**2018 Load Impact Evaluation for Pacific Gas & Electric Company’s SmartAC™ Program**

**CALMAC Study ID PGE0429**

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*April 1, 2019*

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# Executive Summary

This report documents *ex-post* and *ex-ante* load impact evaluations of Pacific Gas and Electric’s (PG&E) SmartAC™ program for 2018. The evaluation produces estimates of the *ex-post* load impacts for each hour of each event called in 2018, and it develops *ex-ante* load impact forecasts for the program through 2029.

## ES.1 Resources Covered

SmartAC™ is a direct load control central air conditioner (AC) cycling program for residential customers. PG&E’s SmartAC™ program was integrated into the CAISO wholesale market in program year 2018. SmartAC™ program participants receive a one-time incentive for allowing PG&E to cycle their AC for up to 6 hours per day in response to CAISO market awards, during periods of system or local area emergencies for PG&E capacity, or for limited testing for a maximum of 100 hours per summer (May 1 through October 31). Upon enrollment in SmartAC™, PG&E installs an AC control switch on the participant’s central AC unit. During program years 2009 through 2013, the program offered switches and programmable communicating thermostats (PCT) to participants, however, the program population primarily consists of switches. When events are called, PG&E sends signals to the PCTs and switches. As dictated by the tariff, PG&E cycles the AC unit for residential customers for approximately 50% of the compressor run-time during each half-hour. Both PCTs and switches are cycled using adaptive algorithms.

In past program years, PG&E has evaluated a combination of system-wide serial number and Sub-Load Aggregation Point (sub-LAP) test events. System-wide actual events include all participants and can be initiated based on CAISO or PG&E emergencies. System-wide test events call all SmartAC™ customers for the event except one or two control groups. During serial events, a random sample of SmartAC™ customers throughout the service territory are called for the event based on the factory programmed serial number of their installed device. During sub-LAP level events all SmartAC™ participants with devices that are associated with a given sub-LAP are called for the event. Historically, “addressing” was used to associate new SmartAC™ devices with the appropriate sub-LAP by sending a signal to the device after installation. This year, because of CAISO wholesale market integration of the SmartAC™ program, only sub-LAP-level events were called. One of the events (July 27, 2018) was triggered by a local emergency, while the remaining eight events were CAISO market awards. There were three SmartAC™ events (July 24, 25, and 26) during which the event hours differed across sub-LAPs. Otherwise, sub-LAPs that were called for the same event were called for the same event hours.

The primary goals of the evaluation include:

1. Estimate hourly *ex-post* load impacts for the 2018 program year, including:
   1. Hourly and average daily load impacts for each event;
   2. The distribution of hourly and average daily load impacts by customer segment, including: sub-LAP, CARE/non-CARE customers, net-metering solar customers (NEM), housing type (*i.e.*, single family vs. multifamily customers), AC usage intensity, device type (*i.e.*, ExpressStat, Utilipro, Gen 1, and Gen 2), customers with multiple devices, and by marketing cohort;
   3. Load Impact estimates for SmartAC™-only customers as compared to customers who are dually enrolled in SmartAC™ and SmartRate™;
   4. The opt-out rate by customer segment; and
   5. The persistence of load reductions across event-hours for multiple hour events.
2. Produce *ex-ante* load impact forecasts for 2019-2029 by local capacity area (LCA) on an aggregate and per customer basis for a typical event day and the monthly system peak load day for May through October. Forecasts are based on the following four sets of weather conditions:
   1. PG&E’s peaking conditions in a 1-in-2 weather year;
   2. PG&E’s peaking conditions in a 1-in-10 weather year;
   3. CAISO peaking conditions in a 1-in-2 weather year; and
   4. CAISO peaking conditions in a 1-in-10 weather year.

## ES.2 Evaluation Methodologies

In this evaluation, we estimate load impacts by comparing SmartAC™ customer loads to that of a quasi-experimental matched control group on event days, net of the differences in loads on non-event days with comparable weather conditions. The eligible control-group customers consist of residential customers who are not enrolled in SmartAC™ or SmartRate™. Matched control group customers are selected based on the similarity of available customer characteristics (*e.g.*, sub-LAP, AC usage, CARE status, NEM status) as well as usage patterns on non-event days.

We then estimate event-day load impacts using a regression-based difference-in-differences method, which produces estimates of standard errors, and thus confidence intervals around the estimated event-hour or event-day usage reductions. This approach also adjusts for differences in usage between the SmartAC™ customers and the matched control group on event-like non-event days, thus representing a difference-in-differences evaluation approach.

## ES.3 Ex-Post Load Impacts

Figure ES.1 summarizes the *ex-post* load impact estimates (in kWh/customer/hour) for the average event-hour for all sub-LAPs called for all nine SmartAC™ events, along with an 80 percent confidence interval (corresponding to the 10th and 90th percentile uncertainty-adjusted load impacts). There were statistically significant load reductions on each of the 9 sub-LAP events, ranging from 0.05 to 0.43 kWh/customer/hour. The significantly lower load impacts on July 27th are for an event called in PGNC only due to a transmission emergency. This sub-LAP tends to provide lower average per-customer load impacts relative to other sub-LAPs. Moreover, the event on July 27th had much later event hours (7 to 11:59 p.m.) compared to the other events, which typically run from late afternoon through early evening.

Figure ES.1: Average Event-Hour Load Impacts by Event

In addition to the overall load impacts, we examined patterns of load impacts at the sub-LAP level by event. We also examined how load impacts are distributed across customer subgroups. Our results were largely consistent with previous findings, while new results indicate that load impacts increase with higher customer levels of AC usage.

## 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. An *enrollment forecast* provided by PG&E 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 *ex-ante* weather conditions provided by PG&E; and
3. A forecast of *load impacts per customer*, again by relevant customer type, where the load impact forecast also varies with weather conditions and is based on *ex-post* results from current or past program years.

Figure ES.2 summarizes the *ex-ante* load impacts for SmartAC™ customers by month and weather scenario. In each case, the results reflect the average aggregate load impacts during the Resource Adequacy (RA) window of each forecast year. (Forecast enrollment does not change from 2019 through 2029.) For each month, we show the load impact associated with each weather scenario (1-in-2 and 1-in-10 weather conditions associated with PG&E’s peak day and the CAISO peak day). The load impact is highest in July in three out of the four weather scenarios, with a maximum load impact of 65 MWh/hour from the PG&E 1-in-10 scenario. For the CAISO 1-in-2 scenario, the load impacts are highest in June (51 MWh/hour). The loads impacts are always the lowest in October, with a minimum of 18 MWh/hour from the PG&E 1-in-2 scenario.

Figure ES.2: Aggregate Load Impacts over RA Window by Month and Weather Scenario

# Introduction and Purpose of the Study

This report documents *ex-post* and *ex-ante* load impact evaluations of Pacific Gas and Electric’s (PG&E) SmartAC™ program for 2018. The evaluation produces estimates of the *ex-post* load impacts for each hour of each event called in 2018, and it develops *ex-ante* load impact forecasts for the program through 2029.

SmartAC™ is a direct load control central air conditioner (AC) cycling program for residential customers. PG&E’s SmartAC™ program was integrated into the CAISO wholesale market in program year 2018. SmartAC™ program participants receive a one-time incentive for allowing PG&E to cycle their AC for up to 6 hours per day in response to CAISO market awards, during periods of system or local area emergencies for PG&E capacity, or for limited testing for a maximum of 100 hours per summer (May 1 through October 31). Upon enrollment in SmartAC™, PG&E installs an AC control switch on the participant’s central AC unit. During program years 2009 through 2013, the program offered switches and programmable communicating thermostats (PCT) to participants, however, the program population primarily consists of switches. When events are called, PG&E sends signals to the PCTs and switches. As dictated by the tariff, PG&E cycles the AC unit for residential customers for approximately 50% of the compressor run-time during each half-hour. Both PCTs and switches are cycled using adaptive algorithms.

In past program years, PG&E has evaluated a combination of system-wide serial number and Sub-Load Aggregation Point (sub-LAP) test events. System-wide actual events include all participants and can be initiated based on CAISO or PG&E emergencies. System-wide test events call all SmartAC™ customers for the event except one or two control groups. During serial events, a random sample of SmartAC™ customers throughout the service territory are called for the event based on the factory programmed serial number of their installed device. During sub-LAP level events all SmartAC™ participants with devices that are associated with a given sub-LAP are called for the event. Historically, sub-LAP “addressing” was done by sending a signal to new SmartAC™ devices after installation to associate these devices with the appropriate sub-LAP. This year, because of CAISO wholesale market integration of the SmartAC™ program, only sub-LAP-level events were called. Table 1‑1 shows the details for each event day in PY2018. One of the events (July 27, 2018) was triggered by a local emergency, while the remaining eight events were CAISO market awards. There were three SmartAC™ events (July 24, 25, and 26) during which the event hours differed across sub-LAPs. Otherwise, sub-LAPs that were called for the same event were called for the same event hours.

Table 1‑1: PY2018 SmartAC™ Events

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Date** | **Hours** | **Reason** | **SmartRate™ Event?** | **Sub-LAPs Called** | **# Customers Called** |
| July 23 | 4 to 8 p.m. | Market Award | No | PGF1, PGKN, PGNP, PGSI | 55,003 |
| July 24 | 4 to 8 p.m.  3 to 7 p.m. (PGNC only) | Market Award | No | PGF1, PGKN, PGNP, PGSI, PGNC, PGZP | 57,897 |
| July 25 | 6 to 7 p.m. (PGSI)  4 to 7 p.m. (PGST) | Market Award | Yes | PGST, PGSI | 20,269 |
| July 26 | 4 to 7 p.m. 3 to 6 p.m. (PGNC only) | Market Award | Yes | PGEB, PGFG, PGNC, PGST, PGZP | 28,088 |
| July 27 | 7 to 11:59 p.m. | Transmission Emergency | No | PGNC | 731 |
| Aug. 8 | 4 to 7 p.m. | Market Award | No | PGEB, PGF1, PGKN, PGST, PGZP | 53,802 |
| Aug. 9 | 4 to 7 p.m. | Market Award | No | PGEB, PGF1, PGKN, PGST, PGZP, PGSI | 70,251 |
| Aug. 10 | 4 to 7 p.m. | Market Award | No | PGF1, PGKN, PGZP | 25,148 |
| Sep. 26 | 5 to 8 p.m. | Market Award | No | PGNC | 719 |

SmartAC™ customers have historically been eligible to also enroll in the SmartRate™ program. A recent CPUC decision grandfathers these dual participants through October 26, 2018, but subsequent new dual participation is prohibited. As of May 2018, SmartAC™ had over 113,000 active enrolled residential customers; approximately 27,000 of these customers were dually enrolled in SmartAC™ and SmartRate™.[[1]](#footnote-1) On days when both a SmartAC™ event and a SmartRate™ event is called, the SmartRate™ customers are withheld from SmartAC™ events and the response from dually enrolled customers is attributed to the SmartRate™ program.

The primary goals of the evaluation include:

1. Estimate hourly *ex-post* load impacts for the 2018 program year, including:
   1. Hourly and average daily load impacts for each event;
   2. The distribution of hourly and average daily load impacts by customer segment, including: sub-LAP, CARE/non-CARE customers, net-metering solar customers (NEM), housing type (*i.e.*, single family vs. multifamily customers), AC usage intensity, device type (*i.e.*, ExpressStat, UtilityPro, Gen 1, and Gen 2)[[2]](#footnote-2), customers with multiple devices, and by marketing cohort[[3]](#footnote-3);
   3. Load Impact estimates for SmartAC™-only customers as compared to customers who are dually enrolled in SmartAC™ and SmartRate™;
   4. The opt-out / override rate by customer segment[[4]](#footnote-4); and
   5. The persistence of load reductions across event-hours for multiple hour events.[[5]](#footnote-5)
2. Produce *ex-ante* load impact forecasts for 2019-2029 by LCA on an aggregate and per customer basis for a typical event day and the monthly system peak load day for May through October. Forecasts are based on the following four sets of weather conditions:
   1. PG&E’s peaking conditions in a 1-in-2 weather year;
   2. PG&E’s peaking conditions in a 1-in-10 weather year;
   3. CAISO peaking conditions in a 1-in-2 weather year; and
   4. CAISO peaking conditions in a 1-in-10 weather year.

The evaluation conforms to the Load Impact Protocols adopted by the California Public Utilities Commission (CPUC) in April 2008 (D.08-04-050).

This report is organized as follows: Section 2 describes the evaluation methods used in the study; Section 3 contains *ex-post* load impact results; Section 4 contains *ex-ante* forecasts; Section 5 compares *ex-post* and *ex-ante* estimates to those from previous years; and Section 6 provides recommendations. Appendices describe the results of our control-group matching process, approaches used to evaluate the quality of results, and contain electronic versions of the required Protocol table generators.

# Study Methodology

The primary objectives of this evaluation were outlined in Section 1. This section describes the data and methods used to produce *ex-post* load impacts and *ex-ante* forecasts.

## Ex-post Load Impact Evaluation

For the *ex-post* evaluation, we estimate load impacts by comparing SmartAC™ customer loads to that of a quasi-experimental matched control group on event days, net of the differences in loads on event-like non-event days. This regression-based approach, known as the difference-in-differences (D-in-D) method, can be used to produce estimates of standard errors to develop confidence intervals about the estimated event hour or event day load impacts. The eligible control-group customers consist of residential customers who are not enrolled in SmartAC™ or SmartRate™. We match control-group customers based on the similarity of available customer characteristics (*e.g.*, sub-LAP, AC usage, CARE status, NEM status) as well as usage patterns on non-event days.

### Data

To address each of the load impact objectives listed in Section 1, the following data is required:

* *Customer* information for SmartAC™ customers and potential control-group customers (*e.g.*, sub-LAP, LCA, weather station, AC usage level, housing type, CARE status, NEM status);
* Billing-based *interval load data* (*i.e.*, hourly loads for each treatment and potential control group customer) for PY2018 (May 1 through October 31);
* *Weather* *data* (*i.e.*, hourly temperatures and other variables for PY2018, by weather station);
* *Program event data* (*i.e.*, dates and hours of SmartAC™ and SmartRate™ events and a list of SmartAC™ customers who are dually enrolled in both programs); and
* *Device Information* for SmartAC™ customers (*i.e.*, the type and number of devices installed at each premise) as well as SmartAC™ customer opt-outs on each date.

### Control Group Selection

The objective in selecting a quasi-experimental matched control group is to identify a group of customers that are as similar as possible to treatment customers, particularly in terms of their hourly load profiles. Due to the high number of potential control customers, we perform the matching in two stages. In the first stage, we use propensity score matching to identify three control customers for each treatment customer that have the closest match in terms of monthly usage (based on billing data), weather station and cooling degree days, and customer characteristics such as CARE status, NEM status, dwelling type, AC usage, and rate schedule. Following the first-stage matching, we obtain interval load data for the treatment customers and the paired-down set of matched control customers.

The first-stage matching allows for a more tractable matching process in the second stage using the interval load data. The second-stage matching process uses propensity score matching to find a single control customer for each SmartAC™ customer with the closest hourly load profile on a selection of non-event, non-holiday weekdays. Moreover, to ensure that customers are matched based on the sensitivity of their energy usage to weather conditions, we perform this matching process using two 24-hour load profiles drawn from different temperature profiles. The first 24-hour load profile reflects usage patterns during the hottest 10 percent of non-event days. The second 24-hour load profile reflects usage over a set of cooler days taken from the middle 50 percent of non-event days. In addition to two 24-hour load profiles, customers are also matched based on CARE-status, NEM-status, dwelling type, and AC usage level. Finally, we require that SmartAC™ customers are matched to a control customer residing in the same sub-LAP area.

Propensity score matching involves estimating a regression to determine each customer’s probability (*i.e.*, “propensity”) of being assigned treatment based upon observable characteristics. Each SmartAC™ customer is then matched to the control customer with the nearest value in terms of their predicted probability, also known as their “propensity score”. For the second stage matching, we assume the probability model is a logistic function of the following form:

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

Table 2‑1: Propensity Score Model Terms

|  |  |
| --- | --- |
| **Symbol** | **Description** |
| *SmartACc* | Variable indicating whether customer c is a SmartAC (1) or Control (0) customer |
| *avgkW*c,h | Average load during hour h for customer *c* |
| *Xc,j* | The value of characteristic j for customer c |
| β0 | Estimated constant coefficient |
| β 1,h | Estimated coefficient for hour h of 24-hour load profile |
| β 2,i | Estimated coefficient for customer characteristic j |
| εc | Error term for customer c |

We estimate a logistic regression that includes two 24-hour profiles: one that averages customer load across hot days (*i.e.*, the hottest 10 percent of non-event days) and one that averages customer load across a random selection of cooler days (*i.e.*, days that fall between the 25th and 75th percentile of non-event days based on average temperature). Furthermore, we include indicators for CARE status, NEM status, type of dwelling, and AC usage level as customer characteristics in the regression. This model is estimated separately for each sub-LAP.

For the first stage matching, we estimate a similar logistic regression to the one described above, however, this regression is based on monthly billing data and includes the average usage divided by the number of billed days in place of the 24-hour load profiles above, as well as characteristics that include: average cooling degrees per billed day, an indicator for weather station, the share of billed days on each type of rate schedule, an indicator for whether the customer switched rate schedules, an indicator for dwelling type, and an indicator for AC usage.

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. More details about our matching process, including evaluation of match quality, are provided in Section 3.1 and Appendix A.

### Analysis Methods

We estimate the following panel model for each hour of the day and sub-LAP:

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

Table 2‑2: *Ex-Post* Load Impacts Model Terms

|  |  |
| --- | --- |
| **Symbol** | **Description** |
| *kW*c,d | Load during a given hour for customer *c* on day *d* |
| *SmartACc,d* | Variable indicating whether customer *c* is a SmartAC (1) or Control (0) customer |
| *Evti,d* | Variable indicating that day *d* is the *i*th event day (1) or not (0) |
| Xc,d,j | The value of weather variable j on day d for customer c |
| β0 | Estimated constant coefficient |
| β1,i | Estimated load impact for event *i* |
| β2,i | Estimated coefficient for customer characteristic j |
| *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 (*e.g.*, weather) and time-invariant customer characteristics (*e.g.*, home size). In addition, the model includes time variant weather controls such as the mean temperature across the first 17 hours of the day[[6]](#footnote-6). The *1,i* coefficients represent the estimated load impacts for each hour of every event day.

We estimate this model separately for each hour of the day using only event and event-like non-event days (*i.e.*, the hottest 10% of non-event days). The distribution of load impacts across different customer subgroups is explored by estimating the above model separately for each subgroup*.* These variables include CARE status, NEM status, housing type, AC usage level, device type, customers with multiple devices, marketing cohort, and customers who are dually enrolled in SmartRate™.

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 show the uncertainty around the estimated impacts. These methods use the estimated load-impact parameter values and the associated variances to derive scenarios of hourly load impacts. Due to variation in event hours both within and across event days, we are not able to estimate the uncertainty associated with the average event hour or the uncertainty associated with the typical event day.

We validated the *ex-post* load impact estimates against simple difference-in-difference calculations from load data. Specifically, for each sub-LAP and event day, we compared the average treatment customer hourly loads to the average control-group hourly loads. The comparisons included events during which the sub-LAP was not called, which allowed us to ensure that the event information we were provided was correct and that our methods did not produce “false positives” (*i.e.*, estimated load impacts for dates/locations in which customers were not called).

## 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; and
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 years 2019 through 2029, both for the monthly system peak load as well as 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. Furthermore, *ex-ante* load impacts are developed for the following subgroups of customers:

1. LCA;
2. Customers enrolled in only SmartAC™ vs. customers dually enrolled in SmartAC™ and SmartRate™; and
3. Busbar (by November 1, 2019).

PG&E provided the enrollment forecasts and *ex-ante* weather conditions for each required scenario.

### Reference Loads

The *per-customer reference loads* are simulated based on regression models, which reflect customer load patterns on non-event days and estimate the relationship between load patterns and weather. Reference loads are simulated using the appropriate weather scenario data (*i.e.*, the 1-in-2 and 1-in-10 weather-year conditions provided by the utilities) and month.

The regression model uses data for treatment customers from all non-holiday weekdays that do not coincide with SmartAC™ or SmartRate™ events from May 1 to October 31 in 2018. Average load profiles are created for each LCA and enrollment segment (*i.e.*, SmartAC™-only and dually enrolled customers). The regressions account for differences in loads by hour, day-of-week, or month by including various indicator control variables.

The *ex-ante* reference load regression model is as follows:

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

Table 2‑3: *Ex-Ante* Reference Loads Model Terms

|  |  |
| --- | --- |
| **Symbol** | **Description** |
| *avgkWd,h* | The average load (kWh/customer/hour) on day *d* during hour *h* |
| *CDD60d* | The cooling degrees on day *d* |
| *Β1,h* | Estimated increase in average load during hour *h* from an increase of one cooling degree |
| *Β2,h* | Estimated average load during hour *h* |
| *Β3,h* | Estimated difference in average load during hour *h* on Mondays |
| *Β4,h* | Estimated difference in average load during hour *h* on Fridays |
| *Hh* | Variable indicating that the hour is *h* (1) or not (0) |
| *Mond* | Variable indicating that day *d* is a Monday (1) or not (0) |
| *Frid* | Variable indicating that day *d* is a Friday (1) or not (0) |
| *Dd* | Day of the week fixed effects |
| *Md* | Month of the year fixed effects |
| *εd,h* | Error term (robust) |

The model includes hour fixed effects to allow loads to vary by hour of the day. Monday and Friday hourly fixed effects allow for differences in load profiles on Mondays and Fridays. Day of the week fixed effects allow the daily load level to vary by day of the week. Month fixed effects allow the daily load level to vary by month of the year. The *1,h* coefficients represent the estimated increase in average loads during hour *h* due to a one cooling degree day increase. We estimate this model separately for each LCA and enrollment segment.

Reference loads are simulated by applying the cooling degree days from the weather scenarios provided by PG&E to the estimated *1,h* coefficients along with the other relevant load shape variables and fixed effects. The estimated reference loads for each month and weather scenario are assumed to be the monthly system peak load (or typical event day) for a Wednesday event.

### Load Impacts

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 of weather on the estimated load impacts. The resulting per-customer load impacts are then coupled with the appropriate reference loads to develop the forecasted load impacts and event-day reference load profiles.

We modeled the relationship between the load impact and weather conditions as follows:

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

Table 2‑4: *Ex-Ante* Load Impacts Model Terms

|  |  |
| --- | --- |
| **Symbol** | **Description** |
| *Impactl,h,evt i* | The estimated per-customer load impact (kWh/customer/hour) in LCA *l* during hour *h* on event *i* |
| *Templ,h,evt i* | The average temperature in LCA *l* during hour *h* on event *i* |
| *Mean8l,evt i* | The average temperature in LCA *l* over the first eight hours of the day on event *i* |
| *β1* | Estimated increase in per-customer load impact due to a one degree increase in the average hourly temperature |
| *β2,l* | Estimated increase in per-customer load impact in LCA *l* due to a 1 degree increase in the average temperature over the first eight hours of the day |
| *LCAl* | Variable indicating if the LCA is *l* (1) or not (0) |
| *Hh* | Variable indicating if the hour is *h* (1) or not (0) |
| *εl,h,evt i* | Error term (robust) |

The model includes LCA and hour fixed effects to allow load impacts to vary by LCA and hour of the day. The ** coefficients represent the estimated increase in per-customer load impact (in kWh/hour/customer) that results from a one-degree increase in temperature, either hourly or the average of the first eight hours of the event day. The standard errors from this model are the basis for the uncertainty-adjusted load impacts.

We build our *ex-ante* load impact forecasts based only on serial number events called in 2017. There are two main reasons for basing our *ex-ante* load impact forecasts on the 2017 estimated *ex-post* load impacts. First, only sub-LAP events were called in 2018, which tend to yield smaller estimated load impacts compared to serial number events due to higher rates of commercial paging system issues or equipment malfunction associated with calling only a subset of PG&E’s sub-LAP areas.[[7]](#footnote-7) Moreover, serial number events are more representative of the load impacts that would be achieved from system-wide events. Second, there were six sub-LAPs that were not called in 2018, which makes it necessary to develop *ex-ante* forecasts for these sub-LAPs from the 2017 estimated *ex-post* load impacts.

In addition, we use 2017 load impacts that correspond to SmartAC™-only customers, consistent with how this analysis was done in the PY2017 report. To arrive at load impacts for dually enrolled customers, we apply a multiplicative factor of 0.85 based on our examination of the relationship between SmartAC™-only customers and dually enrolled customers during SmartAC™-only events in 2018. This is also consistent with the approach taken in PY2017. Moreover, to account for dispatch issues with PGKN that are expected to continue into PY2019, we apply a multiplicative factor of 0.05, which reconciles the average load impact for PGKN during sub-LAP events in PY2018 with results from PY2017.

The snapback in the three hours following the event (when the customer’s AC unit is running more than it would have in the absence of the event day to bring the home’s temperature back to the thermostat’s set point) is modeled as a share of the total event-hour load impact, by LCA. That is, larger event-hour load impacts are associated with higher post-event snapback.

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 2018 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.

# *Ex-Post* Load Impacts

This section documents the findings from the *ex-post* load impact analysis. The primary load impact results include estimates of the aggregate and per-customer event-hour load impacts for each event. Due to the nature of sub-LAP events, where different sub-LAPs are called for different events and potentially different hours within the same event, we are not able to present results for the typical event day. Instead, we average the hourly load impacts across all potential event hours, or in some cases choose an illustrative event hour or event day. Our main findings are summarized in this section in various figures and data tables, while detailed results for each hour, event, and sub-LAP 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 SmartAC™ customers and a matched control group. In addition to the controls described in the estimated model in Section 2.1.3, we control for concurrent events that are called for SmartRate™ by including separate indicators for customers who are dually enrolled in SmartAC™ and SmartRate™ (there were two concurrent events on July 25th and July 26th). Furthermore, we drop SmartRate™-only events from the pool of SmartAC™ non-event days to ensure that non-event loads are comparable between SmartAC™ customers and matched controls on all non-event days.

## Control Group Matching Results

In this section, we present 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.[[8]](#footnote-8)

Table 3‑1 provides the mean percentage error (MPE) and mean absolute percentage error (MAPE) calculated across the average 24-hour load profile as well over the RA window. We evaluate match quality based on the two 24-hour load profiles that we used in matching. The first corresponds to the average load profile over the hottest 10 percent of event-like non-event days, while the second corresponds to a random sample of cooler days taken from the middle 50 percent of days based on temperature. We also evaluate the match quality of the cooler days that were not sampled for use in matching, which helps assess whether there is good match quality on out-of-sample days. Additional results by sub-LAP are presented in Appendix A.

Table 3‑1: Match Quality Statistics

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| **Comparison Days** | **MPE** | **MAPE** | **MPE RA Window** | **MAPE RA Window** |
| Hot Days | 0.63% | 0.63% | 0.60% | 0.60% |
| Cool Days | 0.57% | 0.57% | 0.77% | 0.77% |
| Non-Matching Cool Days | 0.72% | 0.72% | 1.37% | 1.37% |

Figure 3‑1 illustrates the matched load profiles for selected event-like days. This figure contains the average hourly profiles for the treatment and matched control-group customers by day type including hot days, cooler days that were used in matching, and the cooler days that were not used in matching. The solid lines represent the average usage of treatment customers on hot days (red), cooler matching days (blue), and cooler non-matching days (green). Similarly, the dashed lines represent the average usage of the matched control customers on hot days (yellow), cooler matching days (gray), and cooler non-matching days (black). Regardless of the comparison day, the average load profiles are nearly identical between treatment and control. Moreover, cool days that are used in matching are nearly identical to cool days that are not used in matching.

Figure 3‑1: Treatment and Control Non-Event Day Load Profiles

## Overall Load Impacts

This section summarizes results for all SmartAC™ customers. In later sections, we discuss how these load impacts are distributed across subgroups of interest, including for customers who are dually enrolled in SmartRate™. The presented results include: the average event-hour load impacts for each event; the average event-hour load impacts for each sub-LAP and event; and the hourly load impacts for a selected event.

The *ex-post* load impacts are summarized for all nine events in Figure 3‑2. The blue bars indicate the magnitude of the average per customer load impact (in kWh/customer/hour) during hours that each sub-LAP was called for the event, while the labels show the maximal range of event hours over which all sub-LAPs were called.[[9]](#footnote-9) 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 called event hours.

***Overall results range from 0.05-0.43 kWh/customer/hour***

These results indicate that SmartAC™ customers had statistically significant load reductions on each of the nine event days, ranging from 0.05 to 0.43 kWh/customer/hour.

***Lower load impacts for PGNC-only events, late night events, and transmission emergencies***

Two of the events (July 27th and September 26th) had lower load impacts compared to the remaining seven events. One of these events (July 27, 2018) was a transmission emergency. Moreover, PGNC was the only sub-LAP called for both events. In general, the load impacts for PGNC tend to be lower than most of the other sub-LAPs. Furthermore, the event on July 27th had evening event hours (7 – 11:59 p.m.), while the other events were earlier in the afternoon.

***Load impacts average 0.31 kWh/customer/hour for most afternoon events***

The load impacts for the remaining seven events averaged 0.31 kWh/customer/hour. Figure 3‑2 also shows some evidence of a relationship between load impacts and average temperatures, where temperatures tend to be lower in PGNC.

Figure 3‑2: Average Event-Hour Load Impacts by Event

***The number of called customers drives large variation in aggregate event impacts***

Table 3‑2 presents a more complete summary of event information, including the sub-LAPs called, the sub-LAP-specific event hours, the type of event, and the number customers called, as well as average load impacts (per customer and in aggregate), reference loads, and percentage load impacts across the hours for which each sub-LAP was called for each event day. The number of called customers varies dramatically across events, leading to large variation in aggregate load impacts from 0.04 MWh/hour to 24.51 MWh/hour. In percentage terms, the load impacts range from 3.4 percent to 15.1 percent of reference loads. The 3.4 percent load impact corresponds to the late evening event on July 27th. All the other events had load impacts that were at least 8 percent of reference loads.

Table 3‑2: Average Event-Hour Load Impacts by Event

|  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Event Date** | **Event Hours** | **sub-LAPs Called** | **Type of Event** | **SmartRate™ Event?** | **# Called** | **Average Event Hour** | | | | |
| **Reference (kW/Cust)** | **Impact (kW/Cust)** | **% Impact** | **Aggregate Impact (MW)** | **Avg. Temp (°F)** |
| 7/23/2018 | 4 to 8 p.m. (HE17 to HE20) | PGF1, PGKN, PGNP, PGSI | Market Award | No | 55,003 | 2.64 | 0.28 | 10.5% | 15.25 | 98.2 |
| 7/24/2018 | 4 to 8 p.m. (HE17 to HE20) 3 to 7 p.m. (HE16 to HE19)  \*PGNC only | PGF1, PGKN, PGNP, PGSI, PGNC, PGZP | Market Award | No | 57,897 | 2.73 | 0.29 | 10.8% | 13.59 | 100.8 |
| 7/25/2018 | 6 to 7 p.m. (HE19)  \*PGSI only  4 to 7 p.m. (HE17 to HE19)  \*PGST only | PGST, PGSI | Market Award | Yes | 20,269 | 2.86 | 0.43 | 15.1% | 4.60 | 100.9 |
| 7/26/2018 | 4 to 7 p.m. (HE17 to HE19) 3 to 6 p.m. (HE16 to HE18)  \*PGNC only | PGEB, PGFG, PGNC, PGST, PGZP | Market Award | Yes | 28,088 | 2.14 | 0.32 | 14.8% | 6.68 | 90.7 |
| 7/27/2018 | 7 to 11:59 p.m.  (HE20 to HE24) | PGNC | Transmission Emergency | No | 731 | 1.60 | 0.05 | 3.4% | 0.04 | 79.1 |
| 8/8/2018 | 4 to 7 p.m. (HE17 to HE 19) | PGEB, PGF1, PGKN, PGST, PGZP | Market Award | No | 53,802 | 2.16 | 0.26 | 12.1% | 14.06 | 96.1 |
| 8/9/2018 | 4 to 7 p.m. (HE17 to HE19) | PGEB, PGF1, PGKN, PGST, PGZP, PGSI | Market Award | No | 70,251 | 2.46 | 0.35 | 14.2% | 24.51 | 99.8 |
| 8/10/2018 | 4 to 7 p.m. (HE17 to HE19) | PGF1, PGKN, PGZP | Market Award | No | 25,148 | 2.66 | 0.21 | 8.0% | 5.38 | 102.2 |
| 9/26/2018 | 5 to 8 p.m. (HE18 to HE20) | PGNC | Market Award | No | 719 | 1.22 | 0.11 | 9.4% | 0.08 | 94.1 |

Next, we examine the results at the sub-LAP level. Figure 3‑3 summarizes the sub-LAP level *ex-post* load impacts by event. The blue bars indicate the magnitude of the average per customer load impact (in kWh/customer/hour) across the sub-LAP-specific event hours. 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 in each sub-LAP during the event hours.

***PGEB, PGF1, PGSI, and PGST consistently produce the highest load impacts***

Figure 3‑3 illustrates that there is considerable variation across sub-LAP areas within the same event, as well as within sub-LAP across events. Several sub-LAPs including PGEB, PGF1, PGSI, and PGST have consistently higher average load impacts per customer than the others.

***A dispatch malfunction throughout PY2018 led PGKN to produce low load impacts***

While PGKN had high per-customer load impacts in the PY2017 evaluation, during PY2018 there was an error in dispatching SmartAC customers in this sub-LAP.[[10]](#footnote-10) The yellow bars represent the magnitude of the average per customer load impacts for all five events called in PGKN. Although the load impacts are higher for PGKN during the July 23rd event compared to the other events for which PGKN was called, the load impacts fall behind PGF1 and PGSI, which were comparable in PY2017. For the remaining events on July 24th and August 8th, 9th, and 10th, PGKN has a load response that does not exceed 0.05 kWh/customer/hour, although this response is generally statistically significant. These results confirm that there was some malfunction in dispatching most customers in this sub-LAP, leading to a small share of the SmartAC™ customers being dispatched for these events.

Figure 3‑3: Average Event-Hour Load Impacts by Sub-LAP and Event

***PGEB has the highest aggregate and percentage load impacts***

Table 3‑3 provides the detailed information underlying Figure 3-3, including the number customers called, the average event load impacts (per customer and in aggregate), reference loads, and percentage load impacts for each sub-LAP for each event. The number of called customers varies dramatically across sub-LAPs leading to aggregate load impacts that range from 0.04 MWh/hour for PGNC to 7.8 MWh/hour for PGEB. In percentage terms, the load impacts range from 3.4 percent of reference loads for PGNC (excluding PGKN) to 17.1 percent of reference loads for PGEB. For PGKN, percentage loads impacts are 6 percent on July 23rd event, and are close to 1 percent thereafter.

Table 3‑3: Average Event-Hour Load Impacts by Sub-LAP and Event

|  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Event Date** | **Sub-LAP** | **Event Hours** | **SmartRate™ Event?** | **# Called** | **Average Event Hour** | | | | |
| **Reference (kW/Cust)** | **Impact (kW/Cust)** | **% Impact** | **Aggregate Impact (MW)** | **Avg. Temp (°F)** |
| 23-Jul | PGF1 | 4-8 p.m. | No | 17,471 | 2.76 | 0.32 | 11.4% | 5.51 | 99.1 |
| PGKN | 5,621 | 2.89 | 0.17 | 6.0% | 0.97 | 100.0 |
| PGNP | 15,195 | 2.41 | 0.20 | 8.2% | 3.01 | 97.0 |
| PGSI | 16,716 | 2.64 | 0.34 | 13.0% | 5.76 | 97.7 |
| 24-Jul | PGF1 | 4-8 p.m. | No | 17,442 | 2.90 | 0.37 | 12.8% | 6.50 | 103.3 |
| PGKN | 5,618 | 2.96 | 0.04 | 1.3% | 0.22 | 102.8 |
| PGNC | 3-7 p.m. | 734 | 2.46 | 0.28 | 11.5% | 0.21 | 94.5 |
| PGNP | 4-8 p.m. | 15,170 | 2.47 | 0.21 | 8.6% | 3.23 | 98.5 |
| PGSI | 16,652 | 2.70 | 0.37 | 13.6% | 6.15 | 99.8 |
| PGZP | 2,281 | 2.77 | 0.30 | 10.7% | 0.68 | 102.2 |
| 25-Jul | PGSI | 6-7 p.m. | Yes | 14,478 | 2.97 | 0.40 | 13.4% | 5.77 | 102.7 |
| PGST | 4-7 p.m. | 5,791 | 2.77 | 0.46 | 16.7% | 2.68 | 99.3 |
| 26-Jul | PGEB | 4-7 p.m. | Yes | 17,866 | 1.97 | 0.30 | 15.4% | 5.41 | 88.4 |
| PGFG | 2,078 | 1.20 | 0.11 | 8.8% | 0.22 | 77.0 |
| PGNC | 3-6 p.m. | 624 | 2.42 | 0.24 | 9.9% | 0.15 | 95.5 |
| PGST | 4-7 p.m. | 5,787 | 2.78 | 0.46 | 16.4% | 2.64 | 99.0 |
| PGZP | 1,733 | 2.77 | 0.28 | 10.1% | 0.49 | 101.2 |
| 27-Jul | PGNC | 7-11:59 p.m. | No | 731 | 1.60 | 0.05 | 3.4% | 0.04 | 79.1 |
| 8-Aug | PGEB | 4-7 p.m. | No | 21,077 | 1.65 | 0.25 | 15.1% | 5.25 | 90.6 |
| PGF1 | 17,325 | 2.58 | 0.35 | 13.4% | 6.00 | 101.4 |
| PGKN | 5,592 | 2.73 | 0.02 | 0.7% | 0.11 | 103.3 |
| PGST | 7,545 | 2.16 | 0.31 | 14.2% | 2.31 | 93.0 |
| PGZP | 2,263 | 2.31 | 0.17 | 7.4% | 0.39 | 98.3 |
| 9-Aug | PGEB | 4-7 p.m. | No | 21,061 | 2.16 | 0.37 | 17.1% | 7.79 | 96.8 |
| PGF1 | 17,316 | 2.76 | 0.39 | 14.2% | 6.81 | 103.5 |
| PGKN | 5,590 | 2.84 | 0.04 | 1.5% | 0.24 | 103.3 |
| PGSI | 16,482 | 2.34 | 0.37 | 15.7% | 6.05 | 98.9 |
| PGST | 7,539 | 2.56 | 0.42 | 16.6% | 3.20 | 99.2 |
| PGZP | 2,263 | 2.42 | 0.19 | 7.7% | 0.42 | 98.3 |
| 10-Aug | PGF1 | 4-7 p.m. | No | 17,297 | 2.67 | 0.28 | 10.6% | 4.89 | 102.5 |
| PGKN | 5,589 | 2.81 | 0.05 | 1.6% | 0.25 | 104.0 |
| PGZP | 2,262 | 2.20 | 0.11 | 4.8% | 0.24 | 94.9 |
| 26-Sep | PGNC | 4-7 p.m. | No | 719 | 1.22 | 0.11 | 9.4% | 0.08 | 94.1 |

***Consecutive sub-LAP events do not lead to diminished load impacts***

Table 3‑4 compares the load impacts for sub-LAPs that have two or three consecutive events to analyze whether having consecutive events leads to diminishing load impacts. It appears that two or even three consecutive events do not significantly diminish the event load impacts once we control for weather. That is, it appears that load impacts are higher on second event days and lower on third event days, but this is in fact due to higher temperatures on second event days and lower temperatures on third event days. For example, PGZP has lower per-customer load impacts on the third of three consecutive event days, but that day was also significantly cooler than the preceding event days.

Table 3‑4: Sub-LAPs with Consecutive Events

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
| **Event Date** | **Sub-LAP** | **Event Hours** | **SmartRate™ Event?** | **# Called** | **Average Event Hour** | |
| **Impact (kW/Cust)** | **Avg. Temp (°F)** |
| 8/8/2018 | PGEB | 4-7 p.m. | No | 21,077 | 0.25 | 90.6 |
| 8/9/2018 | 4-7 p.m. | No | 21,061 | 0.37 | 96.8 |
| 7/23/2018 | PGF1 | 4-8 p.m. | No | 17,471 | 0.32 | 99.1 |
| 7/24/2018 | 4-8 p.m. | No | 17,442 | 0.37 | 103.3 |
| 8/8/2018 | 4-7 p.m. | No | 17,325 | 0.35 | 101.4 |
| 8/9/2018 | 4-7 p.m. | No | 17,316 | 0.39 | 103.5 |
| 8/10/2018 | 4-7 p.m. | No | 17,297 | 0.28 | 102.5 |
| 7/23/2018 | PGNP | 4-8 p.m. | No | 15,195 | 0.20 | 97.0 |
| 7/24/2018 | 4-8 p.m. | No | 15,170 | 0.21 | 98.5 |
| 7/23/2018 | PGSI | 4-8 p.m. | No | 16,716 | 0.34 | 97.7 |
| 7/24/2018 | 4-8 p.m. | No | 16,652 | 0.37 | 99.8 |
| 7/25/2018 | 6-7 p.m. | Yes | 14,478 | 0.40 | 102.7 |
| 7/25/2018 | PGST | 4-7 p.m. | Yes | 5,791 | 0.46 | 99.3 |
| 7/26/2018 | 4-7 p.m. | Yes | 5,787 | 0.46 | 99.0 |
| 8/8/2018 | 4-7 p.m. | No | 7,545 | 0.31 | 93.0 |
| 8/9/2018 | 4-7 p.m. | No | 7,539 | 0.42 | 99.2 |
| 8/8/2018 | PGZP | 4-7 p.m. | No | 2,263 | 0.17 | 98.3 |
| 8/9/2018 | 4-7 p.m. | No | 2,263 | 0.19 | 98.3 |
| 8/10/2018 | 4-7 p.m. | No | 2,262 | 0.11 | 94.9 |

***PGEB, PGF1, and PGSI produced 76 percent of the PY2018 load reductions***

Next, we look at how load impacts are distributed across sub-LAPs. Figure 3‑4 compares the sub-LAP shares of estimated aggregate event-hour load impacts, reference loads, and enrollments multiplied by the number of hours that the sub-LAP was called for SmartAC™ events. The load impacts for SmartAC™ customers are mainly driven by three sub-LAPs (PGEB, PGF1, and PGSI), which collectively produced 76 percent of the PY2018 load reductions. Furthermore, these three sub-LAP areas as well as PGST have a higher share of load impacts than of enrollments or reference loads. All other sub-LAPs have a lower share of load impacts compared to the share of enrollments and reference loads.

Figure 3‑4: All Event-Hour Load Impacts by Sub-LAP

***Load impacts peak during second hour of event with significant post-event snapback***

Figure 3‑5 shows an example of the aggregate hourly reference loads, observed loads, and estimated load impacts using the August 9th event. Since there is no typical event day, we have selected a SmartAC™-only event in which a large share of enrolled SmartAC™ customers were called for the event. On August 9th, 70,251 or 69 percent of enrolled SmartAC™ customers were called for the event. Table 3‑5 contains the hourly results for August 9th in the manner required by the Protocols, including hourly temperatures and uncertainty adjusted load impacts. Notice that the load impacts peak at 27.7 MWh during the second hour of this event (5:00 to 6:00 p.m.). Furthermore, there is significant post-event snapback, when loads increase by 19.2 MWh the first hour after the event. Snapback peaks at 20.2 MWh the second hour after the event and declines over the course of the evening.

Figure 3‑5: Hourly Load Impacts and Uncertainty Adjusted Estimates on August 9, 2018

Table 3‑5: Hourly Load Impacts and Uncertainty Adjusted Estimates on August 9, 2018



## Subgroup Load Impacts

This section summarizes how SmartAC™ load impacts are distributed across subgroups of interest including: CARE/non-CARE customers, NEM/non-NEM customers, housing type, AC usage intensity, device type, customers with multiple devices, and by marketing cohort. We also compare load impacts for customers who are only enrolled in SmartAC™ to customers who are also enrolled in SmartRate™. These comparisons are based on average load impacts within each subgroup across a representative event hour, HE 18 (5-6 p.m.), since there is no typical event. Additional results for these subgroups, including the load profiles, can be found in electronic form in Protocol table generators provided along with this report.

One factor to consider when making subgroup comparisons is that customers within a given subgroup may disproportionately reside within certain sub-LAPs. For example, CARE customers tend to live in hotter locations and therefore have more AC load to curtail than non-CARE customers. Thus, a finding that CARE customers have higher load impacts may not reflect a behavioral difference from non-CARE customers as much as a difference in circumstances.

The *ex-post* load impacts during HE 18 (5-6 p.m.) across all events in which that hour was called are summarized for each subgroup of interest in Figure 3‑6. These results exclude PGKN due to the previously described issue with dispatching this sub-LAP during 2018. The blue bars indicate the magnitude of the average per customer load impact (in kWh/customer/hour) within each subgroup. The green bands correspond to 80 percent confidence intervals around these estimates. The orange line represents the average temperatures experienced by the customers in each subgroup during HE 18 across all events that include HE 18.

***Most sub-group comparisons are consistent with PY2017 results***

There are statistically significant load impacts for every subgroup except for customers with ExpressStat devices. The pattern of load impacts is largely similar to subgroup comparisons from the PY2017 report, which were based on serial events, including the following:

* SmartAC™-only customers have significantly higher load impacts than dually enrolled customers.
* Customers enrolled in SmartAC™ after 2014 (when PG&E’s SmartAC™ marketing methods changed) have substantially higher load impacts than customers enrolled earlier.
* Single-device residences have significantly higher load impacts than multiple-device residences.
* The device-type results are also similar, with the thermostats (*i.e.*, ExpressStat and UtilityPro) performing more poorly than the Gen 1 or Gen 2 switches. Moreover, UtilityPro devices lead to significant load impacts, while ExpressStat devices do not; and the Gen 2 switches lead to significantly higher load impacts compared to the Gen 1 switches.

***CARE and NEM comparisons differ from PY2017 results***

Some results that differ from those presented in the PY2017 report include the CARE and NEM results, which were not significantly different in PY2017. Our results suggest that CARE customers have significantly higher load impacts than non-CARE customers and NEM customers have substantially lower load impacts than non-NEM customers. Once again, these differences could reflect differences in customer circumstances rather than behavioral differences.

***Different housing types do not have statistically different load impacts***

The housing type comparisons are not comparable to previous analyses. In the PY2017 report, customers were classified into single-family and multi-family dwellings based on key words in the physical service address. In contrast, we are using categories provided by PG&E, which include detached residences, shared wall residences, and common area. There are very few SmartAC™ customers classified as common area, which prevents the reliable estimation of results for this subgroup. Detached residences have slightly higher load impacts than shared wall residences, which is qualitatively the same as the single-family results compared to the multi-family residence results in the PY2017 report. However, the differences between these two groups, while significant, is much less stark than previously reported, suggesting that these categories are only rough proxies for the categories used previously.

Figure 3‑6: Average HE 18 (5-6 p.m.) Load Impacts by Subgroup

***Load impacts increase with the level of AC usage***

We contribute new subgroup analysis in this report by comparing customer load impacts by the intensity of AC usage. Customers are sorted by PG&E into three groups based on estimated intensity of AC usage: low AC usage, medium AC usage, and high AC usage. The estimates suggest that load impacts increase with AC usage intensity, with a much larger difference between customers with high and medium AC usage levels compared to the difference between customers with low and medium AC usage levels.

***Comparing subgroups by percentage load impacts can lead to different results***

Table 3‑6 provides the detailed information underlying Figure 3‑6, including the average number of customers called for events that include HE 18, the total number of enrolled customers in each subgroup, the average HE 18 load impacts, reference loads, percentage load impacts, and temperatures. The main takeaway from this table is that comparing subgroups by percentage load impacts often leads to different results than level load impacts. That is, while some subgroups have higher load impacts, they may have higher reference loads as well, which can lead to comparable or even lower percentage impacts. This is true for NEM customers, dwelling type, and AC usage level.

Table 3‑6: Average HE 18 (5-6 p.m.) Load Impacts by Subgroup

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
| **Subgroup** | **Avg. # Called** | **Enrolled Customers** | **Average HE 18 (5-6 p.m.)** | | | | |
| **Reference (kW/Cust)** | **Impact (kW/Cust)** | **% Impact** | **Aggregate Impact (MW)** | **Avg. Temp (°F)** |
| All SmartAC™ Customers | 11,741 | 102,440 | 2.50 | 0.36 | 14.5% | 4.3 | 98.7 |
| SmartAC™ Only | 9,615 | 83,568 | 2.49 | 0.37 | 14.8% | 3.6 | 98.6 |
| Dually Enrolled | 2,125 | 18,872 | 2.52 | 0.31 | 12.3% | 0.7 | 99.1 |
| Old Customer | 9,408 | 82,371 | 2.46 | 0.33 | 13.6% | 3.1 | 98.5 |
| New Customer | 2,332 | 20,069 | 2.68 | 0.48 | 17.9% | 1.1 | 99.1 |
| CARE | 4,105 | 29,602 | 2.78 | 0.42 | 15.0% | 1.7 | 100.5 |
| Non-CARE | 7,635 | 72,838 | 2.36 | 0.34 | 14.2% | 2.6 | 97.7 |
| NEM | 2,489 | 21,428 | 1.15 | 0.25 | 22.0% | 0.6 | 98.6 |
| Non-NEM | 9,252 | 81,012 | 2.87 | 0.39 | 13.6% | 3.6 | 98.7 |
| Detached Residence | 11,220 | 96,856 | 2.53 | 0.36 | 14.4% | 4.1 | 98.7 |
| Shared Wall Residence | 510 | 5,495 | 1.96 | 0.34 | 17.4% | 0.2 | 97.8 |
| Low A/C | 1,141 | 12,903 | 1.10 | 0.21 | 19.1% | 0.2 | 96.4 |
| Medium A/C | 3,747 | 33,777 | 1.94 | 0.26 | 13.6% | 1.0 | 98.3 |
| High A/C | 6,136 | 46,958 | 3.34 | 0.48 | 14.3% | 2.9 | 99.8 |
| Single Device | 10,431 | 90,560 | 2.48 | 0.37 | 15.0% | 3.9 | 98.7 |
| Multiple Devices | 976 | 8,925 | 2.64 | 0.30 | 11.4% | 0.3 | 98.2 |
| ExpressStat | 120 | 494 | 2.61 | 0.03 | 1.1% | 0.0 | 100.7 |
| UtilityPro | 629 | 5,817 | 2.65 | 0.11 | 4.1% | 0.1 | 99.0 |
| Gen 1 Switch | 8,019 | 70,595 | 2.43 | 0.36 | 14.7% | 2.9 | 98.4 |
| Gen 2 Switch | 2,656 | 22,433 | 2.66 | 0.47 | 17.7% | 1.25 | 99.17 |

### Dually Enrolled Customers

This section compares results for customers who are only enrolled in the SmartAC™ program to customers who are dually enrolled in SmartAC™ and SmartRate™. We present results for the average event-hour for each event day. Additional results for these customers can be found in electronic form in Protocol table generators provided along with this report.

Table 3‑7 summarizes the per-customer and aggregate results for SmartAC™-only and dually enrolled customers. Roughly 18 percent of SmartAC™ customers were dually enrolled in SmartRate™ during PY2018, which explains why the aggregate load impacts from SmartAC™-only customers dwarf the load impacts for dually enrolled customers. On a per-customer basis, the level and percentage load impacts are higher for SmartAC™-only customers than for dually enrolled customers, with the following exceptions: the two SmartAC™-SmartRate™ event days on July 25th and July 26th; and the two events in which PGNC was the only sub-LAP called (July 27th and September 26th). In summary, dually enrolled customers have lower load impacts than SmartAC™-only customers in general, but they have a higher response on SmartRate™ and SmartAC™ combined event days.

Table 3‑7: Average Event-Hour Load Impacts by Event, SmartAC™ Only vs. Dually Enrolled

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Enrollment Segment** | **Event Date** | **SmartRate™ Event?** | **# Called** | **Average Event Hour** | | | | |
| **Reference (kW/Cust)** | **Impact (kW/Cust)** | **% Impact** | **Aggregate Impact (MW)** | **Avg. Temp (°F)** |
| Dually Enrolled | 7/23/18 | No | 10,222 | 2.64 | 0.22 | 8.3% | 2.2 | 98.0 |
| 7/24/18 | No | 10,860 | 2.72 | 0.23 | 8.5% | 2.0 | 100.7 |
| 7/25/18 | Yes | 3,888 | 2.72 | 0.48 | 17.8% | 1.2 | 100.1 |
| 7/26/18 | Yes | 5,826 | 2.05 | 0.37 | 18.1% | 1.6 | 90.4 |
| 7/27/18 | No | 107 | 1.63 | 0.03 | 2.1% | 0.0 | 83.3 |
| 8/8/18 | No | 10,058 | 2.17 | 0.21 | 9.7% | 2.1 | 95.8 |
| 8/9/18 | No | 12,145 | 2.44 | 0.29 | 11.7% | 3.5 | 99.4 |
| 8/10/18 | No | 4,993 | 2.79 | 0.21 | 7.7% | 1.1 | 102.0 |
| 9/26/18 | No | 108 | 1.35 | 0.14 | 10.2% | 0.0 | 95.6 |
| SmartAC™ Only | 7/23/18 | No | 44,781 | 2.64 | 0.29 | 11.0% | 13.0 | 98.3 |
| 7/24/18 | No | 47,037 | 2.72 | 0.30 | 11.2% | 11.5 | 100.8 |
| 7/25/18 | Yes | 20,269 | 2.87 | 0.44 | 15.4% | 4.7 | 100.9 |
| 7/26/18 | Yes | 28,088 | 2.14 | 0.31 | 14.7% | 6.6 | 90.7 |
| 7/27/18 | No | 624 | 1.60 | 0.07 | 4.1% | 0.0 | 78.4 |
| 8/8/18 | No | 43,744 | 2.16 | 0.27 | 12.6% | 11.9 | 96.1 |
| 8/9/18 | No | 58,106 | 2.45 | 0.36 | 14.5% | 20.6 | 99.9 |
| 8/10/18 | No | 20,155 | 2.63 | 0.21 | 8.0% | 4.2 | 102.2 |
| 9/26/18 | No | 611 | 1.20 | 0.11 | 9.5% | 0.1 | 93.8 |

## Event Override Rate

Customers are allowed to override (opt-out of) SmartAC™ events. Table 3‑8 summarizes the number of overrides by event day, including the number of enrolled customers in the sub-LAPs called for each event. In total, only 0.4% of called customers exercised their right to override during PY2018 events. Only one event, on July 27th, had a high override rate. That was an emergency event from 7 p.m. through midnight called for only the North Coast sub-LAP (PGNC). Because this sub-LAP contains few SmartAC™ customers, the high override rate has little influence on overall event participation.

Table 3‑8: Customer Overrides by Event Day

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Date** | **Hours** | **Sub-LAPs Called** | **Overrides** | **Enrollment** | **Override Rate** |
| 7/23/2018 | 4 to 8 p.m. | PGF1, PGKN, PGNP, PGSI | 145 | 55,003 | 0.3% |
| 7/24/2018 | 4 to 8 p.m.  3 to 7 p.m. (PGNC only) | PGF1, PGKN, PGNP, PGSI, PGNC, PGZP | 328 | 57,897 | 0.6% |
| 7/25/2018 | 6 to 7 p.m. (PGSI)  4 to 7 p.m. (PGST) | PGST, PGSI | 266 | 20,269 | 1.3% |
| 7/26/2018 | 4 to 7 p.m. 3 to 6 p.m. (PGNC only) | PGEB, PGFG, PGNC, PGST, PGZP | 132 | 28,088 | 0.5% |
| 7/27/2018 | 7 to 11:59 p.m. | PGNC | 71 | 731 | 9.7% |
| 8/8/2018 | 4 to 7 p.m. | PGEB, PGF1, PGKN, PGST, PGZP | 77 | 53,802 | 0.1% |
| 8/9/2018 | 4 to 7 p.m. | PGEB, PGF1, PGKN, PGST, PGZP, PGSI | 184 | 70,251 | 0.3% |
| 8/10/2018 | 4 to 7 p.m. | PGF1, PGKN, PGZP | 120 | 25,148 | 0.5% |
| 9/26/2018 | 5 to 8 p.m. | PGNC | 5 | 719 | 0.7% |
| **Total** | | | **1,328** | **311,908** | **0.4%** |

# *Ex-Ante* Load Impacts

This section provides the *ex-ante* SmartAC™ load impact forecasts for the period from 2019 to 2029. The forecasts are based on analyses of per-customer load impacts from *ex-post* evaluations, weather-sensitive reference loads, and incorporation of PG&E’s forecasts of program enrollments. Results are presented for customers who are enrolled in SmartAC™-only and for customers who are dually enrolled in SmartAC™ and SmartRate™. We present the following: a summary contrasting current enrollments with the enrollments forecasted by PG&E; a table and figures showing the hourly reference loads and load impacts on a typical event day; a figure summarizing how *ex-ante* load impacts vary by month and weather scenario; and a figure showing the share of load impacts on a typical event day by LCA. Detailed results for each hour, weather scenario, month, forecast year, and enrollment segment (*i.e.*, SmartAC™-only and dually enrolled customers) are available in electronic form in Protocol table generators provided along with this report.

The enrollment forecast provided by PG&E did not vary over the years 2019 through 2029. Rather it makes a one-time shift in customer composition in 2019 and holds these customer counts constant for the remainder of the forecast period. Table 4‑1 compares customer composition by enrollment segment and LCA across events in 2018 to PG&E’s forecasted change in composition in 2019.[[11]](#footnote-11) Overall, enrollments are expected to increase in Greater Fresno, Other LCAs, Sierra, and Stockton and will decrease in the Greater Bay Area, Humboldt, Kern, and Northern Coast. The largest increase will be in Greater Fresno (1,407 additional customers) and the largest decrease with be in the Greater Bay Area (1,551 fewer customers). Comparing the changes in enrollments for dually enrolled customers compared to SmartAC™-only customers, we can see that there is a shift away from dually enrolled to SmartAC™-only.[[12]](#footnote-12),[[13]](#footnote-13) Customers enrolled only in the SmartAC™ program are forecasted to decrease in Northern Coast, while all other LCAs (except Humboldt) are expected to increase. The largest increase will occur in the Greater Bay Area (2,138 additional customers), while the largest percentage increase will occur in Greater Fresno and Stockton (10 percent).

Table 4‑1: Changes in Enrollment by LCA and Enrollment Segment: 2018-2019

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| **Enrollment Segment** | **LCA** | **Average 2018 Enrollment** | **Forecast Enrollment 2019-2029** | **Percent Change** |
| All | Greater Bay Area | 33,440 | 31,889 | -5% |
| Greater Fresno | 17,348 | 18,755 | 8% |
| Humboldt | 2 | 2 | -5% |
| Kern | 5,597 | 5,565 | -1% |
| Northern Coast | 4,507 | 4,139 | -8% |
| Other | 17,373 | 18,219 | 5% |
| Sierra | 16,532 | 16,752 | 1% |
| Stockton | 7,546 | 8,150 | 8% |
| Dually Enrolled | Greater Bay Area | 5,994 | 2,306 | -62% |
| Greater Fresno | 3,301 | 3,300 | 0% |
| Humboldt | 0 | 0 | 0% |
| Kern | 1,174 | 1,040 | -11% |
| Northern Coast | 408 | 329 | -19% |
| Other | 4,101 | 4,010 | -2% |
| Sierra | 2,095 | 2,018 | -4% |
| Stockton | 1,773 | 1,823 | 3% |
| SmartAC™ Only | Greater Bay Area | 27,445 | 29,583 | 8% |
| Greater Fresno | 14,048 | 15,455 | 10% |
| Humboldt | 2 | 2 | -5% |
| Kern | 4,423 | 4,525 | 2% |
| Northern Coast | 4,099 | 3,810 | -7% |
| Other | 13,272 | 14,209 | 7% |
| Sierra | 14,437 | 14,734 | 2% |
| Stockton | 5,773 | 6,327 | 10% |

Figure 4‑1 illustrates the aggregate reference load, observed load, and load impact for all SmartAC™ customers on the typical event day in any year from 2019 to 2029 for the PG&E 1-in-2 weather scenario. The shape of the *ex-ante* loads and load impacts are similar to the *ex-post* results in Figure 3‑5, however the *ex-ante* loads and load impacts are much larger in magnitude. The *ex-post* aggregate load impacts are for all customers called for the event on August 9, 2018, while the *ex-ante* load impacts correspond to a system-wide event on a typical event day. Moreover, the *ex-ante* load impacts account for the forecasted increase the number of SmartAC™ customers. The average RA window load impact is 50 MWh/hour, or 23 percent of the average RA window reference loads.

Figure 4‑1: Aggregate Hourly Loads and Load Impacts for *PG&E 1-in-2* Typical Event Day: All SmartAC™ customers

Figure 4‑2 illustrates the aggregate reference load, observed load, and load impact for SmartAC™-only customers on the typical event day in August in any year from 2019 to 2029 for the PG&E 1-in-2 weather scenario. The shape of the *ex-ante* loads and load impacts is similar to the results for all SmartAC™ program customers. The average RA window load impact is 44 MWh/hour, or 23 percent of the average RA window reference loads.

Figure 4‑2: Aggregate Hourly Loads and Load Impacts for *PG&E 1-in-2* Typical Event Day: SmartAC™-only customers

Figure 4‑3 illustrates the aggregate reference load, observed load, and load impact for customers who are dually enrolled in SmartAC™ and SmartRate™ on the typical event day in August in any year from 2019 to 2029 for the PG&E 1-in-2 weather scenario. The shape of the *ex-ante* reference load is flatter than for SmartAC™-only customers, with a slightly less pronounced peak. The magnitude of the loads and load impacts are much smaller compared to SmartAC™-only customers due to lower dual enrollments, however dually enrolled customers are still less responsive than SmartAC™-only customers based on the methodology employed. See Section 2.2.2 for more details of our load impacts modeling approach. The average RA window load impact is 6 MWh/hour, or 19 percent of the average RA window reference loads.

Figure 4‑3: Aggregate Hourly Loads and Load Impacts for *PG&E 1-in-2* Typical Event Day: Dually Enrolled Customers

Table 4‑2 summarizes average loads and load impacts, percentage load impacts, and average temperature for the RA window on the typical event day in any year from 2019 to 2029 for the PG&E 1-in-2 weather scenario by LCA and enrollment segment. Per-customer load impacts range from 0.03 to 0.57 (kWh/customer/hour) with a large variation in aggregate load impacts due to the distribution of enrolled customers across LCAs. The Greater Bay area will have the largest aggregate load reduction of 16 MWh/hour and the largest percentage reduction of 31.6 percent from dually enrolled customers the Greater Bay Area. The ongoing dispatch issues in Kern are reflected in the low per-customer load impacts (0.04 kWh/customer/hour), low aggregate load impacts (0.2 MWh/hour), and low percentage load impacts (1.3 percent) corresponding to all SmartAC™ customers in Kern.

Table 4‑2: Average RA Window Load Impacts for *PG&E 1-in-2* Typical Event Day by LCA and Enrollment Segment

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
| **Enrollment Segment** | **LCA** | **Enrolled** | **Average RA Window Hour** | | | | |
| **Reference (kW/Cust)** | **Impact (kW/Cust)** | **% Load Impact** | **Aggregate Impact (MW)** | **Avg. Temp (°F)** |
| All | Greater Bay Area | 31,889 | 1.67 | 0.50 | 30.1% | 16.0 | 88.2 |
| Greater Fresno | 18,755 | 2.68 | 0.50 | 18.5% | 9.3 | 101.2 |
| Humboldt[[14]](#footnote-14) | 2 | 1.61 | 0.50 | 30.9% | 0.0 | 92.2 |
| Kern | 5,565 | 2.77 | 0.04 | 1.3% | 0.2 | 100.9 |
| Northern Coast | 4,139 | 1.48 | 0.40 | 27.0% | 1.7 | 86.1 |
| Other | 18,219 | 2.19 | 0.54 | 24.8% | 9.9 | 96.9 |
| Sierra | 16,752 | 2.20 | 0.51 | 23.3% | 8.6 | 95.0 |
| Stockton | 8,150 | 2.51 | 0.55 | 21.9% | 4.5 | 96.4 |
| Dually Enrolled | Greater Bay Area | 2,306 | 1.27 | 0.40 | 31.6% | 0.9 | 86.3 |
| Greater Fresno | 3,300 | 2.69 | 0.43 | 16.1% | 1.4 | 101.2 |
| Kern | 1,040 | 2.91 | 0.03 | 1.1% | 0.0 | 92.2 |
| Northern Coast | 329 | 1.47 | 0.42 | 28.4% | 0.1 | 100.9 |
| Other | 4,010 | 2.05 | 0.47 | 23.0% | 1.9 | 89.7 |
| Sierra | 2,018 | 2.07 | 0.42 | 20.1% | 0.8 | 96.5 |
| Stockton | 1,823 | 2.38 | 0.48 | 20.3% | 0.9 | 93.9 |
| SmartAC™ Only | Greater Bay Area | 29,583 | 1.70 | 0.51 | 30.0% | 15.1 | 96.4 |
| Greater Fresno | 15,455 | 2.68 | 0.51 | 19.0% | 7.9 | 88.4 |
| Humboldt | 2 | 1.61 | 0.50 | 30.9% | 0.0 | 101.2 |
| Kern | 4,525 | 2.74 | 0.04 | 1.3% | 0.2 | 92.2 |
| Northern Coast | 3,810 | 1.48 | 0.40 | 26.9% | 1.5 | 100.9 |
| Other | 14,209 | 2.23 | 0.56 | 25.3% | 8.0 | 85.8 |
| Sierra | 14,734 | 2.21 | 0.53 | 23.7% | 7.7 | 97.0 |
| Stockton | 6,327 | 2.55 | 0.57 | 22.3% | 3.6 | 95.2 |

Figure 4‑4 illustrates the seasonality and variation by weather scenario in the forecastedload impacts by comparing aggregate load impacts for the average hour in the Resource Adequacy (RA) window in any year from 2019-2029 across months and weather scenarios. The load impact is highest in July in three out of the four weather scenarios, with a maximum load impact of 65 MWh/hour from the PG&E 1-in-10 scenario. For the CAISO 1-in-2 scenario, the load impacts are highest in June (51 MWh/hour). The loads impacts are always the lowest in October, with a minimum of 18 MWh/hour from the PG&E 1-in-2 scenario.

Figure 4‑4: Aggregate Load Impacts over RA Window by Month and Weather Scenario

Figure 4‑5 compares the LCA shares of average RA window load impacts, reference loads, and enrollments on the typical event day during any year from 2019 to 2029 for the PG&E 1-in-2 scenario. The load impacts for the SmartAC™ program are highest in the Greater Bay Area with 32 percent of aggregate load impacts, 31 percent of enrolled customers, and 24 percent of reference loads. The top four LCA’s, including the Greater Bay Area, Greater Fresno, Other LCAs, and Sierra, contribute 83 percent of the aggregate load reductions for SmartAC™. The Greater Bay Area, Greater Fresno, Other LCAs, Sierra, and Stockton all have higher shares of load impacts than enrollments, suggesting that they are relatively more responsive on a per-customer basis. The remaining LCAs have a lower share of load impacts than enrollments or reference loads, with the contrast being especially strong for Kern due to dispatch issues.

Figure 4‑5: RA Window Load Impacts for *PG&E 1-in-2* Typical Event Day by LCA

# 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 SmartAC™, 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 PY2018. The term “previous” refers to findings in reports for PY2017. In the final comparison above, we illustrate the linkage between the PY2018 *ex-post* load impacts and the “current” *ex-ante* forecast for 2019.

## Previous vs. Current Ex-Post

In this section we compare *ex-post* load impacts from the current and previous studies. We focus on comparing results only for sub-LAP events (*i.e.*, excluding serial number events in PY2017), since there were no serial number events called in 2018.

Table 5‑1 shows the average HE 18 (5 to 6 p.m.) reference loads, load impacts, and temperatures across sub-LAP events that include HE 18 during the current and previous program years. No sub-LAP events were called in either year for the following sub-LAPS: PGCC, PGEB, PGFG, PGHB, PGNB, PGP2, PGSB, PGSF, and PGST. For PGF1, PGSI, and PGZP the load impacts and temperatures were comparable, while the reference loads were higher in 2017. For PGNC load impacts were higher in 2018 despite lower reference loads and comparable temperatures. PGNP is the only sub-LAP where load impacts are notably lower in 2018 despite comparable temperatures. For PGKN the load impacts are widely different due to issues dispatching this sub-LAP during 2018. Considering that dispatch issues are expected to persist in this sub-LAP, we apply the ratio of the PY2018 load impact to the PY2017 load impact (0.05) to adjust the *ex-ante* load impacts in PY2018.

The bottom row of the table compares average load impacts across sub-LAPs that had events in both years (excluding PGKN). Overall, more customers were called in 2018 with comparable weather conditions. There was a small decrease in per-customer load impacts and a more substantial decrease in per-customer reference loads.

Table 5‑1: Current vs. Previous *Ex-Post* Load Impacts for the HE 18 by sub-LAP

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **sub-LAP** | **Avg. # called** | | **Reference (kW/cust)** | | **Load Impact (kW/cust)** | | **Avg Temp (**°F) | |
| **PY2017** | **PY2018** | **PY2017** | **PY2018** | **PY2017** | **PY2018** | **PY2017** | **PY2018** |
| PGEB |  | 21,069 |  | 1.98 |  | 0.35 |  | 92.8 |
| PGF1 | 18,898 | 17,370 | 3.18 | 2.80 | 0.36 | 0.39 | 103.2 | 102.8 |
| PGFG |  | 2,078 |  | 1.22 |  | 0.10 |  | 76.0 |
| PGKN | 5,367 | 5,602 | 3.29 | 2.90 | 0.75 | 0.04 | 103.3 | 103.0 |
| PGNC | 752 | 727 | 2.80 | 2.12 | 0.17 | 0.26 | 93.5 | 93.9 |
| PGNP | 14,789 | 15,183 | 2.75 | 2.50 | 0.39 | 0.25 | 98.9 | 99.1 |
| PGP2 | 3,347 |  | 1.82 |  | 0.31 |  | 88.2 |  |
| PGSB | 7,904 |  | 1.55 |  | 0.22 |  | 88.9 |  |
| PGSI | 12,986 | 16,617 | 3.00 | 2.61 | 0.46 | 0.40 | 98.8 | 99.6 |
| PGST |  | 7,542 |  | 2.59 |  | 0.45 |  | 98.2 |
| PGZP | 2,018 | 2,267 | 2.79 | 2.55 | 0.24 | 0.24 | 98.0 | 99.4 |
| **Common Sub-LAPs** | **49,442** | **52,163** | **2.98** | **2.63** | **0.38** | **0.34** | **100.4** | **100.4** |

## Previous vs. Current Ex-Ante

In this section, we compare the *ex-ante* forecast from the previous study to the *ex-ante* forecast contained in the current study. We focus on average load impacts across the RA window, which differs between forecasts. In both studies, the *ex-ante* forecast assumes that event hours exactly match the RA window. The previous study had an RA window from 1 p.m. to 6 p.m., while the current study has an RA window from 4 p.m. to 9 p.m.

Table 5‑2 reports the average event-hour load impacts for the July 2019 peak day under PG&E 1-in-2 weather conditions. The aggregate load impact forecast decreased across years from 66.2 MWh/hour in the previous study to 53.9 MWh/hour in the current study. This decrease is due to diminished load impacts in Kern as well as a lower program enrollment forecast. The decline in Kern leads per-customer load impacts to decrease from 0.56 kWh/customer/hour to 0.52 kWh/customer/hour. The RA window per-customer reference load and temperature are lower in the current study. These differences are being driven by the later RA window in the current study as well as a slight shift in the distribution of customers across LCAs. When combined with changes in enrollment forecasts, these changes lead to aggregate reference loads that are significantly lower in the current study.

Table 5‑2: Previous vs. Current *Ex-Ante* Load Impacts, *PG&E 1-in-2 July 2019 Peak Day*

|  |  |  |  |
| --- | --- | --- | --- |
| **Level** | **Outcome** | **PY2017** | **PY2018** |
| **Total** | # SAIDs | 118,563 | 103,471 |
| Reference (MW) | 296.8 | 240.4 |
| Load Impact (MW) | 66.2 | 53.9 |
| Avg. Temp (°F) | 100.4 | 98.3 |
| % Load Impact | 22.3% | 22.4% |
| **Per SAID** | Reference (kW) | 2.50 | 2.32 |
| Load Impact (kW) | 0.56 | 0.52 |

## Previous Ex-ante vs. Current Ex-Post

In this section, we compare the *ex-ante* forecast from the previous study to the *ex-post* forecast contained in the current study. There are several drawbacks from making such a comparison. Most importantly, the *ex-ante* load impacts are based on serial number events, while the *ex-post* load impacts in the current study are exclusively based on sub-LAP events. As previously discussed, serial number events lead to substantially higher load impacts compared to sub-LAP level events. Another drawback from making this comparison is that sub-LAP events call only a subset of sub-LAPs, while *ex-ante* forecasts are based on LCAs, which often correspond to several sub-LAPs. To address this issue, we use LCA-level results from the appropriate peak month of the *ex-ante* forecast from the previous year and create average impacts that correspond to the month in which each event occurred in PY2018 and the LCAs that had at least one sub-LAP called for the event. A final drawback from comparing *ex-ante* forecasts to *ex-post* load impacts results from differences in event hours. The *ex-ante* forecast from the previous study predicts load impacts during the RA window from 1 to 6 p.m., whereas most events in PY2018 occurred later in the day from 4 to 7 p.m.

Table 5‑3 provides a comparison of the *ex-ante* forecast of 2018 load impacts for the PG&E 1-in-2 scenario from the previous study to the *ex-post* load impacts estimated as part of the current study. We have omitted PGKN from these comparisons due to issues with dispatching this sub-LAP during PY2018. The *ex-post* load impacts are averaged across the event hours during which each sub-LAP was called for each event in PY2018. There is a difference between the number of customers called for the event and the number of customers in the LCAs that had at least one sub-LAP called for the event. The second measure is a more appropriate comparison with the forecast enrolled customers for each event. Even with this closer comparison, the forecast event enrollments are still significantly larger than the actual LCA enrollments.

The most notable finding from the table is that the per-customer load impacts are almost twice as high in the previous study’s forecast compared to the *ex-post* results. As previously mentioned, this is due to these impacts being derived from fundamentally different types of events. Moreover, we discussed previously how the results in the current report are in line with the *ex-post* results from the previous report for sub-LAP events. There are also large differences in the event temperatures in some cases, which results from discrepancies between RA window hours and event hours. The July 25th event is an example of a more reasonable comparison between the forecast and the *ex-post* results. On this day, the sub-LAP enrollments are the same as the LCA enrollments, meaning that all sub-LAPs were called within the called LCAs, and the event temperatures are more in line. This leads to a per-customer load impact of 0.43 kWh/hour compared to the forecasted load impact of 0.59 kWh/hour. The remaining difference is due to the different type of events being compared. The event on July 27th has a particularly big discrepancy in per-customer load impacts due to there being no overlap between the RA window and the late-night event hours.

We compare aggregate load impacts based on the number of customers called for the event in PY2018, since there are such large differences in enrollments. On July 25th the *ex-post* load impacts were 8.8 MWh/hour compared to the forecasted load impacts of 11.9 MWh/hour. Overall, this comparison illustrates that *ex-ante* forecasts are not highly predictive of sub-LAP event impacts.

Table 5‑3: Comparison of Previous *Ex-Ante* and Current *Ex-Post* Impacts

|  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Date** | **Event Hours** | **# Called in LCA PY2018** | **# Enrolled in LCA PY2018** | **Forecast # Enrolled in LCA** | **Load Impact (kW/cust)** | | **Load Impact (MW)** | | **Avg. Temp (°F)** | |
| ***Ex-Post*** | ***Ex-Ante*** | ***Ex-Post*** | ***Ex-Ante*** | ***Ex-Post*** | ***Ex-Ante*** |
| 23-Jul | 4-8 p.m. | 49,382 | 51,667 | 63,522 | 0.29 | 0.58 | 14.3 | 28.5 | 98.0 | 102.5 |
| 24-Jul | 3-8 p.m. | 52,279 | 56,068 | 68,394 | 0.32 | 0.56 | 16.8 | 29.5 | 100.6 | 102.0 |
| 25-Jul | 4-7 p.m. | 20,269 | 20,269 | 27,942 | 0.43 | 0.59 | 8.8 | 11.9 | 100.9 | 101.1 |
| 26-Jul | 3-7 p.m. | 28,088 | 50,717 | 73,740 | 0.32 | 0.53 | 8.9 | 14.8 | 90.7 | 97.9 |
| 27-Jul | 7-11:59 p.m. | 731 | 4,519 | 4,872 | 0.05 | 0.40 | 0.0 | 0.3 | 79.1 | 95.5 |
| 8-Aug | 4-7 p.m. | 48,210 | 75,648 | 90,457 | 0.29 | 0.48 | 14.0 | 23.0 | 95.2 | 97.6 |
| 9-Aug | 4-7 p.m. | 64,661 | 92,090 | 109,502 | 0.38 | 0.48 | 24.3 | 31.2 | 99.5 | 97.7 |
| 10-Aug | 4-7 p.m. | 19,559 | 34,645 | 44,477 | 0.26 | 0.53 | 5.1 | 10.4 | 101.6 | 101.5 |
| 26-Sep | 4-7 p.m. | 719 | 4,468 | 4,872 | 0.11 | 0.35 | 0.1 | 0.3 | 94.1 | 93.5 |

## Current Ex-Post vs. Current Ex-Ante

In this section, we compare the *ex-post* findings from the current study to the *ex-ante* forecast contained in the current study in a similar fashion as the previous comparison. For the *ex-ante* load impacts, we take the RA window load impacts from the appropriate peak month in 2019 and make comparable LCA averages for each event in PY2018 based on the LCAs that had a least one sub-LAP called for the event. Both the *ex-post* and *ex-ante* results include Kern for events where PGKN was called.

Table 5‑4 compares the *ex-post* and *ex-ante* load impacts from the current study. The *ex-ante* load impacts in the table represent the PG&E 1-in-2 weather conditions for 2019. Once again, there is a difference between the number of customers called for the event and the number of customers in the LCAs that had at least one sub-LAP called for the event. Comparing LCA enrollments to forecast enrollments, the forecast enrollments are higher. The per-customer load impacts are significantly higher in the current forecast compared to the *ex-post* load impacts, because the *ex-ante* forecast is based on serial group event load impacts, while the *ex-post* results are from sub-LAP events. There are large differences in the event temperatures for most events due to differences in event hours and changes in the forecasted distribution of customers across LCAs.

Aggregate load impacts, based on the number of customers called for events in PY2018, are driven by the difference between per-customer load impacts from serial number events and sub-LAP events. It is for this reason that *ex-ante* forecasts are not closely aligned with the PY2018 *ex-post* impacts.

Table 5‑4: Comparison of Current *Ex-Post* and *Ex-Ante* Load Impacts

|  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Date** | **Event Hours** | **# Called in LCA PY2018** | **# Enrolled in LCA PY2018** | **Forecast # Enrolled in LCA** | **Load Impact (kW/cust)** | | **Load Impact (MW)** | | **Avg. Temp (°F)** | |
| ***Ex-Post*** | ***Ex-Ante*** | ***Ex-Post*** | ***Ex-Ante*** | ***Ex-Post*** | ***Ex-Ante*** |
| 23-Jul | 4-8 p.m. | 55,003 | 51,667 | 59,291 | 0.28 | 0.51 | 15.3 | 28.1 | 98.2 | 101.0 |
| 24-Jul | 3-8 p.m. | 57,897 | 56,068 | 63,430 | 0.29 | 0.51 | 17.0 | 29.3 | 100.8 | 100.2 |
| 25-Jul | 4-7 p.m. | 20,269 | 20,269 | 24,902 | 0.43 | 0.57 | 8.8 | 11.6 | 100.9 | 98.8 |
| 26-Jul | 3-7 p.m. | 28,088 | 50,717 | 62,397 | 0.32 | 0.55 | 8.9 | 15.5 | 90.7 | 94.6 |
| 27-Jul | 7-11:59 p.m. | 731 | 4,519 | 4,139 | 0.05 | 0.45 | 0.0 | 0.3 | 79.1 | 89.0 |
| 8-Aug | 4-7 p.m. | 53,802 | 75,648 | 82,578 | 0.26 | 0.49 | 14.1 | 26.1 | 96.1 | 94.3 |
| 9-Aug | 4-7 p.m. | 70,251 | 92,090 | 99,330 | 0.35 | 0.49 | 24.5 | 34.6 | 99.8 | 94.5 |
| 10-Aug | 4-7 p.m. | 25,148 | 34,645 | 42,539 | 0.21 | 0.45 | 5.4 | 11.3 | 102.2 | 98.9 |
| 26-Sep | 4-7 p.m. | 719 | 4,468 | 4,139 | 0.11 | 0.33 | 0.1 | 0.2 | 94.1 | 83.5 |

Table 5‑5 documents the various potential sources of differences between the *ex-post* and *ex-ante* load impacts. The two biggest drivers of differences are the shift in the distribution of enrollments across LCAs and the large difference in load impacts between sub-LAP events and serial group events.

Table 5‑5: Comparison of *Ex-Post* and *Ex-Ante* Factors

|  |  |  |  |
| --- | --- | --- | --- |
| **Factor** | ***Ex-Post*** | ***Ex-Ante*** | **Expected Impact** |
| Weather | Average temperature of 98 °F during the hours sub-LAP are called across all events. | Average RA window temperature of 97 °F corresponding to the PG&E 1-in-2 weather scenario. | All else equal, lower *ex-ante* temperatures would reduce load impacts. However, this is not a significant driver of differences between *ex-post* and *ex-ante* impacts. |
| Event window | Varies, in PY2018 event hours ranged from 3 p.m. to 11:59 p.m. | RA window spans 5 p.m. to 9 p.m. | Varies by event hours, but the effect is most notable for the latest ex-post event, which had much lower load impacts. |
| % of resource dispatched | 31 percent on average | 100 percent | Sub-LAP events yield lower load impacts than serial group events due to paging and device issues. |
| Enrollment | 102,345 service accounts. | 107,709 service accounts. | Higher *ex-ante* enrollment, including the addition of new two-way devices, leads to higher aggregate load impact. There is also a shift in the distribution of enrollments to hotter regions such as Greater Fresno. |
| Methodology | Panel models by sub-LAP with fixed customer and date effects and a matched control-group of non-participants. | Simulated LCA-specific reference loads by LCA based on PY2018 usage patterns. Load impacts are derived from the PY2017 *ex-post* analysis of serial group events. | The use of PY2017 ex-post impacts as the basis of our ex-ante load impacts is the largest driver of differences between the two types of impacts. This is illustrated in detail in the previous sub-sections. |

# Recommendations

While we understand that sub-LAP events are the source of value from CAISO market awards, we recommend that there also be some serial group or system-wide events called going forward. That is, because system-wide and serial group events take advantage of factory programmed addressing and because of the inherent randomization, these events will enable a more complete program evaluation and should produce more accurate forecasts of the program’s capacity as a whole.

Also, as PGKN is normally a highly responsive sub-LAP for the SmartAC™ program, solving dispatch challenges at the sub-LAP level would contribute to higher load impacts. Although PGKN was called for five events during PY2018, most customers were not dispatched due to issues with a commercial paging transmitter outage, leading to uncharacteristically low load impacts based on historical performance for PGKN in sub-LAP level events.

Lastly, dispatching two-way communicating devices would increase program impacts. Customers with new two-way communicating switches were not successfully dispatched in PY2018. Including these customers in future events is expected to notably increase program load impacts, as they are believed to be more responsive than the one-way communicating switches.

# Appendices

The following Appendices accompany this report. Appendix A presents further information about how we evaluated the quality of our *ex-post* load impact evaluation and *ex-ante* forecast. The additional appendices consist of Excel files that can produce the tables required by the Protocols.

Appendix C SmartAC™ *Ex-post* Load Impact Tables

Appendix D SmartAC™ *Ex-ante* Load Impact Tables

## Appendix A. Additional Control Group Matching Results

Table A1-1 provides the mean percentage error (MPE) and mean absolute percentage error (MAPE) calculated across the average 24-hour load profile as well over the RA window. Again, we evaluate match quality based on 24-hour load profiles for hot days and cooler days used in matching as well as cooler days not using in matching. Although the MPE and MAPE are slightly higher by sub-LAP than the overall results, the average MAPE is only 0.9 percent. The largest MAPE, which is still only 2.1 percent, corresponds to PGFG on cooler matching days. PGZP also has an RA window MAPE of 2.1 percent on hot matching days.

Table A-1: Match Quality Statistics by Sub-LAP

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Sub-LAP** | **Comparison Days** | **MPE** | **MAPE** | **MPE RA Window** | **MAPE RA Window** |
| PGEB | Hot Days | 0.7% | 0.7% | 0.7% | 0.7% |
| Cool Days | 0.8% | 0.8% | 0.8% | 0.8% |
| Non-Matching Cool Days | 0.5% | 0.5% | 1.1% | 1.1% |
| PGF1 | Hot Days | 0.7% | 0.7% | 0.5% | 0.5% |
| Cool Days | 0.9% | 0.9% | 1.0% | 1.0% |
| Non-Matching Cool Days | 1.1% | 1.1% | 1.5% | 1.5% |
| PGFG | Hot Days | 1.4% | 1.4% | 0.3% | 0.3% |
| Cool Days | 2.1% | 2.1% | 1.4% | 1.4% |
| Non-Matching Cool Days | 1.9% | 1.9% | 2.0% | 2.0% |
| PGKN | Hot Days | 1.0% | 1.0% | 0.9% | 0.9% |
| Cool Days | 1.5% | 1.5% | 1.4% | 1.4% |
| Non-Matching Cool Days | 1.7% | 1.7% | 1.6% | 1.6% |
| PGNC | Hot Days | -0.6% | 0.6% | -0.9% | 0.9% |
| Cool Days | 0.1% | 0.1% | 0.1% | 0.1% |
| Non-Matching Cool Days | 0.4% | 0.4% | 1.5% | 1.5% |
| PGNP | Hot Days | 0.7% | 0.7% | 0.5% | 0.5% |
| Cool Days | 0.2% | 0.2% | 0.4% | 0.4% |
| Non-Matching Cool Days | 0.4% | 0.4% | 1.0% | 1.0% |
| PGSI | Hot Days | 0.8% | 0.8% | 0.8% | 0.8% |
| Cool Days | 0.7% | 0.7% | 1.0% | 1.0% |
| Non-Matching Cool Days | 1.1% | 1.1% | 2.0% | 2.0% |
| PGST | Hot Days | -0.7% | 0.7% | -0.1% | 0.1% |
| Cool Days | -1.5% | 1.5% | -0.3% | 0.3% |
| Non-Matching Cool Days | -0.8% | 0.8% | 0.9% | 0.9% |
| PGZP | Hot Days | 1.0% | 1.0% | 2.1% | 2.1% |
| Cool Days | -0.3% | 0.3% | 0.1% | 0.1% |
| Non-Matching Cool Days | -0.1% | 0.1% | 0.4% | 0.4% |

## Appendix B. Additional Ex-Ante Results

**Previous vs Current *Ex-Ante* Load Impacts**

Figure B-1 illustrates the *ex-ante* load impacts for a PG&E 1-in-2 scenario corresponding to an August peak load from the previous study and the current study. To illustrate how the magnitude of per-customer *ex-ante* load impacts is consistent with the PY2017 forecast, we first present the average load impacts excluding Kern. Although the shapes of the load impacts differ, the magnitudes of the peaks are identical as well as the magnitudes of the post-event snapback. The reason for the different hours over which there is a positive load impact is due to the different RA windows for each forecast. The figure shows the consistency between forecasts across years, despite the change in the RA window.

Figure B-1: Average Load Impacts (excluding Kern) for a PG&E 1-in-2 August Peak: Previous Study vs. Current Study

To illustrate the role of the downward adjustment to Kern’s *ex-ante* load impacts, Figure B-2 presents the *ex-ante* load impacts for all LCAs. Anticipated dispatch issues in Kern lead to a peak of 0.58 kWh/customer/hour compared to 0.61 kWh/customer/hour in the PY2017 forecast. The post-event snapback in the current forecast is 0.25 kWh/customer/hour compared to 0.27 kWh/customer/hour in the PY2017 forecast.

Figure B-2: Average Load Impacts (all LCAs) for a PG&E 1-in-2 August Peak: Previous Study vs. Current Study

1. These enrollment values include some customers not included in this study, as described in Section 4. [↑](#footnote-ref-1)
2. Two-way devices were not dispatchable during PY2018 due to IT systems integration efforts. Customers with two-way devices are not included in the *ex-post* analysis but are included in the *ex-ante* reference loads. [↑](#footnote-ref-2)
3. Since 2015, PG&E has employed a targeted marketing strategy to recruit SmartAC™ customers with the greatest potential for producing large load reductions. PG&E defines these customers as medium and high AC usage customers. [↑](#footnote-ref-3)
4. The opt-out rate is the portion of program participants who request by phone or website to override the control of their AC device during specific events. [↑](#footnote-ref-4)
5. Because there is an almost perfect correlation between the hour of the event and the hour of day (*e.g.*, HE 18 is the second event hour in 29 of 34 sub-LAP events), we cannot effectively analyze the persistence of load impacts across hours within an event. Instead, we focus on the persistence of load impacts across consecutive event days. [↑](#footnote-ref-5)
6. 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 sub-LAP). [↑](#footnote-ref-6)
7. Calling specific sub-LAPs historically depended on all devices being properly addressed to sub-LAPs, which is imperfect process. The installation of new two-way communicating devices, which are not dependent on sub-LAP addressing, should bring sub-LAP event load impacts more in line with serial number event load impacts for future evaluations. [↑](#footnote-ref-7)
8. 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 period. [↑](#footnote-ref-8)
9. On July 24th, July 25th, and July 26th not all called sub-LAP areas were called for the same event hours. In Figure 3‑2, we aggregate across hours during which customers were called, while in the protocol table generators the hourly load impacts are aggregated across all called sub-LAPs for each hour of the day. This can dampen the estimated load impacts during hours where only a subset of called sub-LAP areas are called during the hour. [↑](#footnote-ref-9)
10. PG&E confirmed that a transmitter in Bakersfield was not functioning during PGKN’s event days, though they were not aware of this at the time of the events. This malfunction is expected to persist in PY2019. As a result, we make an adjustment in our *ex-ante* forecast to account for this issue. [↑](#footnote-ref-10)
11. A large share of the difference in enrollments between 2018 and 2019 are two-way device customers who enrolled in 2018 but were not dispatchable for any events in 2018. There were 8,987 two-way device customers who were enrolled in SmartAC™ at some point during PY2018. The 2018 enrollments reported in this table also do not include customers who were enrolled at some point during PY2018 but were not enrolled during any of the PY2018 events. Overall, there were 117,220 customers who were enrolled at some point during PY2018 in the SmartAC™ program, compared to 102,345 dispatchable customers who were enrolled for at least one event. [↑](#footnote-ref-11)
12. Although there is a slight increase in dual enrollments projected for Stockton, this is not true once we consider more broadly defined enrollment figures. There were at least 1,835 customers who were dually enrolled in SmartAC™ and SmartRate™ in Stockton at some point during PY2018. [↑](#footnote-ref-12)
13. Per CPUC Decision 18-11-029, enrollment in Critical Peak Pricing (including SmartRate™) and another DR program is prohibited for all customers not currently dually-enrolled, until further notice. The existing dually-enrolled customers may continue to participate in both programs. [↑](#footnote-ref-13)
14. Due to small sample size issues, the forecast for Humboldt is based on the estimated load impacts and per-customer reference loads for Northern Coast. The two listed customers for Humboldt are not directly used to develop the forecast. [↑](#footnote-ref-14)