributed to higher per-customer reference loads in that year.

Table .: Current vs. Previous *Ex-Post* Load Impacts for the Average Event

|  |  |  |  |
| --- | --- | --- | --- |
| **Level** | **Outcome** | **PY2016** | **PY2017** |
| **Total** | # SAIDs | 206,786 | 203,183 |
| Reference (MW) | 1,016 | 1,318 |
| Load Impact (MW) | 25.4 | 15.0 |
| Avg. Temp. | 88.9 | 94.5 |
| **Per SAID** | Reference (kW) | 4.9 | 6.5 |
| Load Impact (kW) | 0.12 | 0.07 |
| % Load Impact | 2.5% | 1.1% |

***Previous versus current ex-ante***

In this sub-section, we compare the *ex-ante* forecast prepared following PY2016 (the “previous study”) to the *ex-ante* forecast contained in this study (the “current study”). Table 3.23 reports the average event-hour load impacts for the August 2018 peak day under utility-specific 1-in-2 weather conditions. The aggregate 2018 load impact forecast declined substantially across years, from 44.6 MWh/hour to 16.5 MWh/hour. Lower forecast enrollments explain a portion of the decline, but a halving of the percentage load impact (from 2.2 to 1.1 percent) is the primary driver.

Table .: Previous vs. Current *Ex-Ante* Load Impacts, *Utility 1-in-2 August 2018 Peak Day*

|  |  |  |  |
| --- | --- | --- | --- |
| **Level** | **Outcome** | **Previous Study** | **Current Study** |
| **Total** | # SAIDs | 297,371 | 235,093 |
| Reference (MW) | 2,041 | 1,558 |
| Load Impact (MW) | 44.6 | 16.5 |
| Avg. Temp. | 91.2 | 92.5 |
| **Per SAID** | Reference (kW) | 6.9 | 6.6 |
| Load Impact (kW) | 0.15 | 0.07 |
| % Load Impact | 2.2% | 1.1% |

***Previous ex-ante versus current ex-post***

Table 3.24 provides a comparison of the *ex-ante* forecast of 2017 load impacts prepared following PY2016 and the PY2017 load impacts estimated as part of this study. The *ex-ante* forecast shown in the table represents the August peak day during a utility-specific 1-in-2 weather year. The *ex-post* load impacts are based on the average event day. The forecast created as part of the previous study predicted higher load impacts than we estimated in this study. While enrollments are lower than were forecast, the lower percentage load impacts are the primary driver of the difference.

Table .: Comparison of Previous *Ex-Ante* and Current *Ex-Post* Impacts

|  |  |  |  |
| --- | --- | --- | --- |
| **Level** | **Outcome** | ***Ex-Ante* for 2017 August Peak Day from PY2016 Study** | ***Ex-Post* for Average Event Day from PY2017 Study** |
| **Total** | # SAIDs | 225,654 | 203,183 |
| Reference (MW) | 1,517 | 1,318 |
| Load Impact (MW) | 33.3 | 15.0 |
| Avg. Temp. | 91.3 | 94.5 |
| **Per SAID** | Reference (kW) | 6.7 | 6.5 |
| Load Impact (kW) | 0.15 | 0.07 |
| % Load Impact | 2.2% | 1.1% |

***Current ex-post versus current ex-ante***

Table 3.25 compares the *ex-post* and *ex-ante* load impacts from this study. The *ex-ante* load impacts in the table represent the 2018 August peak day with utility-specific 1-in-2 weather conditions. The forecast calls for an increase in the aggregate load impact from 15.0 MWh/hour in PY2017 to 16.5 MWh/hour in 2018. This is almost entirely due to an increase in customer enrollment.

Table .: Comparison of Current *Ex-Post* and *Ex-Ante* Load Impacts

|  |  |  |  |
| --- | --- | --- | --- |
| **Level** | **Outcome** | ***Ex-Post* for Average Event Day from PY2017 Study** | ***Ex-Ante* for 2018 August Peak Day from PY2017 Study** |
| **Total** | # SAIDs | 203,183 | 235,093 |
| Reference (MW) | 1,318 | 1,558 |
| Load Impact (MW) | 15.0 | 16.5 |
| Avg. Temp. | 94.5 | 92.5 |
| **Per SAID** | Reference (kW) | 6.5 | 6.6 |
| Load Impact (kW) | 0.07 | 0.07 |
| % Load Impact | 1.1% | 1.1% |

Table 3.26 documents the various potential sources of differences between the *ex-post* and *ex-ante* load impacts. As stated above, the expected increase in customer enrollment is the primary driver of the forecast increase in the aggregate load impact.

Table .: Comparison of *Ex-Post* and *Ex-Ante* Factors

|  |  |  |  |
| --- | --- | --- | --- |
| Factor | *Ex-Post* | *Ex-Ante* | Expected Impact |
| Weather | Average event-hour temperature of 94.5 °F during the average event day. | Average event-hour temperature of 92.5 °F during the PG&E 1-in-2 August peak day. | Slightly higher *ex-post* temperatures may have increased the per-customer load impact (*ceteris paribus*). |
| Event window | Hours-ending 15 through 18. | Hours-ending 15 through 18. | None, though *ex-ante* load impact summaries for the Resource Adequacy window will be lower because they include non-event hours (HE 14 from Apr. to Oct.; HE 19-21 from Nov. to Mar.) |
| % of resource dispatched | 100 percent | 100 percent | None. |
| Enrollment | 203,183 service accounts. | 235,093 service accounts. | Higher *ex-ante* enrollment leads to higher aggregate load impact. |
| Methodology | Panel models by size and LCA with fixed customer and date effects and a matched control-group of non-participants. | Simulated size- and LCA-specific reference loads by LCA from a representative sample of customers. Then applied percentage load impacts derived from the *ex-post* analysis, excluding the weekend event day. | The method is not expected to consistently produce differences between the *ex-post* and *ex-ante* impacts. |

# SCE

## 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, all results presented in this section are derived from panel fixed-effects regression analyses of hourly data for CPP customers and a matched control group. The evaluation of match quality and a discussion thereof is presented in the appendix. The estimated model is described in Section 2.1.2, with the SCE model including the morning load variable and the mean temperature for the first 17 hours of each day. Furthermore, we control for concurrent events that are called for other programs, including BIP, CBP, and DRC, by including indicators for customers who are dually enrolled and who are called (or in the case of CBP and DRC, nominated when their aggregator is called) for a given event that occurs during an event or non-event day.

### Large Customers

This section summarizes results for all large SCE 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 average 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, and TA/TI customers are presented in subsequent sub-sections.

The *ex-post* load impacts for SCE’s large CPP customers 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 80 percent confidence intervals around these estimates (*i.e.*, the 10th and 90th percentile scenarios from the uncertainty-adjusted load impacts). The orange line represents 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 16 to 29 MWh/hour. The load impact averaged 22 MWh/hour, with 67 percent of the event days having a load impact in excess of 20 MWh/hour. Figure 4.1 shows some evidence of a relationship between load impacts and average temperatures. The two events with the lowest load impacts (July 27th and July 31st) experienced the lower than average temperatures (approximately 87 °F on both dates), whiles the event with the highest load impact (August 29th) had the highest average temperature for the event days of 96 °F.

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

Table 4.1 summarizes enrollments, average event-hour load impacts, and reference loads for each event day and the average event. There a slight increase in enrolled customers over the course of the season. Estimated load reductions averaged 10 kWh/hour/customer across event days, which amounts to a 4 percent load reduction.

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

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
| **Event Date** | **# Enrolled** | **Aggregate (MWh/hour)** | | **Per-Customer (kWh/hour)** | | **% Load Impact** | **Ave. Event Temp.** |
| **Ref. Load** | **Load Impact** | **Ref. Load** | **Load Impact** |
| 6/19/2017 | 2,277 | 530.4 | 21.6 | 232.9 | 9.5 | 4.1% | 88.2 |
| 6/20/2017 | 2,274 | 543.5 | 18.9 | 239.0 | 8.3 | 3.5% | 90.5 |
| 7/6/2017 | 2,274 | 542.7 | 24.7 | 238.6 | 10.9 | 4.5% | 90.5 |
| 7/7/2017 | 2,275 | 548.7 | 24.1 | 241.2 | 10.6 | 4.4% | 95.2 |
| 7/27/2017 | 2,287 | 544.0 | 15.9 | 237.8 | 6.9 | 2.9% | 87.3 |
| 7/31/2017 | 2,288 | 532.2 | 16.2 | 232.6 | 7.1 | 3.0% | 86.4 |
| 8/1/2017 | 2,288 | 560.9 | 22.1 | 245.1 | 9.7 | 3.9% | 89.9 |
| 8/28/2017 | 2,305 | 584.6 | 25.7 | 253.6 | 11.1 | 4.4% | 94.0 |
| 8/29/2017 | 2,305 | 607.6 | 29.4 | 263.6 | 12.8 | 4.8% | 95.4 |
| 8/31/2017 | 2,309 | 604.0 | 24.0 | 261.6 | 10.4 | 4.0% | 94.6 |
| 9/5/2017 | 2,309 | 570.3 | 18.3 | 247.0 | 7.9 | 3.2% | 86.1 |
| 9/12/2017 | 2,307 | 561.0 | 22.5 | 243.2 | 9.7 | 4.0% | 83.6 |
| **Typical Event Day** | **2,292** | **560.8** | **21.9** | **244.7** | **9.6** | **3.9%** | **90.1** |

Figure 4.2 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 require by the Protocols, including hourly temperatures and uncertainty adjusted load impacts. Notice that the highest load impact tends to occur in the first hour of the event (2:00 to 3:00 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 smaller load impacts in the hours immediately preceding (10 MWh from 1:00 to 2:00 p.m.) and following (4 MWh from 6:00 to 7:00 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 .: Typical Event Day Reference Loads and Load Profile, SCE *Large*

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



Next, we look at SCE large customer estimate by industry group. Table 4.3 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 the reference load). Enrollments are concentrated in the Manufacturing and Offices, Hotels, Health & Services groups, which represent a combined 53 percent of large customers. These two groups also have the largest estimated reference loads of 156 and 157 MWh/hour, respectively. Manufacturing, with 15 MWh/hour of load impact, accounts for the bulk of the load impacts for large CPP customers, representing two-thirds of the aggregate load reduction. There are ---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------.

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Table .: Typical Event Day 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** |
| Agriculture, Mining, & Construction | 63 | 9.1 | 8.1 | 1.0 | 11.3% |
| Manufacturing | 644 | 155.7 | 141.2 | 14.5 | 9.3% |
| Wholesale, Transportation, & Other Utilities | 380 | 94.1 | 92.0 | 2.1 | 2.2% |
| Retail Stores | 185 | 49.2 | 48.8 | 0.5 | 1.0% |
| Offices, Hotels, Health, Services | 573 | 156.8 | 155.1 | 1.7 | 1.1% |
| Schools |  |  |  |  |  |
| Entertainment, Other Services, Government | 189 | 48.8 | 47.1 | 1.7 | 3.5% |
| Other or unknown |  |  |  |  |  |

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 4.3. Since Manufacturing represents such a large share of the load impact, all of the other industry groups (with the exception of Agriculture, Mining, & Construction) have lower shares of the load impact than the shares of enrolled customers or reference loads. Offices, Hotels, Health & Services has a particularly low share of load impact (8 percent) relative to its share of enrollments and reference loads.

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Figure 4.3: Typical Event Day Event-Hour Load Impacts by Industry Group, *SCE Large*

Table 4.4 and Figure 4.4 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 483 MWh/hour. This LCA also accounts for the largest load impact of 18 MWh/hour. We can see in Figure 4.4 that the LA Basin’s share of customers, reference loads, and load impacts all exceed 80 percent.

Table .: Typical Event Day Load Impacts by LCA, *SCE Large*

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **LCA** | **# of Service Accounts** | **Estimated Reference Load (MW)** | **Observed Load (MW)** | **Estimated Load Impact (MW)** | **% LI** |
| LA Basin | 1,944 | 483.3 | 465.3 | 18.0 | 3.7% |
| Outside Basin | 117 | 29.2 | 27.2 | 2.1 | 7.0% |
| Ventura | 230 | 49.1 | 46.9 | 2.1 | 4.4% |

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

### SMB Customers

This section summarizes results for all small and medium (SMB) SCE customers, defined as customers with maximum demand less than 20 kW and between 20 and 199.99 kW, respectively. 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 customers, AutoDR customers, and TA/TI customers are presented in subsequent sub-sections.

The *ex-post* load impacts for SCE’s SMB CPP customers are summarized for all 12 events in Figure 4.5. In contrast to large customers, the load impacts are not statistically significant on each event day. Five events days (July 27th, August 1st, August 28th, August 31st, and September 5th) have small estimated load reductions or increases in load. However, on the remaining seven event days, there are significant load impacts that range between 0.7 and 1.4 MWh/hour with an average of 0.9 MWh/hour (1.5 percent). The SMB customers do not show a relationship between load impacts and temperature.

Figure .: Average Event-Hour Load Impacts by Event, SC*E SMB*

Table 4.5 summarizes enrollments, average event-hour load impacts, and reference loads for each event day and the average event. Although enrollments fluctuated, the season ended with nearly the same number of SMB customers as there were at the beginning. Overall, SMB customers had an aggregate load impact of 0.6 MWh/hour, which is 0.8 kWh/hour/customer on average, or about a 1 percent load reduction.

Table .: Average Event-Hour Load Impacts by Event, *SCE SMB*

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
| **Event Date** | **# Enrolled** | **Aggregate (MWh/hour)** | | **Per-Customer (kWh/hour)** | | **% Load Impact** | **Ave. Event Temp.** |
| **Ref. Load** | **Load Impact** | **Ref. Load** | **Load Impact** |
| 6/19/2017 | 824 | 61.1 | 1.2 | 74.1 | 1.4 | 1.9% | 87.3 |
| 6/20/2017 | 807 | 62.6 | 1.4 | 77.6 | 1.7 | 2.2% | 89.4 |
| 7/6/2017 | 812 | 62.4 | 0.9 | 76.8 | 1.2 | 1.5% | 89.3 |
| 7/7/2017 | 812 | 63.8 | 0.9 | 78.6 | 1.1 | 1.4% | 93.9 |
| 7/27/2017 | 816 | 62.8 | 0.3 | 76.9 | 0.3 | 0.5% | 86.4 |
| 7/31/2017 | 814 | 61.7 | 0.7 | 75.8 | 0.9 | 1.2% | 85.1 |
| 8/1/2017 | 813 | 64.1 | -0.3 | 78.9 | -0.3 | -0.4% | 89.1 |
| 8/28/2017 | 817 | 66.9 | 0.4 | 81.9 | 0.5 | 0.6% | 93.0 |
| 8/29/2017 | 819 | 69.2 | 0.7 | 84.5 | 0.9 | 1.0% | 94.7 |
| 8/31/2017 | 820 | 69.6 | 0.0 | 84.9 | 0.0 | 0.0% | 94.0 |
| 9/5/2017 | 820 | 65.4 | 0.4 | 79.7 | 0.4 | 0.6% | 85.6 |
| 9/12/2017 | 822 | 63.7 | 0.8 | 77.4 | 1.0 | 1.3% | 81.8 |
| **Typical Event Day** | **816** | **64.4** | **0.6** | **78.9** | **0.8** | **1.0%** | **89.1** |

Figure 4.6 shows the aggregate hourly reference loads, observed loads, and estimated load impacts on the typical event day for medium customers. Table 4.6 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 0.8 MWh/hour occur at the beginning of the event (2:00 to 4:00 p.m.). There is no evidence of pre-cooling or post-event snapback, and in fact, there are small significant load impacts of 0.3 MWh/hour in the hours directly preceding the event and several hours after the event concludes. Overall, these results do not suggest that medium customers respond to events by shifting event-hour loads to hours outside the event window.

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

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



Figure 4.7 shows the aggregate hourly reference loads, observed loads, and estimated load impacts on the typical event day for small customers. Table 4.7 contains the hourly typical event day results, hourly temperatures, and uncertainty adjusted load impacts. SCE’s small customers have a somewhat odd reference load profile and do not display the load impact profile one would expect (in which load impacts are uniformly highest during the event hours. The majority of small customers correspond to the Wholesale, Transport, and Other Utilities industry, which may explain the somewhat atypical load profile. Overall, the results do not point to significant load impacts during the event hours.

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

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



Next, we look at SCE SMB customer estimates by industry group. Table 4.8 summarizes the 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 the reference load). Although none of the industry groups has a load impact that reaches 1 MWh/hour, the Manufacturing group has the highest magnitude load impact in level and percentage terms (0.3 MWh/hour and 2.3 percent). Figure 4.8 shows the shares of enrollments, reference loads, and load impacts by industry group. The load impacts are concentrated in Manufacturing, which realizes almost 40 percent of the total load impact representing only 18 percent of enrolled customers and reference loads. Wholesale, Transportation & Other Utilities, with a load impact of 0.2 MWh/hour (1.7 percent of reference load), is the only industry group next to Manufacturing that has a higher share of load impacts than of enrollments and reference loads.

Table .: Typical Event Day Load Impacts by Industry Group, *SCE SMB*

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Industry Group** | **# of Service Accounts** | **Estimated Reference Load (MWh/hour)** | **Observed Load (MWh/hour)** | **Estimated Load Impact (MWh/hour)** | **% LI** |
| Agriculture, Mining, & Construction |  |  |  |  |  |
| Manufacturing | 144 | 11.6 | 11.4 | 0.3 | 2.3% |
| Wholesale, Transportation, & Other Utilities | 176 | 9.7 | 9.5 | 0.2 | 1.7% |
| Retail Stores | 91 | 10.2 | 10.1 | 0.1 | 0.8% |
| Offices, Hotels, Health, Services | 225 | 20.3 | 20.1 | 0.2 | 0.8% |
| Schools | 51 | 3.2 | 3.3 | -0.1 | -1.6% |
| Entertainment, Other Services, Government | 102 | 8.0 | 8.0 | 0.0 | 0.1% |
| Other or unknown |  |  |  |  |  |

Figure .: Typical Event Day Event-Hour Load Impacts by Industry Group, *SCE SMB*

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Table 4.9 and Figure 4.9 provide the same summaries as above by LCA. Enrollments and reference loads are highly concentrated in LA Basin, with over 80 percent of SMB enrollment and over 90 percent of SMB load impacts.

Table . Typical Event Day Load Impacts by LCA, *SCE SMB*

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **LCA** | **# of Service Accounts** | **Estimated Reference Load (MWh/hour)** | **Observed Load (MWh/hour)** | **Estimated Load Impact (MWh/hour)** | **% LI** |
| LA Basin | 671 | 56.9 | 56.3 | 0.6 | 1.0% |
| Outside Basin | 52 | 1.9 | 1.9 | 0.0 | 2.4% |
| Ventura | 94 | 5.6 | 5.6 | 0.0 | -0.8% |

Figure .: Typical Event Day Event-Hour Load Impacts by LCA, *SCE SMB*

### NEM Customers

This section summarizes results for all SCE net-metering (NEM) customers, defined as customers that are flagged as net-metering customers by SCE or customers with negative usage in any hour.[[15]](#footnote-15) 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 customers, AutoDR customers, and TA/TI customers are presented in subsequent sub-sections.

The *ex-post* load impacts for SCE’s NEM CPP customers are summarized for all 12 events in Figure 4.10. ------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------

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

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

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Table .: Average Event-Hour Load Impacts by Event, *SCE NEM*

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
| **Event Date** | **# Enrolled** | **Aggregate (MWh/hour)** | | **Per-Customer (kWh/hour)** | | **% Load Impact** | **Ave. Event Temp.** |
| **Ref. Load** | **Load Impact** | **Ref. Load** | **Load Impact** |
| 6/19/2017 |  |  |  |  |  |  |  |
| 6/20/2017 |  |  |  |  |  |  |  |
| 7/6/2017 |  |  |  |  |  |  |  |
| 7/7/2017 |  |  |  |  |  |  |  |
| 7/27/2017 |  |  |  |  |  |  |  |
| 7/31/2017 |  |  |  |  |  |  |  |
| 8/1/2017 |  |  |  |  |  |  |  |
| 8/28/2017 |  |  |  |  |  |  |  |
| 8/29/2017 |  |  |  |  |  |  |  |
| 8/31/2017 |  |  |  |  |  |  |  |
| 9/5/2017 |  |  |  |  |  |  |  |
| 9/12/2017 |  |  |  |  |  |  |  |
| **Typical Event Day** |  |  |  |  |  |  |  |

Figure 4.11 shows the aggregate hourly reference loads, observed loads, and estimated load impacts on the typical event day for NEM customers. Table 4.11 contains the hourly typical event day results, including hourly temperatures, and uncertainty adjusted load impacts. ----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------

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

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

Next, we look at SCE NEM customer estimates by industry group. Table 4.12 summarizes the aggregate event-hour results for the typical event day for six 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 the reference load).[[16]](#footnote-16) -------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------

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Table .: Typical Event Day Load Impacts by Industry Group, *SCE NEM*

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Industry Group** | **# of Service Accounts** | **Estimated Reference Load (MWh/hour)** | **Observed Load (MWh/hour)** | **Estimated Load Impact (MWh/hour)** | **% LI** |
| Manufacturing |  |  |  |  |  |
| Wholesale, Transportation, & Other Utilities |  |  |  |  |  |
| Retail Stores |  |  |  |  |  |
| Offices, Hotels, Health, Services |  |  |  |  |  |
| Schools |  |  |  |  |  |
| Entertainment, Other Services, Government |  |  |  |  |  |

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

Table 4.13 and Figure 4.13 provide the same summaries as above by LCA. -----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------

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Table .: Typical Event Day Load Impacts by LCA, *SCE NEM*

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **LCA** | **# of Service Accounts** | **Estimated Reference Load (MWh/hour)** | **Observed Load (MWh/hour)** | **Estimated Load Impact (MWh/hour)** | **% LI** |
| LA Basin |  |  |  |  |  |
| Outside Basin |  |  |  |  |  |
| Ventura |  |  |  |  |  |

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

### Dually Enrolled Customers

This section summarizes results for customers who are enrolled in CPP as well as another SCE demand response program. The three programs in which SCE customers can enroll along with CPP include Base Interruptible Program (BIP), Capacity Bidding Program (CBP), and Aggregator Managed Program (AMP, also known as Demand Response Contracts, or DRC).[[17]](#footnote-17) 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.

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Table 4.14 summarizes aggregate event-hour results for each event-day as well as the average event day for customers who are dually enrolled in BIP and CPP, including the number of enrolled customers, the reference and observed loads, and the estimated load impacts (in MWh/hour and as a percentage of the reference load). -------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------

Table .: Average Event-Hour Load Impacts for CPP+BIP customers by Event, SC*E*

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Event Date** | **# of Service Accounts** | **Estimated Reference Load (MWh/hour)** | **Observed Load (MWh/hour)** | **Estimated Load Impact (MWh/hour)** | **% LI** |
| 6/19/2017 |  |  |  |  |  |
| 6/20/2017 |  |  |  |  |  |
| 7/6/2017 |  |  |  |  |  |
| 7/7/2017 |  |  |  |  |  |
| 7/27/2017 |  |  |  |  |  |
| 7/31/2017 |  |  |  |  |  |
| 8/1/2017 |  |  |  |  |  |
| 8/28/2017 |  |  |  |  |  |
| 8/29/2017 |  |  |  |  |  |
| 8/31/2017 |  |  |  |  |  |
| 9/5/2017 |  |  |  |  |  |
| 9/12/2017 |  |  |  |  |  |
| **Typical Event Day** |  |  |  |  |  |

Table 4.15 summarizes aggregate event-hour results for each event-day as well as the typical event day for customers who are dually enrolled in CBP and CPP, including the number of enrolled customers, the reference and observed loads, and the estimated load impacts (in MWh/hour and as a percentage of the reference load). ---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------

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Table .: Average Event-Hour Load Impacts for CPP+CBP customers by Event, SC*E*

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Event Date** | **# of Service Accounts** | **Estimated Reference Load (MWh/hour)** | **Observed Load (MWh/hour)** | **Estimated Load Impact (MWh/hour)** | **% LI** |
| 6/19/2017 |  |  |  |  |  |
| 6/20/2017 |  |  |  |  |  |
| 7/6/2017 |  |  |  |  |  |
| 7/7/2017 |  |  |  |  |  |
| 7/27/2017 |  |  |  |  |  |
| 7/31/2017 |  |  |  |  |  |
| 8/1/2017 |  |  |  |  |  |
| 8/28/2017 |  |  |  |  |  |
| 8/29/2017 |  |  |  |  |  |
| 8/31/2017 |  |  |  |  |  |
| 9/5/2017 |  |  |  |  |  |
| 9/12/2017 |  |  |  |  |  |
| **Typical Event Day** |  |  |  |  |  |

Table 4.16 summarizes aggregate event-hour results for each event-day as well as the typical event day for customers who are dually enrolled in AMP and CPP, including the number of enrolled customers, the reference and observed loads, and the estimated load impacts (in MWh/hour and as a percentage of the reference load). ----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------

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Table .: Average Event-Hour Load Impacts for CPP+AMP customers by Event, SC*E*

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Event Date** | **# of Service Accounts** | **Estimated Reference Load (MWh/hour)** | **Observed Load (MWh/hour)** | **Estimated Load Impact (MWh/hour)** | **% LI** |
| 6/19/2017 |  |  |  |  |  |
| 6/20/2017 |  |  |  |  |  |
| 7/6/2017 |  |  |  |  |  |
| 7/7/2017 |  |  |  |  |  |
| 7/27/2017 |  |  |  |  |  |
| 7/31/2017 |  |  |  |  |  |
| 8/1/2017 |  |  |  |  |  |
| 8/28/2017 |  |  |  |  |  |
| 8/29/2017 |  |  |  |  |  |
| 8/31/2017 |  |  |  |  |  |
| 9/5/2017 |  |  |  |  |  |
| 9/12/2017 |  |  |  |  |  |
| **Typical Event Day** |  |  |  |  |  |

### AutoDR and TA/TI Customers

This section summarizes results for CPP customers who participated in the Technical Assistance and Technology Incentives (TA/TI) and Automated Demand Response (AutoDR) programs. TA/TI is no longer offered by the IOUs, but we summarize load impacts from customers that received program incentives in the past. The program had two parts: technical assistance in the form of energy audits, and technology incentives. The objective of the TA portion of the program was to subsidize customer energy audits that had the objective of identifying ways in which customers could reduce load during DR events. The TI portion of the program provided incentive payments for the installation of equipment or control software supporting DR.

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.

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Table 4.17 summarizes aggregate event-hour results for each event-day as well as the typical event day for CPP customers who participated in the AutoDR program, including the number of enrolled customers, the reference and observed loads, and the estimated load impacts (in MWh/hour and as a percentage of the reference load). ------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------

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

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
| **Event Date** | **# of Service Accounts** | **Estimated Reference Load (MWh/hour)** | **Observed Load (MWh/hour)** | **Estimated Load Impact (MWh/hour)** | **% LI** | **Approved MW** |
| 6/19/2017 |  |  |  |  |  |  |
| 6/20/2017 |  |  |  |  |  |  |
| 7/6/2017 |  |  |  |  |  |  |
| 7/7/2017 |  |  |  |  |  |  |
| 7/27/2017 |  |  |  |  |  |  |
| 7/31/2017 |  |  |  |  |  |  |
| 8/1/2017 |  |  |  |  |  |  |
| 8/28/2017 |  |  |  |  |  |  |
| 8/29/2017 |  |  |  |  |  |  |
| 8/31/2017 |  |  |  |  |  |  |
| 9/5/2017 |  |  |  |  |  |  |
| 9/12/2017 |  |  |  |  |  |  |
| **Typical Event Day** |  |  |  |  |  |  |

Table 4.18 summarizes aggregate event-hour results for each event-day as well as the typical event day for CPP customers who participated in the TA/TI program, including the number of enrolled customers, the reference and observed loads, and the estimated load impacts (in MWh/hour and as a percentage of the reference load). ---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------

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Table . Average Event-Hour Load Impacts for TA/TI Customers by Event, SC*E*

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
| **Event Date** | **# of Service Accounts** | **Estimated Reference Load (MWh/hour)** | **Observed Load (MWh/hour)** | **Estimated Load Impact (MWh/hour)** | **% LI** | **Approved MW** |
| 6/19/2017 |  |  |  |  |  |  |
| 6/20/2017 |  |  |  |  |  |  |
| 7/6/2017 |  |  |  |  |  |  |
| 7/7/2017 |  |  |  |  |  |  |
| 7/27/2017 |  |  |  |  |  |  |
| 7/31/2017 |  |  |  |  |  |  |
| 8/1/2017 |  |  |  |  |  |  |
| 8/28/2017 |  |  |  |  |  |  |
| 8/29/2017 |  |  |  |  |  |  |
| 8/31/2017 |  |  |  |  |  |  |
| 9/5/2017 |  |  |  |  |  |  |
| 9/12/2017 |  |  |  |  |  |  |
| **Typical Event Day** |  |  |  |  |  |  |

## 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, with the small and medium customers combined into an SMB section. 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, in a manner similar to the approach used in the 2016 evaluation, 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. For large customers, we use the share of enrollments by LCA in 2017. For SMB customers, we use the share of enrollments by LCA from the 2017 report, since our *ex-ante* forecasts are based on what is reported therein.

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### Large Customers

Figure 4.14 summarizes SCE’s enrollment forecast for large customers. SCE anticipates that large CPP customer enrollment will grow by 10 customers per year, or 0.3 percent.

Figure .: CPP Enrollments, *SCE Large*

Figure 4.15 illustrates the aggregate reference load, observed load, and load impact for large customers on the typical event day in August in 2022 for the SCE 1-in-2 weather scenario. The shape of the *ex-ante* loads and load impacts is similar to the *ex-post* results in Figure 4.2, while the magnitudes are somewhat larger due to higher enrollment. The average event-hour load impact is 30 MWh/hour, or 4 percent of the reference load.

Figure .: Aggregate Hourly Loads and Load Impacts in 2022 for *SCE 1-in-2 Typical Event Day, SCE Large*

Figure 4.16 shows the forecasted share of load impacts by LCA during the average event hour on the typical event day in 2022 under SCE’s 1-in-2 weather scenario. As expected, the LA Basin accounts for over 80 percent of the total load impact.

Figure .: Share of Load Impacts by LCA in 2022 for *SCE 1-in-2 Typical Event Day,   
SCE Large*

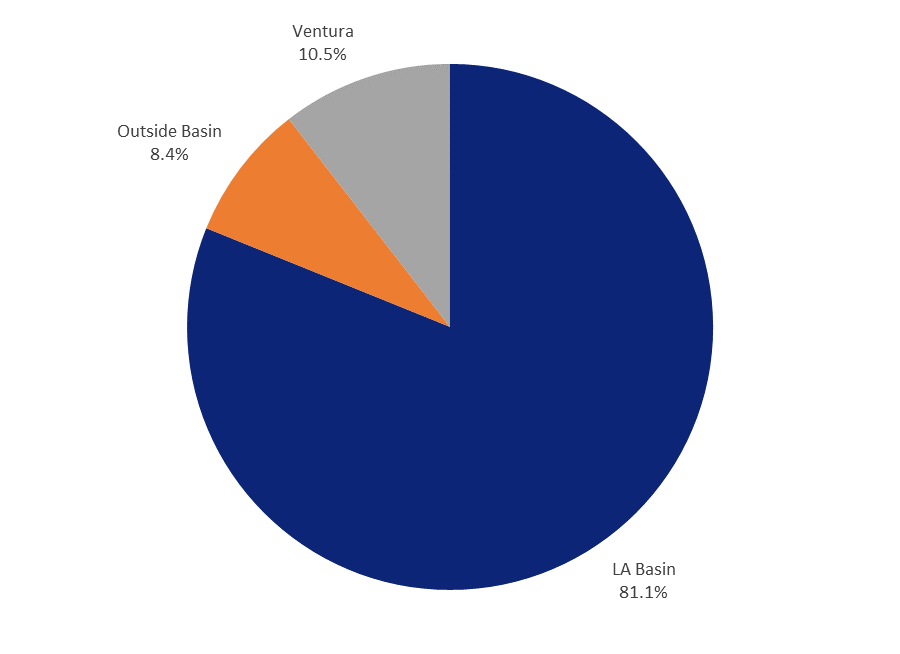


Figure 4.17 illustrates the seasonality in the forecastedload impacts for by comparing aggregate load impacts for the average hour in the Resource Adequacy (RA) window in 2022 across months for SCE’s 1-in-2 peak day weather scenario. The RA window is 1 to 6 p.m. from April through October and 4 to 9 p.m. for the remainder of the year. The lower load impacts from November through March are largely due to the fact that the RA window in those months includes three hours that are not CPP event hours, where the summer RA window includes only one such hour. The load impact is highest in August (27 MWh/hour) and lowest in January and December (9 MWh/hour).

Figure .: Aggregate Load Impacts by Month over RA Window in 2022 for *SCE 1-in-2 Peak Day*, *SCE Large*

Figure 4.18 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 .: Aggregate Load Impacts for Typical Event Day by Year and Weather Scenario over RA Window, *SCE Large*

### SMB Customers

Figure 4.19 summarizes SCE’s enrollment forecast for SMB customers. There will be no SMB customers in 2018. In 2019, SMB customers will be defaulted into the CPP program, and SCE projects initial enrollment of 215,205 small customers and 34,795 medium customers. In 2020, SCE anticipates that roughly 60 percent of SMB customers will opt-out of CPP. After 2020, SMB enrollments are expected to remain constant. This pattern is reflected in the load impact forecasts shown in Figure 4.26 and Figure 4.27.

Figure .: CPP Enrollments, *SCE SMB*

Figure 4.20 illustrates the aggregate reference loads, observed loads, and load impacts for medium customers on the typical event day in August in 2022 for the SCE 1-in-2 weather scenario.

Because SCE has not yet defaulted its SMB customers onto CPP, we do not have *ex-post* impacts on which to base the *ex-ante* forecast. This was also the case for the previous evaluation, in which the *ex-ante* forecast was based on a combination of reference loads from samples of SCE customers and percentage load impacts adapted from PG&E *ex-post* estimates. In the interest of continuity, we base our *ex-ante* forecast of SCE’s SMB customers on the forecast in the previous study. Specifically, we retain the per-customer reference loads and load impacts, but re-scale them to the updated enrollment forecast.[[18]](#footnote-18) Because of how the forecast is developed, there is not a close correspondence to the *ex-post* estimates for SCE’s SMB customers, as that group is currently comprised of a fairly small number of customers who enrolled in CPP voluntarily (rather than being defaulted onto the rate).

The forecast predicts an average load impact of 4 MWh/hour for medium customers on the typical event day in 2022 for the SCE 1-in-2 weather scenario, which is a two percent reduction in reference loads.

Figure .: Aggregate Hourly Loads and Load Impacts in 2022 for *SCE 1-in-2 Typical Event Day, SCE Medium*

Figure 4.21 illustrates the aggregate reference loads, observed loads, and load impacts for small customers on the typical event day in August in 2022 for the SCE 1-in-2 weather scenario. For these customers, the forecast predicts an average load impact of 3 MWh/hour on the typical event day in 2022 for the SCE 1-in-2 weather scenario, which is a four percent reduction in reference loads.

Figure .: Aggregate Hourly Loads and Load Impacts in 2022 for *SCE 1-in-2 Typical Event Day, SCE Small*

Figure 4.22 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 2022 under SCE’s 1-in-2 weather scenario. LA Basin is expected to have the largest share of load impacts at 81 percent, followed by Ventura at 13 percent, then Outside Basin at 6 percent.

Figure .: Share of Load Impacts by LCA in 2022 for *SCE 1-in-2 Typical Event Day,   
SCE Medium*

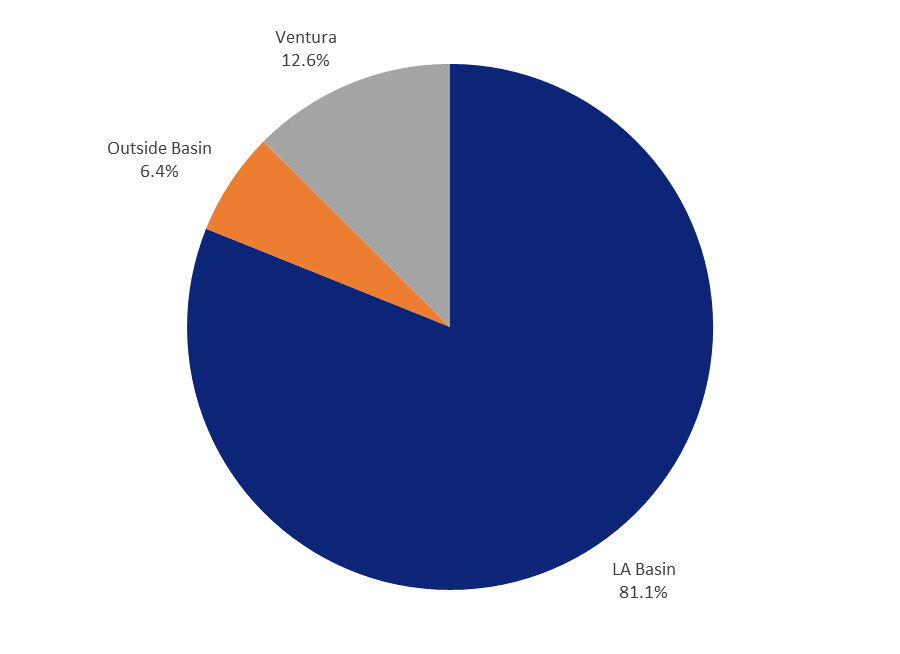


Figure 4.23 shows the same information for small customers. The shared by LCA are similar to those of the medium customers, with 80 percent in the LA Basin, 15 percent in Ventura, and 5 percent in Outside Basin.

Figure .: Share of Load Impacts by LCA in 2022 for *SCE 1-in-2 Typical Event Day,   
SCE Small*

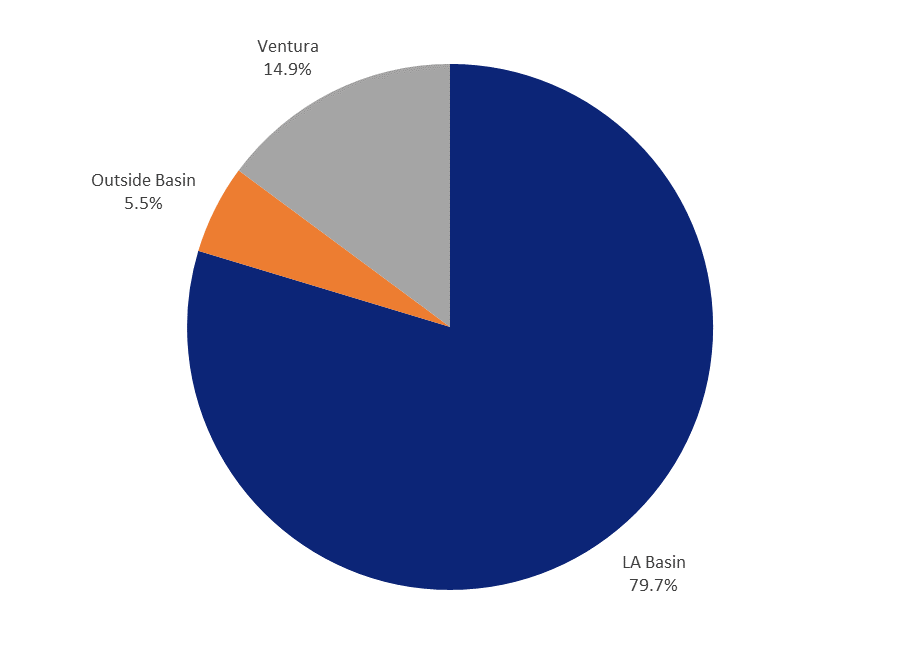


Figure 4.24 shows the seasonality of the forecastedload impacts for medium customers based on the 2022 aggregate load impacts for the average hour in the RA window for SCE’s 1-in-2 weather scenario. The seasonality in load impacts results from the change in the RA window during the year, with the November to March RA window including three non-event hours. The load impact is highest in August (4.2 MWh/hour) and lowest in December (1.2 MWh/hour).

Figure .: Aggregate Load Impacts by Month over RA Window in 2022 for *SCE 1-in-2 Peak Day*, *SCE Medium*

Figure 4.25 illustrates the seasonality in the forecastedload impacts for small customers. The seasonal pattern is similar to that of the medium customers. The load impact is highest in August (3.0 MWh/hour) and lowest in March (1.6 MWh/hour).

Figure .: Aggregate Load Impacts by Month over RA Window in 2022 for *SCE 1-in-2 Peak Day*, *SCE Small*

Figure 4.26 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 no *ex-ante* load impacts in 2018 due to zero forecast enrollments. Customers who are defaulted into CPP in 2019 cause forecasted load impacts to increase to approximately 10 MWh/hour across weather scenarios, after which load impacts drop to approximately 4 MWh/hour in 2020. There are relatively minor differences between the forecasted load impacts for the alternative weather scenarios over the forecast period.

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

Figure 4.27 shows the same information for small customers. As with medium customers, the changes in load impacts reflect changes in enrollments. Customers who are defaulted into CPP in 2019 cause forecasted load impacts to increase to approximately 7 MWh/hour, after which load impacts drop to approximately 3 MWh/hour in 2020. There are relatively minor differences between the forecasted load impacts for the alternative weather scenarios over the forecast period.

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

## 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 PY2017. The term “previous” refers to findings in reports for PY2016.

### SCE Large Customer Reconciliations

***Previous vs. Current Ex-Post***

Table 4.19 shows the average event-hour reference loads and load impacts for the average event day during the current and previous program years. The total load impact is somewhat lower in the current study (561 MWh/hour vs. 595 MWh/hour in the previous study). This is due to a combination of lower enrollment and lower per-customer load impacts (3.9 percent in this study vs. 5.8% in the previous study).

Table .: Current vs. Previous *Ex-Post* Load Impacts for the Average Event

|  |  |  |  |
| --- | --- | --- | --- |
| **Level** | **Outcome** | **PY2016** | **PY2017** |
| **Total** | # SAIDs | 2,545 | 2,292 |
| Reference (MW) | 595 | 561 |
| Load Impact (MW) | 34.4 | 21.9 |
| Avg. Temp. | 90.2 | 90.4 |
| **Per SAID** | Reference (kW) | 234 | 245 |
| Load Impact (kW) | 13.5 | 9.6 |
| % Load Impact | 5.8% | 3.9% |

***Previous versus current ex-ante***

In this sub-section, we compare the *ex-ante* forecast prepared following PY2016 (the “previous study”) to the *ex-ante* forecast contained in this study (the “current study”). Table 4.20 reports the average event-hour load impacts for the August 2018 peak day under utility-specific 1-in-2 weather conditions. The forecast load impact is lower in the current study (29.8 MWh/hour vs. 35.3 MWh/hour in the previous study) despite having higher forecast enrollments. This is due to a lower percentage impact, which is 3.7 percent in the current study versus 5.7 percent in the previous study (where both values are consistent with their contemporaneous *ex-post* load impact study).

Table .: Previous vs. Current *Ex-Ante* Load Impacts, *Utility* *1-in-2 August 2018 Peak Day*

|  |  |  |  |
| --- | --- | --- | --- |
| **Level** | **Outcome** | **Previous Study** | **Current Study** |
| **Total** | # SAIDs | 2,599 | 3,300 |
| Reference (MW) | 615 | 803 |
| Load Impact (MW) | 35.3 | 29.8 |
| Avg. Temp. | 91.7 | 89.4 |
| **Per SAID** | Reference (kW) | 237 | 243 |
| Load Impact (kW) | 54.3 | 9.0 |
| % Load Impact | 5.7% | 3.7% |

***Previous ex-ante versus current ex-post***

Table 4.21 provides a comparison of the *ex-ante* forecast of 2017 load impacts prepared following PY2016 and the PY2017 load impacts estimated as part of this study. The *ex-ante* forecast shown in the table represents the August peak 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 higher total load impacts than we estimated in the current study. This is due to both a lower-than-expected enrollment level and a lower-than-forecast percentage load impact.

Table .: Comparison of Previous *Ex-Ante* and Current *Ex-Post* Impacts

|  |  |  |  |
| --- | --- | --- | --- |
| **Level** | **Outcome** | ***Ex-Ante* for 2017 August Peak Day from PY2016 Study** | ***Ex-Post* for Average Event Day from PY2017 Study** |
| **Total** | # SAIDs | 2,591 | 2,292 |
| Reference (MW) | 613 | 561 |
| Load Impact (MW) | 35.2 | 21.9 |
| Avg. Temp. | 91.7 | 90.4 |
| **Per SAID** | Reference (kW) | 237 | 245 |
| Load Impact (kW) | 13.6 | 9.6 |
| % Load Impact | 5.7% | 3.9% |

***Current ex-post versus current ex-ante***

Table 4.22 compares the *ex-post* and *ex-ante* load impacts from this study. The *ex-ante* load impacts in the table represent the 2018 August peak day with utility-specific 1-in-2 weather conditions. The forecast calls for an increase in the aggregate load impact, from 21.9 MWh/hour to 29.8 MWh/hour, which is attributable to a forecast increase in enrollment from 2,292 to 3,300 customers.

Table .: Comparison of Current *Ex-Post* and *Ex-Ante* Load Impacts

|  |  |  |  |
| --- | --- | --- | --- |
| **Level** | **Outcome** | ***Ex-Post* for Average Event Day from PY2017 Study** | ***Ex-Ante* for 2018 August Peak Day from PY2017 Study** |
| **Total** | # SAIDs | 2,292 | 3,300 |
| Reference (MW) | 561 | 803 |
| Load Impact (MW) | 21.9 | 29.8 |
| Avg. Temp. | 90.4 | 89.4 |
| **Per SAID** | Reference (kW) | 245 | 243 |
| Load Impact (kW) | 9.6 | 9.0 |
| % Load Impact | 3.9% | 3.7% |

Table 4.23 documents the various potential sources of differences between the *ex-post* and *ex-ante* load impacts. As explained above, the difference in enrollments is the driving force behind the forecast increase in load impacts.

Table .: Comparison of *Ex-Post* and *Ex-Ante* Factors

|  |  |  |  |
| --- | --- | --- | --- |
| Factor | *Ex-Post* | *Ex-Ante* | Expected Impact |
| Weather | Average event-hour temperature of 90.4 °F during the average event day. | Average event-hour temperature of 89.4 °F during the SCE 1-in-2 August peak day. | Slightly lower *ex-post* temperatures may have reduced the per-customer load impact (*ceteris paribus*). |
| Event window | Hours-ending 15 through 18. | Hours-ending 15 through 18. | None, though *ex-ante* load impact summaries for the Resource Adequacy window will be lower because they include non-event hours (HE 14 from Apr. to Oct.; HE 19-21 from Nov. to Mar.) |
| % of resource dispatched | 100 percent | 100 percent | None. |
| Enrollment | 2,292 service accounts. | 3,300 service accounts. | Higher *ex-ante* enrollment leads to higher aggregate load impact. |
| Methodology | Panel models by LCA with fixed customer and date effects and a matched control-group of non-participants. | Simulated LCA-specific reference loads by LCA from the enrolled customer data. Then applied percentage load impacts derived from the *ex-post* analysis. | The method is not expected to consistently produce differences between the *ex-post* and *ex-ante* impacts. |

### SCE SMB Customer Reconciliations

***Previous vs. Current Ex-Post***

Table 4.24 shows the average event-hour reference loads and load impacts for the average event day during the current and previous program years. The aggregate load impact is lower in the current study (0.6 MWh/hour vs. 0.8 MWh/hour in the previous study), resulting from a combination of offsetting factors. While enrollment and percentage load impacts were lower in PY2017, the per-customer reference load was higher. It is possible that the current study has higher reference loads because we placed NEM customers in their own class.

Table .: Current vs. Previous *Ex-Post* Load Impacts for the Average Event

|  |  |  |  |
| --- | --- | --- | --- |
| **Level** | **Outcome** | **PY2016** | **PY2017** |
| **Total** | # SAIDs | 1,045 | 820 |
| Reference (MW) | 39.6 | 64.6 |
| Load Impact (MW) | 0.8 | 0.6 |
| Avg. Temp. | 90.4 | 90.2 |
| **Per SAID** | Reference (kW) | 39.7 | 78.7 |
| Load Impact (kW) | 0.75 | 0.75 |
| % Load Impact | 2.0% | 1.0% |

***Previous versus current ex-ante***

In this sub-section, we compare the *ex-ante* forecast prepared following PY2016 (the “previous study”) to the *ex-ante* forecast contained in this study (the “current study”). Table 4.25 reports the average event-hour load impacts for the August 2020 peak day under utility-specific 1-in-2 weather conditions. As expected because the current study is based on the previous study, the per-customer results are nearly identical, but the aggregate results are much lower due to lower forecast enrollment.

Table .: Previous vs. Current *Ex-Ante* Load Impacts, *Utility 1-in-2 August 2020 Peak Day*

|  |  |  |  |
| --- | --- | --- | --- |
| **Level** | **Outcome** | **Previous Study** | **Current Study** |
| **Total** | # SAIDs | 251,065 | 100,000 |
| Reference (MW) | 794 | 314 |
| Load Impact (MW) | 19.1 | 7.6 |
| Avg. Temp. | 92.0 | 92.0 |
| **Per SAID** | Reference (kW) | 3.2 | 3.1 |
| Load Impact (kW) | 0.08 | 0.08 |
| % Load Impact | 2.4% | 2.4% |

***Previous ex-ante versus current ex-post***

Table 4.26 provides a comparison of the *ex-ante* forecast of 2017 load impacts prepared following PY2016 and the PY2017 load impacts estimated as part of this study. The *ex-ante* forecast shown in the table represents the August peak 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 percentage load impacts and enrollment).

Table .: Comparison of Previous *Ex-Ante* and Current *Ex-Post* Impacts

|  |  |  |  |
| --- | --- | --- | --- |
| **Level** | **Outcome** | ***Ex-Ante* for 2017 August Peak Day from PY2016 Study** | ***Ex-Post* for Average Event Day from PY2017 Study** |
| **Total** | # SAIDs | 1,059 | 820 |
| Reference (MW) | 9.2 | 64.6 |
| Load Impact (MW) | 0.23 | 0.6 |
| Avg. Temp. | 91.9 | 90.2 |
| **Per SAID** | Reference (kW) | 8.7 | 78.7 |
| Load Impact (kW) | 0.21 | 0.75 |
| % Load Impact | 2.5% | 1.0% |

***Current ex-post versus current ex-ante***

Table 4.27 compares the *ex-post* and *ex-ante* load impacts from this study. The *ex-ante* load impacts in the table represent the 2018 August peak day with utility-specific 1-in-2 weather conditions. In this case, the *ex-post* and *ex-ante* load impacts are not related to one another. The *ex-post* impacts are based on a relatively small number of voluntarily enrolled customers, while the *ex-ante* impacts are based on simulated default-customer reference loads and assumed percentage load impacts derived from PG&E *ex-post* studies.

Table .: Comparison of Current *Ex-Post* and *Ex-Ante* Load Impacts

|  |  |  |  |
| --- | --- | --- | --- |
| **Level** | **Outcome** | ***Ex-Post* for Average Event Day from PY2017 Study** | ***Ex-Ante* for 2020 August Peak Day from PY2017 Study** |
| **Total** | # SAIDs | 820 | 100,000 |
| Reference (MW) | 64.6 | 314 |
| Load Impact (MW) | 0.6 | 7.6 |
| Avg. Temp. | 90.2 | 92.0 |
| **Per SAID** | Reference (kW) | 78.7 | 3.1 |
| Load Impact (kW) | 0.75 | 0.08 |
| % Load Impact | 1.0% | 2.4% |

Table 4.28 documents the various potential sources of differences between the *ex-post* and *ex-ante* load impacts. Again, we would expect to *ex-ante* forecast to result in very different outcomes than the *ex-post* study because it is based on different inputs (higher enrollment, reference loads that reflect defaulted customers, and percentage load impacts derived from PG&E *ex-post* studies).

Table .: Comparison of *Ex-Post* and *Ex-Ante* Factors

|  |  |  |  |
| --- | --- | --- | --- |
| Factor | *Ex-Post* | *Ex-Ante* | Expected Impact |
| Weather | Average event-hour temperature of 90.2 °F during the average event day. | Average event-hour temperature of 92.0 °F during the SCE 1-in-2 August peak day. | None given the disconnect between the *ex-post* and *ex-ante* studies, as explained below. |
| Event window | Hours-ending 15 through 18. | Hours-ending 15 through 18. | None, though *ex-ante* load impact summaries for the Resource Adequacy window will be lower because they include non-event hours (HE 14 from Apr. to Oct.; HE 19-21 from Nov. to Mar.) |
| % of resource dispatched | 100 percent | 100 percent | None. |
| Enrollment | 820 service accounts. | 100,000 service accounts. | Higher *ex-ante* enrollment leads to higher aggregate load impact. |
| Methodology | Panel models by LCA with fixed customer and date effects and a matched control-group of non-participants. | *Ex-ante* forecast developed in PY2016, rescaled to current enrollment forecast. | The *ex-post* impacts were based on responses from the relatively few customers who happened to be enrolled in CPP despite it being primarily a large customer program during PY2017. The *ex-ante* study uses assumed percentage load impacts based on estimates from PG&E. |

# SDG&E

## SDG&E Ex-Post Load Impacts

This section documents the findings from the *ex-post* load impact analysis for SDG&E. The primary load impact results include estimates of average event-hour load impacts, in aggregate and per-customer, for the average weekday event day as well as for each individual event. Results for all hours for the average weekday event 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, all results presented in this section are derived from panel fixed-effects regression analyses of hourly data for CPP customers and a matched control group. The evaluation of match quality and a discussion thereof is presented in the appendix. The estimated model is described in Section 2.1.2. Furthermore, we control for concurrent events that are called for other programs, including BIP, CBP, and Summer Saver, by including indicators for customers who are dually enrolled and who are called (or in the case of CBP, nominated when their aggregator is called) for a given event that occurs during an event or non-event day. Customers dually enrolled in SCTD are excluded from this analysis to prevent any double counting of load impacts because they are included in a separate report analysis.

Summaries of load impacts for dually enrolled customers and AutoDR customers are presented in Section 5.1.3.

### Large Customers

This section summarizes results for all large SDG&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 average event day; and load impacts by industry group.

The *ex-post* load impacts for SDG&E’s large CPP customers are summarized for all three events and the average weekday event in Figure 5.1. The weekday events are August 31st and September 1st. The blue bars indicate the magnitude of the aggregate load impact (in MWh/hour). The green bands correspond to 80 percent confidence intervals around these estimates (*i.e.*, the 10th and 90th percentile scenarios from the uncertainty-adjusted load impacts). The orange line represents the average temperatures experienced by the customers during the event hours.

The results indicate that large customers had statistically significant load reductions on each of the three event days, ranging from 9 to 19 MWh/hour. The load impact averaged 15 MWh/hour over the three days or 18 MWh/hour for the average weekday event. The events occurred on consecutive days, with the load impact declining on each successive day. It is difficult to identify any relationship of weather and load impacts illustrated in Figure 5.1 because of the small number of events, the consecutive nature of the events, and that the last event date takes place on a weekend.

Figure .: Average Event-Hour Load Impacts by Event, *SDG&E Large*

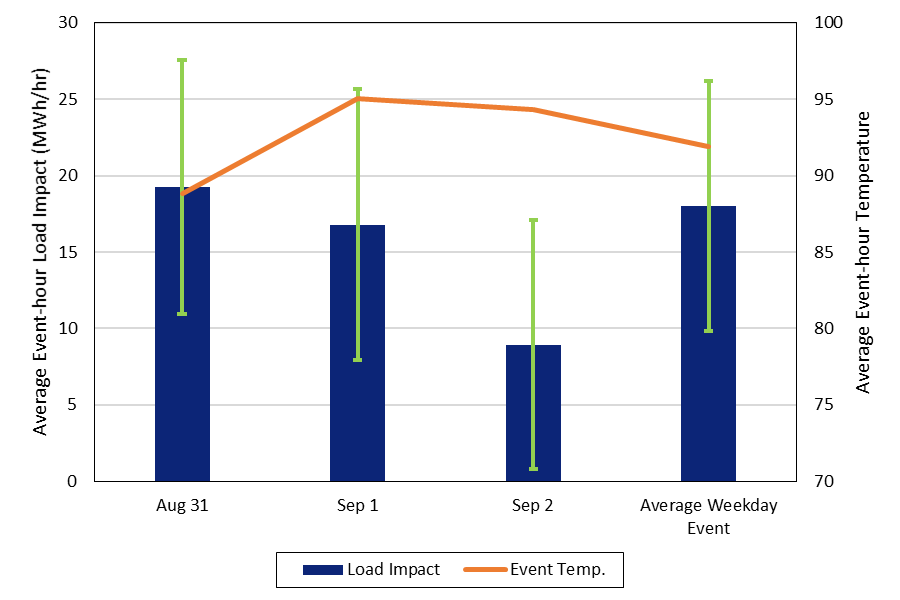


Table 5.1 summarizes enrollments, average event-hour load impacts, and reference loads for each event day and the average event. The enrollments remain the same for the three consecutive event days. Estimated load reductions averaged for 14.1 kWh/hour/customer across weekday event days, which amounts to a 4.3 percent load reduction.

Table .: Average Event-Hour Load Impacts by Event, *SDG&E Large*

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
| **Event Date** | **# Enrolled** | **Aggregate (MWh/hour)** | | **Per-Customer (kWh/hour)** | | **% Load Impact** | **Ave. Event Temp.** |
|
| **Ref. Load** | **Load Impact** | **Ref. Load** | **Load Impact** |
|
| 8/31/2017 | 1,281 | 416.2 | 19.2 | 324.9 | 15.0 | 4.6% | 88.8 |
| 9/1/2017 | 1,281 | 413.4 | 16.8 | 322.7 | 13.1 | 4.1% | 95.0 |
| 9/2/2017 | 1,281 | 310.0 | 8.9 | 242.0 | 7.0 | 2.9% | 94.3 |
| **Average Weekday Event** | **1,281** | **414.8** | **18.0** | **323.8** | **14.1** | **4.3%** | **91.9** |

Figure 5.2 shows the aggregate hourly reference loads, observed loads, and estimated load impacts on the average weekday event. Table 5.2 contains the hourly average weekday event results in the manner required by the Protocols, including hourly temperatures and uncertainty adjusted load impacts. 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 of approximated 8 MWh in the hours immediately preceding (10:00 to 11:00 a.m.) and following (6:00 to 7:00 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 .: Average Weekday Event Reference Loads and Load Profile, *SDG&E Large*

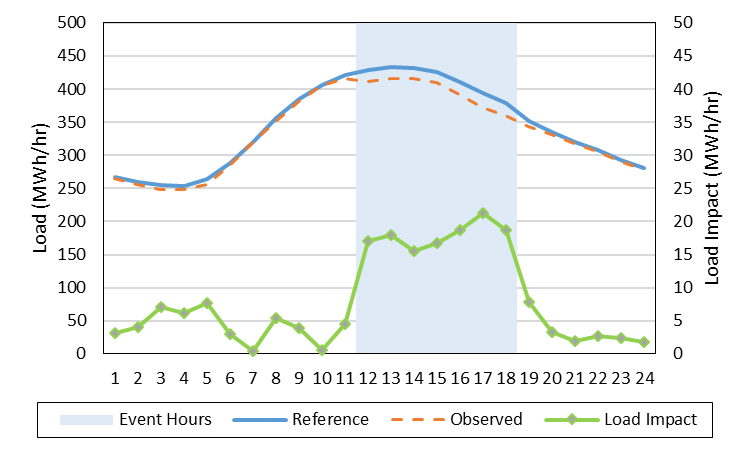


Table .: Average Weekday Event Load Impacts and Uncertainty Adjusted Estimates by hour, *SDG&E Large*



Next, we look at SDG&E large customer estimates by industry group. Table 5.3 summarizes aggregate event-hour results for the average weekday event 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 the reference load). Enrollments are concentrated in the Offices, Hotels, Health & Services groups, which represents 37 percent of large customers. This groups also comprises 49% of the reference load with an estimated reference loads of 203 MWh/hour. Offices, Hotels, Health & Services groups provides the largest level load impact of 8.56 MWh/hour while the Institutional/Government group has the largest percentage load impact of 16.7%. There are three industry groups for which we estimated negative load impacts, thus indicating an *increase* in load), including Wholesale, Transportation, Utilities; Retail Stores; and Other.

Table .: Average Weekday Event Load Impacts by Industry Group, *SDG&E Large*

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Industry Type** | **# of Service Accounts** | **Estimated Reference Load (MWh/hour)** | **Observed Load (MWh/hour)** | **Estimated Load Impact (MWh/hour)** | **% LI** |
|
| 1. Agriculture, Mining, Construction |  |  |  |  |  |
| 2. Manufacturing | 162 | 43.6 | 41.1 | 2.44 | 5.6% |
| 3. Wholesale, Transportation, Utilities | 152 | 31.7 | 32.0 | -0.27 | -0.9% |
| 4. Retail Stores | 119 | 35.2 | 35.2 | -0.08 | -0.2% |
| 5. Offices, Hotels, Health, Services | 472 | 203.4 | 194.9 | 8.56 | 4.2% |
| 6. Schools | 219 | 55.0 | 54.5 | 0.48 | 0.9% |
| 7. Institutional/Government | 130 | 37.8 | 31.5 | 6.31 | 16.7% |
| 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 5.3.[[19]](#footnote-19) The load impacts for large customers are mainly driven by the Offices, Hotels, Health, Services group; which has the highest share of enrollments, reference loads, and load impacts. The Institutional/Government group has the largest difference between its share of load impacts and its shares of customers and reference load.

Figure 5.3: Average Weekday Event-Hour Load Impacts by Industry Group,   
*SDG&E Large*

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### Medium Customers

This section summarizes results for SDG&E’s medium-sized CPP customers (defined as customers with maximum demand between 20 and 199.99 kW), excluding those dually enrolled in SCTD. 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 for the average event hour.

The *ex-post* load impacts for SDG&E’s medium CPP customers are summarized for each of the three events along with the average weekday event in Figure 5.4. In contrast to large customers, the load impacts are only statistically significant for the weekend event day (September 2nd) which also indicates an *increase* in usage. Similar to the results of large customers, there is not enough information to suggest a relationship between load impacts and temperatures.

Figure .: Average Event-Hour Load Impacts by Event, *SDG&E Medium*

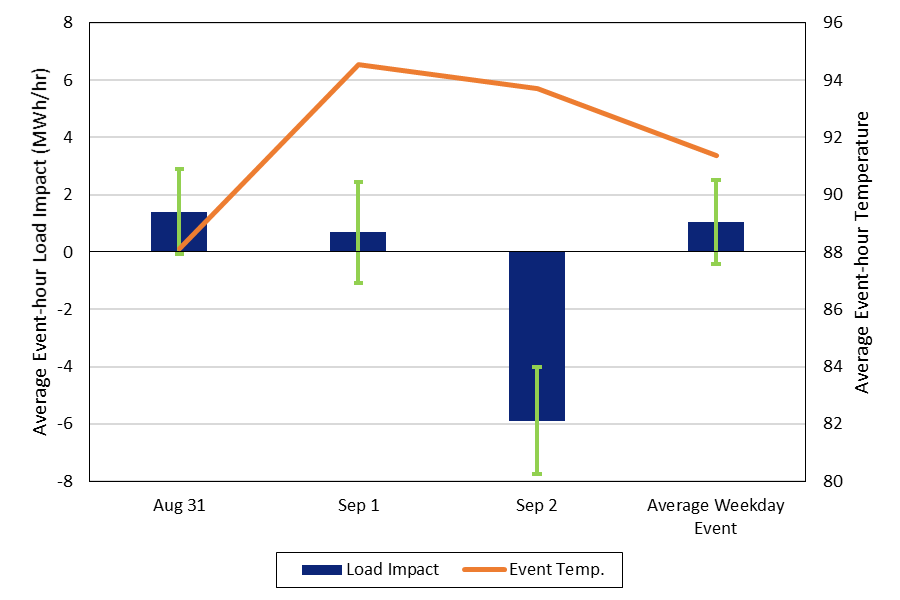


Table 5.4 summarizes enrollments, average event-hour load impacts, and reference loads for each event day and the average weekday event. Enrollments increased by one for the weekend event. The average weekday event day exhibits a load impact of 1 MWh/hour for the two weekday events, although this amounts to only 0.2% of the reference load (and as the previous figure indicated, is not statistically significant). Our estimates indicate an *increase* in usage for the weekend event of 5.9 MWh/hour (1.6% of reference load).

Table .: Average Event-Hour Load Impacts by Event, *SDG&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** |
|
| 8/31/2017 | 11,808 | 450.2 | 1.4 | 38.1 | 0.1 | 0.3% | 88.1 |
| 9/1/2017 | 11,808 | 459.7 | 0.7 | 38.9 | 0.1 | 0.1% | 94.6 |
| 9/2/2017 | 11,809 | 367.4 | -5.9 | 31.1 | -0.5 | -1.6% | 93.7 |
| **Average Weekday Event** | **11,808** | **455.0** | **1.0** | **38.5** | **0.1** | **0.2%** | **91.4** |

Figure 5.5 shows the aggregate hourly reference loads, observed loads, and estimated load impacts on the average weekday event for medium customers. Table 5.5 contains the hourly average weekday event results in the manner required by the Protocols, including hourly temperatures and uncertainty adjusted load impacts. There is no evidence of pre-cooling or post-event snapback. Overall, these results do not suggest that medium customers respond to events by reducing load during the event hours or in the hours surrounding the event, for the average weekday event.

Figure .: Average Weekday Event Reference Load and Load Profile, *SDG&E Medium*

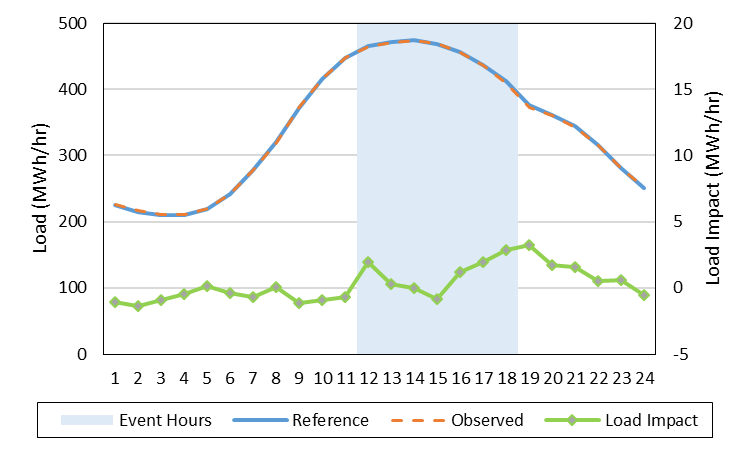


Table .: Average Weekday Event Load Impacts and Uncertainty Adjusted Estimates by hour, *SDG&E Medium*



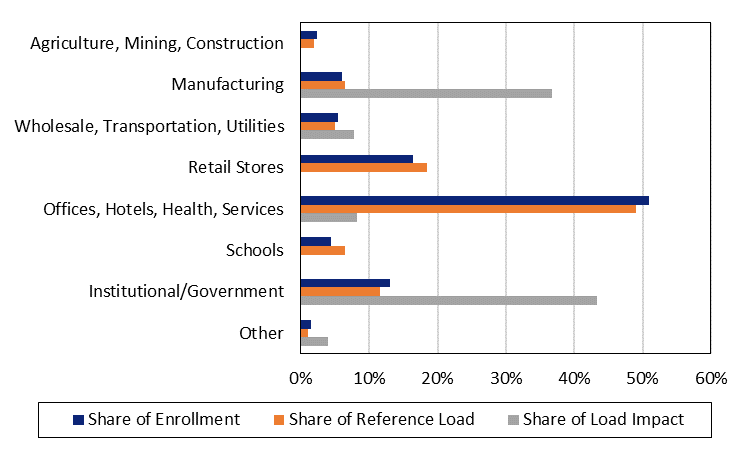
Next, we look at SDG&E medium customer estimates by industry group. Table 5.6 summarizes the aggregate event-hour results for the average weekday event for eight industry groups, including the number of enrolled customers, the reference and observed loads, and the estimated load impacts (in MWh/hour and as a percentage of the reference load). Although none of the industry groups has a load impact that reaches 1 MWh/hour, Institutional/Government has the highest magnitude load impact of 0.87 MWh/hour or 1.6% of the reference load.

Table .: Average Weekday Event Load Impacts by Industry Group, *SDG&E Medium*

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Industry Type** | **# of Service Accounts** | **Estimated Reference Load (MWh/hour)** | **Observed Load (MWh/hour)** | **Estimated Load Impact (MWh/hour)** | **% LI** |
|
| 1.Agriculture, Mining, Construction | 277 | 8.7 | 8.9 | -0.15 | -1.8% |
| 2.Manufacturing | 707 | 29.6 | 28.8 | 0.74 | 2.5% |
| 3.Wholesale, Transportation, Utilities | 635 | 23.0 | 22.8 | 0.16 | 0.7% |
| 4.Retail Stores | 1,933 | 83.9 | 84.4 | -0.57 | -0.7% |
| 5.Offices, Hotels, Health, Services | 6,013 | 222.8 | 222.7 | 0.16 | 0.1% |
| 6.Schools | 523 | 29.3 | 29.5 | -0.24 | -0.8% |
| 7. Institutional/Government | 1,544 | 52.9 | 52.1 | 0.87 | 1.6% |
| 8.Other | 176 | 4.8 | 4.7 | 0.08 | 1.7% |

Figure 5.6 illustrates the shares of enrollments, reference loads, and load impacts by industry group.[[20]](#footnote-20) The Offices, Hotels, Health, Services group comprises the largest share of enrollments and reference loads. However, Institutional/Government group provides the largest contribution to the load impact with a decrease in usage of 0.87 MWh/hour. Similarly, the Manufacturing group provides a greater contribution of load impact relative to their share of enrollments and reference loads.

Figure .: Average Weekday Event-Hour Load Impacts by Industry Group,   
*SDG&E Medium*



### Dually Enrolled and AutoDR Customers

Table 5.7 provides the aggregate event-hour load impacts for each event-day, for customers dually enrolled in demand response programs other than CPP. Customers enrolled in CPP during the *ex-post* analysis were allowed to be dually enrolled in the Base Interruptible Program (BIP), the Capacity Bidding Program (CBP), Summer Saver (SS), and Small Customer Technology Deployment (SCTD). The SCTD load impacts are analyzed in a different study; as a result, customers dually enrolled in SCTD were removed from this analysis to prevent any double counting of load impacts. There were only four customers dually enrolled in BIP that are not reported here.

Table .: Average Event-Hour Aggregate Load Impacts by Event, *SDG&E Dually Enrolled Customers*

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
| **Dually Enrolled** | **Date** | **# of Service Accounts** | **Estimated Reference Load (MWh/hour)** | **Observed Load (MWh/hour)** | **Estimated Load Impact (MWh/hour)** | **% LI** |
|
| CBP | 8/31/2017 | 44 | 6.9 | 6.0 | 0.83 | 12.1% |
| 9/1/2017 | 44 | 7.1 | 7.0 | 0.09 | 1.3% |
| 9/2/2017 | 44 | 5.8 | 7.1 | -1.25 | -21.4% |
| **Average Weekday Event** | **44** | **7.0** | **6.5** | **0.46** | **6.6%** |
| Summer Saver | 8/31/2017 | 463 | 16.2 | 16.5 | -0.30 | -1.9% |
| 9/1/2017 | 463 | 16.8 | 17.2 | -0.40 | -2.4% |
| 9/2/2017 | 463 | 13.3 | 13.5 | -0.23 | -1.7% |
| **Average Weekday Event** | **463** | **16.5** | **16.8** | **-0.35** | **-2.1%** |
| Not Dually Enrolled | 8/31/2017 | 12,575 | 848.4 | 828.1 | 20.32 | 2.4% |
| 9/1/2017 | 12,575 | 854.0 | 836.4 | 17.57 | 2.1% |
| 9/2/2017 | 12,573 | 662.5 | 657.3 | 5.18 | 0.8% |
| **Average Weekday Event** | **12,575** | **851.2** | **832.3** | **18.94** | **2.2%** |

Table 5.8 provides the aggregate event-hour load impacts for each event-day for AutoDR. ------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------

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Table .: Average Event-Hour Aggregate Load Impacts by Event, *SDG&E AutoDR Customers*

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
| **Event Date** | **# of Service Accounts** | **Estimated Reference Load (MWh/hour)** | **Observed Load (MWh/hour)** | **Estimated Load Impact (MWh/hour)** | **% LI** | **Approved MW** |
| 8/31/2017 |  |  |  |  |  |  |
| 9/1/2017 |  |  |  |  |  |  |
| 9/2/2017 |  |  |  |  |  |  |
| **Average Weekday Event** |  |  |  |  |  |  |

## 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 2022 are illustrated in figures to convey the shape of *ex-ante* reference loads and compare *ex-ante* results with *ex-post* results presented in Section 5.1. 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 current *ex-post* load impacts. The *ex-post* percentage load impacts for the two weekday events, August 31st and September 1st, are applied to the *ex-ante* reference loads to produce *ex-ante* load impacts that vary by weather scenario and month.[[21]](#footnote-21) Beginning on December 1, 2017, SDG&E changed its CPP event hours, reducing the seven-hour event window of 11 a.m. to 6 p.m. (HE 12 to 18) to a four-hour event widow of 2 to 6 p.m. (HE 15 to 18). In order to apply *ex-post* 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 5.9 summarizes our categorization of each hour, with the *ex-post* column representing the old event hours and the *ex-ante* column representing the new CPP event window. The *ex-post* reference loads and load impacts are averaged over these periods to obtain percentage load impacts, which are then applied to *ex-ante* reference loads during the corresponding categorized period to calculate the *ex-ante* load impacts. For example, the percentage load impact for the hour before the event in *ex-post* (HE 11) is applied the *ex-ante* reference load for the hour before the event in *ex-ante* (HE 14).

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

|  |  |  |
| --- | --- | --- |
| **Hour** | ***Ex-Post*** | ***Ex-Ante*** |
| 1 | beginning of event day | beginning of event day |
| 2 |
| 3 |
| 4 |
| 5 |
| 6 |
| 7 |
| 8 |
| 9 |
| 10 |
| 11 | pre-event hour |
| 12 | beginning of event |
| 13 |
| 14 | middle of event | pre-event hour |
| 15 | beginning of event |
| 16 | middle of event |
| 17 | end of event |
| 18 | end of event |
| 19 | hour-ending 19 | hour-ending 19 |
| 20 | hour-ending 20 | hour-ending 20 |
| 21 | hour-ending 21 | hour-ending 21 |
| 22 | hour-ending 22 | hour-ending 22 |
| 23 | hour-ending 23 | hour-ending 23 |
| 24 | hour-ending 24 | hour-ending 24 |

### Large Customers

Figure 5.7 summarizes SDG&E’s enrollment forecast for large customers. The enrollments exclude any customers dually enrolled in SCTD. SDG&E anticipates an average increase in large customers of about 2% per year after 2018.

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

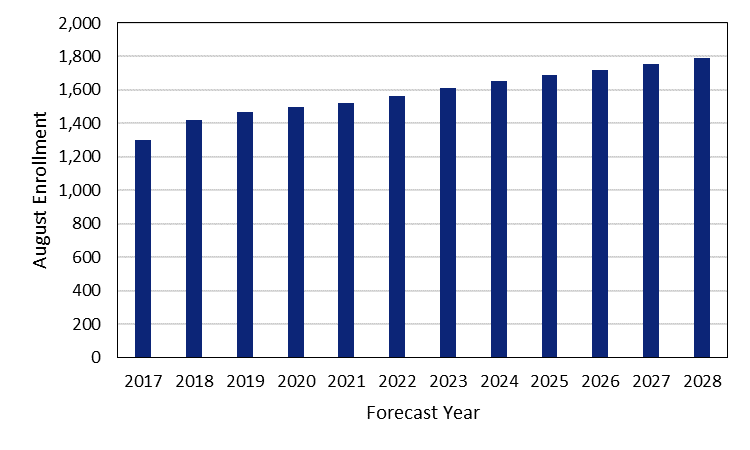


Figure 5.8 illustrates the aggregate reference loads, observed loads, and load impacts for large customers on the average weekday event in August in 2022 for the SDG&E 1-in-2 weather scenario. The shape of the *ex-ante* loads and load impacts is similar to the *ex-post* results in Figure 5.2, while the magnitudes are slightly larger because of the larger reference loads. The duration of the event-hours has also been reduced by three hours (from 11:00 a.m. to 6:00 p.m. in *ex-post* to 2:00 p.m. to 6:00 p.m. in *ex-ante*). The forecast predicts an average load impact of 18.9 MWh/hour for large customers on the average weekday event in 2022 for the SDG&E 1-in-2 weather scenario, which is a 4.3 percent reduction in reference loads.

Figure .: Aggregate Hourly Loads and Load Impacts in 2022 for *SDG&E 1-in-2  
 Average Weekday Event, SDG&E Large*

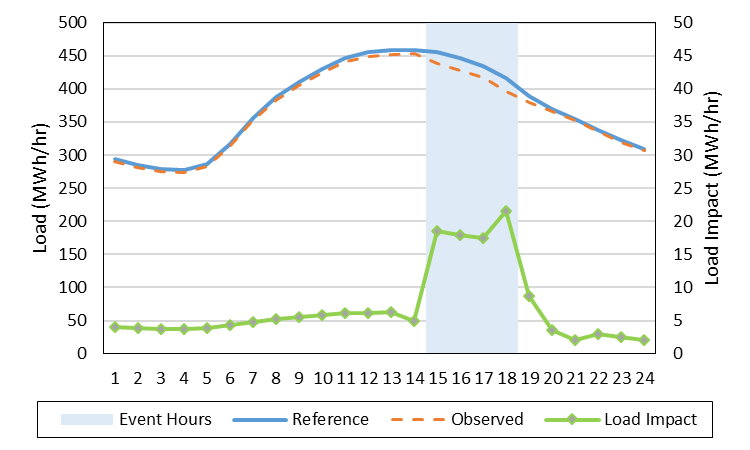


Figure 5.9 illustrates the seasonality in the forecastedload impacts by comparing aggregate load impacts for the average hour in the Resource Adequacy (RA) window in 2022 across months for SDG&E’s 1-in-2 peak day weather scenario. The RA window is 1 to 6 p.m. from April through October and 4 to 9 p.m. for the remainder of the year. The lower load impacts from November through March are largely due to the fact that the RA window in those months includes three hours that are not CPP event hours, where the summer RA window includes only one such hour. The load impact is highest in September (17.8 MWh/hour) and lowest in December (7.8 MWh/hour).

Figure .: Aggregate Load Impacts by Month over RA Window in 2022 for   
*SDG&E 1-in-2 Peak Day, SDG&E Large*

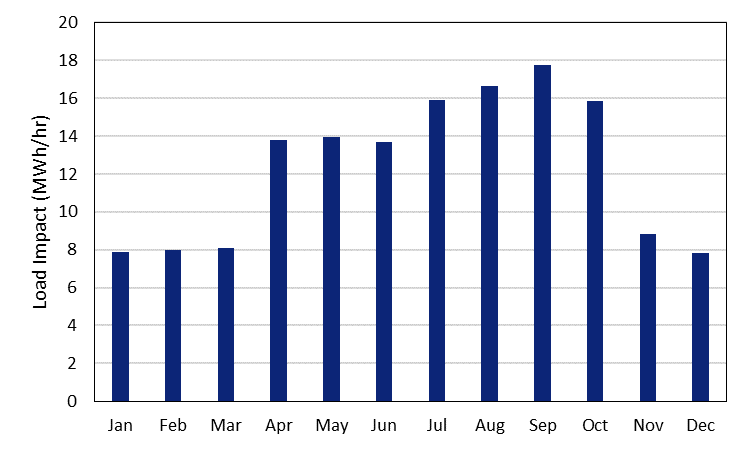
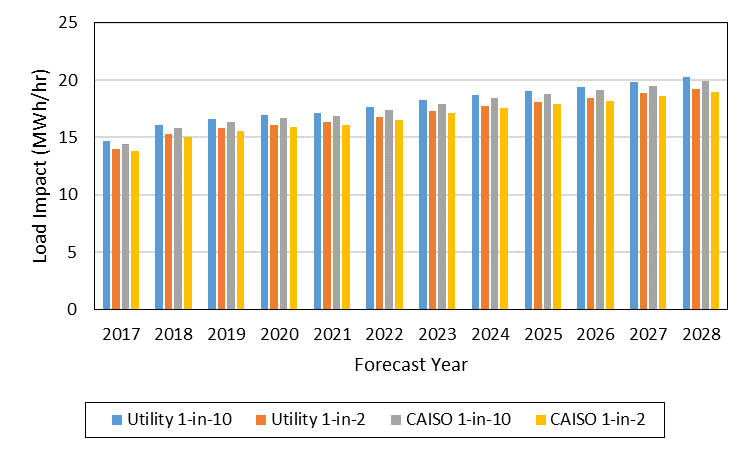


Figure 5.10 shows the change in load impacts over time and across weather scenarios. Each value is the aggregate load impact during the RA window of the average weekday event. Load impacts increase over time because of increases in enrollments. As expected, the largest load impacts occur for the SDG&E 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 1.1 MWh/hour.

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



### Medium Customers

Figure 5.11 summarizes SDG&E’s enrollment forecast for medium customers. The enrollments exclude any customers dually enrolled in SCTD. SDG&E anticipates an average decrease in medium customers of 1% per year after 2018.

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

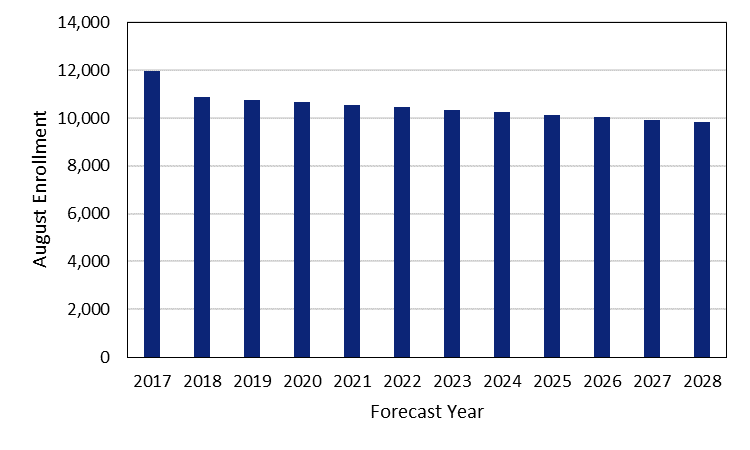


Figure 5.12 illustrates the aggregate reference loads, observed loads, and load impacts for medium customers on the average weekday event in August in 2022 for the SDG&E 1-in-2 weather scenario. The shape of the *ex-ante* loads and load impacts is similar to the *ex-post* results in Figure 5.5, while the magnitudes are smaller because of the decrease in enrollments. Additionally, the duration of the event-hours has been reduced by three hours (from 11:00 a.m. to 6:00 p.m. in *ex-post* to 2:00 p.m. to 6:00 p.m. in *ex-ante*). The forecast predicts an average load impact of 0.8 MWh/hour, or 0.2 percent of the reference load.

Figure .: Aggregate Hourly Loads and Load Impacts in 2022 for   
*SDG&E 1-in-2 Average Weekday Event, SDG&E Medium*

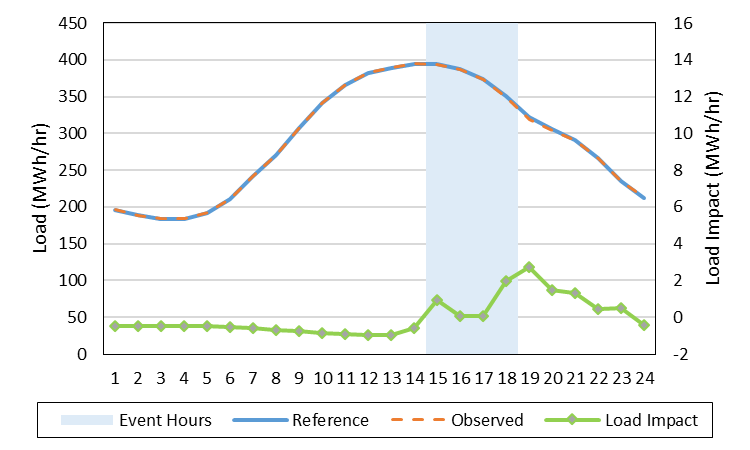


Figure 5.13 shows the seasonality of the forecastedload impacts for medium customers based on the 2022 aggregate load impacts for the average hour in the RA window for SDG&E’s 1-in-2 weather scenario. As with the large customers, the seasonal pattern in load impacts is due to the changing RA window definition. Unlike the large customers, medium customer load impacts are higher from November through March. Recall that the percentage load impact during event hours is 0.2% and not statistically significant (see Table 5.4). The increase in winter load impacts is caused by the later RA window which corresponds to the last hour of the event and post-event hours. As Figure 5.12 illustrates, the hours following the event exhibit positive load impacts, the first of which is larger than the load impacts during the event hours.

The load impact is highest in April (1.3 MWh/hour) and lowest in May and June (0.4 MWh/hour).

Figure .: Aggregate Load Impacts by Month over RA Window in 2022 for   
*SDG&E 1-in-2 Peak Day, SDG&E Medium*

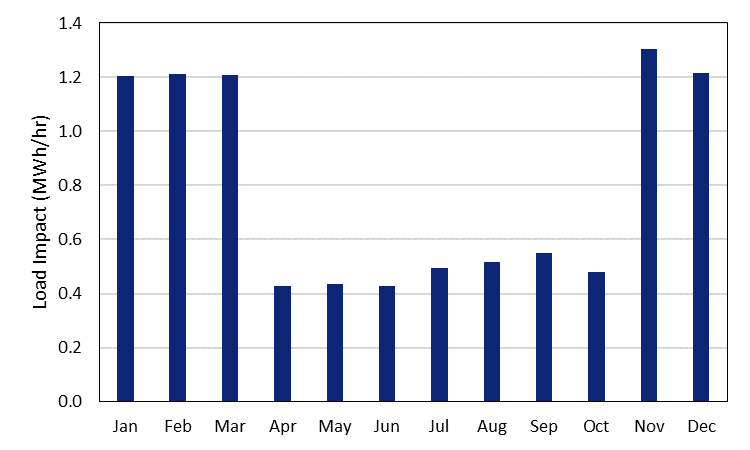
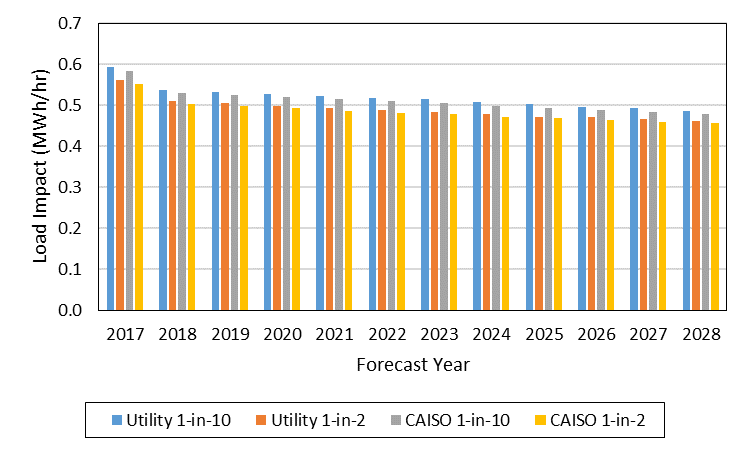


Figure 5.14 shows the change in load impacts over time and across weather scenarios. Each value is the aggregate load impact during the RA window of the average weekday event. Load impacts decrease over time because of the reduction in forecast enrollments. As expected, the largest load impacts occur 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 0.04 MWh/hour.

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



## SDG&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 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 PY2017. The term “previous” refers to findings in reports for PY2016.

### SDG&E Large Customer Reconciliations

***Previous vs. Current Ex-Post***

Table 5.10 shows the average event-hour reference loads and load impacts for the average weekday event during the current and previous program years. The number of enrolled customer decreased slightly from 1,299 in PY2016 to 1,281 in PY2017; however, all customer dually enrolled in CPP and SCTD are completely removed from the PY2017 analysis. The average per-customer reference load is larger in the PY2017 study, even with the average event-hour temperature being cooler. The PY2017 study exhibits a higher percentage load impact of 4.3 percent compared to 2.0 percent in PY2016.

Table .: Current vs. Previous *Ex-Post* Load Impacts for the Average Weekday Event,   
*SDG&E Large*

|  |  |  |  |
| --- | --- | --- | --- |
| **Level** | **Outcome** | **PY2016** | **PY2017** |
| **Total** | # SAIDs | 1,299 | 1,281 |
| Reference (MW) | 363 | 415 |
| Load Impact (MW) | 7.3 | 18.0 |
| Avg. Temp. | 97.8 | 91.9 |
| **Per SAID** | Reference (kW) | 279 | 324 |
| Load Impact (kW) | 5.6 | 14.1 |
| % Load Impact | 2.0% | 4.3% |

***Previous versus current ex-ante***

In this sub-section, we compare the *ex-ante* forecast prepared following PY2016 (the “previous study”) to the *ex-ante* forecast contained in this study (the “current study”). Table 5.11 reports the average weekday event-hour load impacts for the August 2018 peak day under utility-specific 1-in-2 weather conditions. The total forecast load impact is higher in the current study, primarily due to the higher percentage load impact.

Table .: Previous vs. Current *Ex-Ante* Load Impacts, *Utility* *1-in-2   
August 2018 Peak Day, SDG&E Large*

|  |  |  |  |
| --- | --- | --- | --- |
| **Level** | **Outcome** | **Previous Study** | **Current Study** |
| **Total** | # SAIDs | 1,437 | 1,422 |
| Reference (MW) | 383 | 430 |
| Load Impact (MW) | 8.8 | 18.5 |
| Avg. Temp. | 84.6 | 86.2 |
| **Per SAID** | Reference (kW) | 267 | 302 |
| Load Impact (kW) | 6.1 | 13.0 |
| % Load Impact | 2.3% | 4.3% |

***Previous ex-ante versus current ex-post***

Table 5.12 provides a comparison of the *ex-ante* forecast of 2017 load impacts prepared following PY2016 and the PY2017 load impacts estimated as part of this study. The *ex-ante* forecast shown in the table represents the August peak day during a utility-specific 1-in-2 weather year. The *ex-post* load impacts are based on the average event day. While the number of customers in 2017 was below forecast levels, the average per-customer reference load was higher than forecast (324 kWh/hour to 267 kWh/hour). The percentage load impact was also higher than expected (4.3 percent vs. 2.3 percent).

Table .: Comparison of Previous *Ex-Ante* and Current *Ex-Post* Impacts, *SDG&E Large*

|  |  |  |  |
| --- | --- | --- | --- |
| **Level** | **Outcome** | ***Ex-Ante* for 2017 August Peak Day from PY2016 Study** | ***Ex-Post* for Average Weekday Event from PY2017 Study** |
| **Total** | # SAIDs | 1,425 | 1,281 |
| Reference (MW) | 380 | 415 |
| Load Impact (MW) | 8.7 | 18.0 |
| Avg. Temp. | 84.6 | 91.9 |
| **Per SAID** | Reference (kW) | 267 | 324 |
| Load Impact (kW) | 6.1 | 14.1 |
| % Load Impact | 2.3% | 4.3% |

***Current ex-post versus current ex-ante***

Table 5.13 compares the *ex-post* and *ex-ante* load impacts from this study. The *ex-ante* load impacts in the table represent the 2018 August peak day with utility-specific 1-in-2 weather conditions. The percentage load impact is equivalent between the current *ex-post* and *ex-ante* analysis by design. The enrollment number is higher in the *ex-ante* study which contributes to the higher aggregate reference load and load impact. The per-customer load impact level is slightly lower in the *ex-ante­* study due to the cooler August 2018 peak day temperature.

Table .: Comparison of Current *Ex-Post* and *Ex-Ante* Load Impacts, *SDG&E Large*

|  |  |  |  |
| --- | --- | --- | --- |
| **Level** | **Outcome** | ***Ex-Post* for Average Weekday Event from PY2017 Study** | ***Ex-Ante* for 2018 August Peak Day from PY2017 Study** |
| **Total** | # SAIDs | 1,281 | 1,422 |
| Reference (MW) | 415 | 430 |
| Load Impact (MW) | 18.0 | 18.5 |
| Avg. Temp. | 91.9 | 86.2 |
| **Per SAID** | Reference (kW) | 324 | 302 |
| Load Impact (kW) | 14.1 | 13.0 |
| % Load Impact | 4.3% | 4.3% |

Table 5.14 documents the various potential sources of differences between the *ex-post* and *ex-ante* load impacts.

Table .: Comparison of *Ex-Post* and *Ex-Ante* Factors

|  |  |  |  |
| --- | --- | --- | --- |
| Factor | *Ex-Post* | *Ex-Ante* | Expected Impact |
| Weather | Average event-hour temperature of 91.9 °F during the average weekday event. | Average event-hour temperature of 86.2 °F during the SDG&E 1-in-2 August peak day. | Lower *ex-ante* temperatures result in smaller reference load and load impacts. |
| Event window | Hours-ending 12 through 18. | Hours-ending 15 through 18. | The shorter event window during the later period corresponds with higher average event hour temperatures and reference loads. |
| % of resource dispatched | 100% | 100% | None. All customers are assumed to be called in both cases. |
| Enrollment | 1,281 service accounts. | 1,422 service accounts. | Higher *ex-ante* enrollment leads to higher aggregate reference loads and load impacts (*ceteris paribus)*. |
| Methodology | Panel models by industry group with customer and date fixed effects and a matched control-group of non-participants. | Simulated reference loads using average program loads for large customers. Then applied percentage load impacts derived from the *ex-post* analysis, excluding the weekend event day. | The method is not expected to consistently produce differences between the *ex-post* and *ex-ante* impacts. |

### SDG&E Medium Customer Reconciliations

***Previous vs. Current Ex-Post***

Table 5.15 shows the average event-hour reference loads and load impacts for the average weekday event day during the current and previous program years. The average per-customer reference loads are similar between years, even though the average event-hour temperature decreased. The percentage load impact is directionally different between PY2016 and PY2017. However, the load impacts are not statistically significant in either study.

Table .: Current vs. Previous *Ex-Post* Load Impacts for the Average Weekday Event,   
*SDG&E Medium*

|  |  |  |  |
| --- | --- | --- | --- |
| **Level** | **Outcome** | **PY2016** | **PY2017** |
| **Total** | # SAIDs | 11,002 | 11,808 |
| Reference (MW) | 438 | 455 |
| Load Impact (MW) | -3.0 | 1.0 |
| Avg. Temp. | 97.5 | 91.4 |
| **Per SAID** | Reference (kW) | 40 | 39 |
| Load Impact (kW) | -0.3 | 0.1 |
| % Load Impact | -0.7% | 0.2% |

***Previous versus current ex-ante***

In this sub-section, we compare the *ex-ante* forecast prepared following PY2016 (the “previous study”) to the *ex-ante* forecast contained in this study (the “current study”). Table 5.16 reports the average event-hour load impacts for the August 2018 peak day under utility-specific 1-in-2 weather conditions. The total forecast load impact is lower in the current study (0.8 MWh/hour vs 2.7 MWh/hour), due to a combination of lower forecast enrollment and a lower percentage load impact. Note that the different temperatures between the previous and current studies occurs from having different compositions of customers at varying weather stations.

Table .: Previous vs. Current *Ex-Ante* Load Impacts, *Utility 1-in-2   
August 2018 Peak Day, SDG&E Medium*

|  |  |  |  |
| --- | --- | --- | --- |
| **Level** | **Outcome** | **Previous Study** | **Current Study** |
| **Total** | # SAIDs | 11,221 | 10,879 |
| Reference (MW) | 444 | 399 |
| Load Impact (MW) | 2.7 | 0.8 |
| Avg. Temp. | 84.7 | 86.1 |
| **Per SAID** | Reference (kW) | 40 | 37 |
| Load Impact (kW) | 0.2 | 0.1 |
| % Load Impact | 0.6% | 0.2% |

***Previous ex-ante versus current ex-post***

Table 5.17 provides a comparison of the *ex-ante* forecast of 2017 load impacts prepared following PY2016 and the PY2017 load impacts estimated as part of this study. The *ex-ante* forecast shown in the table represents the August peak day during a utility-specific 1-in-2 weather year. The *ex-post* load impacts are based on the average weekday event. The forecast load impact was higher than the *ex-post* load impact (2.7 MWh/hour vs. 1.0 MWh/hour) because of a lower-than-forecast percentage load impact. The reduction in the total load impact was mitigated by higher-than-forecast enrollments.

Table .: Comparison of Previous *Ex-Ante* and Current *Ex-Post* Impacts,   
*SDG&E Medium*

|  |  |  |  |
| --- | --- | --- | --- |
| **Level** | **Outcome** | ***Ex-Ante* for 2017 August Peak Day from PY2016 Study** | ***Ex-Post* for Average Weekday Event from PY2017 Study** |
| **Total** | # SAIDs | 11,320 | 11,808 |
| Reference (MW) | 448 | 455 |
| Load Impact (MW) | 2.7 | 1.0 |
| Avg. Temp. | 84.7 | 91.4 |
| **Per SAID** | Reference (kW) | 40 | 39 |
| Load Impact (kW) | 0.2 | 0.1 |
| % Load Impact | 0.6% | 0.2% |

***Current ex-post versus current ex-ante***

Table 5.18 compares the *ex-post* and *ex-ante* load impacts from this study. The *ex-ante* load impacts in the table represent the 2018 August peak day with utility-specific 1-in-2 weather conditions. The percentage load impact is equivalent between the current *ex-post* and *ex-ante* analysis by design. *Ex-ante* enrollment is somewhat lower than *ex-post* enrollment, which results in lower total reference loads and load impacts. The per-customer reference load is slightly lower in the *ex-ante* study because of the cooler 86-degree temperature.

Table .: Comparison of Current *Ex-Post* and *Ex-Ante* Load Impacts, *SDG&E Medium*

|  |  |  |  |
| --- | --- | --- | --- |
| **Level** | **Outcome** | ***Ex-Post* for Average Weekday Event from PY2017 Study** | ***Ex-Ante* for 2018 August Peak Day from PY2017 Study** |
| **Total** | # SAIDs | 11,808 | 10,879 |
| Reference (MW) | 455 | 399 |
| Load Impact (MW) | 1.0 | 0.8 |
| Avg. Temp. | 91.4 | 86.1 |
| **Per SAID** | Reference (kW) | 39 | 37 |
| Load Impact (kW) | 0.1 | 0.1 |
| % Load Impact | 0.2% | 0.2% |

Table 5.19 documents the various potential sources of differences between the *ex-post* and *ex-ante* load impacts.

Table .: Comparison of *Ex-Post* and *Ex-Ante* Factors

|  |  |  |  |
| --- | --- | --- | --- |
| Factor | *Ex-Post* | *Ex-Ante* | Expected Impact |
| Weather | Average event-hour temperature of 91.4 °F during the average weekday event. | Average event-hour temperature of 86.1 °F during the SDG&E 1-in-2 August peak day. | Lower *ex-ante* temperatures result in smaller reference load and load impacts. |
| Event window | Hours-ending 12 through 18. | Hours-ending 15 through 18. | The shorter event window during the later period corresponds with higher average event hour temperatures and reference loads. |
| % of resource dispatched | 100% | 100% | None. All customers are assumed to be called in both cases. |
| Enrollment | 11,808 service accounts. | 10,879 service accounts. | Lower *ex-ante* enrollment leads to lower aggregate reference loads and load impacts (*ceteris paribus)*. |
| Methodology | Panel models by industry group with customer and date fixed effects and a matched control-group of non-participants. | Simulated reference loads using average program loads for medium customers. Then applied percentage load impacts derived from the *ex-post* analysis, excluding the weekend event day. | The method is not expected to consistently produce differences between the *ex-post* and *ex-ante* impacts. |

# Recommendations

In 2017, SDG&E called few events relative to SCE and PG&E. Furthermore, those events were clustered together prior to and including a holiday weekend (the Thursday through Saturday preceding Labor Day). Calling events on a more diverse set of days may improve the understanding of customer response to the program.

PG&E called 15 events in 2017 compared to 12 in 2016. While the percentage load impact for large customers decreased somewhat across years (from 4.9 to 4.2 percent), the SMB percentage load impact exhibited a more substantial drop (from 2.5 to 1.1 percent).

Because SMB load impacts are very low in percentage terms, the estimated load impacts may be prone to capturing “noise” in the data. That is, variations in SMB usage that are not explained by included variables (*e.g.*, weather or day of week) will be attributed to load impacts. The inability of the models to fully explain customer usage may be the cause of the variability of the estimated SMB load impacts, which ranged from 0.3 to 2.1 percent across event days. Accordingly, careful consideration should be taken to assess the contribution, benefits and continued participation of SMB in PDP, and caution is encouraged while forecasting their 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. Matching Quality

This appendix presents summaries of our control-group matching process. Because we are employing a control-group approach, our validity assessment focuses on comparisons of treatment and control-group loads for selected event-like non-event days. We also report statistics such as the mean absolute percentage error (MAPE) and mean percent error (MPE), which provide measures of accuracy and bias in the matches, respectively.[[22]](#footnote-22)

### PG&E

Table A.1 provides, by size group for PG&E, the mean percentage error (MPE) and mean absolute percentage error (MAPE) calculated across the average 24-hour load profile as well over the event-hour window.

Table A.1: Match Quality Statistics, *PG&E*

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Size** | **# of Service Accounts** | **MPE** | **MAPE** | **MPE Event Window** | **MAPE Event Window** |
| Below 20 kW | 152,814 | -2.6% | 2.6% | -0.7% | 0.8% |
| 20 to 199.99 kW | 45,623 | -1.9% | 2.0% | -0.1% | 0.6% |
| 200 kW and Above | 2,094 | -5.0% | 5.3% | 0.7% | 1.0% |

Figures A.1 through A.3 illustrate the matched load profiles for selected event-like days. Each figure contains the average hourly profiles for the treatment and matched control-group customers by day type (*i.e.,* hot days and all other days). The solid lines represent the average usage of treatment customers on hot days (red) and all other days (blue). Similarly, the dashed lines represent the average usage of the matched control customers on hot days (yellow) and all other days (gray). The shaded region illustrates the PG&E PDP event hours.

Figure A.1: Treatment and Control Non-Event Day Load Profiles, *PG&E Small*

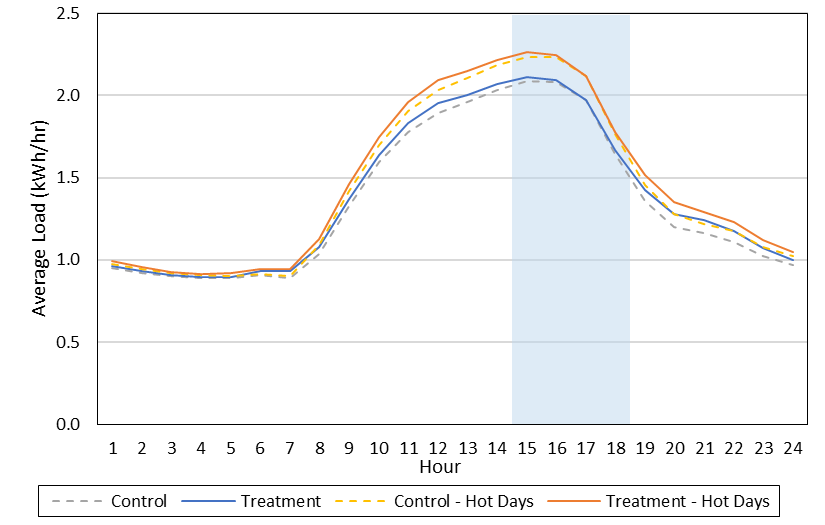


Figure A.2: Treatment and Control Non-Event Day Load Profiles, *PG&E Medium*

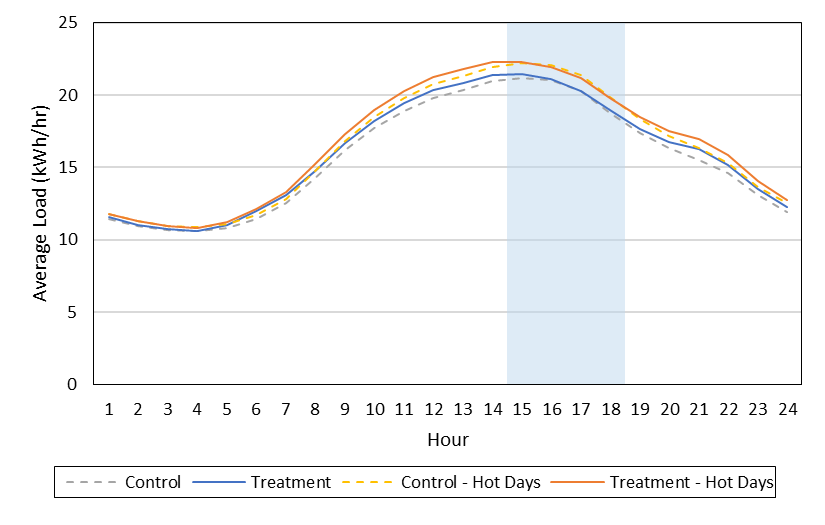
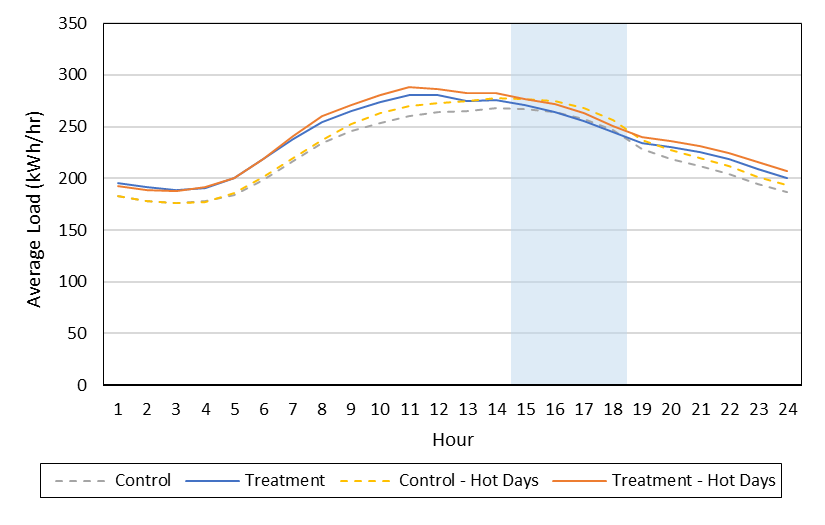


Figure A.3: Treatment and Control Non-Event Day Load Profiles, *PG&E Large*



### SCE

Table A.2 provides, by size group for SCE, the mean percentage error (MPE) and mean absolute percentage error (MAPE) calculated across the average 24-hour load profile as well over the event-hour window.

Table A.2: Match Quality Statistics, *SCE*

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Size** | **# of Service Accounts** | **MPE** | **MAPE** | **MPE Event Window** | **MAPE Event Window** |
| Below 20 kW | 475 | -2.1% | 2.6% | 1.0% | 1.4% |
| 20 to 199.99 kW | 756 | -0.6% | 1.3% | 0.0% | 0.2% |
| 200 kW and Above | 2,330 | -0.8% | 1.5% | 1.5% | 1.5% |
| NEM | 139 | -7.6% | 8.0% | -4.9% | 6.9% |

Figures A.4 through A.7 illustrate the matched load profiles for selected event-like days. Each figure contains the average hourly profiles for the treatment and matched control-group customers by day type (*i.e.,* hot days and all other days). The solid lines represent the average usage of treatment customers on hot days (red) and all other days (blue). Similarly, the dashed lines represent the average usage of the matched control customers on hot days (yellow) and all other days (gray). The shaded region illustrates the SCE CPP event hours.

Figure A.4: Treatment and Control Non-Event Day Load Profiles, *SCE Small*

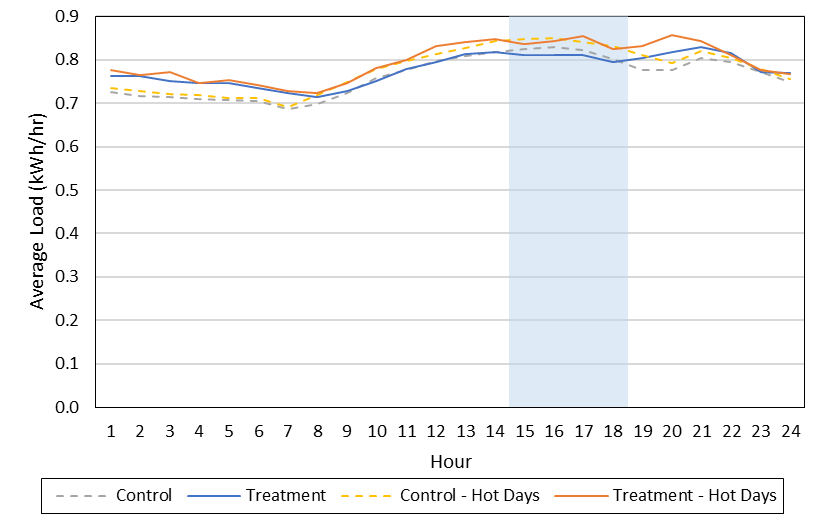


Figure A.5: Treatment and Control Non-Event Day Load Profiles, *SCE Medium*

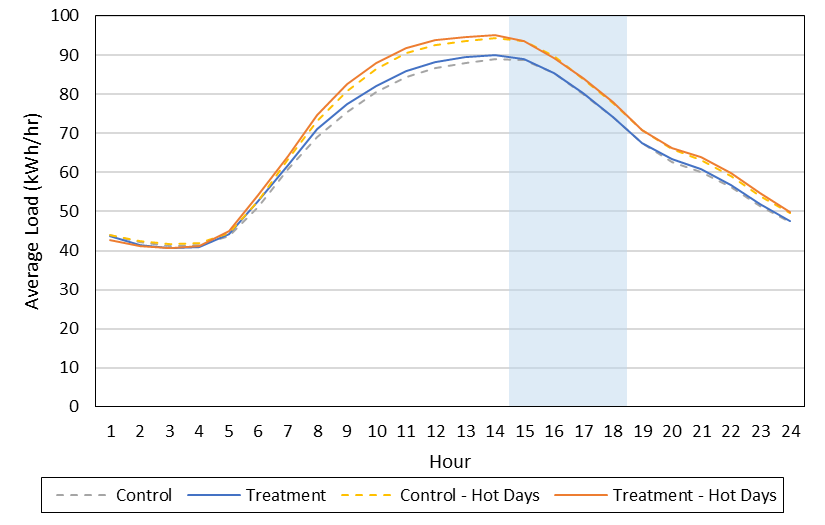


Figure A.6: Treatment and Control Non-Event Day Load Profiles, *SCE Large*

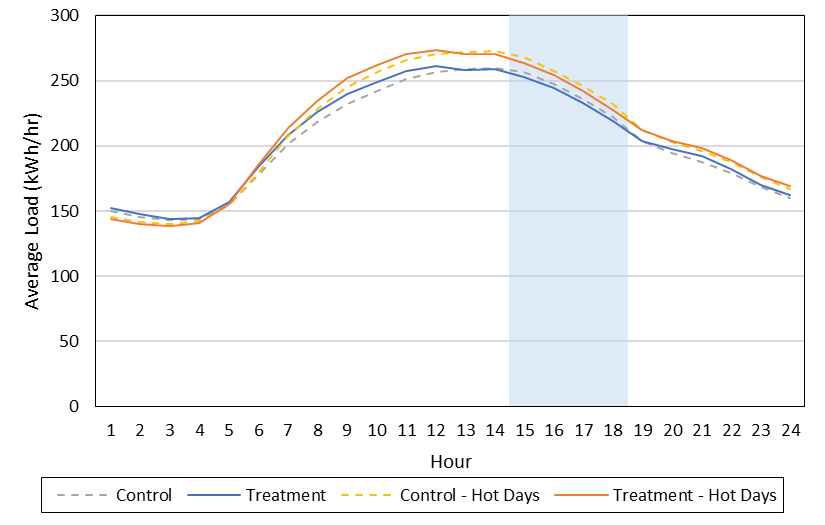
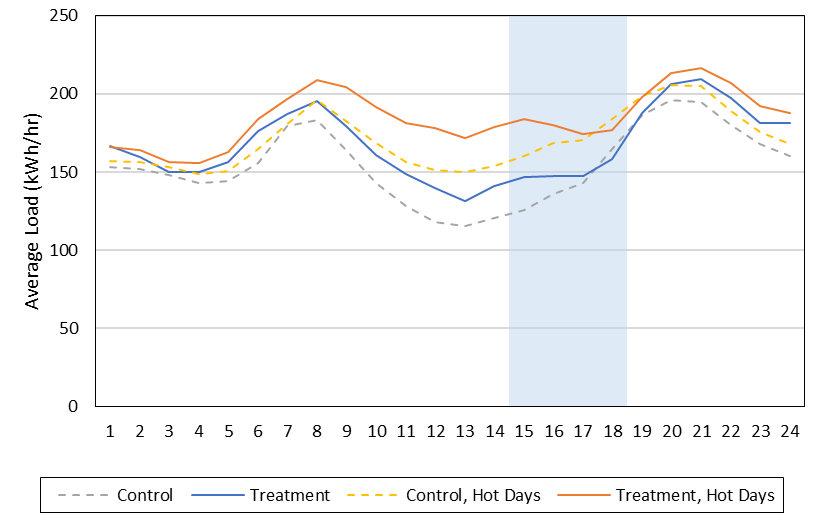


Figure A.7: Treatment and Control Non-Event Day Load Profiles, *SCE NEM*



### SDG&E

Table A.3 provides, by size group for SDG&E, the mean percentage error (MPE) and mean absolute percentage error (MAPE) calculated across the average 24-hour load profile as well over the event-hour window.

Table A.3 Match Quality Statistics, *SDG&E*

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Size** | **# of Service Accounts** | **MPE** | **MAPE** | **MPE Event Window** | **MAPE Event Window** |
| 20 to 199.99 kW | 11,809 | 0.4% | 1.4% | 1.0% | 1.0% |
| 200 kW and Above | 1,281 | 1.3% | 2.3% | 1.0% | 2.0% |

Figures A.8 and A.9 illustrate the matched load profiles for selected event-like days. Each figure contains the average hourly profiles for the treatment and matched control-group customers by day type (*i.e.,* weekdays and weekends). The solid lines represent the average usage of treatment customers on weekdays (red) and weekends (blue). Similarly, the dashed lines represent the average usage of the matched control customers on weekday (yellow) and all weekends (gray). The shaded region illustrates the SDG&E CPP event hours. The average profile representing differences for weekday and weekends are shown because SDG&E matches were done separately for weekday and weekends. In other words, treatment customers can have different matched control customers for weekday and for the weekend. This is done because customers that match particularly well on weekday profiles does not necessarily indicate similar usage patterns on the weekend (*e.g.,* manufacturers that shut down for the weekend while others that do not). Separating weekend and weekday matching provides closer matched pairs in terms of usage, which potentially reduces any unobserved bias in the estimation of CPP load impacts for weekday and weekend events.

Figure A.8: Treatment and Control Non-Event Day Load Profiles, *SDG&E Large*

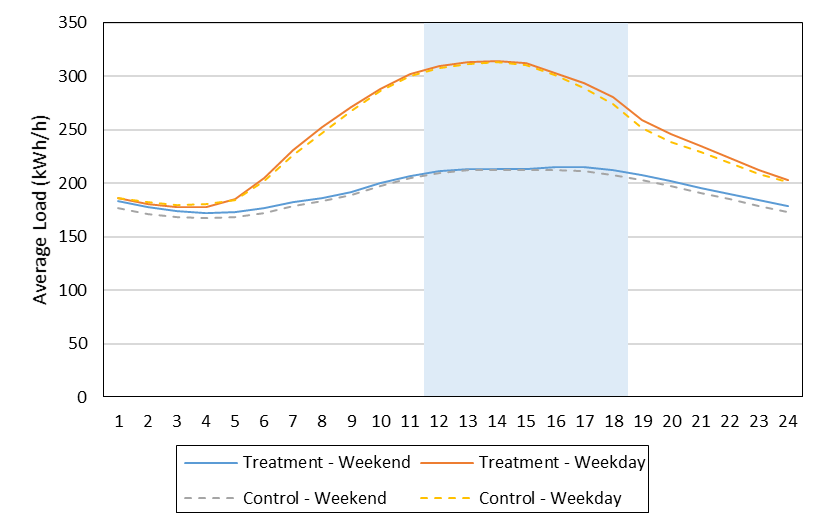
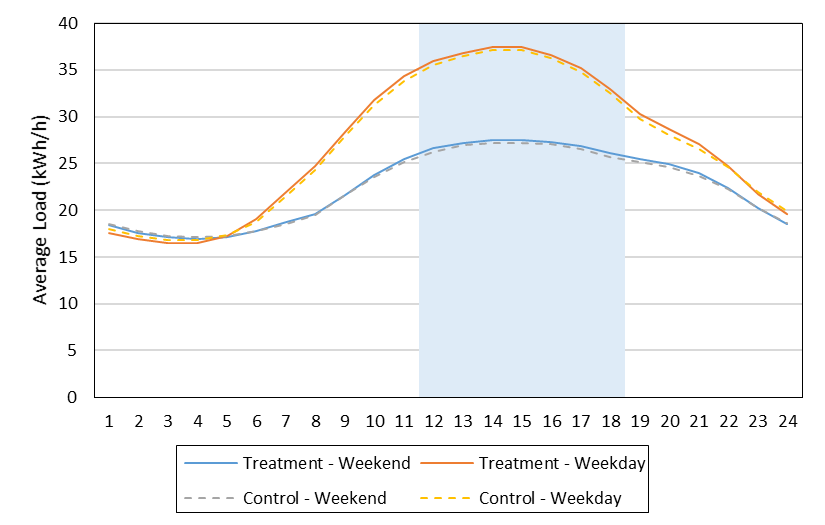


Figure A.9: Treatment and Control Non-Event Day Load Profiles, *SDG&E Medium*



1. Most of the defaulted customers were previously served under tariffs with TOU energy and/or demand charges, such that they already had varying incentives to reduce load during peak periods on all summer weekdays. [↑](#footnote-ref-1)
2. For SDG&E, the forecast period covers 2017-2028, with the values for 2017 serving as weather-normalized versions of the 2017 *ex-post* load impacts. [↑](#footnote-ref-2)
3. For large customers who did not have a close match in the eligible control group, we tested the difference between including them in the panel model and excluding them from the panel model and estimating their load impact using a customer-specific regression. We found that the total load impact estimate (across all treatment customers) did not differ much across methods. We therefore included all customers in the panel models. [↑](#footnote-ref-3)
4. This within-year analysis focuses on incremental event-day load impacts, but does not allow for the estimation of non-event day load impacts. We also estimate non-event-day load impacts for the PG&E CPP customers who were defaulted in November 2016, which requires matching customers on pre-enrollment data and estimating models using two years of data (from the summers of 2016 and 2017). [↑](#footnote-ref-4)
5. SDG&E used separate weekday and weekend load profiles instead, because one of the three event days took place on a weekend. (Only one of PG&E’s fifteen event days was on a weekend and none of SCE’s were.) [↑](#footnote-ref-5)
6. Some industry groups were combined to increase within-group sample sizes. PG&E matched by manufacturing, schools, and all other industry groups. SCE matched by manufacturing vs. non-manufacturing. SDG&E used all eight industry groups in its matching. [↑](#footnote-ref-6)
7. The inclusion of weather variables may improve the effectiveness of the date fixed effects, particularly in models that include customers in different weather regions (*e.g.*, models by size and industry group that include customers in all LCAs). [↑](#footnote-ref-7)
8. The morning load variable can help the model identify days on which the customer is operating (*e.g.*, a manufacturing customer in production vs. not in production) or open for business (*e.g.*, for commercial customers). [↑](#footnote-ref-8)
9. SDG&E’s forecast begins in 2017. [↑](#footnote-ref-9)
10. Small customers are defined as customers with maximum demand under 20 kW. Medium customers have maximum demand from 20 to 199.99 kW. [↑](#footnote-ref-10)
11. See the appendices for more details of our matching approach and how we evaluate match quality. [↑](#footnote-ref-11)
12. This was done by examining customer-specific load impact estimates for the members of this group. [↑](#footnote-ref-12)
13. The “2016 Default” category also includes customers who were early enrollees in PDP from October 2016 through September 2017. However, the majority of the customers in this category joined PDP in November or December 2016, the timing of which indicates they were defaulted onto the rate. [↑](#footnote-ref-13)
14. This difference is the cause of a similarly counter-intuitive comparison between items 3 and 5 for large customers. [↑](#footnote-ref-14)
15. This group includes all customers that meet these criteria regardless of the size of demand (or how negative the load is). [↑](#footnote-ref-15)
16. Two industry groups have no NEM customers: Agriculture, Mining & Construction; and Other or Unknown. [↑](#footnote-ref-16)
17. Based on SCE’s *ex-ante* enrollment forecast, the Aggregator Managed Program is ending in 2017. [↑](#footnote-ref-17)
18. Nexant’s study applied a lower percentage load impacts in the first year following customer default than it did for the subsequent years. In this evaluation, we have uniformly used the “steady state” percentage load impacts from the 2020+ years of their evaluation. [↑](#footnote-ref-18)
19. The contribution of load impacts by industry group is after setting negative load impacts to zero. [↑](#footnote-ref-19)
20. The contribution of load impacts by industry group is after setting negative load impacts to zero. [↑](#footnote-ref-20)
21. The *ex-post* percentage load impacts for the weekday events are used because the small sample size of events reduces the variation that can be used to identify an adequate relationship between load impacts and weather. [↑](#footnote-ref-21)
22. Note that “biased” matches do not necessarily adversely affect the estimated load impacts, as we employ a difference-in-differences estimation methodology that accounts for load differences during the matching (pre-treatment) period. [↑](#footnote-ref-22)