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2023 Load Impact Evaluation for Pacific Gas & Electric Company's SmartAC™ Program

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Table of Contents

List of Figures

List of Tables

EXECUTIVE SUMMARY

This report documents ex-post and ex-ante load impact evaluations of Pacific Gas and Electric's (PG&E) SmartAC™ program for 2023. The evaluation produces estimates of the ex-post load impacts for each hour of each event dispatched in 2023, and it develops ex-ante load impact forecasts for the program through 2034.

ES.1 Resources Covered

SmartAC™ is a direct load control central air conditioner (AC) cycling program for residential customers that 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 a Zigbee AC load control switch on the participant's central AC unit that communicates bi-directionally over the AMI network. Legacy technology, installed prior to August 2017, is capable of one-way communication over commercial paging systems and includes programmable communicating thermostats (PCT) and switches. When events are dispatched, PG&E sends signals to the PCTs and switches.

PG&E employs a combination of events including system-wide serial events or at the Sub-Load Aggregation Point (sub-LAP) level. System-wide events include all participants and can be initiated based on CAISO or PG&E emergencies or for testing purposes. System-wide test events generally dispatch all SmartAC™ customers throughout the service territory except for a random sample of SmartAC™ customers that serve as the control group based on the last digit of the factory programmed serial number of their installed device (i.e., one or more serial groups are withheld from the event).[1] During sub-LAP events, all SmartAC™ participants with devices that are associated with a given sub-LAP are dispatched for the event. One event during PY2023 was a serial test event with one serial group withheld from the event dispatch, while the remaining ten events were CAISO market awards.

The primary goals of the evaluation include:

1. Estimate hourly ex-post load impacts for the 2023 program year, including:
    a. Hourly and average daily load impacts for each event;
    b. The distribution of hourly and average daily load impacts by customer segment, including: sub-LAP, local capacity area (LCA), CARE/non-CARE customers, net-metering solar customers (NEM), housing type (i.e., detached vs. shared wall residences), AC usage intensity, and device type (i.e., two-way vs. one-way; by one-way device type: UtilityPro, Gen 1, and Gen 2);
    c. Load Impact estimates for SmartAC™-only customers as compared to customers who are dually enrolled in SmartAC™ and SmartRate™;

[1] Currently, not all installed devices have a serial number that conforms to this serial group selection process. For these devices, customers are randomly assigned to a serial group at the time of device installation.

    d. The opt-out/override rate by customer segment; and
    e. The persistence of load reductions across event hours for multiple hour events.

2. Produce ex-ante load impact forecasts for 2024 to 2034 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:
    a. PG&E's peaking conditions in a 1-in-2 weather year;
    b. PG&E's peaking conditions in a 1-in-10 weather year;
    c. CAISO peaking conditions in a 1-in-2 weather year; and
    d. CAISO peaking conditions in a 1-in-10 weather year.

ES.2 Evaluation Methodologies

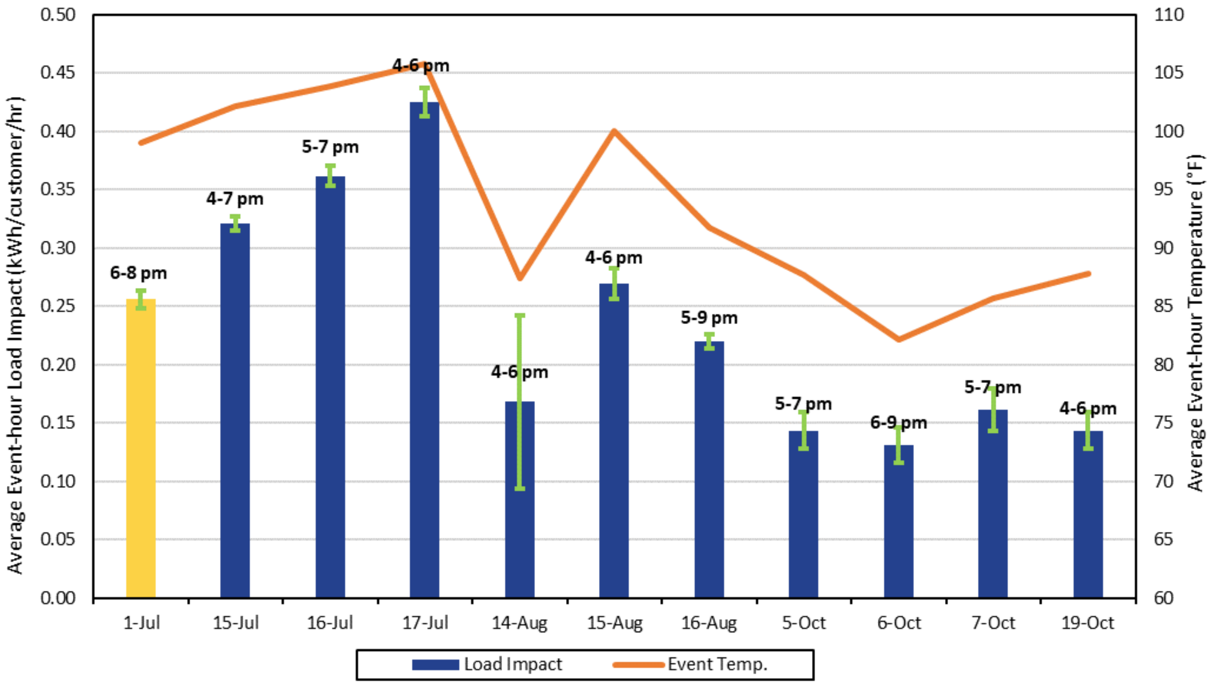
In this evaluation, we estimate load impacts by comparing SmartAC™ customer loads to that of a control group on event days, net of the differences in loads on non-event days with comparable weather conditions. For system-wide serial test events in which at least one serial group is withheld from the event, we use this random sample of SmartAC™ customers as an additional control group. For all events, we use a matched control group consisting of residential customers who are not enrolled in any demand response programs, including SmartAC™ or SmartRate™. Matched control group customers are selected based on the similarity of available customer characteristics (e.g., rate schedule, sub-LAP, AC usage level, 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 treated SmartAC™ customers and the 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 full event hour for all SmartAC™ events in PY2023, along with an 80 percent confidence interval (corresponding to the 10^{th} and 90^{th} percentile uncertainty-adjusted load impacts). There are eleven events dispatched across eleven event days. The yellow bar indicates the serial event on July 1^{st}, while the blue bars correspond to the sub-LAP events. These results indicate that SmartAC™ customers had statistically significant load reductions on each of the eleven event days, ranging from 0.13 to 0.42 kWh/customer/hour. Differences in event temperatures, the sub-LAPS dispatched for events, and variation in sub-LAP performance drive the variation of average load impacts across events in 2023. Temperature remains the largest driving factor in the average event-hour load impacts per customer.

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



In addition to the overall load impacts, we examine patterns of load impacts at the sub-LAP level. We also examine how load impacts are distributed across customer subgroups. Two-way devices have higher load impacts than one-way devices in both serial and sub-LAP events.

ES.4 Ex-Ante Load Impacts

Ex-ante load impacts represent forecasts of load impacts that are expected to occur when program events are dispatched in future years under standardized weather conditions.

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

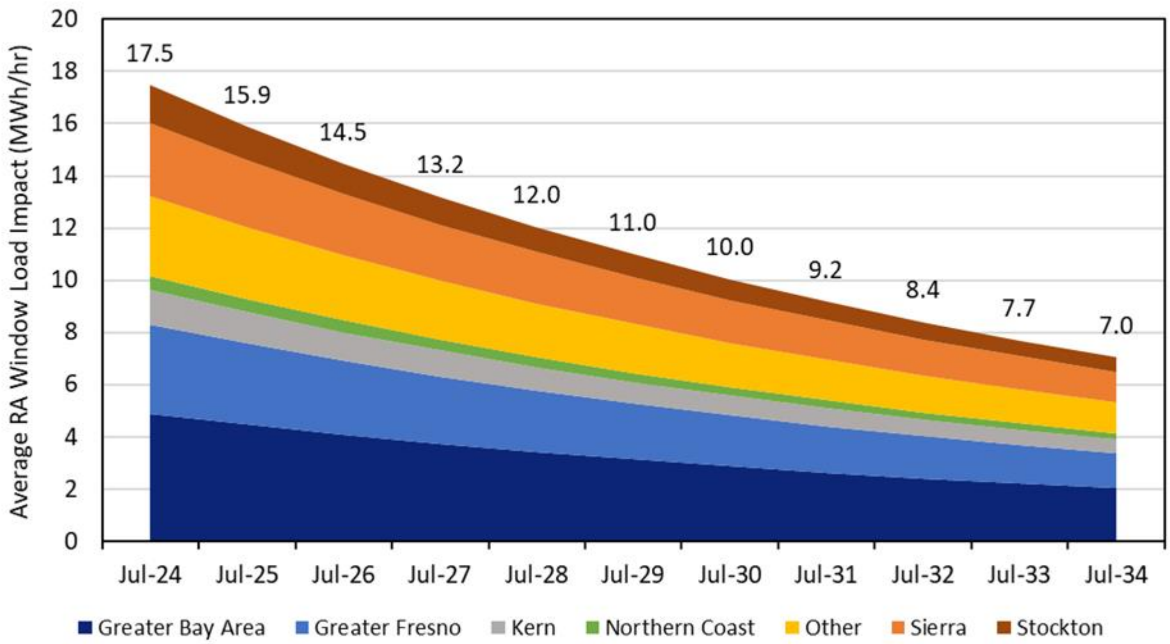
1. An *enrollment forecast* for relevant components of the program, which consists of forecasts of the number of customers by required type of customer;
2. *Reference loads* by customer type; and
3. A forecast of *load impacts per customer*, again by relevant customer type, where the load impact forecast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

Figure ES-2 summarizes the ex-ante program load impact forecast for 2024 to 2034 for SmartAC™ by plotting the average aggregate load impacts for the resource adequacy (RA) window over time by LCA.[2] For this comparison we use the PG&E 1-in-2 scenario for July peak

[2] Beginning in 2024, the RA window will be shifted during the month of May to 5 to 10 p.m. but will remain at 4 to 9 p.m. during other months in which SmartAC™ events may be called. The aggregate load impacts

days. The trend of declining aggregate load impacts is driven by declining enrollments due program attrition, as SmartAC™ is closed to new participants beginning in 2024. Aggregate load impacts steadily decline by about 8.7 percent per year, consistent with the percentage decline in enrollments.

Figure ES-2: Aggregate Load Impacts over RA Window for PG&E 1-in-2 July Peak Scenario (2024-2034)



are shown for the July peak day scenario in Figure ES.2, which is not impacted by the shift in the May RA window.

1. 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 2023. The evaluation produces estimates of the ex-post load impacts for each hour of each event dispatched in 2023, and it develops ex-ante load impact forecasts for the program through 2034.

SmartAC™ is a direct load control central air conditioner (AC) cycling program for residential customers that 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 a Zigbee AC load control switch on the participant's central AC unit that communicates bi-directionally over the AMI network. Legacy technology, installed prior to August 2017, is capable of one-way communication over commercial paging systems and includes programmable communicating thermostats (PCT) and switches. As part of the second phase of the Reliability Order Instituting Rulemaking decision (D.21-12-015), PG&E is authorized to offer SmartAC™ customers with one-way devices a $25 incentive for PG&E to upgrade their switch to a two-way Zigbee device during 2023. After 2023, enrollment in the SmartAC™ program will be closed.[3] When events are dispatched, 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 percent of the compressor run-time during each half-hour. Switches and some PCTs are cycled using adaptive algorithms.

PG&E employs a combination of events including system-wide serial events or at the Sub-Load Aggregation Point (sub-LAP) level. System-wide events include all participants and can be initiated based on CAISO or PG&E emergencies or for testing purposes. System-wide test events generally dispatch all SmartAC™ customers throughout the service territory except for a random sample of SmartAC™ customers that serve as the control group based on the last digit of the factory programmed serial number of their installed device (i.e., one or more serial groups are withheld from the event).[4] During sub-LAP events, all SmartAC™ participants with devices that are associated with a given sub-LAP are dispatched 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. Since the CAISO wholesale market integration of the SmartAC™ program in 2018, a majority of SmartAC™ events are sub-LAP-level events, while a select number of serial events are dispatched for testing purposes.

Table 1-1 shows the details for each event in program year 2023 (PY2023). There were eleven SmartAC™ events dispatched across eleven event days in 2023. Ten events were CAISO market

[3] PG&E proposed closing the SmartAC program to new enrollments in its "Application for Pacific Gas and Electric Company (U 39 E) for approval of its demand response programs, pilots, and budgets for programs years 2023-2027" and anticipates that this change will be approved by the CPUC. See https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M472/K478/472478718.PDF.

[4] Currently, not all installed devices have a serial number that conforms to this serial group selection process. For these devices, customers are randomly assigned to a serial group at the time of device installation.

awards. There was a single serial test event on July 1st. There were no emergency events dispatched in 2023.

On August 16th and October 6th, customers in different sub-LAPs were dispatched for different event hours. On July 1st, all sub-LAPs were dispatched for the event.

Table 1-1: PY2023 SmartAC™ Events

Date	Smart-Rate™ Event?	Reason	Event Hours (p.m.)	Sub-LAPs/Serial Groups Dispatched	# Customers Dispatched
7/1	Yes	Test	6-8	All Sub-LAPs, Serial Group 4 withheld	53,078
7/15	Yes	Market	4-7	PGNP, PGSI, PGST, PGKN, PGF1, PGZP, PGEB	48,147
7/16	No	Market	5 7	PGNP, PGSI, PGST, PGKN, PGF1, PGZP	39,900
7/17	Yes	Market	4-6	PGKN, PGF1, PGZP	14,135
8/14	No	Market	4-6	PGNC	428
8/15	Yes	Market	4-6	PGSI, PGST, PGNC	13,713
8/16	Yes	Market	5-8	PGSI, PGST, PGNC	13,708
			6-8	PGF1, PGZP, PGFG, PGNB, PGEB, PGSB, PGP2	33,923
			6-9	PGNP	8,292
			7-8	PGKN	2,934
10/5	No	Market	5-7	PGNB, PGSB, PGP2	9,468
10/6	No	Market	6-8	PGSB	5,782
			7-9	PGNB, PGP2	3,686
10/7	No	Market	6-8	PGNB, PGSB, PGP2	9,468
10/19	No	Market	5-8	PGNB, PGSB, PGP2	9,468

SmartAC™ customers are permitted to be dually enrolled in SmartAC™ and the SmartRate™ program if they were enrolled before October 26, 2018, but subsequent new dual participation is prohibited. As of May 2023, SmartAC™ had over 68,000 active enrolled residential customers; approximately 5,500 of these customers were dually enrolled in SmartAC™ and SmartRate™. During days in which both SmartAC™ and SmartRate™ events are dispatched, the SmartRate™ customers are withheld from our summary of SmartAC™ events and the response from dually enrolled customers is attributed to the SmartRate™ program.

PG&E is in the process of replacing existing one-way devices with two-way devices before the one-way technology becomes obsolete. Prior to PY2023, PG&E had planned to de-enroll all remaining customers with one-way devices in January 2024. PG&E has since decided to retain participants with one-way devices for the present. Starting January 2024 new enrollment in the program has been closed.

The primary goals of the evaluation include:

1. Estimate hourly ex-post load impacts for the 2023 program year, including:
    a. Hourly and average daily load impacts for each event;
    b. The distribution of hourly and average daily load impacts by customer segment, including: sub-LAP, local capacity area (LCA), CARE/non-CARE customers, net-metering solar customers (NEM), housing type (i.e., detached vs. shared wall

residences), AC usage intensity, and device type (i.e., two-way vs. one-way; by one-way device type: UtilityPro, Gen 1, and Gen 2);

   c. Load Impact estimates for SmartAC™-only customers as compared to customers who are dually enrolled in SmartAC™ and SmartRate™;

   d. The opt-out/override rate by customer segment[5]; and

   e. The persistence of load reductions across event hours for multiple hour events.

2. Produce ex-ante load impact forecasts for 2024 to 2034 by sub-LAP and 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:

   a. PG&E's peaking conditions in a 1-in-2 weather year;

   b. PG&E's peaking conditions in a 1-in-10 weather year;

   c. CAISO peaking conditions in a 1-in-2 weather year; and

   d. 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.

2. 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.

2.1 Ex-post Load Impact Evaluation

We estimate load impacts by comparing SmartAC™ customer loads to that of a quasi-experimental matched control group of non-SmartAC™ customers 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 any demand response programs, including SmartAC™ or SmartRate™. We match control-group customers based on the similarity of available customer characteristics (e.g., sub-LAP, rate schedule, AC usage level, CARE status, NEM status) as well as usage patterns on non-event days.

[5] 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.

2.1.1 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, rate schedule, 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 PY2023 (May 1 through October 31);
- *Weather data* (i.e., hourly temperatures and other variables for PY2023, 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 and the serial number to determine treatment and control groups for the serial event) as well as SmartAC™ customer opt-outs on each date.

2.1.2 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 nearest neighbor matching to identify three control customers for each treatment customer that have the closest match in terms of average daily usage (based on monthly billing data), weather station and average 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 of the 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.[6] Finally, we require that SmartAC™ customers are matched to a control customer residing in the same sub-LAP area with a similar rate schedule (i.e., TOU rates vs. other rates).

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

[6] Propensity score matching does not guarantee that treatment customers are matched with a control that has the same CARE status, NEM status, etc. However, this approach leads to a similar distribution across these characteristics for the treatment group and control group.

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:

$$logit(SmartAC_c) = \beta_0 + \sum_{h=1}^{24} \beta_{1,h} avgkW_{c,h} + \sum_{all\ j} \beta_{2,j} X_{c,j} + \varepsilon_c$$

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

Table 2-1: Propensity Score Model Terms

Symbol	Description
$SmartAC_c$	Variable indicating whether customer *c* is a SmartAC (1) or Control (0) customer
$avgkW_{c,h}$	Average load during hour *h* for customer *c*
$X_{c,j}$	The value of characteristic *j* for customer *c*
β_0	Estimated constant coefficient
$\beta_{1,h}$	Estimated coefficient for hour *h* of 24-hour load profile
$\beta_{2,i}$	Estimated coefficient for customer characteristic *j*
ε_c	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 25^{th} and 75^{th} 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 and three rate schedule groups (E1, TOU-B/TOU-D, and other rates which includes TOU-C).

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.

2.1.3 Analysis Methods

To produce estimates of ex-post load impacts, we estimate the following panel model for each hour of the day and sub-LAP:

$$kW_{c,d} = \beta_0 + \sum_{i=1}^{n} \left(\beta_{1,i} SmartAC_{i,c,d} \times Evt_{i,d}\right) + \sum_{all\ j} \beta_{2,j} X_{c,d,j} \times AC_c + C_c + D_d + \varepsilon_{c,d}$$

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*
$SmartAC_{c,d}$	Variable indicating whether customer *c* is a treated SmartAC customer (1) or Control (0) customer on the i^{th} event day (control customers include SmartAC customers in withheld serial groups)
$Evt_{i,d}$	Variable indicating that day *d* is the i^{th} event day (1) or not (0)
$X_{c,d,j}$	The value of weather variable *j* on day *d* for customer *c*
AC_c	Variable indicating customer *c*'s level of AC usage (no AC, low, medium, or high)
β_0	Estimated constant coefficient
$\beta_{1,i}$	Estimated load impact for event *i*
$\beta_{2,j}$	Estimated coefficient for weather variable *j*
C_c	Customer fixed effects
D_d	Date fixed effects
$\varepsilon_{c,d}$	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 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[7]. The $\beta_{1,i}$ coefficients represent the estimated load impacts for each hour of every event day.

For the serial test event on July 1st, there is an additional control group consisting of SmartAC™ customers with device serial numbers ending in 4 (i.e., this serial group was not dispatched for the event). We estimate load impacts for the serial test event and the sub-LAP events using one model, consistent with the PY2022 evaluation.

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 percent of non-event days). We estimate the distribution of load impacts across different customer subgroups by interacting the event variables with indicator variables for customer subgroups of interest (e.g., CARE vs. non-CARE). While this approach produces subgroup load impacts for each event, these results are not necessarily representative of the system-wide results but are limited to the sub-LAPs dispatched for sub-LAP events. Moreover, the matching procedure used for sub-LAP events does not guarantee that treatments and matched controls have the same subgroup status.

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 across event days, we are not able to estimate the uncertainty associated with the typical event day.

[7] The inclusion of weather variables may improve the effectiveness of the date fixed effects, particularly in models that include customers in different weather regions (e.g., models by sub-LAP). Similar to the previous year's evaluation, we have allowed the relationship between weather and loads to vary by AC usage level. This was not necessary to do in evaluations prior to PY2022, as the relationship was comparable across these groups.

We validate the ex-post load impact estimates against simple difference-in-difference calculations from load data. Specifically, for each sub-LAP and event day, we compare the average treatment customer hourly loads to the average control-group hourly loads. The comparisons include events during which the sub-LAP was not dispatched, which allow us to ensure that the event information we were provided is correct and that our methods do not produce "false positives" (i.e., estimated load impacts for dates/locations in which customers were not dispatched).

2.2 Developing Ex-Ante Load Impacts

Ex-ante load impacts represent forecasts of load impacts that are expected to occur when program events are dispatched 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 2024 through 2034, 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. Sub-LAP;
2. LCA; and
3. Customers enrolled in only SmartAC™ vs. customers dually enrolled in SmartAC™ and SmartRate™.

PG&E provided the enrollment forecasts and ex-ante weather conditions for each required scenario. This forecast accounts for changes to the SmartAC™ program approved by the CPUC such as the swap out of remaining one-way devices for two-way devices (D.21-12-015) and changes that have been proposed by PG&E such as the closure of SmartAC™ to new enrollments. Our load impact models distinguish between the performance of one-way and two-way devices to allow program load impacts to adjust as devices are replaced.

2.2.1 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 PG&E) 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 2023. Average load profiles are created for each sub-LAP 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:

$$avgkW_{d,h} = \beta_0 + \sum_{h=1}^{24} \beta_{1,h}(CDD65_d \times H_h) + \sum_{h=1}^{24} \beta_{2,h}\left(CDD65_d{}^2 \times H_h\right) + \sum_{h=1}^{24} \beta_{3,h} H_h + \sum_{h=1}^{24} \beta_{4,h}(Mon_d \times H_h) + \sum_{h=1}^{24} \beta_{5,h}(Fri_d \times H_h) + D_d + M_d + \varepsilon_{d,h}$$

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

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

Symbol	Description
$avgkW_{d,h}$	Average load (kWh/customer/hour) on day *d* during hour *h*
$CDD65_d$	The cooling degrees on day *d*
$CDD65_d^2$	The cooling degrees on day *d* squared
H_h	Variable indicating that the hour is *h* (1) or not (0)
Mon_d	Variable indicating that day *d* is a Monday (1) or not (0)
Fri_d	Variable indicating that day *d* is a Friday (1) or not (0)
β_0	Estimated constant coefficient
$\beta_{1,h}$	Estimated increase in average load during hour *h* that results from a one degree increase in cooling degrees
$\beta_{2,h}$	Estimated increase in average load during hour *h* that results from a one degree increase in squared cooling degrees
$\beta_{3,h}$	Estimated average load during hour *h*
$\beta_{4,h}$	Estimated difference in average load during hour *h* on Mondays
$\beta_{5,h}$	Estimated difference in average load during hour *h* on Fridays
D_d	Day of the week fixed effects
M_d	Month of the year fixed effects
$\varepsilon_{d,h}$	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 $\beta_{1,h}$ coefficients represent the estimated increase in average loads during hour *h* due to a one cooling degree day increase, while the $\beta_{2,h}$ coefficients represent the estimated increase in average loads during hour *h* due to an increase in squared cooling degrees by one. We estimate this model separately for each sub-LAP and enrollment segment to be consistent with the load impact model described in Section 2.2.2. We then aggregate results from the sub-LAP level models to LCA based on the share of customers in each sub-LAP and LCA in PY2023.

Reference loads are simulated by applying the cooling degree days from the weather scenarios provided by PG&E to the estimated $\beta_{1,h}$ and $\beta_{2,h}$ 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.

2.2.2 Load Impacts

The ex-ante *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 ex-ante per-customer load impacts are then coupled with the appropriate simulated ex-ante reference loads to develop the load impact forecast.

We develop an ex-ante forecast that projects program performance during sub-LAP events. We include load impacts from all sub-LAP and serial events in PY2020, PY2021, PY2022, and PY2023 and develop a model that estimates the relationship between ex-post load impacts (for both serial and sub-LAP events) and event day temperatures and simulate the model results for sub-LAP events.

We model the relationship between load impacts and weather conditions as follows:

$$\begin{aligned} Impact_{s,h,evt\ i} &= \beta_0 + \beta_{1,h} Mean17_{s,evt\ i} \times H_h + \beta_2 Temperature_{s,h,evt\ i} \\ &\quad + \delta_s Serial_{evt\ i} \times subLAP_s + \mu_s subLAP_s + \varepsilon_{s,h,evt\ i} \end{aligned}$$

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

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

Symbol	Description
$Impacts_{s,h,evt\ i}$	Estimated load impact in sub-LAP *s* during hour *h* on event *i*
$Mean17_{s,evt\ i}$	Average temperature over the first 17 hours of the day
H_h	Variable indicating if the hour is *h* (1) or not (0)
$Temperature_{s,h,evt\ i}$	Average temperature during hour *h*
$Serial_{evt\ i}$	Variable indicating if event *i* is a serial event (1) or not (0)
$subLAP_s$	Variable indicating if the sub-LAP is *s* (1) or not (0)
β_0	Estimated constant coefficient
$\beta_{1,h}$	Estimated increase in load impact in hour *h* from a 1 degree increase in the average temperature over the first 17 hours of the day
β_2	Estimated increase in load impact from a 1 degree increase in event-hour temperature
δ_s	Estimated difference in load impacts in sub-LAP*s* during serial events
μ_s	Estimated difference in load impacts for sub-LAP *s*
$\varepsilon_{s,h,evt\ i}$	Error term (robust)

The $\beta_{1,h}$ coefficients represent the estimated increase in load impact during hour *h* that results from a one-degree increase in the average temperature over the first seventeen hours of the event day. The β_2 coefficient is the estimated increase in load impact that results from a one-degree increase in average event-hour temperature. The δ coefficient measures the additional load impacts during serial events, which may vary by sub-LAP, and the μ coefficients allow load impacts to vary by sub-LAP. The standard errors from this model are the basis for the uncertainty-adjusted load impacts.

We build our ex-ante load impact forecasts based on a combination of sub-LAP and serial events dispatched in 2020, 2021, 2022, 2023. As there were dispatch issues for some two-way devices in 2022, we give the PY2020, PY2021, and PY2023 load impacts twice the weight in the regression as the PY2022 load impacts to reflect the assumption that the operational issues are expected to be mostly resolved by 2024. PY2022 load impacts are included to incorporate operational issues into the forecast, but to a lesser extent. The load impacts simulated using this model are for sub-LAP events to reflect the nature of how events will be dispatched for the SmartAC™ program in future program years.[8]

In addition, we separately estimate the model using load impacts for one-way and two-way devices. We simulate ex-ante results using different weather scenarios and compute the aggregate load impacts by using the enrollment forecast for one-way and two-way devices. We assume that load impacts are comparable for SmartAC™-only and dually enrolled customers based on our examination of the relative performance of these customers during sub-LAP events in 2020 and 2021[9]. We further discuss the performance of SmartAC™-only and dually enrolled customers in Section 3.5.1.

The snapback during 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 sub-LAP. 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 2023 and the temperatures in the various weather scenarios). We also compare current and previous ex-post load impacts, and current and previous ex-ante load impacts. Additionally, we analyze the impact of device swap-outs on the forecasted load impacts.

3. 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 (ten out of eleven events), during which different sub-LAPs are dispatched for different events and, in some cases, different event hours, we are not able to present results for the typical event day.[10] Instead, we average the hourly load impacts across all potential, full 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 or LCA 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 D-in-D regression analyses of hourly data for SmartAC™ customers and a control group. In addition to the controls described in the estimated model in Section 2.1.3, we control for the five concurrent SmartRate™ event days by including separate indicators for customers who are dually enrolled in SmartAC™ and SmartRate™. Furthermore, we drop SmartRate™-only events from the pool of

[8] To simulate the load impacts for sub-LAP events, we set $Serial_{evti}$ equal to zero so that the incremental load impacts during serial events are not included in the simulated load impacts.

[9] We are unable to determine whether SmartAC™-only and dually enrolled customers have comparable load impacts in 2022 or 2023 because all system-wide events in 2022 and 2023 were dual events.

[10] In the ex-post Protocol table generator, we use the serial event on July 1st for the "typical event day."

SmartAC™ non-event days to ensure that non-event loads are comparable between SmartAC™ customers and controls on all non-event days.

3.1 Control Group Matching Results

In this section, we present summaries of our control group matching process. 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.[11]

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 use 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 (i.e., the middle 50 percent of days based on temperature) that are not sampled for use in matching and the weekend non-event days, 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

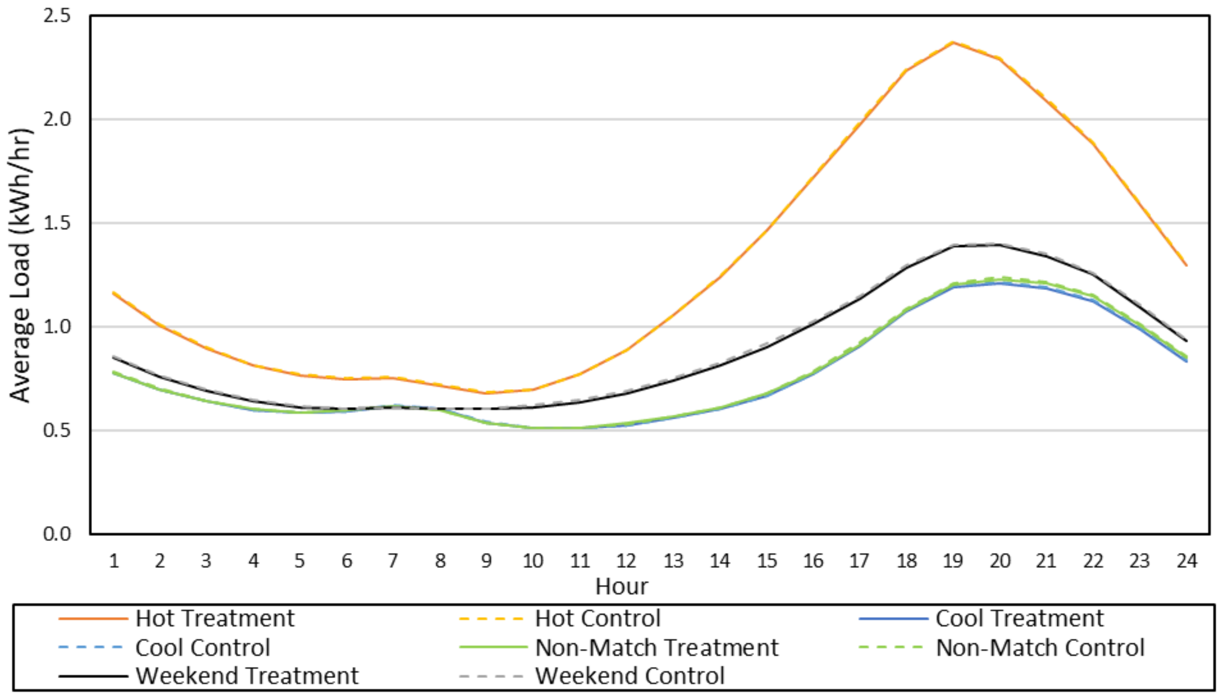
Comparison Days	MPE	MAPE	MPE RA Window	MAPE RA Window
Hot Days	0.4%	0.4%	0.4%	0.4%
Cool Days	0.3%	0.3%	0.5%	0.5%
Non-Matching Cool Days	0.3%	0.3%	0.7%	0.7%
Weekend Days	0.9%	1.0%	0.8%	0.8%

Figure 3-1 illustrates the load profiles for selected event-like days for treatment and matched control customers. 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, the cooler days that were not used in matching, and weekend days (not used in matching). The solid lines represent the average usage of treatment customers on hot days (red), cooler matching days (blue), cooler non-matching days (green), and weekend days (black). Similarly, the dashed lines represent the average usage of the matched control customers on hot days (yellow), cooler matching days (blue), cooler non-matching days (green), and weekend days (gray). Regardless of the comparison day, the average load profiles are nearly identical between treatment and control. Cool days that are used in matching have comparable loads to cool days that are not used in matching and the control loads on each type of day tracks the treatment loads very closely. Moreover, weekend loads have a comparable load shape to cool

[11] 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.

weekdays. These results also suggest that matches based on weekdays are appropriate for estimating load impacts for weekend events dispatched in PY2023.

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



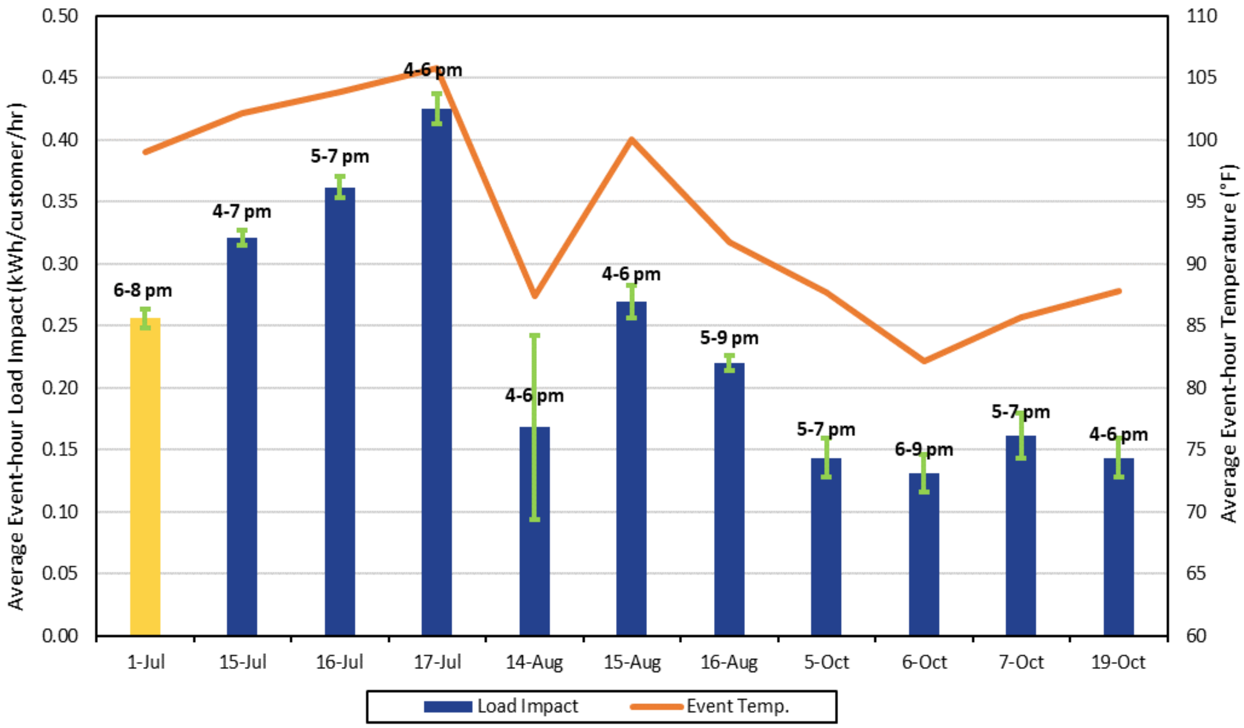
3.2 Overall Load Impacts

This section summarizes overall results for all SmartAC™ events. In later sections, we focus attention on sub-LAP events, serial events, and discuss how these load impacts are distributed across subgroups of interest, including for customers who are dually enrolled in SmartRate™.

The ex-post load impacts are summarized for all full event hours for the eleven event days in Figure 3-2. The bars indicate the magnitude of the average per-customer load impact (in kWh/customer/hour) during the full event hours dispatched for each event, while the labels show the maximal range of full event hours over which all customers were dispatched.[12] The gold bar indicates the average per-customer load impact during the full event hours of the serial event on July 1st. The blue bars represent the sub-LAP events. The green bands correspond to 80 percent confidence intervals around these estimates (i.e., the 10th and 90th percentile scenarios from the uncertainty-adjusted load impacts). The orange line represents the average temperatures experienced by the customers during the event.

[12] On August 16th and October 6th, sub-LAPs were dispatched for different event hours. In Figure 3-2, we aggregate across hours during which customers were dispatched, while in the Protocol table generators, the hourly load impacts are aggregated across all dispatched sub-LAPs dispatched during the event day for each hour of the day, which can dampen the estimated load impacts during hours in which only a subset of sub-LAP are dispatched.

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



Overall results range from 0.13-0.42 kWh/customer/hour

These results indicate that SmartAC™ customers have statistically significant load reductions on each of the eleven event days, ranging from 0.13 kWh/customer/hour on October 6th to 0.42 kWh/customer/hour on July 17th with an average of 0.24 kWh/customer/hour.

Temperatures explain most of the variation in per-customer load impacts

Figure 3-2 also shows that events with lower load impacts correspond to cooler event temperatures. Differences in event temperature explain most of the variation of average load impacts across events. Differences in the sub-LAPs dispatched and variation in sub-LAP performance are another factor driving load impact variation across events.

Weekend events have comparable load impacts

There were four weekend SmartAC™ event days in PY2023 (July 1st, 15th, and 16th and October 7th). The weekend event on October 7th had a per-customer load impact of 0.16 kWh/hour compared to 0.14 kWh/hour for weekday events on October 5th and 19th despite slightly higher temperatures during those events.

The serial event on July 1st has comparable load impact to a sub-LAP event on August 15th

Historically, load impacts tend to be higher during serial events, however the average load impact for the serial event on July 1st is 0.26 kWh/customer/hour compared to 0.27 kWh/customer/hour during the sub-LAP event on August 15th. Temperatures were slightly higher on August 15th.

The number of dispatched customers and average event temperatures drive large variation in aggregate event load impacts

Table 3-2 presents a more complete summary of event information, including the sub-LAPs dispatched, the sub-LAP-specific event hours, the type of event, and the number of customers dispatched, as well as average load impacts (per-customer and in aggregate), reference loads, and percentage load impacts across the full event hours for which each sub-LAP was dispatched for each event day. The correlation coefficient between the event temperature and per-customer load impacts is 0.96. The number of dispatched customers varies dramatically across events, from 428 customers dispatched for the sub-LAP event on August 14th to 58,857 customers for the event on August 16th. Aggregate load impacts, which averaged 6.51 MWh/hour, ranged from 0.07 MWh/hour on August 14th to 15.44 MWh/hour on July 15th.

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

Date	SmartRate™ Event?	Type of Event	Event Hours (p.m.)	Sub-LAPs/ Serial Groups Dispatched	# Dispatched	Average Event Hour				
						Reference (kWh/ cust/hr)	Impact (kWh/ cust/hr)	% Impact	Aggregate Impact (MWh/hr)	Avg. Temp (°F)
7/1	Yes	Test	6-8	All Sub-LAPs, Serial Group 4 withheld	53,078	2.79	0.26	9.2%	13.59	99.0
7/15	Yes	Market	4-7	PGNP, PGSI, PGST, PGKN, PGF1, PGZP, PGEB	48,147	2.71	0.32	11.8%	15.44	102.1
7/16	No	Market	5-7	PGNP, PGSI, PGST, PGKN, PGF1, PGZP	39,900	3.17	0.36	11.4%	14.44	103.9
7/17	Yes	Market	4-6	PGKN, PGF1, PGZP	14,135	3.06	0.42	13.9%	6.00	105.8
8/14	No	Market	4-6	PGNC	428	1.86	0.17	9.0%	0.07	87.4
8/15	Yes	Market	4-6	PGSI, PGST, PGNC	13,713	2.86	0.27	9.4%	3.69	100.1
8/16	Yes	Market	5-8	PGSI, PGST, PGNC	58,857	2.80	0.22	7.9%	12.89	91.8
			6-8	PGF1, PGZP, PGFG, PGNB, PGEB, PGSB, PGP2						
			6-9	PGNP						
			7-8	PGKN						
10/5	No	Market	5-7	PGNB, PGSB, PGP2	9,468	1.57	0.14	9.1%	1.36	87.7
10/6	No	Market	6-8	PGSB	9,468	1.65	0.13	7.9%	1.24	82.1
			7-9	PGNB, PGP2						
10/7	No	Market	6-8	PGNB, PGSB, PGP2	9,468	1.78	0.16	9.1%	1.53	85.7
10/19	No	Market	5-8	PGNB, PGSB, PGP2	9,468	1.29	0.14	11.1%	1.36	87.8

Percentage load impacts range from 7.9 percent to 13.9 percent

There is variation in the percentage load impacts ranging from 7.9 percent of reference loads on August 16th and October 6th to 13.9 percent on July 17th. The correlation between percentage load impact and event temperatures is 0.71. Percentage load impacts also depend on which sub-LAPs are dispatched for events due to variation in sub-LAP performance.

Load Impacts are persistent across event hours for multiple hour events

Table 3-3 compares average per-customer load impacts and hourly temperatures across hours within each event to analyze whether load impacts persist across event hours.[13] The event on August 16th was a four-hour event, however the sub-LAPs were not all dispatched for the same hours. On August 16th, the load impacts for sub-LAPs dispatched for three hours[14] decline by up to 0.12 kWh/customer/hour from the first to last event hour, accompanied by decrease in temperature of more than six degrees. The event on July 15th lasts three hours and the highest load impacts of 0.34 kWh/customer/hour are observed during the second event hour, and the load impacts persist in the third event hour consistent with hourly temperatures that remain elevated across all three event hours. Load impacts are generally comparable across two-hour events. Larger declines in per-customer load impacts between the first and second event hour are associated with larger declines in hourly temperatures of at least three degrees.

Table 3-3: Persistence of Load Impacts Across Consecutive Events

Date	Full Event Hours (p.m.)	SmartRate™ Event?	Impact (kWh/cust/hour)			Avg. Temp (°F)		
			Hour 1	Hour 2	Hour 3	Hour 1	Hour 2	Hour 3
7/1	6-8	Yes	0.28	0.23		100.7	97.3	
7/15	4-7	Yes	0.31	0.34	0.32	102.5	102.8	101.0
7/16	5 7	No	0.37	0.35		105.0	102.8	
7/17	4-6	Yes	0.43	0.42		106.3	105.3	
8/14	4-6	No	0.20	0.14		88.7	86.0	
8/15	4-6	Yes	0.26	0.28		100.5	99.6	
8/16	5-8	Yes	0.29	0.28	0.21	100.9	96.6	92.2
	6-8		0.26	0.16		89.4	86.1	
	6-9		0.22	0.20	0.10	97.5	94.2	91.2
	7-8		0.24			96.0		
10/5	5-7	No	0.15	0.13		89.2	86.3	
10/6	6-8	No	0.16	0.12		84.6	81.5	
	7-9		0.14	0.09		82.2	79.3	
10/7	6-8	No	0.19	0.13		87.9	83.4	
10/19	5-8	No	0.15	0.14		89.0	86.6	

[13] On August 16th and October 6th, different sub-LAPs were dispatched for different event hours. Sub-LAPs dispatched at different times are summarized separately.

[14] PGSI, PGST and PGNC were dispatched from 5 to 8 p.m. and PGNP was dispatched from 6 to 9 p.m.

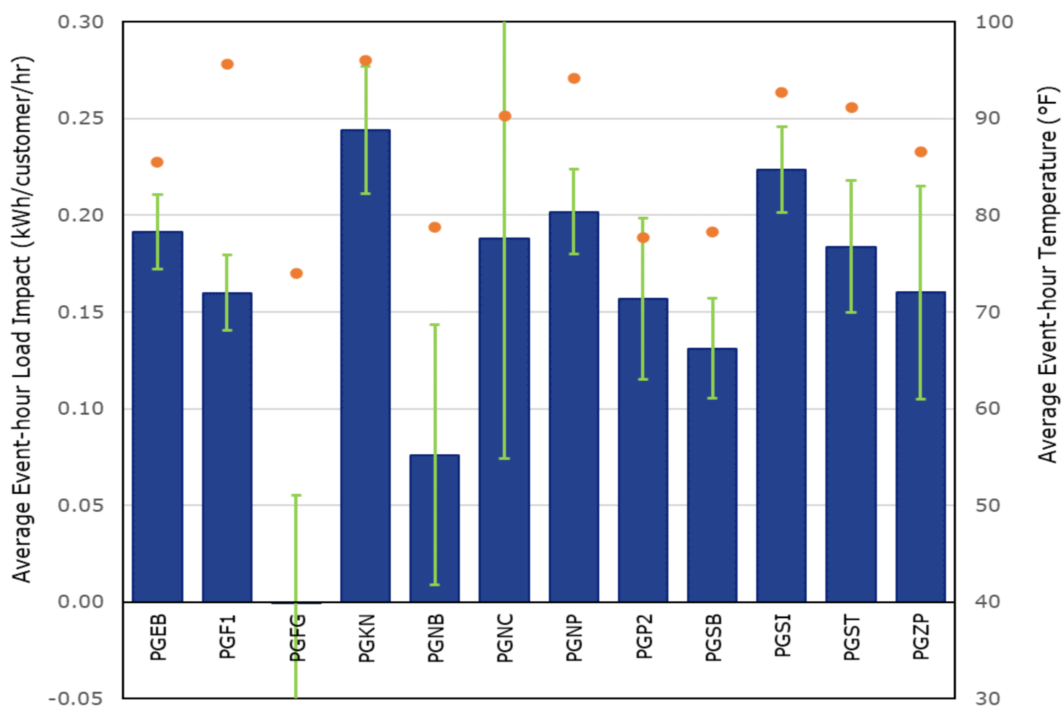
3.3 Sub-LAP Event Load Impacts

Next, we examine the results for sub-LAP events at the sub-LAP level. Figure 3-3 summarizes the sub-LAP level ex-post load impacts for the August 16th event, for which most sub-LAPs were dispatched. Since sub-LAPs were dispatched for different event hours on this event day, we summarize load impacts for the common event hour from 7 to 8 p.m. across all sub-LAPs. The bars indicate the magnitude of the average per-customer load impacts (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 scatter plot represents the average temperatures experienced by the customers in each sub-LAP during the event hours.

Temperature differences drive variation in load impacts across sub-LAPs

Load impact ranges from -0.0008 kWh/customer/hour for PGFG to 0.24 kWh/customer/hour for PGKN. For all sub-LAPs, the August 16th event had relatively low temperatures, which explains the low per-customer load impacts. While the load impact for PGFG is negative, the error bars indicate that this estimate is not statistically significant. This result is not surprising given the low event temperature of 74 degrees suggests that many customers may not have substantial AC load to curtail. Figure 3-3 illustrates that there is considerable variation in load impacts across sub-LAPs, which is driven by large variation in temperature during the common event hour. The lowest average temperature was 76 degrees for PGFG and the highest was 96 degrees for PGKN. PGF1 performed worse than other sub-LAPs with temperatures above 90 degrees.

Figure 3-3: Load Impacts by Sub-LAP on August 16, 2023 (7-8 p.m.)



Sub-LAP event load impacts range from 0.03 to 0.60 kWh/customer/hour

Table 3-4 provides the number of customers dispatched, the average event load impacts (per-customer and in aggregate), reference loads, and percentage load impacts for each sub-LAP event in 2023. Across all sub-LAP events, load impacts range from 0.03 kWh/customer/hour for PGFG on August 16th to 0.60 kWh/customer/hour for PGKN on July 16th.

PGEB has the highest aggregate load impacts

The number of customers dispatched varies across sub-LAPs leading to aggregate load impacts that range from 0.03 MWh/hour for PGFG on August 16th to 4.65 MWh/hour for PGF1 on July 16th. In percentage terms, the load impacts range from 1.7 percent of reference loads for PGFG on August 16th to 17.0 percent for PGKN on July 16th.

Table 3-4: Average Event-Hour Load Impacts by Sub-LAP and Event for Sub-LAP Events

Date	Sub-LAP	Full Event Hours (p.m.)	Smart-Rate™ Event?	# Dis-patched	Average Event Hour				
					Reference (kWh/ cust/hr)	Impact (kWh/ cust/hr)	% Impact	Aggregate Impact (MWh/hr)	Avg. Temp (°F)
7/15	PGEB	4-7	Yes	12,290	2.37	0.30	12.7%	3.71	97.7
	PGF1	4-7		9,898	2.99	0.36	12.1%	3.57	105.1
	PGKN	4-7		2,945	2.95	0.48	16.4%	1.42	105.0
	PGNP	4-7		8,335	2.66	0.26	9.6%	2.14	103.1
	PGSI	4-7		9,404	2.79	0.37	13.2%	3.48	103.1
	PGST	4-7		3,976	2.87	0.22	7.6%	0.87	102.7
	PGZP	4-7		1,299	2.68	0.20	7.5%	0.26	99.1
7/16	PGF1	5-7	No	11,006	3.32	0.42	12.7%	4.65	105.3
	PGKN	5-7		3,293	3.56	0.60	17.0%	1.99	109.3
	PGNP	5-7		9,581	2.95	0.25	8.5%	2.40	103.0
	PGSI	5-7		9,932	3.14	0.41	13.0%	4.06	103.8
	PGST	5-7		4,644	3.20	0.23	7.1%	1.05	101.4
	PGZP	5-7		1,444	2.65	0.20	7.5%	0.29	96.3
7/17	PGF1	4-6	Yes	9,892	3.16	0.43	13.8%	4.30	106.1
	PGKN	4-6		2,944	3.07	0.47	15.3%	1.38	108.8
	PGZP	4-6		1,299	2.34	0.25	10.6%	0.32	97.0
8/14	PGNC	4-6	No	428	1.86	0.17	9.0%	0.07	87.4
8/15	PGNC	4-6	Yes	383	2.62	0.21	8.0%	0.08	96.3
	PGSI	4-6		9,361	2.83	0.29	10.2%	2.71	100.2
	PGST	4-6		3,969	2.95	0.23	7.7%	0.90	100.1
8/16	PGEB	6-8	Yes	12,213	2.60	0.24	9.4%	2.98	87.3
	PGF1	6-8		9,883	3.08	0.24	7.9%	2.39	97.1
	PGFG	6-8		1,148	1.75	0.03	1.7%	0.03	75.5
	PGKN	7-8		2,934	3.07	0.24	7.9%	0.72	96.0
	PGNB	6-8		901	1.95	0.14	7.0%	0.12	81.3
	PGNC	5-8		383	2.77	0.30	11.0%	0.12	94.2
	PGNP	6-9		8,292	2.89	0.17	6.0%	1.44	94.3
	PGP2	6-8		2,745	2.20	0.17	7.6%	0.46	79.0
	PGSB	6-8		5,734	2.00	0.16	8.0%	0.92	80.1
	PGSI	5-8		9,356	3.13	0.27	8.7%	2.54	97.9
	PGST	5-8		3,969	3.13	0.23	7.3%	0.91	93.5
	PGZP	6-8		1,299	2.67	0.21	8.0%	0.28	88.6

Date	Sub-LAP	Full Event Hours (p.m.)	Smart-Rate™ Event?	# Dis-patched	Average Event Hour				
					Reference (kWh/ cust/hr)	Impact (kWh/ cust/hr)	% Impact	Aggregate Impact (MWh/hr)	Avg. Temp (°F)
10/5	PGNB	5-7	No	934	1.61	0.11	6.9%	0.10	87.7
	PGP2	5-7		2,752	1.62	0.15	9.2%	0.41	88.5
	PGSB	5-7		5,782	1.55	0.15	9.5%	0.85	87.3
10/6	PGNB	7-9	No	934	1.49	0.04	2.6%	0.04	79.5
	PGP2	7-9		2,752	1.66	0.15	8.8%	0.40	81.2
	PGSB	6-8		5,782	1.67	0.14	8.3%	0.80	83.0
10/7	PGNB	5-7	No	934	1.77	0.06	3.6%	0.06	87.8
	PGP2	5-7		2,752	1.86	0.16	8.4%	0.43	86.6
	PGSB	5-7		5,782	1.74	0.18	10.3%	1.04	84.9
10/19	PGNB	4-6	No	934	1.31	0.15	11.8%	0.14	90.2
	PGP2	4-6		2,752	1.33	0.13	9.4%	0.35	88.1
	PGSB	4-6		5,782	1.27	0.15	11.8%	0.87	87.3

Load impacts are similar across sub-LAP event hours with large post-event snapback

Figure 3-4 shows an example of the aggregate hourly reference loads, observed loads, and estimated load impacts using the July 15th sub-LAP event, in which over 81 percent enrolled SmartAC™ customers were dispatched from 4 to 7 p.m. Table 3-5 contains these hourly results in the manner required by the Protocols, including hourly temperatures and uncertainty adjusted load impacts (not displayed in Figure 3-4). Load impacts peak at 16.29 MWh during the second event hour (5 to 6 p.m.), and there is statistically significant post-event snapback the first hour after the event during which loads increase by 12.31 MWh decline over throughout the evening.

Figure 3-4: Hourly Load Impacts on July 15, 2023

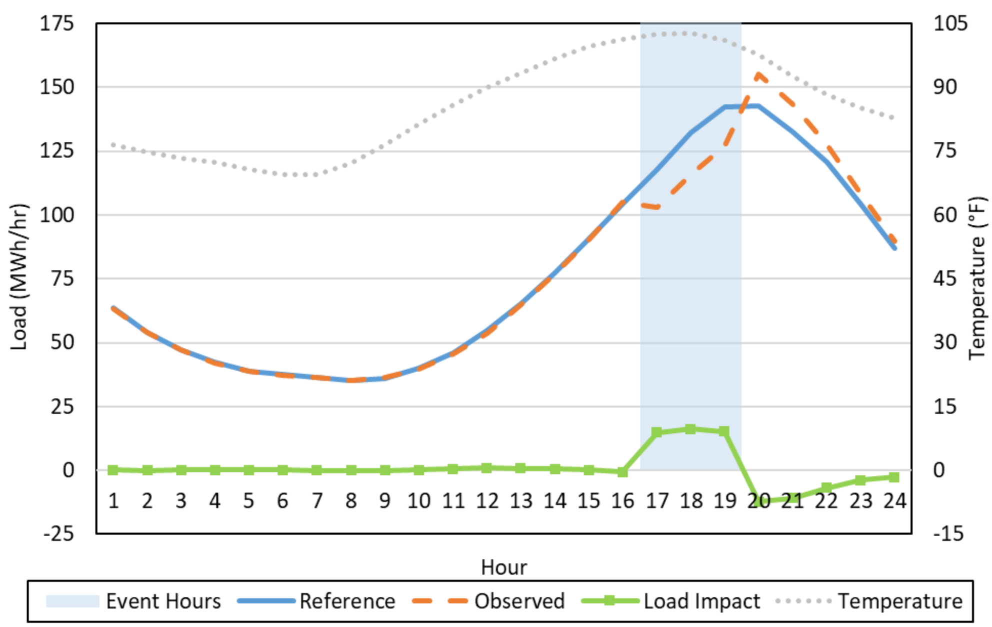


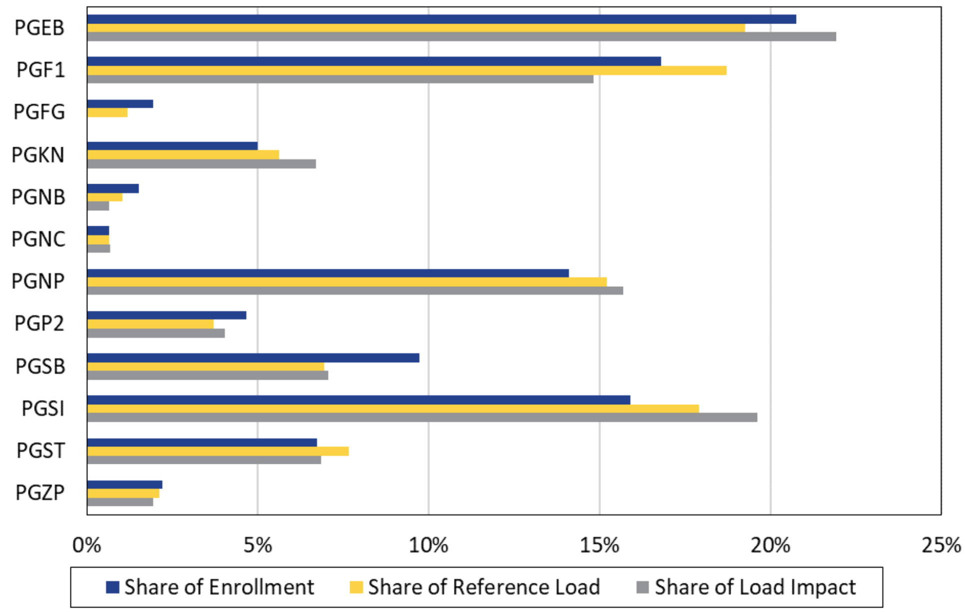
Table 3-5: Hourly Load Impacts and Uncertainty Adjusted Estimates on July 15, 2023

Hour Ending	Estimated Reference Load (MWh/hour)	Observed Event Day Load (MWh/hour)	Estimated Load Impact (MWh/hour)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (MWh/hour)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	63.5	63.4	0.17	76.5	-0.21	0.01	0.17	0.32	0.55
2	54.1	54.1	-0.05	74.7	-0.40	-0.19	-0.05	0.10	0.30
3	47.3	47.1	0.24	73.4	-0.08	0.11	0.24	0.37	0.56
4	42.3	42.1	0.25	72.3	-0.03	0.13	0.25	0.37	0.54
5	38.9	38.7	0.18	70.7	-0.08	0.07	0.18	0.28	0.43
6	37.6	37.3	0.24	69.5	0.01	0.15	0.24	0.34	0.47
7	36.2	36.3	0.00	69.4	-0.23	-0.10	0.00	0.09	0.22
8	35.2	35.1	0.06	72.2	-0.19	-0.05	0.06	0.16	0.30
9	36.1	36.2	-0.12	76.4	-0.39	-0.23	-0.12	-0.01	0.16
10	39.9	39.6	0.26	81.2	-0.05	0.13	0.26	0.38	0.56
11	46.1	45.6	0.48	85.9	0.14	0.34	0.48	0.62	0.82
12	54.7	53.7	0.97	90.0	0.60	0.82	0.97	1.13	1.35
13	65.4	64.7	0.70	93.4	0.28	0.53	0.70	0.87	1.12
14	77.4	76.8	0.62	96.7	0.17	0.44	0.62	0.81	1.07
15	90.6	90.3	0.24	99.6	-0.23	0.05	0.24	0.44	0.72
16	104.3	104.9	-0.59	101.3	-1.08	-0.79	-0.59	-0.38	-0.09
17	117.6	102.8	14.78	102.5	14.29	14.58	14.78	14.99	15.28
18	132.2	115.9	16.29	102.8	15.77	16.08	16.29	16.50	16.81
19	142.4	127.1	15.26	101.0	14.73	15.04	15.26	15.48	15.79
20	142.7	155.0	-12.31	97.7	-12.87	-12.54	-12.31	-12.08	-11.75
21	132.7	143.6	-10.91	92.5	-11.45	-11.13	-10.91	-10.70	-10.38
22	120.7	127.6	-6.95	88.3	-7.47	-7.16	-6.95	-6.74	-6.44
23	104.2	108.1	-3.92	85.1	-4.41	-4.12	-3.92	-3.72	-3.44
24	87.0	89.7	-2.69	82.7	-3.14	-2.88	-2.69	-2.51	-2.24
By Period:	Estimated Reference Energy Use (MWh/hour)	Observed Event Day Energy Use (MWh/hour)	Estimated Change in Energy Use (MWh/hour)	Cooling Degree Hours (Base 75° F)	Uncertainty Adjusted Impact (MWh/hour) - Percentiles				
					10th	30th	50th	70th	90th
Daily	1,849.0	1,835.8	13.20	278.7	8.59	11.31	13.20	15.08	17.81
Avg. Event Hour	130.7	115.3	15.44	81.3	15.15	15.32	15.44	15.57	15.74

PGEB, PGF1 and PGSI produced 70 percent of load reductions

Next, we look at how load impacts are distributed across sub-LAPs. We focus this analysis on the load impacts from the event on August 16th during the common event hour from 7 to 8 p.m. Figure 3-5 compares the sub-LAP shares of estimated aggregate event-hour load impacts, reference loads, and enrollments. Out of customers dispatched for the event, PGEB, PGF1, PGNP, and PGSI have 68 percent of enrolled customers and produce 72 percent of the total load reductions. The share of load impacts for PGEB, PGKN, PGNP, and PGSI exceeds the share of enrollments and reference loads. On the other hand, the share of load impacts for PGF1, PGFG, PGNB, and PGZP are lower than the share of enrollments and reference loads.

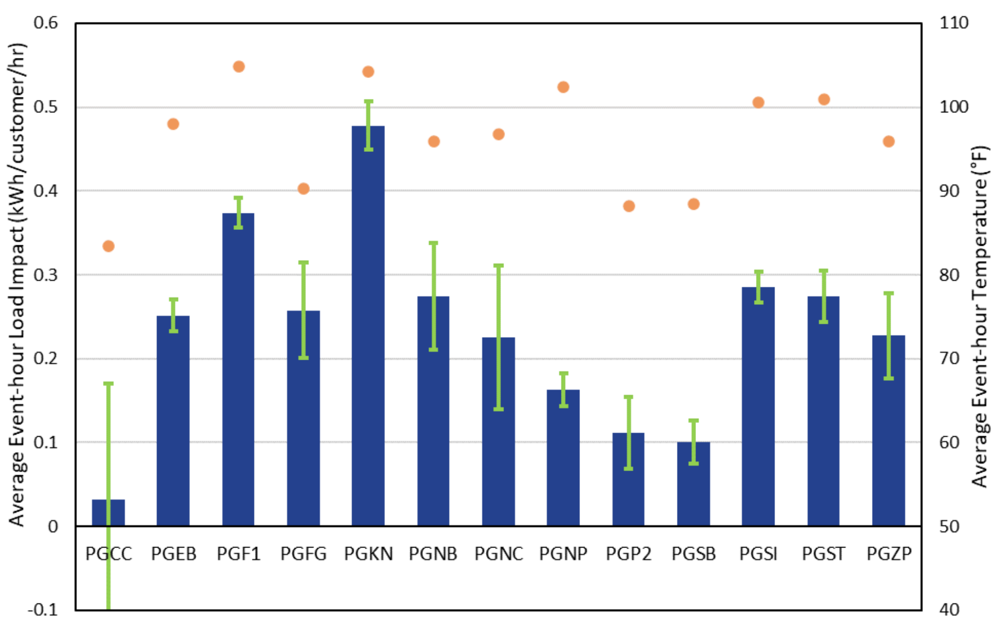
Figure 3-5: Share of Load Impacts by Sub-LAP for August 16, 2023 (7-8 p.m.)



3.4 Serial Event Load Impacts

Next, we examine the results for the serial event on July 1st. Figure 3-6 and Table 3-6 summarize the load impacts by sub-LAP. The bars indicate the magnitude of the average per-customer load impacts (in kWh/customer/hour) across the full serial 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 scatter plot represents the average event temperatures for each sub-LAP.

Figure 3-6: Average Event-Hour Load Impacts by Sub-LAP for the Serial Event



Serial event load impacts range from 0.03 to 0.48 kWh/customer/hour

Load impact ranges from 0.03 kWh/customer/hour for PGCC to 0.48 kWh/customer/hour for PGKN. Variation in event temperatures explains much of the variation in load impacts across sub-LAPs. The lowest average temperature was 83.4 degrees for PGCC and the highest was 104.3 degrees for PGKN. While PGNP had one of this highest event temperatures, it appears that this sub-LAP under-performed relative to other sub-LAPs with comparable temperatures.

Table 3-6: Average Event-Hour Load Impacts by Sub-LAP for the Serial Event

Date	Event Hours (p.m.)	SmartRate™ Event?	Sub-LAP	# Dispatched	Average Event Hour: Reference (kWh/cust/hr)	Impact (kWh/cust/hr)	% Impact	Aggregate Impact (MWh/hr)	Avg. Temp (°F)
7/1	6-8	Yes	PGCC	164	1.82	0.03	1.8%	0.01	83.4
			PGEB	10,998	2.62	0.25	9.6%	2.77	98.0
			PGF1	8,870	3.17	0.37	11.8%	3.32	104.8
			PGFG	1,043	2.26	0.26	11.4%	0.27	90.3
			PGKN	2,693	3.28	0.48	14.6%	1.29	104.3
			PGNB	830	2.25	0.27	12.2%	0.23	95.9
			PGNC	343	2.61	0.23	8.6%	0.08	96.7
			PGNP	7,413	2.89	0.16	5.6%	1.21	102.4
			PGP2	2,453	2.26	0.11	5.0%	0.27	88.2
			PGSB	5,165	2.02	0.10	5.0%	0.52	88.4
			PGSI	8,417	2.95	0.29	9.7%	2.40	100.5
			PGST	3,553	3.15	0.27	8.7%	0.97	101.0
			PGZP	1,136	2.93	0.23	7.8%	0.26	95.9

Load impacts for the serial event on July 1st taper off during the second hour

Figure 3-7 shows the average aggregate hourly reference loads, observed loads, and estimated load impacts for the July 1st serial event from 6 to 8 p.m. Table 3-7 contains the hourly results in the manner required by the Protocols, including hourly temperatures and uncertainty adjusted load impacts (not displayed in Figure 3-7). The load impacts during the serial event hours are averaged across all customers, including the withheld serial group, which diminishes the reported load impacts.[15] Load impacts peak at 14.78 MWh during the first hour of this event (6 to 7 p.m.), which is likely due to higher temperatures in the first event hour.

Post-event snapback is comparable to sub-LAP event post-event snapback

Figure 3-7 also illustrates that there is significant post-event snapback for the serial event. Post-event snapback the first hour after the event as a share of peak event-hour load impacts is comparable between the serial event (75 percent) and the sub-LAP event (76 percent) example for July 15th in Figure 3-4.

[15] By contrast, the results summarized for this event day in Sections 3.2 and in Figure 3-6 and Table 3-6 are limited to the customers dispatched for the serial event (excludes serial group 2).

Figure 3-7: Hourly Load Impacts on July 1, 2023

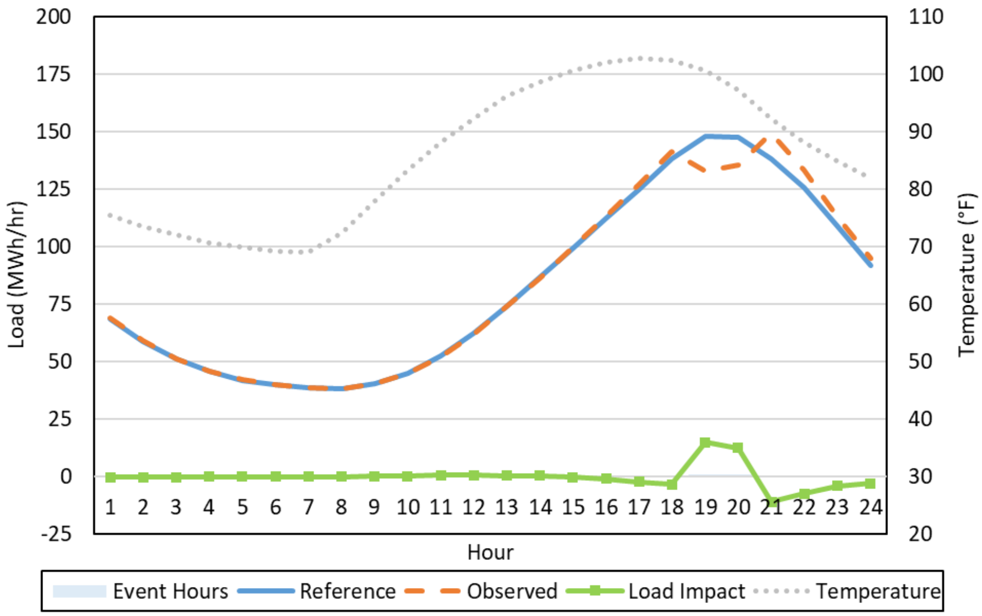


Table 3-7: Hourly Load Impacts and Uncertainty Adjusted Estimates on July 1, 2023

Hour Ending	Estimated Reference Load (MWh/hour)	Observed Event Day Load (MWh/hour)	Estimated Load Impact (MWh/hour)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (MWh/hour)- Percentiles 10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	68.7	69.1	-0.37	75.5	-0.80	-0.54	-0.37	-0.19	0.06
2	58.7	59.2	-0.42	73.4	-0.82	-0.59	-0.42	-0.26	-0.03
3	51.0	51.3	-0.25	72.2	-0.61	-0.39	-0.25	-0.10	0.11
4	45.7	45.7	-0.01	70.7	-0.34	-0.15	-0.01	0.12	0.31
5	41.9	42.0	-0.13	70.0	-0.41	-0.24	-0.13	-0.01	0.16
6	40.0	40.2	-0.16	69.1	-0.42	-0.27	-0.16	-0.06	0.09
7	38.4	38.6	-0.20	69.1	-0.45	-0.30	-0.20	-0.10	0.05
8	38.0	38.1	-0.13	72.5	-0.40	-0.24	-0.13	-0.02	0.14
9	40.5	40.3	0.21	78.0	-0.09	0.09	0.21	0.33	0.51
10	45.1	45.1	0.02	83.4	-0.31	-0.12	0.02	0.16	0.35
11	52.5	52.0	0.52	88.1	0.15	0.37	0.52	0.67	0.89
12	62.5	61.9	0.60	92.4	0.18	0.43	0.60	0.78	1.02
13	74.0	73.8	0.27	96.2	-0.20	0.08	0.27	0.46	0.73
14	86.9	86.6	0.23	98.8	-0.27	0.02	0.23	0.44	0.73
15	99.5	99.8	-0.24	100.6	-0.77	-0.46	-0.24	-0.02	0.29
16	112.2	113.3	-1.04	102.0	-1.60	-1.27	-1.04	-0.82	-0.49
17	124.8	127.1	-2.36	102.8	-2.93	-2.59	-2.36	-2.12	-1.79
18	138.1	141.5	-3.36	102.4	-3.96	-3.60	-3.36	-3.11	-2.76
19	147.9	133.1	14.78	100.7	14.19	14.54	14.78	15.02	15.37
20	147.8	135.4	12.39	97.3	11.81	12.16	12.39	12.63	12.97
21	138.2	149.3	-11.03	92.2	-11.62	-11.27	-11.03	-10.78	-10.43
22	125.8	133.3	-7.50	88.2	-8.07	-7.73	-7.50	-7.26	-6.93
23	109.1	113.2	-4.14	85.0	-4.67	-4.35	-4.14	-3.92	-3.60
24	91.7	94.8	-3.11	81.9	-3.60	-3.31	-3.11	-2.91	-2.62
By Period:	Estimated Reference Energy Use (MWh/hour)	Observed Event Day Energy Use (MWh/hour)	Estimated Change in Energy Use (MWh/hour)	Cooling Degree Hours (Base 75° F)	Uncertainty Adjusted Impact (MWh/hour) - Percentiles 10th	30th	50th	70th	90th
Daily	1,979.3	1,984.8	-5.42	290.7	-10.92	-7.67	-5.42	-3.17	0.08
Avg. Event Hour	147.9	134.3	13.59	48.0	13.17	13.42	13.59	13.75	14.00

3.5 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 (one-way versus two-way and by one-way device type) and different rate groups.[16] Typically, we also compare the load impacts for customers who are enrolled in SmartAC™ to customers who are dually enrolled in SmartRate™ during SmartAC™-only events, however all system-wide events dispatched in PY2023 were dual event days, which precludes such a comparison for 2023. As a result, all comparisons include SmartAC™-only customers, with no dually enrolled customers in these analyses. A comparison between SmartAC™-only and dually enrolled customers by event can be found in Section 3.5.1. Additional results for these subgroups, including the load profiles, can be found in electronic form in Protocol table generators provided along with this report.

The weighted average ex-post load impacts are summarized for each subgroup in Figure 3-8. The blue and gray 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 scatter plot represents the average temperatures experienced by customers in each subgroup.

Figure 3-8 shows that there are statistically significant load impacts for every subgroup. Customers in the various subgroups are not evenly distributed across PG&E's service territory and there are large differences in temperatures between groups because of the wide variation in event temperatures across sub-LAPs during events. Overall, the differences in load impacts between subgroups as summarized below are driven by differences in event temperatures.

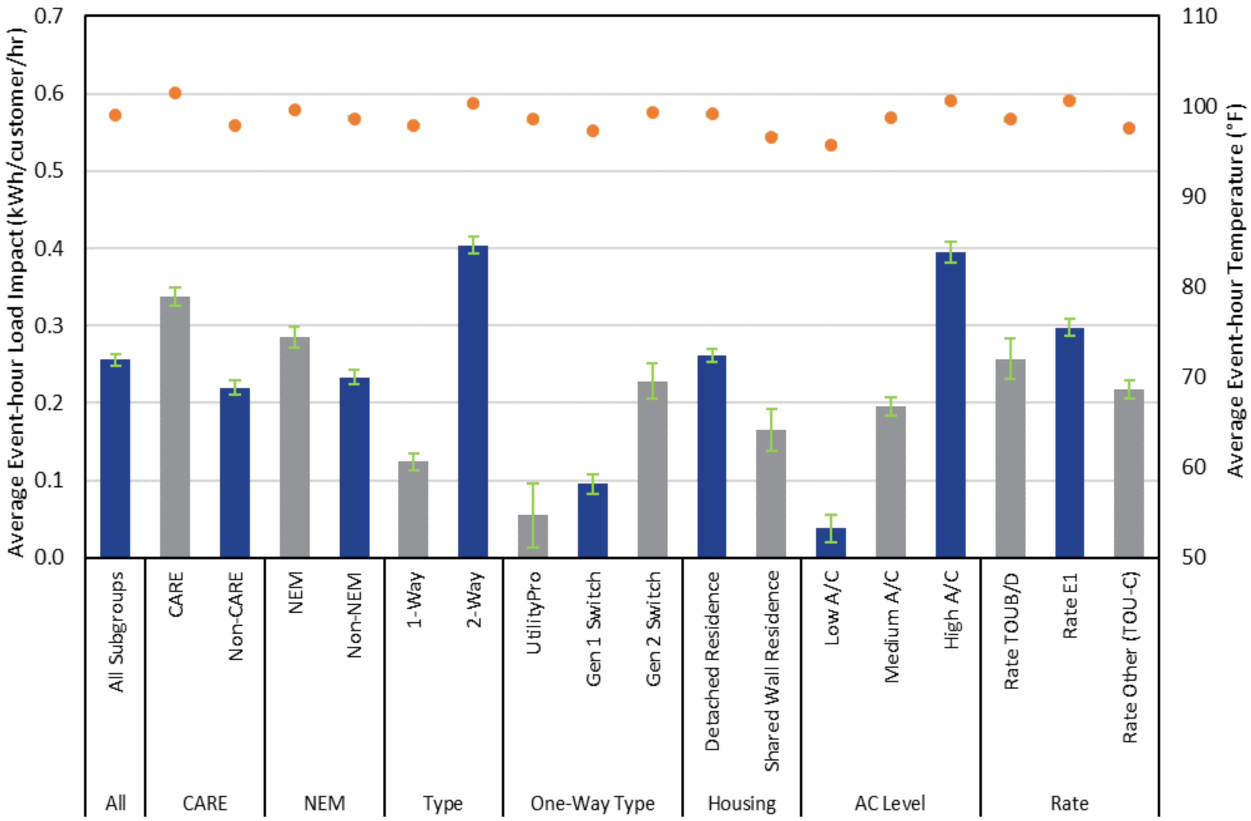
Results that are similar to past evaluations include:

- Gen 1 and Gen 2 switches had higher load impacts than UtilityPro thermostats. Load impacts for UtilityPro thermostats are 0.05 kWh/customer/hour lower than Gen 1 switches despite comparable event temperatures, however the gap is smaller than previous years, mostly due to lower Gen 1 and Gen 2 impacts.
- Load impacts (and temperatures) increase with AC usage intensity, with high AC usage customers having significantly higher load impacts than medium and low AC usage customers.
- Detached (single family) residences have higher load impacts than Shared Wall (multi-family) residences.
- One-way devices have lower load impacts compared to two-way devices. While this is partly driven by higher temperatures for customers with two-way devices, aging one-way devices are more likely to experience device failure, which may contribute to declining one-way device load impacts.
- NEM customers have higher load impacts (and slightly higher temperatures) compared to non-NEM customers.[17]

[16] ExpressStat customers are excluded from the analysis because there are too few customers in this subgroup to estimate load impacts reliably.

[17] While NEM customers historically had comparable or lower load impacts than non-NEM customers, the 2022 evaluation also indicated that NEM customers had higher load impacts than non-NEM customers. A

Figure 3-8: Average Event-Hour Load Impacts by Subgroup



Results that differ from past evaluations include:

- CARE customers have higher load impacts than non-CARE customers.[18] This is driven by the distribution of CARE customers across sub-LAPs, with a higher share of CARE customers in sub-LAPs that experience higher event temperatures. In fact, the event-hour temperatures for CARE customers were almost four degrees higher than non-CARE customers.

Similar to last year's evaluation, we also compare the load impacts by different rate groups. Rate E1 is a non-TOU rate plan with block pricing. The largest share of customers belongs to the "Rate Other" group, which is primarily customers with a TOU-C rate. Customers that have an E1 rate have the highest per-customer load impact, followed by customers with a TOU-B or D rate, and finally by the TOU-C rate/other group. Unlike the PY2022 evaluation, the decline in load impacts across these rate groups is not commensurate with the decline in reference loads. Customers on an E1 rate have lower reference loads, but still show higher absolute and percentage load impacts.

large number of events used in the comparison for 2022 and 2023 are in September and October. Solar irradiance declines throughout the summer after peaking in June, which could lead NEM customers to have higher loads in September and October compared to earlier months for comparable temperatures. As a result, NEM customers may have higher potential for load reductions for events that occur later in the summer.

[18] This is different from PY2022 and PY2020 when CARE customers had comparable load impacts to non-CARE customers but is consistent with PY2021 and PY2019.

Table 3-8 provides the detailed information underlying Figure 3-8, including the average number of customers dispatched, the total number of enrolled customers in each subgroup, the average load impacts, reference loads, percentage load impacts, and temperatures. While comparisons by percentage load impacts mostly follow the same patterns as per-customer load impacts, a different pattern emerges by rate category. TOU-C rate group customers have higher percentage load impacts than customers on TOUB-B or D rate.

Table 3-8: Average Event-Hour Load Impacts by Subgroup

Subgroup	# Dis-Patched	# Enrolled	Average Load Impacts				
			Reference (kWh/cust /hour)	Impact (kWh/cust /hour)	% Impact	Agg. Impact (MWh/ hour)	Avg. Temp (°F)
All SmartAC™ Customers	53,078	59,585	2.79	0.26	9.19%	13.59	99.0
CARE	16,280	18,179	2.89	0.34	11.66%	5.49	101.5
Non-CARE	36,683	41,281	2.74	0.22	8.03%	8.07	97.9
NEM	20,328	22,816	2.99	0.29	9.54%	5.80	99.6
Non-NEM	32,635	36,644	2.65	0.23	8.79%	7.61	98.6
1-Way	28,115	31,638	2.73	0.12	4.56%	3.49	97.9
2-Way	24,963	27,925	2.85	0.40	14.16%	10.08	100.3
UtilityPro	1,867	2,073	2.83	0.05	1.94%	0.10	98.6
Gen 1 Switch	19,293	21,722	2.67	0.10	3.57%	1.84	97.3
Gen 2 Switch	6,238	6,987	2.86	0.23	7.98%	1.42	99.4
Detached Residence	50,466	56,637	2.83	0.26	9.22%	13.19	99.1
Shared Wall Residence	2,575	2,906	1.88	0.16	8.79%	0.42	96.6
Low A/C	6,515	7,326	1.36	0.04	2.79%	0.25	95.8
Medium A/C	20,737	23,253	2.36	0.20	8.29%	4.06	98.7
High A/C	23,310	26,169	3.75	0.40	10.52%	9.21	100.6
Rate TOUB/D	6,256	7,061	3.27	0.26	7.85%	1.61	98.6
Rate E1	22,093	24,718	2.89	0.30	10.31%	6.58	100.7
Rate Other (TOU-C)	24,729	27,806	2.57	0.22	8.45%	5.37	97.6

3.5.1 Dually Enrolled Customers

This section compares results for SmartAC™-only customers to customers who are dually enrolled in SmartAC™ and SmartRate™. We present results for the average full event hour for each event day. On dual event days we limit the comparison to hours where events overlap for the two programs. Additional results for these customers can be found in electronic form in Protocol table generators provided along with this report.

Table 3-9 summarizes the results for SmartAC™-only and dually enrolled customers for each event, including the number of customers dispatched, load impacts, reference loads, and percentage load impacts. Five out of eleven event days in PY2023 were dual event days. For dual event days, we only keep the full SmartAC™ event hours within the SmartRate™ event hours (4-9 p.m.). Less than 10 percent of SmartAC™ customers were dually enrolled in SmartRate™ in

2023, which explains the higher aggregate load impacts for SmartAC™-only customers. The per-customer load impacts are mixed with regards to SmartRate™ dual-enrollment status. During the first three SmartRate™ and SmartAC™ dual events on July 1st, 15th and 17th, the per-customer load impacts of dually enrolled customers were lower than SmartAC™-only customers, however on August 15th and 16th, the load impacts of dually enrolled customers were higher than SmartAC™-only customers. On August 14th, October 5th, 6th, 7th, and 19th less than 100 dually enrolled customers are dispatched, making the estimates of dual customer load impacts unreliable. Dually enrolled customers have a lower load impact on July 16th SmartAC™-only event, which may be influenced by which sub-LAPs were dispatched for the event.[19]

Table 3-9: Average Event-Hour Load Impacts by Event, SmartAC™-only vs. Dually Enrolled

Enrollment Segment	Date	Smart-Rate™ Event?	# Dis-Patched	Average Event Hour				
				Reference (kWh/ cust/hr)	Impact (kWh/ cust/hr)	% Impact	Aggregate Impact (MWh/hr)	Avg. Temp (°F)
Dually Enrolled	7/1	Yes	4,405	2.36	0.18	7.6%	0.8	101.4
	7/15	Yes	4,665	2.40	0.22	9.1%	1.0	102.8
	7/16	No	4,045	2.69	0.15	5.7%	0.6	103.7
	7/17	Yes	1,599	2.91	0.33	11.2%	0.5	106.0
	8/14	No	45	[redacted]				
	8/15	Yes	1,229	2.54	0.29	11.6%	0.4	100.3
	8/16	Yes	4,794	2.34	0.28	12.1%	0.8	93.8
	10/5	No	94	[redacted]				
	10/6	No	94					
	10/7	No	94					
	10/19	No	94					
SmartAC Only	7/1	Yes	53,078	2.78	0.25	9.1%	13.5	99.0
	7/15	Yes	48,147	2.72	0.32	11.9%	15.6	102.1
	7/16	No	35,855	3.22	0.39	12.0%	13.8	103.9
	7/17	Yes	14,135	3.06	0.42	13.8%	6.0	105.8
	8/14	No	383	[redacted]				
	8/15	Yes	13,713	2.86	0.27	9.5%	3.7	100.1
	8/16	Yes	58,857	2.80	0.22	7.9%	7.5	91.8
	10/5	No	9,374	[redacted]				
	10/6	No	9,374					
	10/7	No	9,374					
	10/19	No	9,374					

[19] In the PY2021 and PY2020 evaluations, SmartAC™-only and dually enrolled customers had comparable load impacts during SmartAC™-only events. We continue this assumption in the PY2023 ex-ante forecast as there were no SmartAC™-only system-wide events in 2022 or 2023 that would be needed to re-evaluate this assumption.

3.6 Device Swap-outs

This section summarizes the progress on swap-outs of one-way devices during 2023. Figure 3-9 summarizes the number of swap-outs and new enrollments compared to PG&E's plan for 2023. In most months, device swap-outs met or exceeded the planned swap-outs. However, the swap-out rate declined substantially relative to PG&E's plan beginning in October. There were almost 20,000 device swap-outs completed by December 2023 as well as 700 new customers enrolled in the program compared to 21,000 device swap-outs and 3,000 new enrollments that were planned for 2023.

Figure 3-9: Number of Actual versus Planned Device Installation

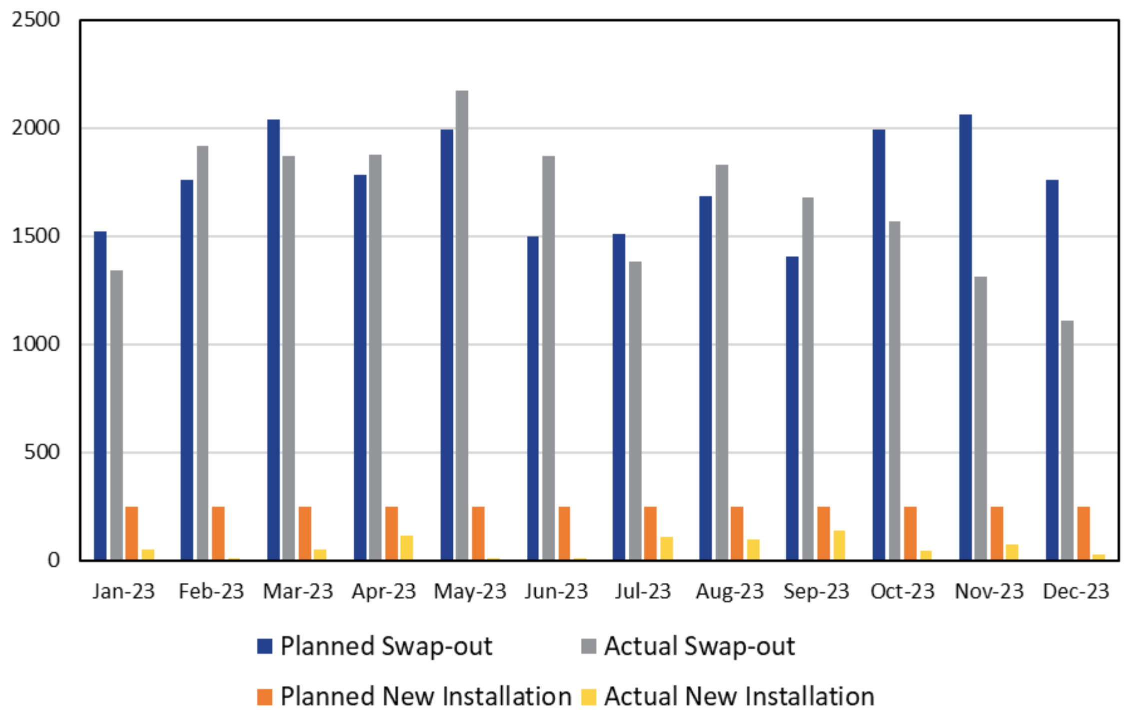
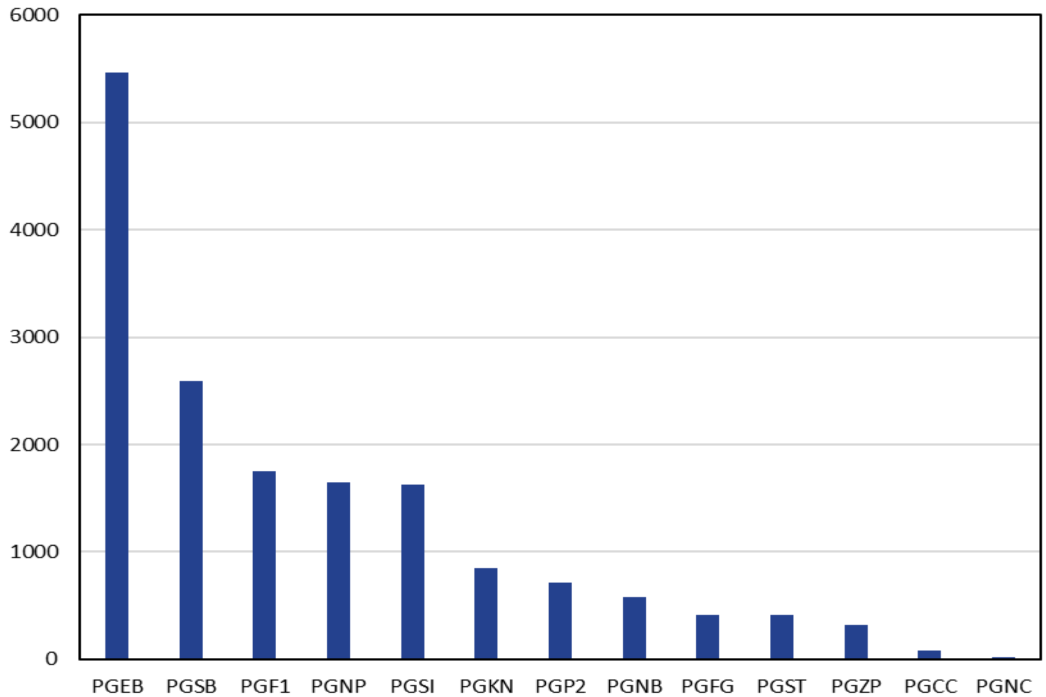


Figure 3-10 summarizes total number of new two-way devices installed in 2023 by sub-LAP, including device swap-outs and new enrollments. PGEB accounts for 33 percent of the new two-way device installed in 2023, while the top five sub-LAPs: PGEB PGSB PGF1 PGNP and PGSI account for 79% of all new two-way devices installed in 2023.

Figure 3-10: Total Number of Two-Way Device Installation in 2023



3.7 Event Override Rate

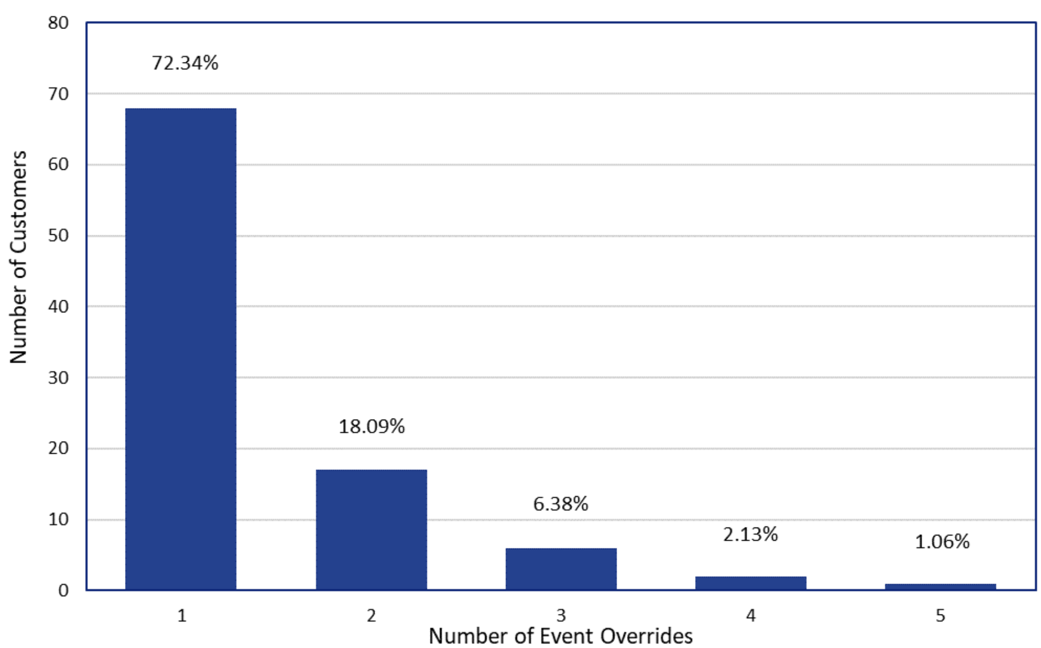
Customers can override (opt out of) SmartAC™ events. Table 3-10 summarizes the number of overrides by event day, including the number of enrolled customers in the sub-LAPs dispatched for each event. In total, the overrides correspond to only 0.05% percent of dispatched customers during PY2023 events. There were no events with high override rates—all were below one percent. Additional tables in Appendix B break down override rates by sub-LAP for each event. All sub-LAPs have override rates below 1 percent.

Table 3-10: Customer Overrides by Event Day

Date	Event Hours (p.m.)	Sub-LAPs Dispatched	Smart-Rate™ Event?	# Over-rides	# Dis-Patched	Override Rate
7/1	6-8	All Sub-LAPs, Serial Group 4 withheld	Yes	29	53,078	0.05%
7/15	4-7	PGNP, PGSI, PGST, PGKN, PGF1, PGZP, PGEB	Yes	27	48,147	0.06%
7/16	5 7	PGNP, PGSI, PGST, PGKN, PGF1, PGZP	No	24	39,900	0.06%
7/17	4-6	PGKN, PGF1, PGZP	Yes	14	14,135	0.10%
8/14	4-6	PGNC	No	0	428	0.00%
8/15	4-6	PGSI, PGST, PGNC	Yes	7	13,713	0.05%
8/16	5-8	PGSI, PGST, PGNC	Yes	24	58,857	0.04%
	6-8	PGF1, PGZP, PGFG, PGNB, PGEB, PGSB,				
	6-9	PGNP				
	7-8	PGKN				
10/5	5-7	PGNB, PGSB, PGP2	No	1	9,468	0.01%
10/6	6-8	PGSB	No	3	9,468	0.03%
	7-9	PGNB, PGP2				
10/7	6-8	PGNB, PGSB, PGP2	No	3	9,468	0.03%
10/19	5-8	PGNB, PGSB, PGP2	No	1	9,468	0.01%
			Total	**133**	**266,130**	**0.05%**

Figure 3-11 illustrates the extent to which customers opted out of multiple events. About 72 percent of the customers that opted out of any event in 2023 did so only once, while 18 percent of customers opted out of two events, and 6 percent of customers opted out of three events. In the previous evaluation a much higher percentage of customers opted out of multiple events. For comparison, only 35 percent of customers opted out of one event in PY2022.

Figure 3-11: Number of Event Day Overrides by Customer



4. EX-ANTE LOAD IMPACTS

This section provides the SmartAC™ ex-ante load impact forecast for the period from 2024 to 2034. 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. The PY2023 ex-ante forecast also reflects SmartAC™ performance during sub-LAP events, consistent with recent evaluations.

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: figures showing the PG&E's enrollment forecast by LCA and by device type; a figure showing the forecast of aggregate load impacts; 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.

Figure 4-1 shows PG&E's enrollment forecast by LCA from 2024 to 2034. The total enrollments in July of each year are displayed above the chart. Enrollments decrease gradually over the forecast period with an assumed annual attrition of 8.5 precent for SmartAC™ customers and 22.37 percent for customers dually enrolled in SmartAC™ and SmartRate™. Beginning in 2024, the SmartAC™ program is closed to new enrollment.

Figure 4-1: Changes in Enrollment by LCA (2024-2034)

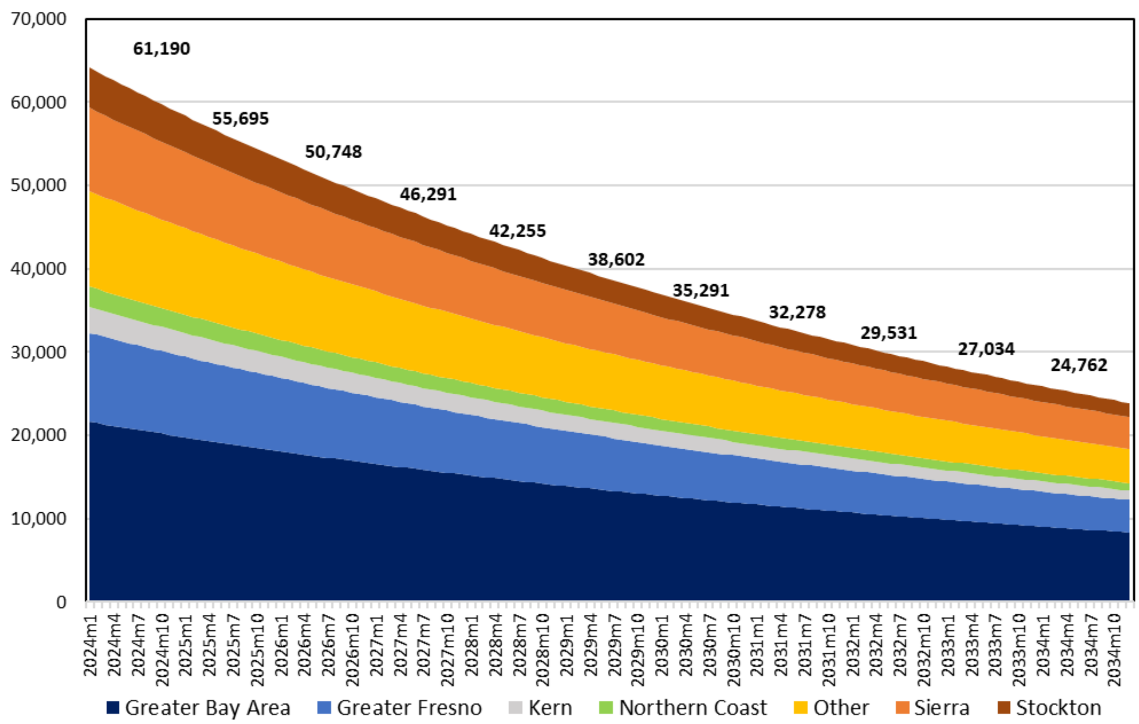


Figure 4-2 illustrates the changes in aggregate load impacts during the Resource Adequacy (RA) window (4 to 9 p.m.) over the forecast period by comparing load impacts for all SmartAC™ customers by LCA for the PG&E 1-in-2 scenario for a July peak day. Aggregate load impacts decrease by about 8.7 percent per year, which is consistent with the percentage decline of enrollments.

Figure 4-2: Aggregate Load Impacts over RA Window by LCA for PG&E 1-in-2 July Peak Scenario (2024-2034)

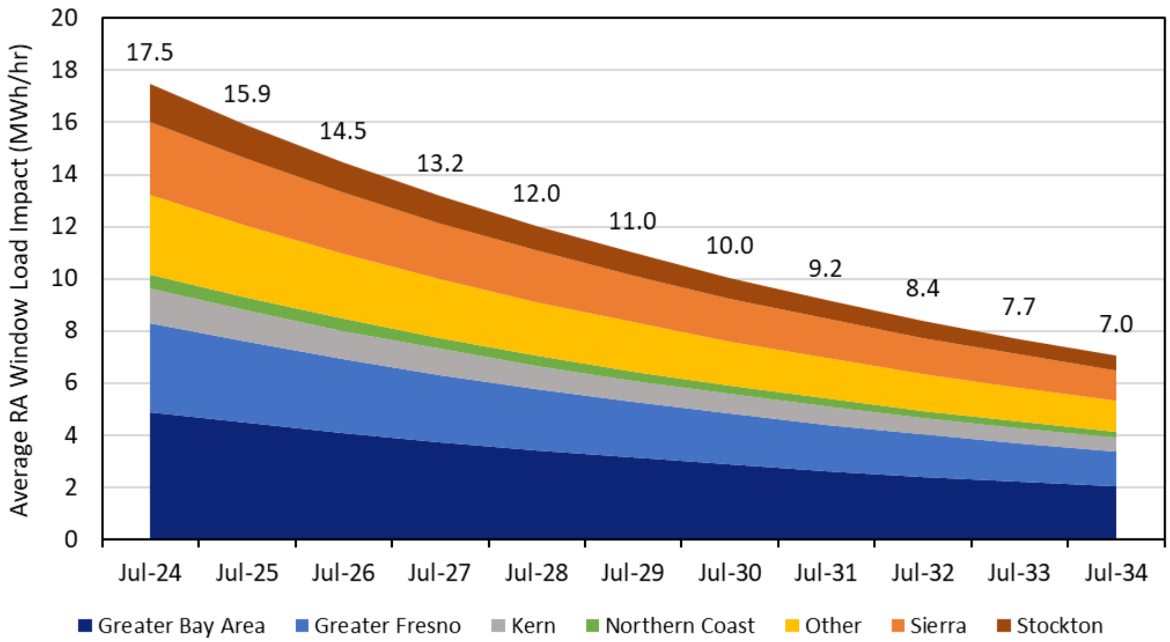


Figure 4-3 illustrates the aggregate reference loads, observed loads, and load impacts for all SmartAC™ customers on a July peak day in 2024 for the PG&E 1-in-2 weather scenario. Ex-ante load impacts peak during the first event hour. The average July RA window load impact is 17.5 MWh/hour, or 11.6 percent of the average RA window reference loads.

Figure 4-3: Aggregate Hourly Loads and Load Impacts for July Peak, *PG&E 1-in-2 Scenario* in 2024: All SmartAC™ Customers

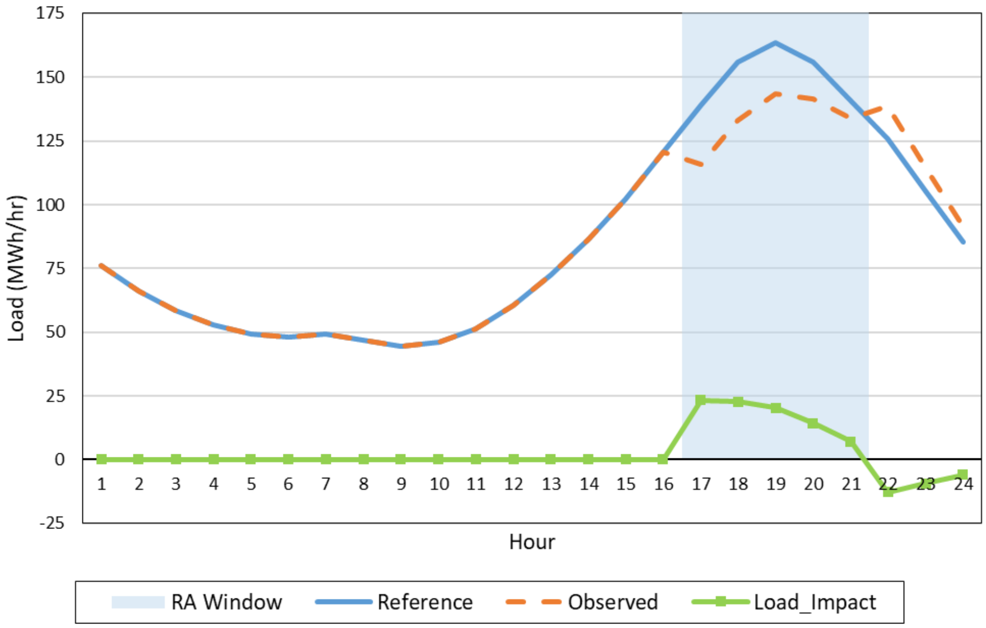


Figure 4-4 illustrates the aggregate reference loads, observed loads, and load impacts for SmartAC™-only customers on a July peak day in 2024 for the PG&E 1-in-2 weather scenario. The shape of the ex-ante loads and load impacts is similar to the results for all SmartAC™ program customers. The average RA window load impact is 16.2 MWh/hour, or 11.4 percent of the average RA window reference loads.

Figure 4-4: Aggregate Hourly Loads and Load Impacts for July Peak, *PG&E 1-in-2* Scenario in 2024: SmartAC™-only Customers

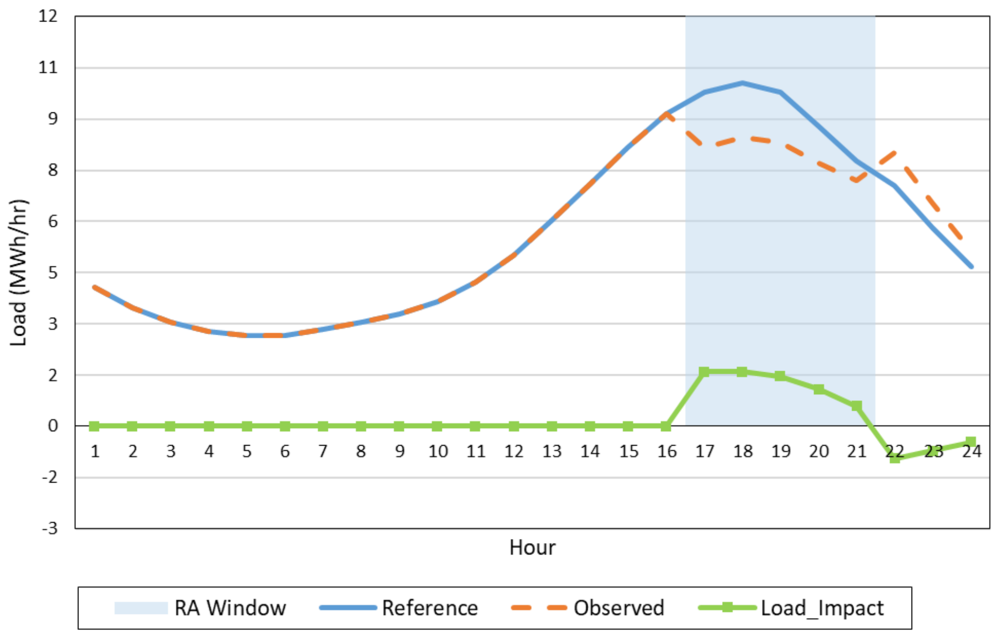


Figure 4-5 illustrates the aggregate reference load, observed load, and load impact for customers who are dually enrolled in SmartAC™ and SmartRate™ on a July peak day in 2024 for the PG&E 1-in-2 weather scenario. The shape of the reference loads differs for dually enrolled customers, with a peak at HE 18 instead of the HE 19 peak for SmartAC™-only customers. The magnitude of the aggregate loads and load impacts is much smaller compared to SmartAC™-only customers due to lower enrollments. The average RA window load impact is 1.3 MWh/hour, or 13.7 percent of the average RA window reference loads.

Figure 4-5: Aggregate Hourly Loads and Load Impacts for July Peak, *PG&E 1-in-2* Scenario in 2024: Dually Enrolled Customers

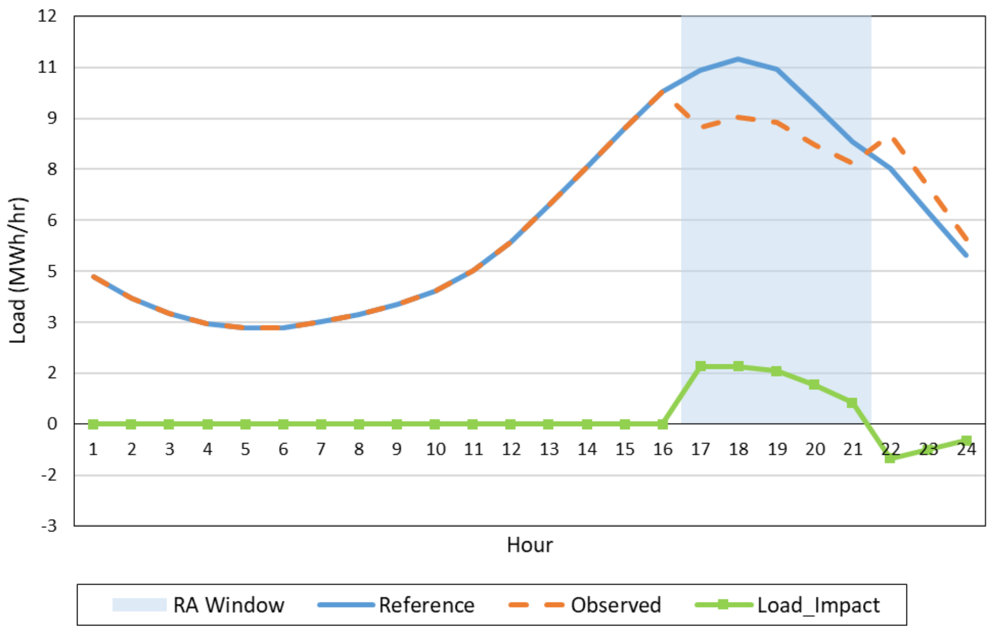


Table 4-1 summarizes average loads and load impacts, percentage load impacts, and average temperatures for the RA window on a July peak day in 2024 for the PG&E 1-in-2 weather scenario by LCA and enrollment segment. Per-customer load impacts range from 0.23 kWh/customer/hour for Northern Coast to 0.45 for Kern. The differences are mainly due to temperatures in these LCAs. There is large variation in aggregate load impacts due to the distribution of enrolled customers across LCAs. Greater Bay Area has the largest aggregate load impacts of 4.9 MWh/hour, and Kern has the largest percent load impact of 16.7 percent of reference loads from dually enrolled customers.

Table 4-1: Average RA Window Load Impacts for *PG&E 1-in-2* July Peak Day in 2024 by LCA and Enrollment Segment

Enrollment Segment	LCA	Enrolled	Average RA Window Hour				
			Reference (kWh/ cust/hr)	Impact (kWh/ cust/hr)	% Load Impact	Aggregate Impact (MWh/hr)	Avg. Temp (°F)
All	Greater Bay Area	20,672	2.03	0.24	11.6%	4.9	88.8
	Greater Fresno	10,172	3.00	0.34	11.2%	3.4	102.2
	Kern	2,953	2.96	0.45	15.3%	1.3	102.6
	Northern Coast	2,343	1.78	0.23	13.1%	0.5	86.2
	Other	10,911	2.53	0.28	11.0%	3.0	98.5
	Sierra	9,536	2.62	0.30	11.3%	2.8	97.5
	Stockton	4,603	2.84	0.31	10.9%	1.4	97.6
	Total	**61,190**	**2.47**	**0.29**	**11.6%**	**17.5**	**95.4**
Dually Enrolled	Greater Bay Area	550	1.79	0.27	15.1%	0.1	91.8
	Greater Fresno	907	2.69	0.36	13.3%	0.3	102.2
	Kern	265	2.73	0.45	16.7%	0.1	102.6
	Northern Coast	108	1.56	0.24	15.7%	0.0	88.7
	Other	1,206	2.14	0.27	12.7%	0.3	98.6
	Sierra	447	2.11	0.30	14.2%	0.1	97.5
	Stockton	586	2.38	0.32	13.2%	0.2	97.6
	Total	**4,069**	**2.27**	**0.31**	**13.7%**	**1.3**	**98.2**
SmartAC™ Only	Greater Bay Area	20,122	2.04	0.23	11.5%	4.7	88.8
	Greater Fresno	9,265	3.03	0.33	11.1%	3.1	102.2
	Kern	2,688	2.98	0.45	15.1%	1.2	102.6
	Northern Coast	2,235	1.79	0.23	13.0%	0.5	86.1
	Other	9,705	2.58	0.28	10.9%	2.7	98.5
	Sierra	9,089	2.65	0.29	11.1%	2.7	97.5
	Stockton	4,017	2.91	0.31	10.6%	1.2	97.6
	Total	**57,121**	**2.48**	**0.28**	**11.4%**	**16.2**	**95.2**

Figure 4-6 illustrates the seasonality and variation by weather scenario in the forecasted load impacts by comparing aggregate load impacts for the average hour in the Resource Adequacy (RA) window in 2024 across months and weather scenarios. Beginning in 2024, the May RA window will be from 5 p.m. to 10 p.m. (HE 18-22). This change in RA window hours leads to lower average RA window load impacts in May relative to the old RA window due to cooler temperatures during later hours, which decrease the load impact potential during SmartAC™ events. The highest load impact comes from the PG&E 1-in-10 scenario in September (24.61 MWh/hour), and the second highest load impact comes from the PG&E 1-in-10 scenario in June (21.93 MWh/hour). For the CAISO 1-in-10 scenario, the load impacts are also highest in September (20.84 MWh/hour). The load impact for the PG&E 1-in-2 (19.42 MWh/hour) and CAISO 1-in-2 (20.84 MWh/hour) scenarios are highest in June.

Figure 4-6: Aggregate Load Impacts over RA Window in 2024 by Month and Weather Scenario

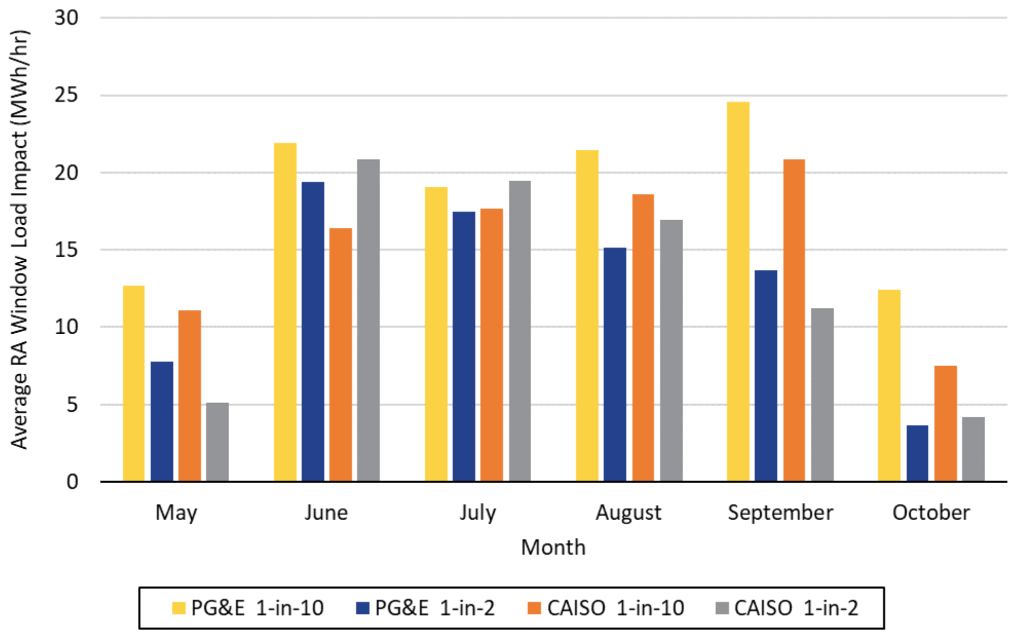
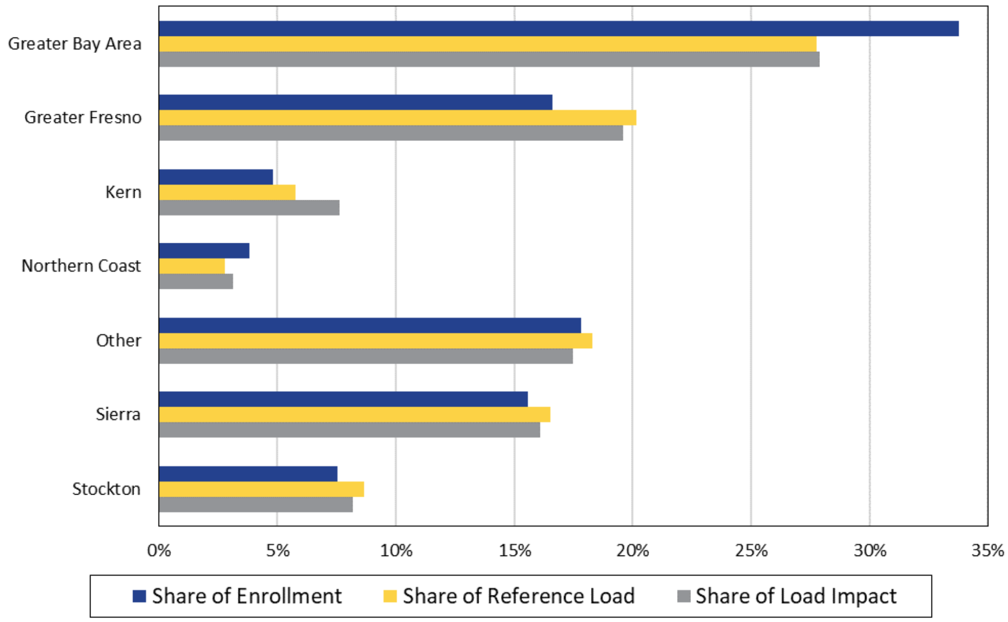


Figure 4-7 compares the LCA shares of average RA window load impacts, reference loads, and enrollments on a July peak day for the PG&E 1-in-2 scenario in 2024. The load impacts for the SmartAC™ program are highest in the Greater Bay Area with 28 percent of aggregate load impacts, 34 percent of enrolled customers, and 28 percent of reference loads. The top four LCAs in terms of enrollments and load impacts, including the Greater Bay Area, Other, Greater Fresno and Sierra, contribute 81 percent of the aggregate load reductions for SmartAC™. Kern has a higher share of load impacts compared to the share of enrollments or reference loads. The rest of the LCAs have a lower share of load impacts compared to the share of enrollments or reference loads.

Figure 4-7: RA Window Load Impacts for *PG&E 1-in-2* July Peak Day in 2024 by LCA



5. 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 PY2023. The term "previous" refers to findings in reports for PY2022. In the final comparison above, we illustrate the linkage between the PY2023 ex-post load impacts and the "current" ex-ante forecast.

5.1 Previous vs. Current Ex-Post

In this section we compare ex-post load impacts from the current and previous studies. We compare results for sub-LAP events to the results from PY2022.

Table 5-1 compares the average per-customer reference loads, load impacts, and temperatures for sub-LAP events for the current and previous program years across the most common event hours from 5 to 7 p.m. Of the twelve sub-LAPs that had sub-LAP events in both years, eight sub-LAPs had lower load impacts in PY2023 compared to PY2022. PGFG, PGNB, PGP2, PGSB, PGST and PGZP had lower load impacts with lower event temperatures, while PGEB and PGNP had lower load impacts despite higher event temperatures. By contrast, PGF1 and PGNC had higher load impacts with lower or comparable event temperatures in PY2023.

The bottom row of the table compares average load impacts across sub-LAPs that had events in both years. About 7,050 fewer customers were dispatched for sub-LAP events in 2023 relative to 2022 due to program attrition.[20] The reference loads in PY2023 are slightly lower than PY2022. Overall, load impacts were 0.02 kWh/customer/hour higher in PY2023, with comparable average event-hour temperatures.

Table 5-1: Previous vs. Current Ex-Post Load Impacts (5-7 p.m.)

sub-LAP	Avg. # dispatched		Reference (kWh/cust/hr)		Load Impact (kWh/cust/hr)		Avg Temp (°F)	
	PY2022	PY2023	PY2022	PY2023	PY2022	PY2023	PY2022	PY2023
PGCC	203		3.48		0.74		89.4	
PGEB	14,246	12,264	3.12	2.56	0.37	0.30	93.9	94.6
PGF1	12,421	11,006	3.34	3.22	0.24	0.39	104.7	104.1
PGFG	1,357	1,148	3.10	1.85	0.23	0.06	102.5	77.0
PGKN	3,633	3,293	3.41	3.33	0.52	0.54	105.7	107.6
PGNB	1,062	934	2.84	1.70	0.34	0.11	99.8	87.4
PGNC	461	428	2.76	2.54	0.21	0.27	95.6	93.2
PGNP	10,595	9,581	2.90	2.91	0.26	0.25	101.8	102.0
PGP2	2,907	2,752	2.86	1.77	0.36	0.15	93.5	86.2
PGSB	6,217	5,782	2.55	1.68	0.32	0.16	94.5	85.3
PGSI	11,584	9,932	3.03	3.06	0.33	0.35	101.2	102.1
PGST	5,152	4,644	3.32	3.12	0.29	0.24	103.3	99.8
PGZP	1,554	1,444	2.91	2.68	0.27	0.22	97.2	95.9
Common Sub-LAPs	**59,646**	**52,592**	**3.14**	**2.96**	**0.31**	**0.33**	**100.60**	**100.61**

5.2 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. The comparison includes average load impacts across the RA window from 4 to 9 p.m.

Table 5-2 reports the average RA window load impacts for the July 2024 peak day under PG&E 1-in-2 weather conditions. The enrollments in the PY2022 forecast of 2024 are much lower due to PG&E's previous plan to de-enroll all one-way devices in January 2024. PG&E has since decided to retain participants with one-way devices for the present. Per-customer references loads are comparable in both forecasts. However, the per-customer load impacts are significantly higher in

[20] For PY2022, six sub-LAPs only have dual events (PGCC, PGEB, PGFG, PGNB, PGP2, PGSB) and in PY2023 two sub-LAPs only have dual events (PGEB, PGFG), so the average number of customers dispatched for these sub-LAPs exclude dually enrolled customers in each year.

the PY2022 forecast, which is driven by differences in device-type composition. The PY2023 forecast of July 2024 peak day, includes the remaining one-way devices that were not swapped out by the end of 2023. The PY2022 forecast drops all remaining one-way devices from the program. Since one-way devices typically have lower load impacts than two-way devices, this leads to higher per-customer load impacts in the PY2022 forecast but lower aggregate load impacts due to lower enrollments.

Table 5-2: Previous vs. Current Ex-Ante Load Impacts (RA Window)

Level	Outcome	July Peak 2024	
		PY2022 PG&E 1-in-2	PY2023 PG&E 1-in-2
Total	Enrollments	38,386	61,190
	Reference (MWh)	95.9	151.1
	Load Impact (MWh)	15.2	17.5
	Avg. RA Window Temp (°F)	97.2	96.2
	Avg. Daily Temp (°F)	85.3	84.5
	% Load Impact	15.9%	11.6%
Per-Participant	Reference (kWh)	2.50	2.47
	Load Impact (kWh)	0.40	0.29

5.3 Previous Ex-ante vs. Current Ex-Post

In this section, we compare the ex-ante forecast from the previous study to the ex-post results during sub-LAP events contained in the current study. We limit the comparison to the full event hours of the sub-LAP event on July 15th. We compare these load impacts to the forecast for a July Peak Day for the PG&E 1-in-10 Scenario to get a closer match of temperatures to the July 15th event. Since July 15th is a dual event day, load reductions from dually enrolled customers are not counted in the SmartAC™ program load impacts. As such, we use the ex-ante scenario for SmartAC™-only customers in this comparison. Furthermore, since July 15th is not a system wide event, only sub-LAPs dispatched on July 15th were included in the comparison.

Table 5-3 provides a comparison of the PY2022 ex-ante forecast of 2023 load impacts to the ex-post load impacts on July 15, 2023. There are about 5,200 fewer customers in ex-post compared to the ex-ante forecast. The per-customer load impact is 0.13 kwh/customer/hour lower in ex-post than ex-ante despite comparable event-hour temperatures. Lower per-customer load impacts are partly due to fewer two-way devices than planned as a result of device swap-out activity in 2023, as discussed in Section 3.6. Moreover, while event temperatures are comparable, daily average temperatures are slightly higher in the ex-ante forecast, which contributes to higher load impacts. The reference loads are also lower on July 15th compared to the forecast, which may be related to daily temperatures. The percentage load impacts are lower on July 15th by about 3.3 percentage points due to lower per-customer load impacts.

Table 5-3: Previous Ex-Ante vs. Current Ex-Post Load Impacts (5-8 p.m.)

Level	Outcome	PY2022 Ex-Ante	PY2023 Ex-Post
Total	Enrollments	53,376	48,147
	Reference (MWh)	157.9	130.7
	Load Impact (MWh)	23.9	15.4
	Avg. Event Hour Temp (°F)	101.5	102.1
	Avg. Daily Temp (°F)	88.7	86.1
	% Load Impact	15.1%	11.8%
Per-Participant	Reference (kWh)	2.96	2.71
	Load Impact (kWh)	0.45	0.32

5.4 Current Ex-Post vs. Current Ex-Ante

In this section, we compare the ex-post findings by device type to the ex-ante forecast for 2024 contained in the current study during the event hours from 5 to 7 p.m.

Table 5-4 compares the ex-post load impacts across all sub-LAP events in 2023, by device type, to the ex-ante load impact forecast for a July peak day with PG&E 1-in-2 weather conditions in 2024. Per-customer load impacts are higher in the forecast compared to one-way device ex-post load impacts and lower than two-way device load impacts, with the result of higher load impacts in the forecast than for ex-post. This is partly due to additional device swap-outs performed after the events in 2023, leading to a higher share of two-way devices in the forecast compared to ex-post. While enrollments decline slightly by July of 2024, aggregate load impacts are higher as a result of higher per-customer load impacts. Per-customer reference loads are lower in the forecast compared to 2023, which may be related to slightly lower daily temperatures in the forecast. Percentage load impacts are higher in the forecast as a result of high load impacts and lower reference loads.

Table 5-4: Current Ex-Post vs. Ex-Ante Load Impacts (5-7 p.m.)

Level	Outcome	PY2023 Sub-LAP Event Load Impacts			PY2023 Forecast
		1-Way	2-Way	All	2024
Total	Enrollments	31,256	31,922	63,178	61,190
	Reference (MWh/hour)	84.9	88.7	173.7	159.8
	Load Impact (MWh/hour)	5.9	12.8	18.7	21.5
	Avg. Event Temp (°F)	97.7	98.2	98.0	98.6
	Avg. Daily Temp (°F)	85.2	85.7	85.5	84.5
	% Load Impact	6.9%	14.5%	10.8%	13.4%
Per-Participant	Reference (kWh/Cust/hour)	2.72	2.78	2.75	2.61
	Load Impact (kWh/Cust/hour)	0.19	0.40	0.30	0.35

Table 5-5 documents the various potential reasons for differences between the ex-post and ex-ante load impacts. The main reason for higher per-customer load impacts in the ex-ante forecast is that a higher share of devices are two-way devices in 2024, which is expected to produce higher per-customer load impacts. However, the five percentage point increase in share of two-way devices is too small to explain all of the increase in load impacts. The aggregate load impacts in 2024 are higher than ex-post though enrollments are slightly lower.

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

Factor	Ex-Post	Ex-Ante	Expected Impact
Weather	Average event-hour temperature of 97.7°F for one-way devices, and 98.2°F for two-way devices.	Average event-hour temperature of 98.6°F.	The comparable temperatures between ex-ante and ex-post of may produce similar per-customer load impacts (ceteris paribus).
Device Composition	About 51% are two-way devices.	About 56% are two-way devices.	Higher percentage of two-way devices leads to higher per-customer load impacts in ex-ante.
Enrollment	63,178	61,190	Lower ex-ante enrollments lower the aggregate load impacts.
Methodology	Difference-in-Differences with matched control group.	Simulated load impacts from the ex-post using events in 2020-2023.	Incorporating events in 2020-2021 may increase the per-customer load impacts while 2022 may decrease the per-customer load impact due to dispatch issues experienced in 2022.

6. RECOMMENDATIONS

We continue to recommend that there be some system-wide or serial events dispatched in isolation going forward for the purpose of load impact estimation. While a serial event was dispatched in 2023 the coincidence of this event with a SmartRate™ event impedes the analysis of differences between SmartAC™-only and dually enrolled customer performance. We recommend calling at least one system-wide SmartAC™-only event in the future for the purpose of load impact evaluation.

7. APPENDICES

The following Appendices accompany this report. Appendix A presents further information about the match quality by sub-LAP in our ex-post analysis. Appendix B provides further details of event override rates by sub-LAP and event. Appendix C illustrates how we evaluated the quality of our ex-post load impact evaluation and ex-ante forecast. Additional appendices consist of Excel files that can produce the tables required by the Protocols.

Appendix D 4a. PGE_2023_SAC_Ex_Post_PUBLIC

Appendix E 4b. PGE_2023_SAC_Ex_Ante_PUBLIC

Appendix A. Additional Control Group Matching Results

Table A-1 provides the mean percentage error (MPE) and mean absolute percentage error (MAPE) calculated across the average 24-hour load profile as well as over the RA window. Also included are the mean error (ME) and mean absolute error (MAE) which show the errors in terms of kWh/customer/hour differences rather than percentage differences. Again, we evaluate match quality based on 24-hour load profiles for hot days and cooler days used in matching as well as days not using in matching.

The MPE and MAPE are higher by sub-LAP than the overall results. The average MAPE is 2.4 percent for all hours and 1.6 percent for the RA window. Table A-1 demonstrates that all ME and MAE values are less than 0.05 kWh/customer/hour in absolute terms except for PGCC, which only has about 160 customers.

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

Sub-LAP	Comparison Days	24 Hour Load Profile				RA Window			
		MPE (%)	ME (kW)	MAPE (%)	MAE (kW)	MPE (%)	ME (kW)	MAPE (%)	MAE (kW)
PGCC	Hot Days	-10.4%	-0.09	10.5%	0.10	-6.9%	0.00	7.3%	0.03
	Cool Days	-12.8%	-0.09	13.3%	0.09	-2.9%	0.00	5.0%	0.02
	Non-Matching Cool Days	-14.8%	-0.10	14.9%	0.10	-7.0%	0.00	7.4%	0.02
	Weekend Days	-11.9%	-0.09	11.9%	0.09	-5.2%	0.00	5.2%	0.02
PGEB	Hot Days	0.6%	0.01	0.9%	0.01	1.0%	0.00	1.0%	0.03
	Cool Days	0.9%	0.01	1.1%	0.01	1.5%	0.00	1.5%	0.02
	Non-Matching Cool Days	0.9%	0.01	1.1%	0.01	2.1%	0.00	2.1%	0.02
	Weekend Days	0.7%	0.01	1.3%	0.01	1.1%	0.00	1.1%	0.02
PGF1	Hot Days	1.0%	0.02	1.0%	0.02	0.7%	0.00	0.7%	0.03
	Cool Days	0.7%	0.01	0.8%	0.01	0.5%	0.00	0.5%	0.02
	Non-Matching Cool Days	0.7%	0.01	0.9%	0.01	0.4%	0.00	0.4%	0.02
	Weekend Days	1.4%	0.01	1.4%	0.01	0.8%	0.00	0.8%	0.02
PGFG	Hot Days	0.7%	0.00	1.6%	0.01	-0.6%	0.00	0.9%	0.03
	Cool Days	0.6%	0.00	1.7%	0.01	-1.5%	0.00	1.5%	0.02
	Non-Matching Cool Days	0.9%	0.00	1.8%	0.01	-1.5%	0.00	1.5%	0.02
	Weekend Days	2.2%	0.01	2.5%	0.02	-0.3%	0.00	0.7%	0.02
PGKN	Hot Days	2.0%	0.03	2.0%	0.03	2.2%	0.00	2.2%	0.03
	Cool Days	1.4%	0.01	1.6%	0.02	2.0%	0.00	2.0%	0.02
	Non-Matching Cool Days	1.7%	0.02	1.8%	0.02	2.7%	0.00	2.7%	0.02
	Weekend Days	2.3%	0.02	2.3%	0.02	2.5%	0.00	2.5%	0.02
PGNB	Hot Days	-1.6%	-0.01	2.0%	0.01	0.3%	0.00	0.7%	0.03
	Cool Days	-1.9%	-0.01	2.3%	0.01	-0.4%	0.00	0.4%	0.02
	Non-Matching Cool Days	-3.0%	-0.02	3.0%	0.02	-1.7%	0.00	1.7%	0.02
	Weekend Days	-1.8%	-0.01	2.1%	0.01	-1.5%	0.00	1.5%	0.02

Sub-LAP	Comparison Days	24 Hour Load Profile				RA Window			
		MPE (%)	ME (kW)	MAPE (%)	MAE (kW)	MPE (%)	ME (kW)	MAPE (%)	MAE (kW)
PGNC	Hot Days	-1.8%	-0.01	3.7%	0.03	1.0%	0.00	1.0%	0.03
	Cool Days	-2.3%	-0.01	3.3%	0.02	0.6%	0.00	1.9%	0.02
	Non-Matching Cool Days	-2.9%	-0.01	4.4%	0.03	2.7%	0.00	2.7%	0.02
	Weekend Days	-0.4%	0.00	2.2%	0.02	-0.1%	0.00	0.8%	0.02
PGNP	Hot Days	-0.5%	0.00	0.6%	0.01	0.0%	0.00	0.1%	0.03
	Cool Days	-0.4%	0.00	0.6%	0.00	-0.1%	0.00	0.3%	0.02
	Non-Matching Cool Days	-0.3%	0.00	0.7%	0.00	0.5%	0.00	0.5%	0.02
	Weekend Days	0.4%	0.00	0.8%	0.01	0.6%	0.00	0.6%	0.02
PGP2	Hot Days	-1.2%	-0.01	1.3%	0.02	-2.3%	0.00	2.3%	0.03
	Cool Days	-1.9%	-0.02	2.0%	0.02	-3.3%	0.00	3.3%	0.02
	Non-Matching Cool Days	-2.5%	-0.02	2.5%	0.02	-3.3%	0.00	3.3%	0.02
	Weekend Days	-1.2%	-0.01	1.7%	0.02	-2.8%	0.00	2.8%	0.02
PGSB	Hot Days	1.3%	0.01	1.3%	0.01	1.0%	0.00	1.0%	0.03
	Cool Days	0.6%	0.00	0.7%	0.00	0.2%	0.00	0.3%	0.02
	Non-Matching Cool Days	0.3%	0.00	0.7%	0.00	0.0%	0.00	0.2%	0.02
	Weekend Days	0.9%	0.01	1.2%	0.01	0.3%	0.00	0.3%	0.02
PGSI	Hot Days	-0.1%	0.00	0.8%	0.01	-0.6%	0.00	0.6%	0.03
	Cool Days	0.2%	0.00	0.7%	0.01	-0.2%	0.00	0.3%	0.02
	Non-Matching Cool Days	0.1%	0.00	0.7%	0.01	0.0%	0.00	0.4%	0.02
	Weekend Days	0.8%	0.01	0.8%	0.01	0.5%	0.00	0.5%	0.02
PGST	Hot Days	0.5%	0.01	0.9%	0.01	1.1%	0.00	1.1%	0.03
	Cool Days	0.9%	0.01	1.0%	0.01	1.8%	0.00	1.8%	0.02
	Non-Matching Cool Days	1.2%	0.01	1.4%	0.01	2.7%	0.00	2.7%	0.02
	Weekend Days	1.5%	0.02	1.5%	0.02	2.2%	0.00	2.2%	0.02
PGZP	Hot Days	-1.3%	-0.02	1.7%	0.02	-1.1%	0.00	1.1%	0.03
	Cool Days	-0.3%	0.00	1.4%	0.01	-0.8%	0.00	0.8%	0.02
	Non-Matching Cool Days	-0.6%	-0.01	1.2%	0.01	-0.9%	0.00	0.9%	0.02
	Weekend Days	0.7%	0.01	1.5%	0.01	0.2%	0.00	0.3%	0.02

Appendix B. Event Overrides by Event and Location

Table B-1 shows customers overrides by sub-LAP for each event day. All override rates are below one percent.

Table B-1: Overrides by Sub-LAP and Event Day

Date	Sub-LAP	Full Event Hours (p.m.)	SmartRate™ Event?	# Overrides	# Dispatched	Override Rate
7/1	PGCC	6-8	Yes	0	164	0.0%
	PGEB	6-8		7	10,998	0.1%
	PGF1	6-8		2	8,870	0.0%
	PGFG	6-8		0	1,043	0.0%
	PGKN	6-8		0	2,693	0.0%
	PGNB	6-8		2	830	0.2%
	PGNC	6-8		0	343	0.0%
	PGNP	6-8		4	7,413	0.1%
	PGP2	6-8		3	2,453	0.1%
	PGSB	6-8		5	5,165	0.1%
	PGSI	6-8		2	8,417	0.0%
	PGST	6-8		3	3,553	0.1%
	PGZP	6-8		1	1,136	0.1%
7/15	PGEB	4-7	Yes	11	12,290	0.1%
	PGF1	4-7		4	9,898	0.0%
	PGKN	4-7		2	2,945	0.1%
	PGNP	4-7		4	8,335	0.0%
	PGSI	4-7		4	9,404	0.0%
	PGST	4-7		1	3,976	0.0%
	PGZP	4-7		1	1,299	0.1%
7/16	PGF1	5-7	No	2	11,006	0.0%
	PGKN	5-7		2	3,293	0.1%
	PGNP	5-7		9	9,581	0.1%
	PGSI	5-7		5	9,932	0.1%
	PGST	5-7		3	4,644	0.1%
	PGZP	5-7		2	1,444	0.1%
7/17	PGF1	4-6	Yes	3	9,892	0.0%
	PGKN	4-6		4	2,944	0.1%
	PGZP	4-6		1	1,299	0.1%
8/14	PGNC	4-6	No	0	428	0.0%
8/15	PGNC	4-6	Yes	0	383	0.0%
	PGSI	4-6		4	9,361	0.0%
	PGST	4-6		2	3,969	0.1%

Date	Sub-LAP	Full Event Hours (p.m.)	Smart-Rate™ Event?	# Overrides	# Dis-patched	Override Rate
8/16	PGEB	6-8	Yes	6	12,213	0.0%
	PGF1	6-8		0	9,883	0.0%
	PGFG	6-8		0	1,148	0.0%
	PGKN	7-8		0	2,934	0.0%
	PGNB	6-8		0	901	0.0%
	PGNC	5-8		1	383	0.3%
	PGNP	6-9		5	8,292	0.1%
	PGP2	6-8		0	2,745	0.0%
	PGSB	6-8		4	5,734	0.1%
	PGSI	5-8		5	9,356	0.1%
	PGST	5-8		3	3,969	0.1%
	PGZP	6-8		0	1,299	0.0%
10/5	PGNB	5-7	No	0	934	0.0%
	PGP2	5-7		1	2,752	0.0%
	PGSB	5-7		0	5,782	0.0%
10/6	PGNB	7-9	No	0	934	0.0%
	PGP2	7-9		0	2,752	0.0%
	PGSB	6-8		3	5,782	0.1%
10/7	PGNB	5-7	No	0	934	0.0%
	PGP2	5-7		1	2,752	0.0%
	PGSB	5-7		2	5,782	0.0%
10/19	PGNB	4-6	No	0	934	0.0%
	PGP2	4-6		0	2,752	0.0%
	PGSB	4-6		1	5,782	0.0%

Appendix C. Scatterplots of Load Impacts and Temperature

Figure C-1 through Figure C-13 show scatterplots of hourly ex-post and ex-ante load impacts compared to average temperatures from PY2023 for all sub-LAPs by device type. The red dots show the ex-post load impacts in 2023. The blue dots show the ex-post load impacts in 2020, 2021 and 2022, while the blue line shows the linear relationship between load impacts and hourly temperatures in all four years. The green dots and line show the ex-ante load impacts from the PY2023 forecast. The results are limited to the hours where ex-post and ex-ante have overlapping event hours from 4 to 9 p.m. For the ex-ante load impacts we use the June, July, August, September, and October peak month weather conditions for the PG&E 1-in-10 weather scenario for 2023.

For most sub-LAPs, the two-way device load impacts (right) are higher than one-way device load impacts (left). In 2023 one-way devices tend to have worse performance than in previous years. Given similar temperatures, the forecasted ex-ante load impacts tend to be in line with the results from ex-post. Considering the dispatch issues for some sub-LAPs in 2022, the inclusion of ex-post results from 2022 in the forecast allows to account for some level of operational issues in the future. However, as the weights assigned to 2020, 2021 and 2023 ex-post results are higher than the weights assigned to 2022 ex-post results, the load impacts from operational issues in the forecast are reduced. Furthermore, the forecasts by device type have slightly different relationships between per-customer load impacts and temperature. Similar to PY2022, in hotter sub-LAPs the highest ex-post temperatures are still higher than the weather scenarios encompass.

Figure C-1: Scatterplot of Hourly Load Impacts vs. Average Temperature, PGCC

[redacted]

Figure C-2: Scatterplot of Hourly Load Impacts vs. Average Temperature, PGEB

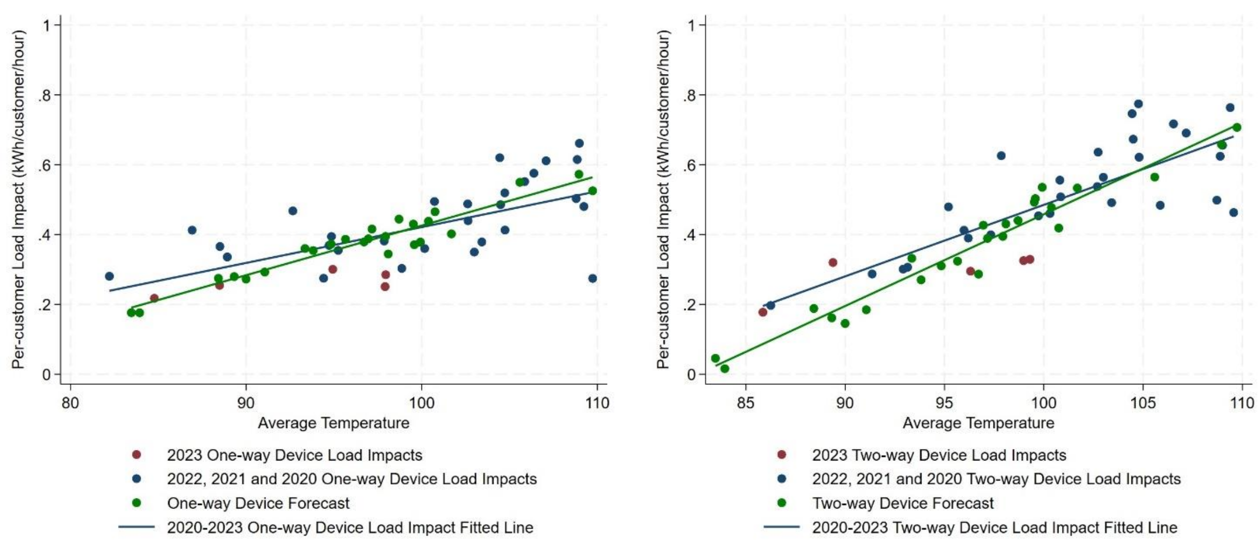


Figure C-3: Scatterplot of Hourly Load Impacts vs. Average Temperature, PGF1

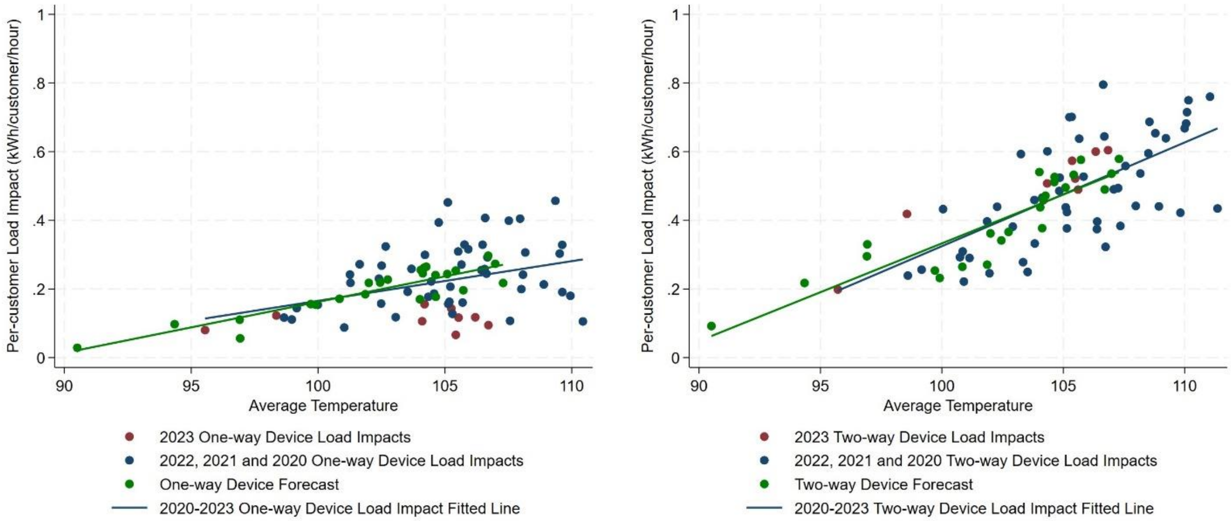


Figure C-4: Scatterplot of Hourly Load Impacts vs. Average Temperature, PGFG

[redacted]

Figure C-5: Scatterplot of Hourly Load Impacts vs. Average Temperature, PGKN

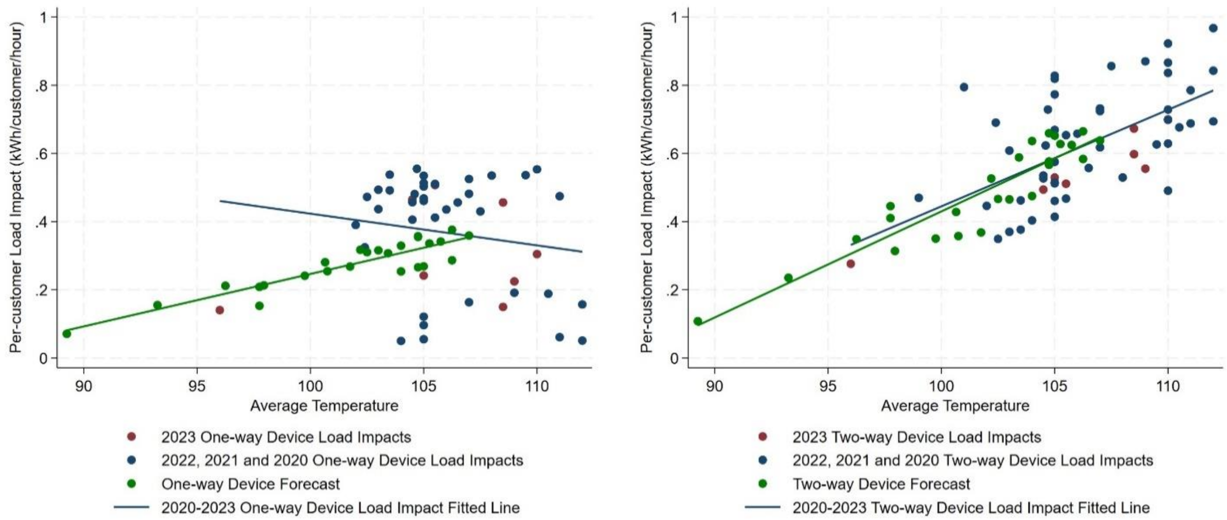


Figure C-6: Scatterplot of Hourly Load Impacts vs. Average Temperature, PGNB

[redacted]

Figure C-7: Scatterplot of Hourly Load Impacts vs. Average Temperature, PGNC

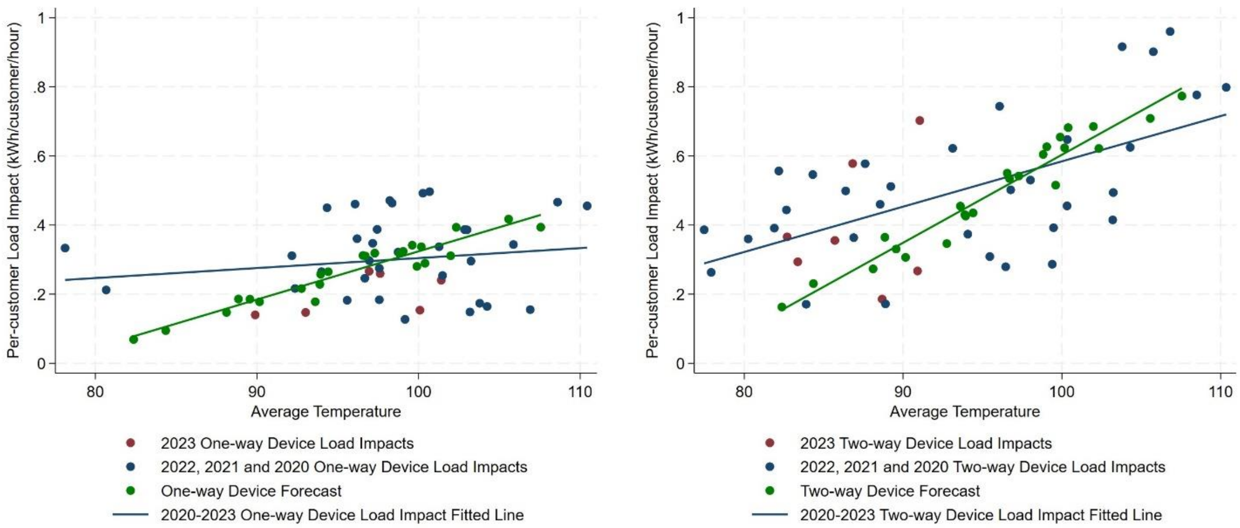


Figure C-8: Scatterplot of Hourly Load Impacts vs. Average Temperature, PGNP

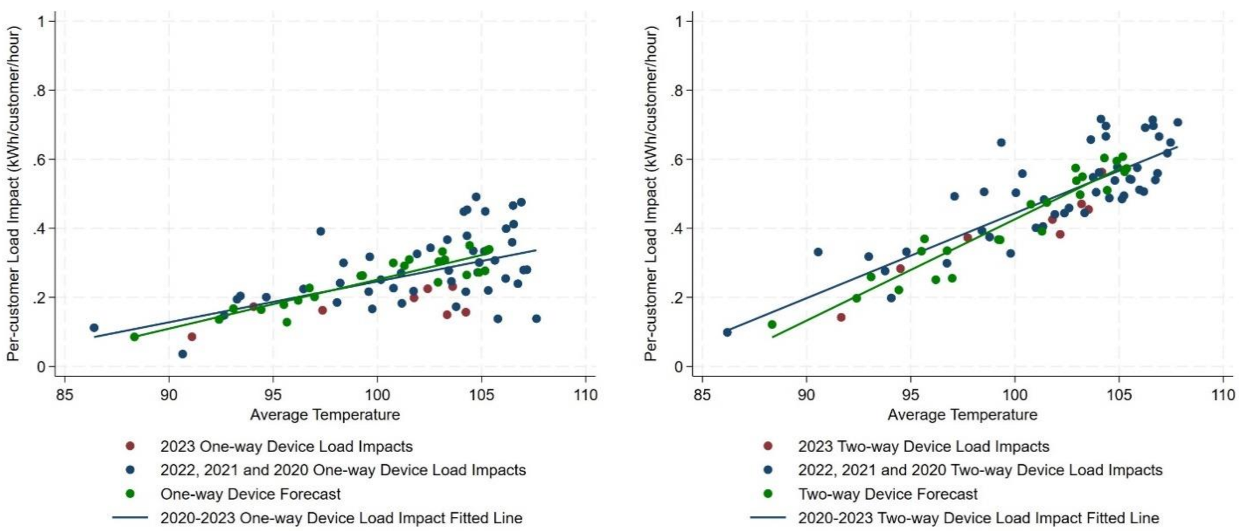


Figure C-9: Scatterplot of Hourly Load Impacts vs. Average Temperature, PGP2

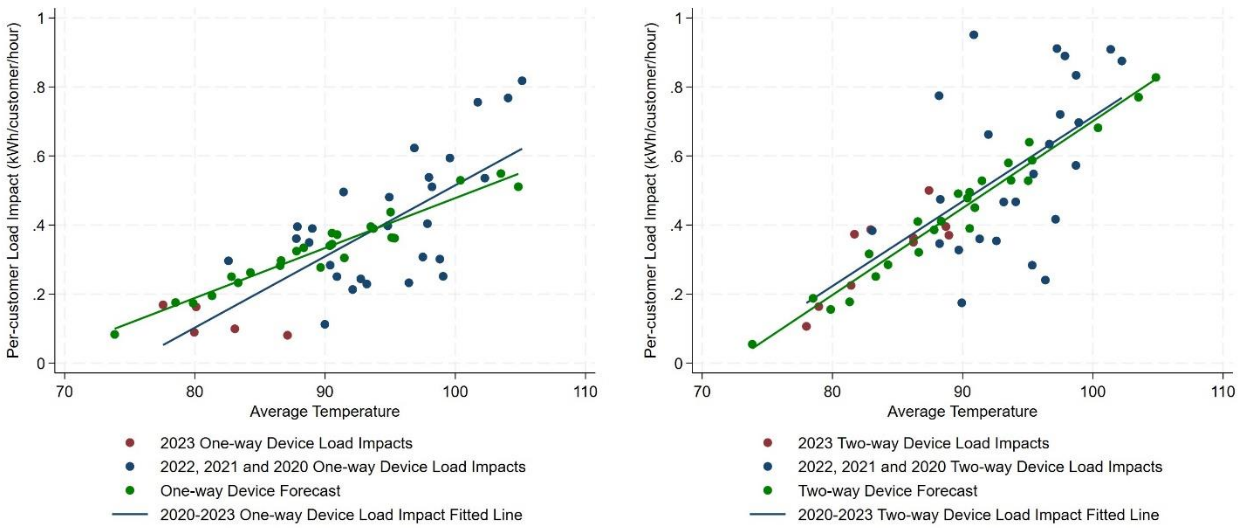


Figure C-10: Scatterplot of Hourly Load Impacts vs. Average Temperature, PGSB

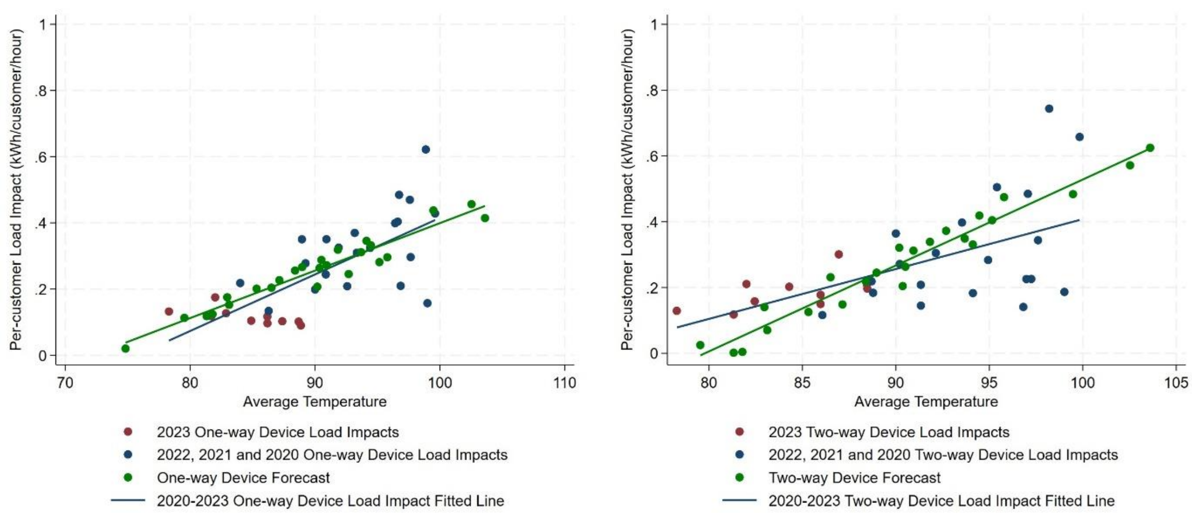


Figure C-11: Scatterplot of Hourly Load Impacts vs. Average Temperature, PGSI

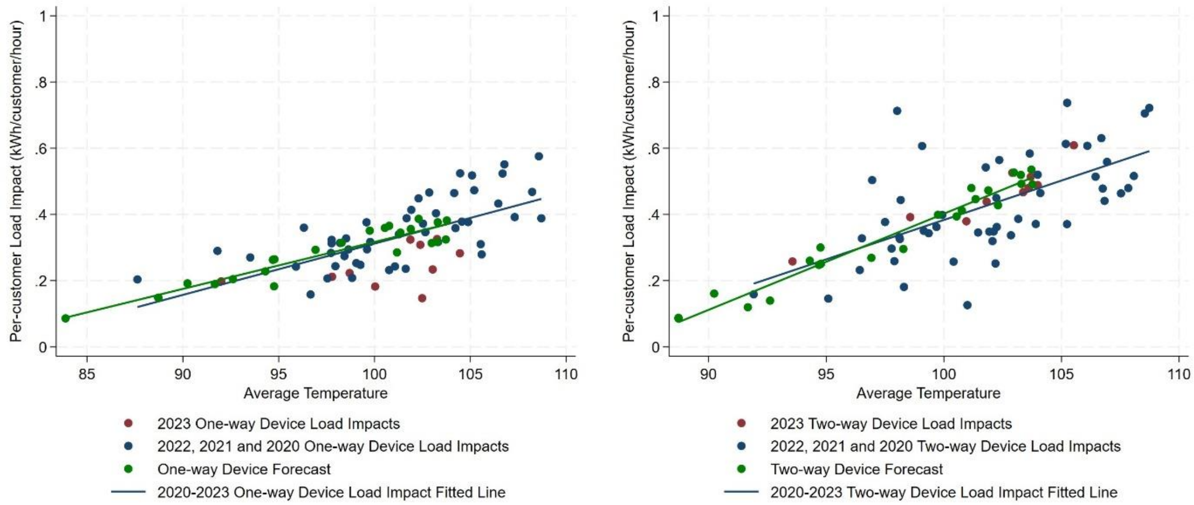


Figure C-12: Scatterplot of Hourly Load Impacts vs. Average Temperature, PGST

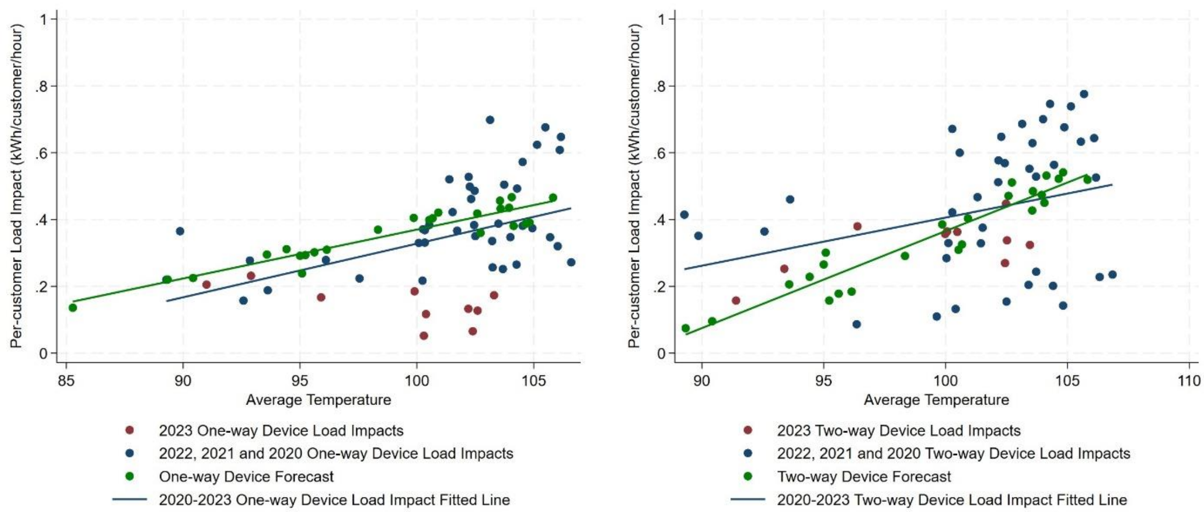


Figure C-13: Scatterplot of Hourly Load Impacts vs. Average Temperature, PGZP