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2023 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers: Ex-post and Ex-ante Report

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April 1st, 2024

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ABSTRACT

This report documents ex-post and ex-ante load impact evaluations for the statewide Base Interruptible Program ("BIP") in place at Pacific Gas and Electric Company ("PG&E") and Southern California Edison ("SCE") in 2023. The report provides estimates of ex-post load impacts that occurred during events called in 2023 and an ex-ante forecast of load impacts for 2024 through 2034 that is based on the investor-owned utilities ("IOU's") enrollment forecasts and the ex-post load impacts estimated for PY2022.[1]

Base Interruptible Programs are statewide voluntary programs that offer customers a monthly capacity bill credit in exchange for the commitment to reduce their energy consumption to an amount that meets the customer's minimum operational requirements, also known as a Firm Service Level ("FSL").

PG&E called three events in 2023 and SCE called one event. Both PG&E and SCE called an event on July 20th with varying event hours (8:27 to 8:32 p.m. for PG&E and 7:45 to 8:19 p.m. for SCE). PG&E called re-test events on September 26th and October 24th that lasted from 4:00-6:00 p.m. July 20th was a Thursday and the two re-test events called by PG&E were called on Tuesdays. SDG&E did not call any events.[2]

Ex-post load impacts were estimated from regression analysis of customer-level hourly load data, where the equations modeled hourly load as a function of variables that control for factors affecting consumers' hourly demand levels. BIP load impacts for each event were obtained by summing the estimated hourly event coefficients across the customer-level models. We performed additional analysis using 15-minute interval data to address the unique nature of the July 20th ex-post event for both SCE and PG&E. Specifically, the SCE event was 34 minutes in duration (7:45 to 8:19 p.m.) and PG&E's July 20th event was five minutes in duration (8:27 to 8:32 p.m.). Load impacts are primarily estimated and reported using hourly data, which is not capable of reflecting full program performance because of the partial event hours. Examining 15-minute usage data allows us to examine performance that is more reflective of program performance than the 60-minute data but still does not have the resolution to fully reflect program performance.

Because of the limitations inherent in this year's ex-post load impact estimates, the ex-ante forecast is based on customer performance during the previous program year (PY 2022).

[1] Due to data limitations discussed in Section ES.3 we use PY2022 as the basis for our ex-ante forecast.

[2] There were no customers enrolled in SDG&E's BIP in 2023. Therefore, ex-post and ex-ante analyses are not included in the PY23 BIP load impact report. On December 14, 2023, Decision (D.) 23-12-005 (page 45 and 46) ordered SDG&E to sunset the Base Interruptible Program (BIP) at the end of 2023.

EXECUTIVE SUMMARY

This report documents ex-post and ex-ante load impact evaluations for the statewide Base Interruptible Program ("BIP") in place at Pacific Gas and Electric Company ("PG&E") and Southern California Edison ("SCE") in 2023. The report provides estimates of ex-post load impacts that occurred during events called in 2023 and an ex-ante forecast of load impacts for 2024 through 2034 that is based on the investor-owned utilities ("IOU's") enrollment forecasts and the ex-post load impacts estimated for the 2022 program year.[3]

The primary research questions addressed by this evaluation are:

1. What were the BIP load impacts in 2023?
2. How were the load impacts distributed across industry groups?
3. How were the load impacts distributed across CAISO local capacity areas?
4. What are the ex-ante load impacts for 2024 through 2034?

ES.1 Resources Covered

Base Interruptible Program

Base Interruptible Programs are statewide voluntary programs that offer customers a monthly capacity bill credit in exchange for the commitment to reduce their energy consumption to an amount that meets the customer's minimum operational requirements, also known as a Firm Service Level ("FSL").

There are a number of similarities and differences in the BIPs offered by the California IOUs. The programs consist of an interruptible tariff available to both customers and aggregators with a minimum demand.

PG&E called three events in 2023. The first event was called as a transmission emergency on Thursday July 20th. The event lasted from 8:27 to 8:32 p.m. The second event was called from 4:00 to 6:00 p.m. on Tuesday September 26th. The third event was called from 4:00 to 6:00 p.m. on Tuesday October 24th.

SCE called one event in 2023. The SCE event was also called in response to the transmission emergency on Thursday July 20th. The event took place from 7:45 to 8:19 p.m.

SDG&E did not call any events in 2023. On December 14, 2023, Decision (D.) 23-12-005 (page 45 and 46) ordered SDG&E to sunset the BIP at the end of 2023.

Enrollment

Enrollment in PG&E's BIP decreased relative to PY2022, from 258 to 249 customers. Of the 249 customers who were enrolled in BIP, only 214 were called to the July 20th event. The sum of enrolled customers' coincident maximum demands was 242.7 MW, or

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[3] 2022 is used as the basis for ex-ante due to data limitations during the 2023 program year.

0.97 MW for the average service agreement during the July 20th event day.[4] Figure ES.1 illustrates the distribution of BIP load across the indicated industry types. The Manufacturing industry group contains 48 percent of the enrolled load.

Figure ES.1: Distribution of BIP Enrolled Load by Industry Type, PG&E

[redacted]

SCE's enrollment in BIP was 351 service accounts during the typical 2023 event day, which is an increase relative to the 343 enrolled service accounts during PY2022. These accounted for a total of 680.1 MW of maximum demand, or 1.94 MW per service account during the July 20th event day. Manufacturers make up 60 percent of the enrolled load. Figure ES.2 illustrates the distribution of SCE's BIP load across the indicated industry types.

Figure ES.2: Distribution of BIP Enrolled Load by Industry Type, SCE

[redacted]

There were no customers enrolled in SDG&E's BIP in 2023.

[4] A customer's coincident maximum demand ("Enrolled Load" in Figures ES.1 and ES.2) is defined as its demand during the hour with the highest aggregate demand on the typical event day, including the estimated load impacts (i.e., using the reference loads).

ES.2 Evaluation Methodology

We estimated ex-post load impacts using regression analysis of customer-level hourly load data. Individual-customer regression equations modeled hourly load as a function of several variables designed to control for factors affecting consumers' hourly demand levels, including:

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

BIP load impacts for each event were obtained by summing the estimated hourly event coefficients from the customer-level regressions. The individual customer models allow the development of information on the distribution of load impacts across industry types and geographical regions, by aggregating customer load impacts for the relevant industry group or local capacity area.

ES.3 Ex-post Load Impacts

PY2023 Ex-post Reporting Changes

In PY2023 neither PG&E nor SCE called a full event that lasted for at least one hour. SCE had one event that lasted 34 minutes (7:45 to 8:19 p.m.). PG&E's emergency event on that same date (July 20th) was five minutes in duration (8:27 to 8:32 p.m.), during which 214 of the 249 enrolled customers were called. PG&E also called two re-test events in September and October that lasted for two hours each, but only 14 and 6 customers were called during those events, respectively.

Historically impacts have been assessed using hourly data and reported over full event hours. Using hourly data to estimate and report impacts for an event that lasted less than a full hour leads to artificially low results because customers are not responding during the entire reporting period. Utilities provided 15-minute interval data to analyze program performance during the July 20th, 2023 ex-post events at a more granular level. This allows us to examine load impacts that are more reflective of program performance than the 60-minute data but still does not have the resolution to fully reflect program performance. The required tables and figures are still presented at an hourly level in this report; however, a 15-minute analysis is included to provide additional insights about how customers responded during the event window for PG&E and SCE.

The lack of full ex-post event hours in this evaluation makes comparisons to prior program years irrelevant. Therefore, we do not present some of our usual reconciliations, such as the comparison of previous and current ex-post impacts. As well, we do not use the PY2023 typical event day results as the basis for our ex-ante analysis. Instead, we use the PY2022 typical event day results to build our ex-ante forecast.

PG&E's July 20th event covered two 15-minute windows, 8:15-8:30 and 8:30-8:45 p.m. The event was active for three and two minutes, respectively during each window. Therefore, the 15-minute results are, like the hourly results, artificially low due to a lack of full event intervals. Despite this limitation, the report includes 15-minute results from the 8:15-8:30 and 8:30-8:45 p.m. window to serve as a contrast to the traditional hourly reporting.

SCE's July 20th event occurred over three 15-minute windows. The windows are 7:45-8:00, 8:00-8:15, and 8:15-8:30 p.m. Of those three windows, only two were full event windows. In addition, the 30-minute notification customers did not reach the end of their notification period until 8:15 p.m. (in contrast, the 15-minute notification customers reached the end of their notification period at 8:00 p.m.), which means that there is no 15-minute period during which we would expect full program response.

PY2023 Ex-post Load Impacts

Table ES.1 summarizes the number of customers called, load impact, percentage load impact, and FSL achievement rate by event for PG&E when analyzed at an hourly level. The total program load impact for PG&E's July 20th event averaged 36 MW, or 22 percent of enrolled load, representing 31 percent of the reduction required to meet the aggregate FSL across the 214 customers who were called for the event when assessed at the hourly level. When assessed at the 8:30-8:45 p.m. 15-minute level, the load impact increases to 54.4 MW, which represented 47 percent of the reduction required to meet the aggregate FSL. As described above, neither the 15-minute nor hourly load impacts are able to fully reflect BIP participant performance due to the short event window.

Table ES.1: Summary of Event-hour Load Impact by Event, *PG&E*

Event	Date	Day of Week	# Service Agreements	Estimated Load Impact (MWh/h)	% LI	Estimated LI / LI at FSL
1	7/20/2023	Thu.	214	36	22%	31%
2	9/26/2023	Tue.	[redacted]			
3	10/24/2023	Tue.				
Typical Event Day			**214**	**36**	**22%**	**31%**

Table ES.2 displays a summary of load impact results for SCE's single BIP event day when analyzed at the hourly level. The total program load impact at the hourly level for the July 20th event was 344 MW, representing a 56 percent decrease relative to the reference load. This was 72 percent of the reduction required to meet the aggregate FSL. When assessed over the 15-minute interval from 8:00 to 8:15 p.m., SCE's customers reduced their load by 377 MW, which represents a 61 percent decrease relative to the reference load and 79 percent of the reduction required to meet the aggregate FSL. As described above, neither the 15-minute nor hourly load impacts are able to fully reflect BIP participant performance due to the short event window overlapping the event notification period.

Table ES.2: Summary of Event-hour Load Impact by Event, *SCE*

Event	Date	Day of Week	# Service Agreements	Estimated Load Impact (MWh/h)	% LI	Estimated LI / LI at FSL
1	7/20/2023	Thu.	351	344	56%	72%
Typical Event Day			**351**	**344**	**56%**	**72%**

ES.4 Ex-ante Load Impacts

Scenarios of ex-ante load impacts are developed by combining enrollment forecasts with per-customer reference loads and load impacts, which were developed using the results of the ex-post load impact evaluation. The most recent full ex-post event is used as the basis for ex-ante impacts. As there were no full events called for either utility in PY2023, the PY2022 typical event day (September 6th, 2022 for both PG&E and SCE) is used as the basis for ex-ante impacts.

PG&E forecasts increasing enrollments from 191 customers in 2024 to 330 customers by the end of 2034. SCE predicts enrollments to remain constant at 303 service accounts from 2024 through 2034.

Figure ES.3 shows PG&E's ex-ante load impacts by weather year (1-in-2 and 1-in-10 for both utility-specific and CAISO-coincident peak conditions) for the August event day, averaged over the resource adequacy window 4 to 9 p.m. The increases in load impact are due to increasing enrollment counts as well as the end of ELRP after 2027.[5] Figures ES.4 shows the ex-ante load impacts for SCE. The ex-ante load impacts illustrate the lack of weather sensitivity at the aggregate level. The forecast remains constant as there are no forecasted changes in enrollment and weather patterns remain constant across years.

[5] The BIP ex-post and ex-ante load impact is capped at a 100% FSL achievement rate for customers that are dually enrolled in BIP and ELRP. Any load impact above the 100% FSL achievement rate is credited towards ELRP. After the end of ELRP in November 2027, BIP load impacts are allowed to exceed the 100% FSL achievement rate for customers who have demonstrated the ability to surpass this threshold prior to enrollment in ELRP.

Figure ES.3: Average August Ex-Ante Load Impacts by Year and Scenario, *PG&E*

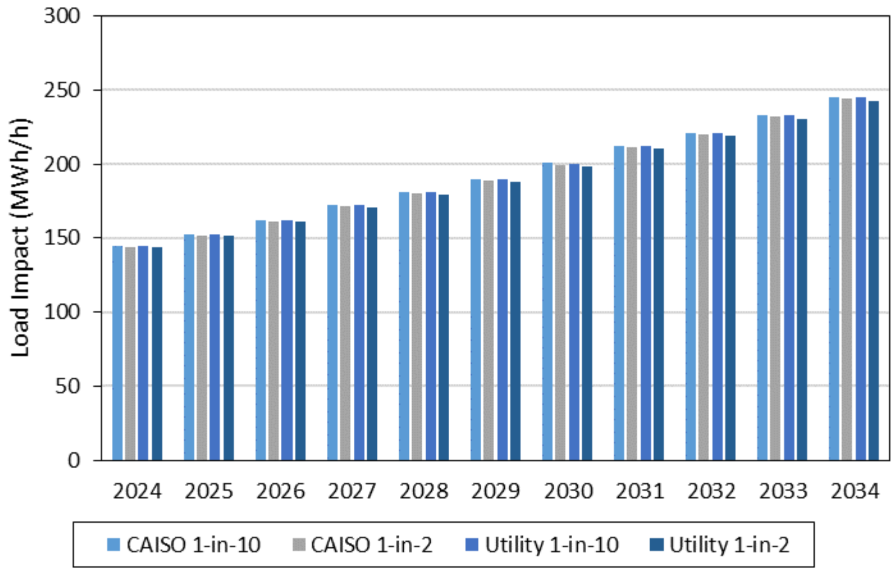
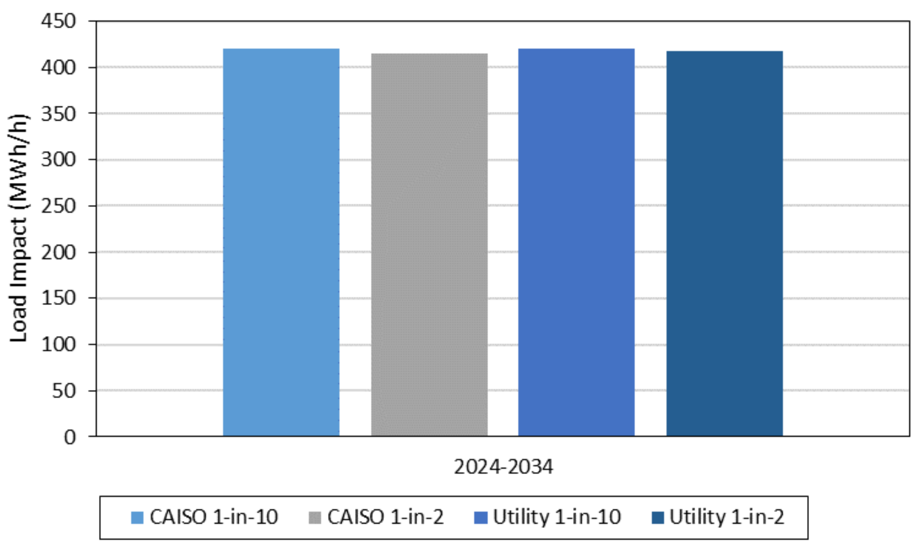


Figure ES.4: Average August Ex-Ante Load Impacts by Year and Scenario, *SCE*



1. INTRODUCTION AND PURPOSE OF THE STUDY

This report documents ex-post and ex-ante load impact evaluations for the statewide Base Interruptible Program ("BIP") in place at Pacific Gas and Electric Company ("PG&E") and Southern California Edison ("SCE") in 2023. The report provides estimates of ex-post load impacts that occurred during events called in 2023 and an ex-ante forecast of load impacts for 2024 through 2034 that is based on the IOU's enrollment forecasts and the ex-post load impacts estimated for the 2022 program year.

The primary research questions addressed by this evaluation are:

1. What were the BIP load impacts in 2023?
2. How were the load impacts distributed across industry groups?
3. How were the load impacts distributed across CAISO local capacity areas?
4. What are the ex-ante load impacts for 2024 through 2034?

The report is organized as follows. Section 2 contains a description of the programs, the enrolled customers, and the events called; Section 3 describes the methods used in the study; Section 4 contains the detailed ex-post load impact results; Section 5 describes the ex-ante load impact forecast; Section 6 contains descriptions of differences in various scenarios of ex-post and ex-ante load impacts; and Section 7 provides recommendations. Appendix A contains an assessment of the validity of the study.

2. DESCRIPTION OF RESOURCES COVERED IN THE STUDY

This section provides details on the Base Interruptible Programs, including the characteristics of the participants enrolled in the programs and the events called in 2023.

2.1 Program Descriptions

Base Interruptible Programs are statewide voluntary programs that offer customers a monthly capacity bill credit in exchange for the commitment to reduce their energy consumption to an amount that meets the customer's minimum operational requirements, also known as a Firm Service Level ("FSL").

There are a number of similarities and differences in the BIPs offered by the California investor-owned utilities ("IOUs"). The programs consist of an interruptible tariff available to both customers and aggregators with a minimum demand. Descriptions of each utility's BIP are provided below.

SCE's Base Interruptible Program

SCE's BIP is designed for customers and aggregators with demands of 200 kW and above. The program includes two participation options:

- Option A, which requires a customer or Aggregated Group to reduce its demand to its FSL within 15 minutes of a Notice of Interruption; or

- Option B, which requires a customer or Aggregated Group to reduce its demand to its FSL within 30 minutes of a Notice of Interruption.

Excess energy charges are applied when a customer is unable to reduce its demand to its FSL during events. Interruption events for an individual BIP customer or aggregated group are limited to no more than one event per day (lasting no more than 6 hours), ten in any calendar month, and a total of 180 hours per calendar year.

An interruption event may be called by the California Independent System Operator ("CAISO") or SCE at any time during the year.

PG&E's Base Interruptible Program

PG&E's BIP, a tariff-based program, is designed to provide load reductions on PG&E's system on a day-of basis when the CAISO issues a curtailment notice or in the event of a transmission or distribution system contingency. Customers must be notified at least 30 minutes prior to the event. BIP operates year-round, with program limits at a maximum of one event per day and six hours per event. The program cannot exceed ten events during a calendar month or 180 hours per calendar year.

Participants who do not comply with the curtailment order are subject to an excess energy charge on any energy used above their FSL for the duration of the event. The potential for excess energy charges has resulted in a high compliance rate. PG&E may require a customer that does not meet program requirements to reduce its load down to or below its FSL to re-test, modify its FSL, or de-enroll from the program.

Directly enrolled customers may participate in PG&E's Underfrequency Relay (UFR) Program. The UFR Program is not available to customers enrolled through aggregators. Under the UFR Program, customers agree to be subject at all times to automatic interruptions of service caused by an underfrequency relay device that may be installed by PG&E. PG&E may require up to 3-years' written notice for termination of participation in the UFR Program. Customers participating in the UFR program will receive a demand credit on a monthly basis based on their average monthly on-peak period demand in the summer and their average monthly partial-peak demand in the winter.

SG&E's Base Interruptible Program

SDG&E's BIP is a voluntary program that offers participants a monthly capacity bill credit in exchange for committing to reduce their demand to a contracted FSL on short notice during emergency situations. Non-residential customers who can commit to curtail 15 percent of monthly peak demand are eligible for the program. Customers are notified no later than 20 minutes before the event. The monthly incentive payments in 2023 were $6.30 per kW during January through December months. Curtailment events for an individual BIP customer are limited to a single 4-hour event per day, no more than 10 events per month and no more than 120 event hours per calendar year. A curtailment event may be called under BIP at any time during the year.

There were no SDG&E BIP participants in 2023. Therefore, ex-post and ex-ante analyses are not included in the PY23 BIP load impact report. On December 14, 2023, Decision (D.) 23-12-005 (page 45 and 46) ordered SDG&E to sunset the BIP at the end of 2023.

2.2 Participant Characteristics

2.2.1 Development of Customer Groups

In order to assess differences in load impacts across customer types, the program participants were categorized according to eight industry types. The industry groups are defined according to their applicable two-digit North American Industry Classification System (NAICS) codes:

1. Agriculture, Mining and Oil and Gas, Construction: 11, 21, 23
2. Manufacturing: 31-33
3. Wholesale, Transport, other Utilities: 22, 42, 48-49
4. Retail stores: 44-45
5. Offices, Hotels, Finance, Services: 51-56, 62, 72
6. Schools: 61
7. Entertainment, Other services and Government: 71, 81, 92
8. Other or unknown.

In addition, each utility provided information regarding the CAISO Local Capacity Area (LCA) in which the customer resides (if any).[6]

2.2.2 Program Participants by Type

The following sets of tables summarize the characteristics of the participating customer accounts, including size, industry type, and LCA. Table 2.1 shows BIP enrollment by industry group for PG&E during the typical event day. Enrollment in PG&E's BIP decreased relative to PY2022, from 258 to 249.[7] The sum of enrolled customers' coincident maximum demands[8] was 242.7 MW, or 0.97 MW for the average service agreement. The manufacturing industry group contains 48 percent of the enrolled load.

[6] Local Capacity Area (or LCA) refers to a CAISO-designated load pocket or transmission constrained geographic area for which a utility is required to meet a Local Resource Adequacy capacity requirement. There are currently seven LCAs within PG&E's service area and 3 in SCE's service territory. In addition, PG&E has many accounts that are not located within any specific LCA.
[7] "Enrollment" is defined as the enrollment on the (July 20th) typical event day in PY2023 compared to the September 6th typical event day in PY2022.
[8] Customer-level demand ("Sum of Max MW" in the tables) is calculated as the coincident maximum demand on the event days listed in footnote 3—demand during the hour with the highest aggregate demand that day—including the estimated load impacts (i.e., using the reference loads).

Table 2.1: BIP Enrollees by Industry Group, *PG&E*

Industry	Enrolled	Sum of Max MWh/h[9]	Percent of Max MWh/h	Average Max MWh/h[10]
Agriculture, Mining & Construction	[redacted]	[redacted]	[redacted]	[redacted]
Manufacturing	66	117.6	48.4%	1.78
Wholesale, Transport, other utilities	76	38.4	15.8%	0.51
Retail stores	[redacted]	[redacted]	[redacted]	[redacted]
Offices, Hotels, Finance, Services	[redacted]	[redacted]	[redacted]	[redacted]
Schools	[redacted]	[redacted]	[redacted]	[redacted]
Other or unknown	[redacted]	[redacted]	[redacted]	[redacted]
Total	**249**	**242.7**	**-**	**0.97**

Table 2.2 shows comparable information on BIP enrollment for SCE. SCE's enrollment in BIP was 351 service accounts on the July 20th, 2023 event day, which is an increase relative to the 343 enrolled service accounts during PY2022. These accounted for a total of 680.1 MW of maximum demand, or 1.94 MW per service account. Manufacturers make up 60 percent of the enrolled load.

Table 2.2: BIP Enrollees by Industry Group, *SCE*

Industry	Enrolled	Sum of Max MWh/h	Percent of Max MWh/h	Average Max MWh/h
Agriculture, Mining & Construction	31	[redacted]	[redacted]	[redacted]
Manufacturing	227	408.6	60.1%	1.80
Wholesale, Transport, other utilities	70	[redacted]	[redacted]	[redacted]
Retail stores	2	[redacted]	[redacted]	[redacted]
Offices, Hotels, Finance, Services	5	[redacted]	[redacted]	[redacted]
Schools	1	[redacted]	[redacted]	[redacted]
Institutional/Government	1	[redacted]	[redacted]	[redacted]
Other (or unknown)	14	[redacted]	[redacted]	[redacted]
Total	**351**	**680.1**	**-**	**1.94**

Tables 2.3 and 2.4 show BIP enrollment by local capacity area for PG&E and SCE, respectively. The greatest portion of PG&E's enrolled load is in the "Kern" LCA category. For SCE, 69.9 percent of enrolled load is in the LA Basin.

[9] "Sum of Max MW" is defined as the sum of the event-day coincident maximum demands across service accounts. The reported values include the estimated load impacts.
[10] "Ave. Max MW" is calculated as "Sum of Max MW" divided by the "# of Service Accounts."

Table 2.3: BIP Enrollees by Local Capacity Area, *PG&E*

Local Capacity Area	Enrolled	Sum of Max MWh/h	Percent of Max MWh/h	Average Max MWh/h
Greater Bay Area	30	[redacted]		
Greater Fresno Area	74			
Humboldt	2			
Kern	26			
North Coast / North Bay	7			
Other	75			
Sierra	18			
Stockton	17			
Total	**249**	**242.7**	0.0%	**0.97**

Table 2.4: BIP Enrollees by Local Capacity Area, *SCE*

Local Capacity Area	Enrolled	Sum of Max MWh/h	Percent of Max MWh/h	Average Max MWh/h
LA Basin	286	475.6	69.9%	1.66
Outside Basin	15	[redacted]		
Ventura	50			
Total	**351**	**680.1**	**-**	**1.94**

2.3 Event Days

Table 2.5 lists BIP event days and hours for the two IOUs in 2023. PG&E called three events, one of which was a transmission emergency that occurred on July 20th and two of which were re-test events called on September 26th and October 24th, respectively. SCE called one transmission emergency event that occurred on July 20th.

Table 2.5: BIP Event Days

Date	Day of Week	PG&E	SCE
7/20/2023	Thursday	Transmission Emergency 8:27 – 8:32 p.m.	Transmission Emergency 7:45 – 8:19 p.m.
9/26/2023	Tuesday	Re-test 4:00 – 6:00 p.m.	
10/24/2023	Tuesday	Re-test 4:00 – 6:00 p.m.	

3. STUDY METHODOLOGY

3.1 Overview

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

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

The models use the level of hourly demand (kW) as the dependent variable and a separate equation is estimated for each enrolled customer. As a result, the coefficients on the event day/hour variables are direct estimates of the ex-post load impacts. For example, a BIP hour 15 event coefficient of -100 would mean that the customer reduced load by 100 kWh during hour 15 of that event day relative to its normal usage in that hour.

We tested a variety of weather variables in an attempt to determine which set best explains usage on event-like non-event days. Each customer was first classified according to whether it is weather-sensitive. We then selected specifications by customer group, defined by industry group and weather sensitivity (i.e., sixteen groups, with eight industry groups for each of the non-weather-sensitive customers and weather-sensitive customers). This process is done separately for weekday and weekend/holiday models and its results are explained in Appendix A.

In PY2023 we also examine 15-minute interval data provided by the IOUs in order to better understand program response during multiple events that did not last a full hour.

3.2 Description of Methods

3.2.1 Regression Model

The following is a general form of the model that was separately estimated for each enrolled BIP customer. The specific form of the model varied across utilities and customer groups, as shown in Appendix A. Table 3.1 below describes the terms included in this equation for the observed demand in a given hour h and date d:

$$
\begin{aligned}
Q_t = & \sum_{i=1}^{24}(b_i^h \times h_{i,t}) + \sum_{Evt=1}^{E}\sum_{i=1}^{24}(b_{i,Evt}^{BIP} \times h_{i,t} \times BIP_t) + \sum_{DR}\sum_{i=1}^{24}(b_i^{DR} \times h_{i,t} \times OtherEvt_{i,t}^{DR}) \\
& + \sum_{i=1}^{24}(b_i^{Weather} \times h_{i,t} \times Weather_t) + \sum_{i=1}^{24}(b_i^{MornLoad} \times h_{i,t} \times MornLoad_{i,t}) \\
& + \sum_{j=2}^{5}(b_j^{DTYPE} \times DTYPE_{j,t}) + \sum_{i=2}^{24}(b_i^{MON} \times h_{i,t} \times MON_t) + \sum_{i=2}^{24}(b_i^{FRI} \times h_{i,t} \times FRI_t) \\
& + \sum_{i=6}^{10}(b_i^{MONTH} \times MONTH_{i,t}) + \sum_{i=2}^{24}(b_i^{SUMMER} \times h_{i,t} \times SUMMER_t) + e_t
\end{aligned}
$$

Table 3.1: Descriptions of Variables included in the Ex-post Regression Equation

Variable Name	Variable Description
Q_t	the demand in hour *t* for a BIP customer
The various *b*'s	the estimated parameters
$h_{i,t}$	an indicator variable for hour *i*, equal to one when *t* corresponds to hour *i* of a given day
BIP_t	an indicator variable for program event days
E	the number of program event days that occurred during the program year
$OtherEvt_{i,t}^{DR}$	an indicator variable for event day *DR* of other demand response programs in which the customer is enrolled (e.g. *DR* = CPP Event 1, CPP Event 2, ...)
$Weather_t$	the weather variables selected using our model screening process
$MornLoad_t$	a variable equal to the average of the day's load in hours 1 through 10 (may be excluded via model screening)
$DTYPE_{j,t}$	a series of indicator variables for each day of the week
MON_t, FRI_t,	indicator variables for Monday and Friday (Sunday hourly indicator variables are included in models that include weekend dates)
$MONTH_{j,t}$	a series of indicator variables for each month (model screening may include separate hourly profiles by month)
$SUMMER_t$	an indicator variable for the summer pricing season[11]
e_t	the error term

The *OtherEvt* variables help the model explain load changes that occur on event days for programs in which the BIP customers are dually enrolled. (In the absence of these variables, any load reductions that occur on such days may be falsely attributed to other included variables, such as weather conditions or day type variables.) The "morning load" variables are included in the same spirit as the day-of adjustment to the 10-in-10 baseline settlement method used in some DR programs. That is, those variables help adjust the reference loads (or the loads that would have been observed in the absence of

[11] The summer pricing season is June through September for SCE. PGE has two separate summer definitions which varies by rate: May through October and June through September.

an event) for factors that affect pre-event usage but are not accounted for by the other included variables.[12]

The model allows for the hourly load profile to differ by time periods, which can vary across specifications selected for each customer group. The time-based patterns reflect day of week, with separate profiles for Monday, Tuesday through Thursday, and Friday; month of year; and pricing season (i.e., summer versus winter), to account for potential customer load changes in response to seasonal changes in rates.

Separate models were estimated for each customer. The load impacts were aggregated across customer accounts as appropriate to arrive at program-level load impacts, as well as load impacts by industry group, local capacity area (LCA), notification type (applicable for SCE), and Sub-LAP (provided in Protocol Tables).

A parallel set of winter models was estimated for each customer, which were used to simulate ex-ante reference loads for those months.[13] The structure matches the model described above, with the appropriate month indicators substituted in. A separate model selection process was conducted for the winter models.

3.2.2 Development of Uncertainty-Adjusted Load Impacts

The Load Impact Protocols require the estimation of uncertainty-adjusted load impacts. In the case of ex-post load impacts, the parameters that constitute the load impact estimates are not estimated with certainty. We base the uncertainty-adjusted load impacts on the variances associated with the estimated load impact coefficients.

Specifically, we added the variances of the estimated load impacts across the customers who are called during the event in question. These aggregations were performed at either the program level, by industry group, by LCA, or by SubLAP, as appropriate. The uncertainty-adjusted scenarios were then simulated under the assumption that each hour's load impact is normally distributed with the mean equal to the sum of the estimated load impacts and the standard deviation equal to the square root of the sum of the variances of the errors around the estimates of the load impacts. Results for the 10th, 30th, 70th, and 90th percentile scenarios are generated from these distributions.

In order to develop the uncertainty-adjusted load impacts associated with the average event hour (i.e., the bottom rows in the tables produced by the ex-post table generator), we estimated an additional set of customer-specific regression models in which each event day's average event-hour load impact is estimated using a single variable (rather than the hour-specific variables used in the primary model described above). The standard error associated with these event-specific coefficients serves as the basis of the average event-hour uncertainty-adjusted load impacts for each ex-post event day. The

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[12] Events that occur later in the day can have load impacts that carry over into the next day, affecting the next day's morning load. As a result, a consecutive event day that has lower morning loads, caused by the previous event day's load impact, can result in estimating lower reference loads during later hours of the day. Underestimating the reference load will also lead to underestimating the load impact for the consecutive event day.

[13] The summer models were estimated over the months May through for September for each utility. The ex-ante winter models cover all other months.

standard errors are used to develop the uncertainty-adjusted scenarios in the same manner as the hour-specific standard errors in the primary model.

4. DETAILED STUDY FINDINGS

The primary objective of the ex-post evaluation is to estimate the aggregate and per-customer BIP event-day load impacts for each utility. In this section we first summarize the estimated BIP load impacts for each of the utilities during the July 20th events using 15-minute interval data. This allows us to examine load impacts that are more reflective of program performance than the 60-minute data but still does not have the resolution to fully reflect program performance during these partial event hours. We summarize load impacts for all events using a metric of estimated *average hourly load impacts* by event and for the average event for both PG&E and SCE. We also report average hourly load impacts for the average event by industry type and local capacity area.

We then present tables of *hourly* load impacts for an *average event* (also referred to as a "typical event day") in the format required by the Load Impact Protocols adopted by the California Public Utilities Commission (CPUC) in Decision (D.) 08-04-050 ("the Protocols"), including risk-adjusted load impacts at different probability levels, and figures that illustrate the reference loads, observed loads and estimated load impacts.

4.1 PG&E Load Impacts

4.1.1 15-Minute Impacts for the July 20th ex-post event

Table 4.1 summarizes the average reference loads and load impacts at the 15-minute level for PG&E's July 20th ex-post event. The results are reported in MWh/60-minutes to be comparable to the hourly load impacts we typically report. The event was called as a transmission emergency and lasted from 8:27-8:32 p.m. across two 15-minute intervals, which means that the reported results for each 15-minute interval will also be artificially low because on two or three minutes of the 15-minute periods were called for the event. Customers had a lower 15-minute FSL Achievement Rate than the hourly rate during the first 15-minute interval but performed above the hourly FSL achievement rate in the second 15-minute interval of the event as well as in the first 15-minute window after the event ended. This is evidence of some persistence of load impacts that occur following BIP event hours. However, the FSL achievement rates are well below the levels we expect based on full-hour events in prior program years. Again, this difference reflects data limitations during this program year rather than a degradation of program performance.

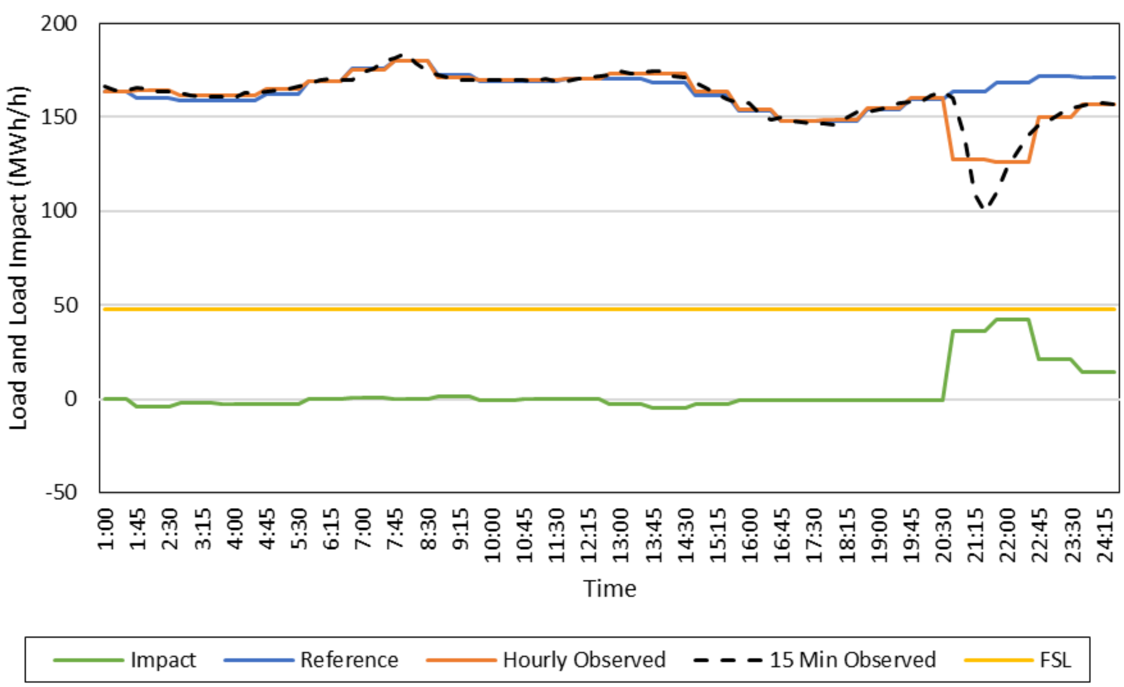
Table 4.1: July 20th Load Impacts by 15-minute Period, *PG&E*

Interval	Reference (MWh/h)	Hourly Impact (MWh/h)	15-min Impact (MWh/h)	Hourly FSL Ach	15-min FSL Ach
8:15-8:30 p.m.	40.9	36.3	23.5	31%	20%
8:30-8:45 p.m.	40.9	36.3	54.5	31%	47%
8:45-9:00 p.m.	40.9	36.3	63.9	31%	55%
Average over event window	**40.9**	**9.1**	**39.0**	**31%**	**34%**

*Yellow highlighting denotes intervals that include the event. By 8:45-9:00 p.m., the event was over.

Figure 4.1 illustrates the reference load and FSL as well as the difference between the 15-minute observed loads and the hourly observed loads. As illustrated in the table above, customers responded more than the hourly load data indicates when more granular data is examined.

Figure 4.1: BIP 15-Minute Loads for July 20th PG&E



4.1.2 Average Event-hour Load Impacts by Industry Group and LCA

Table 4.2 summarizes average event-hour reference loads and load impacts at the hourly program level for each of PG&E's 2023 events.[14] Each of the events was called as an emergency event. The highest load impacts are observed on July 20th. While the event

[14] Typically, results are averaged over full event hours only, i.e., partial event hours are omitted. Because the July 20th event has no full event hours, we report results during the longest partial event hour (HE 21).

was much shorter than the two re-test events, it is the only event where most of the customers were called which is why it is defined as the typical event day. On the typical event day, the average estimated reference load across event hours was 164 MWh/h. The load impact was 36 MWh/h, resulting in a percentage load impact of 22 percent. There were 214 customers called for the first event, 14 customers called for the event on September 26th, and 6 customers called on October 24th.

Table 4.2: Average Event-hour Load Impacts by Event, *PG&E*

Event	Date	Day of Week	# Service Agreements Called	Estimated Reference Load (MWh/h)	Observed Load (MWh/h)	Estimated Load Impact (MWh/h)	% LI[15]
1	7/20/2023	Thu.	214	164	128	36	22%
2	9/26/2023	Tue.	[redacted]				
3	10/24/2023	Tue.					
Typical Event Day			**214**	**164**	**128**	**36**	**22%**

Table 4.3 compares the observed loads and FSLs for each event. Event-day performance at the program level is shown in the rightmost column, as measured by the ratio of the estimated load impact (shown in Table 4.2) to the load impact that would have occurred if customers had (in aggregate) exactly attained their FSL. That is, a 100% value in that column would indicate that observed loads exactly matched the FSL (in aggregate, when averaged across event hours). A value less than 100% indicates aggregate under-performance (i.e., observed loads above the FSL). The hourly FSL achievement rate was 31 percent on July 20th, , [redacted]. Recall that the FSL achievement percentage for the July 20th is not reflective of actual program performance because of the mismatch between the event period (5 minutes across two 15-minute intervals) and the available resolution of the customer load data. This problem does not apply to the two re-test events, which covered two full event hours each.

Table 4.3: Average Event-hour Observed Loads and FSLs by Event, *PG&E*

Event	Date	Day of Week	Observed Load (MWh/h)	Firm Service Level (MWh/h)	Estimated LI / LI at FSL
1	7/20/2023	Thu.	128	48	31%
2	9/26/2023	Tue.	[redacted]		
3	10/24/2023	Tue.			
Typical Event Day			**128**	**48**	**31%**

Table 4.4 summarizes average event-hour BIP load impacts by industry group for the typical event day. The Manufacturing industry group accounted for the largest share of the load impacts, with a 22 MW average event-hour load reduction.

[15] The percentage load impact is calculated as the load impact divided by the reference load.

Table 4.4: Typical Event Day Load Impacts – *PG&E, by Industry Group*

Industry Group	# of Service Agreements Called	Estimated Reference Load (MWh/h)	Observed Load (MWh/h)	Estimated Load Impact (MWh/h)	% LI
Agriculture, Mining & Construction	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Manufacturing	54	59.5	37.1	22.4	38%
Wholesale, Transport, Other Utilities	60	24.1	18.8	5.2	22%
Retail	0	N/A	N/A	N/A	N/A
Offices, Hotels, Finance, Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Schools	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Other or Unknown	0	N/A	N/A	N/A	N/A
Total	**214**	**163.6**	**127.3**	**36.3**	**22%**

Table 4.5 summarizes the typical event day load impacts by local capacity area (LCA), showing that the highest share of the load impacts came customers in the Other LCA.

Table 4.5: Typical Event Day Load Impacts – *PG&E, by LCA*

Local Capacity Area	# of Service Agreements Called	Estimated Reference Load (MWh/h)	Observed Load (MWh/h)	Estimated Load Impact (MWh/h)	% LI
Greater Bay Area	6	[redacted]	[redacted]	[redacted]	[redacted]
Greater Fresno	74	[redacted]	[redacted]	[redacted]	[redacted]
Humboldt	0	[redacted]	[redacted]	[redacted]	[redacted]
Kern	26	[redacted]	[redacted]	[redacted]	[redacted]
Northern Coast	4	[redacted]	[redacted]	[redacted]	[redacted]
Other	71	[redacted]	[redacted]	[redacted]	[redacted]
Sierra	17	[redacted]	[redacted]	[redacted]	[redacted]
Stockton	16	[redacted]	[redacted]	[redacted]	[redacted]
Total	**214**	**163.6**	**127.3**	**36.3**	**22.2%**

4.1.2 Hourly Load Impacts

Table 4.6 presents hourly PG&E BIP load impacts at the program level in the manner required by the Protocols. BIP load impacts were estimated from the individual customer regressions for customers enrolled at the time of the event. The table reflects the July 20th event when 214 customers were called.

Table 4.6: BIP Hourly Load Impacts for the Typical Event Day, *PG&E*

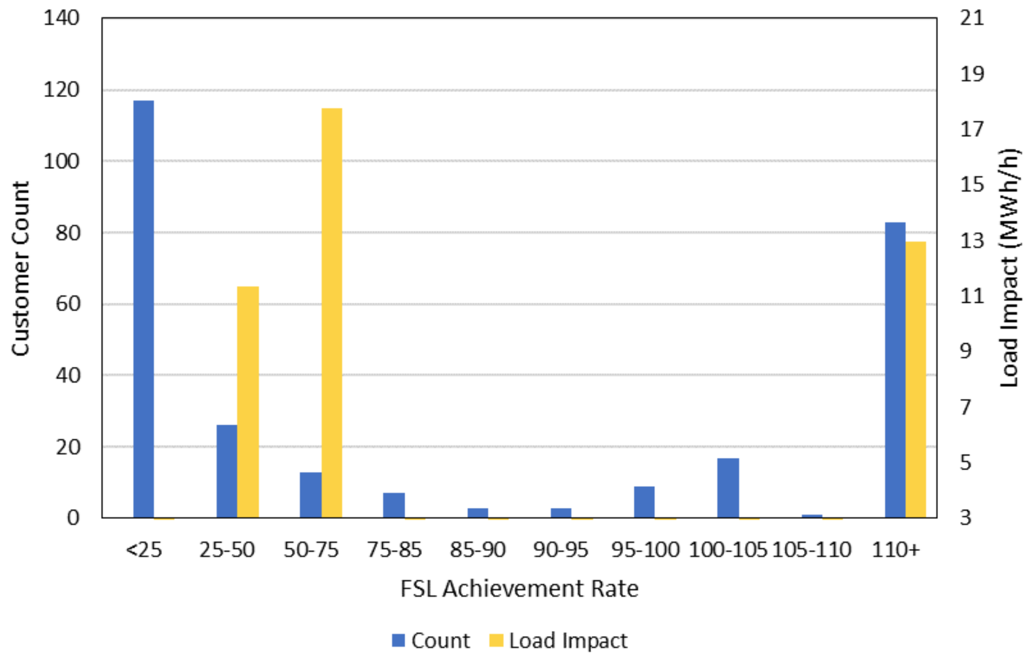
Hour Ending	Estimated Reference Load (MWh/hour)	Event Day Load (MWh/hour)	Estimated Load Impact (MWh/hour)	Average Temperature (°F)	Uncertainty Adjusted Impact (MWh/hr)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	163.7	163.5	0.1	77.4	-0.6	-0.2	0.1	0.4	0.8
2	160.4	164.5	-4.1	75.9	-4.8	-4.4	-4.1	-3.7	-3.3
3	159.0	161.3	-2.3	74.3	-3.0	-2.6	-2.3	-2.0	-1.6
4	158.8	161.8	-3.0	72.6	-3.7	-3.3	-3.0	-2.7	-2.3
5	161.9	164.8	-2.9	71.3	-3.5	-3.1	-2.9	-2.6	-2.2
6	169.2	169.3	-0.1	69.8	-0.8	-0.4	-0.1	0.1	0.6
7	175.9	174.9	1.0	69.1	0.4	0.8	1.0	1.3	1.7
8	179.9	179.8	0.1	71.5	-0.7	-0.2	0.1	0.4	0.9
9	172.6	170.9	1.6	74.9	0.7	1.3	1.6	2.0	2.5
10	169.3	169.7	-0.4	78.5	-1.4	-0.8	-0.4	0.0	0.7
11	169.3	169.6	-0.2	82.6	-1.3	-0.7	-0.2	0.2	0.8
12	170.3	170.5	-0.2	86.5	-1.3	-0.7	-0.2	0.3	1.0
13	170.6	173.5	-2.9	89.6	-4.1	-3.4	-2.9	-2.4	-1.6
14	168.5	173.1	-4.6	92.7	-5.8	-5.1	-4.6	-4.1	-3.4
15	161.3	163.8	-2.5	95.1	-3.6	-3.0	-2.5	-2.1	-1.4
16	153.4	153.9	-0.4	97.1	-1.5	-0.8	-0.4	0.0	0.7
17	147.7	148.1	-0.4	98.1	-1.5	-0.9	-0.4	0.0	0.7
18	148.1	148.5	-0.5	97.8	-1.6	-0.9	-0.5	0.0	0.7
19	154.1	155.0	-0.8	96.6	-2.0	-1.3	-0.8	-0.4	0.3
20	159.7	160.3	-0.7	94.4	-1.9	-1.2	-0.7	-0.2	0.5
21	163.6	127.3	36.3	91.3	35.1	35.8	36.3	36.8	37.5
22	168.4	126.2	42.2	87.9	40.9	41.7	42.2	42.7	43.4
23	171.5	150.2	21.3	84.8	20.0	20.8	21.3	21.9	22.7
24	171.1	157.0	14.1	81.6	12.8	13.6	14.1	14.7	15.5
By Period:	Estimated Reference Energy Use (MWh)	Observed Event Day Energy Use (MWh)	Estimated Change in Energy Use (MWh)	Cooling Degree Hours (Base 75° F)	Uncertainty Adjusted Impact (MWh/hour) - Percentiles				
					10th	30th	50th	70th	90th
Daily	3,948	3,858	91	232.7	60.8	78.5	90.8	103.1	120.9
Event Hours	163.6	127.3	36.3	16.3	35.1	35.8	36.3	36.8	37.5

* The highlighting indicates all hours affected by the event. There are no full event hours so hour-ending 21 is the only highlighted hour which is green to denote that it is a partial hour.

The full set of tables required by the Protocols, including tables for each local capacity area, are in the Excel file attached as an Appendix to this report.

Figure 4.2 shows the range of FSL achievement rates and corresponding load impacts on the July 20th partial-hour event day. Despite the fact that we would not expect to observe full FSL compliance given the data limitations, 51 percent of the customers still had an FSL achievement rate above 100 percent.

Figure 4.2: FSL Achievement Rate and Load Impacts on the Typical Event Day, *PG&E*



4.2 SCE Load Impacts

4.2.1 15-Minute Impacts for the July 20th ex-post event

Table 4.7 summarizes the average reference loads and load impacts at the 15-minute level for SCE's July 20th ex-post event. The results are reported in MWh/60-minutes to be comparable to the hourly load impacts we typically report. The event was called as a transmission emergency and lasted from 7:45-8:19 p.m. The 34 minutes took place across two full 15-minute intervals and one partial 15-minute interval. Customers had a higher 15-minute FSL Achievement Rate than the hourly rate during each of the 15-minute intervals. However, the FSL achievement rates are well below the levels we expect based on full-hour events in prior program years. Again, this difference reflects data limitations during this program year rather than a degradation of program performance.

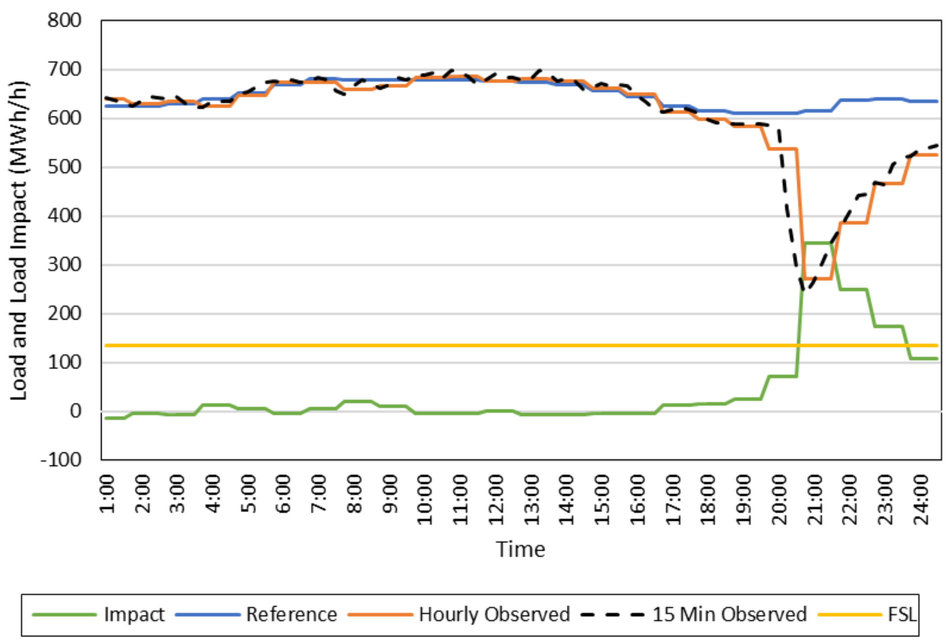
Table 4.7: July 20th Load Impacts by 15-minute Period, *SCE*

Interval	Reference (MWh/h)	Hourly Impact (MWh/h)	15-min Impact (MWh/h)	Hourly FSL Ach	15-min FSL Ach
7:45-8:00 p.m.	610.0	72.3	313.8	15%	66%
8:00-8:15 p.m.	616.0	343.8	377.4	72%	79%
8:15-8:30 p.m.	616.0	343.8	353.2	72%	73%
Average over event window	**613.0**	**208.5**	**345.6**	**53%**	**73%**

*Yellow highlighting denotes intervals that include the event. 8:15-8:30 is only a partial window as the event ended at 8:19 p.m.

Figure 4.3 illustrates the reference load and FSL as well as the difference between the 15-minute observed loads and the hourly observed loads. As illustrated in the table, 15-minute data is able to reflect higher customer performance than 60-minute data given the partial-hour event period.

Figure 4.3: BIP 15-Minute Loads for July 20th SCE



4.2.2 Average Event-hour Load Impacts by Industry Group and LCA

SCE called one event in PY2023. Table 4.8 displays the event-hour reference loads and load impacts for the lone event.[16] The event was called as a transmission emergency. All 351 enrolled BIP customers were called. The typical event day had a 616 MW reference load with a load impact of 344 MW, or 56% of the reference load.

[16] Results are averaged over hour 21 as it was the longest partial event hour.

Table 4.8: Average Event-hour Load Impacts by Event, *SCE*

Event	Date	Day of Week	# Service Agreements Called	Estimated Reference Load (MWh/h)	Observed Load (MWh/h)	Estimated Load Impact (MWh/h)	% LI
1	7/20/2023	Thu.	351	616	272	344	56%
Typical Event Day			**351**	**616**	**272**	**344**	**56%**

Table 4.9 provides the SCE BIP event day observed loads at the hourly level compared to the FSL and FSL achievement rate. The program FSL was 136 MW. The event day had an FSL achievement rate of 72% during the 8:00-9:00 p.m. window.[17] Recall that the FSL achievement percentage for the July 20th is not reflective of actual program performance because of the mismatch between the event period (34 minutes across two hours) and the available resolution of the customer load data.

Table 4.9: Average Event-hour Observed Loads and FSLs by Event, *SCE*

Event	Date	Day of Week	Observed Load (MWh/h)	Firm Service Level (MWh/h)	Estimated LI / LI at FSL
1	7/20/2023	Thu.	272	136	72%
Typical Event Day			**272**	**136**	**72%**

Table 4.10 shows the average event-hour load impact by industry group for the typical event day (July 20th). The total row at the bottom of the table shows the total event-day load impact of 344 MW. Most of the program's load impact came from customers in the Manufacturing industry group.

[17] The FSL achievement rate is capped at 100% for customers who were dually enrolled in ELRP and BIP on dual event days.

Table 4.10: Typical Event Day Load Impacts – *SCE, by Industry Group*

Industry Group	Enrolled	Estimated Reference Load (MWh/h)	Observed Load (MWh/h)	Estimated Load Impact (MWh/h)	Percent Load Impact
Agriculture, Mining & Construction	31	[redacted]	[redacted]	[redacted]	[redacted]
Manufacturing	227	356	159	197	55%
Wholesale, Transport, other utilities	70	[redacted]	[redacted]	[redacted]	[redacted]
Retail stores	2	[redacted]	[redacted]	[redacted]	[redacted]
Offices, Hotels, Finance, Services	5	[redacted]	[redacted]	[redacted]	[redacted]
Schools	1	[redacted]	[redacted]	[redacted]	[redacted]
Institutional/Government	1	[redacted]	[redacted]	[redacted]	[redacted]
Other (or unknown)	14	[redacted]	[redacted]	[redacted]	[redacted]
Total	**351**	**616**	**272**	**344**	**56%**

Table 4.11 summarizes average hourly load impacts by LCA. The majority of the load impact comes from customers in the LA Basin LCA.

Table 4.11: Typical Event Day Load Impacts – *SCE, by LCA*

Local Capacity Area	Enrolled	Estimated Reference Load (MWh/h)	Observed Load (MWh/h)	Estimated Load Impact (MWh/h)	Percent Load Impact
LA Basin	286	419	186	233	56%
Outside Basin	15	[redacted]	[redacted]	[redacted]	[redacted]
Ventura	50	[redacted]	[redacted]	[redacted]	[redacted]
Total	**351**	**616**	**272**	**344**	**56%**

4.2.3 Hourly Load Impacts

Table 4.12 presents hourly load impacts for the typical event day (July 20th) in the manner required by the Protocols.

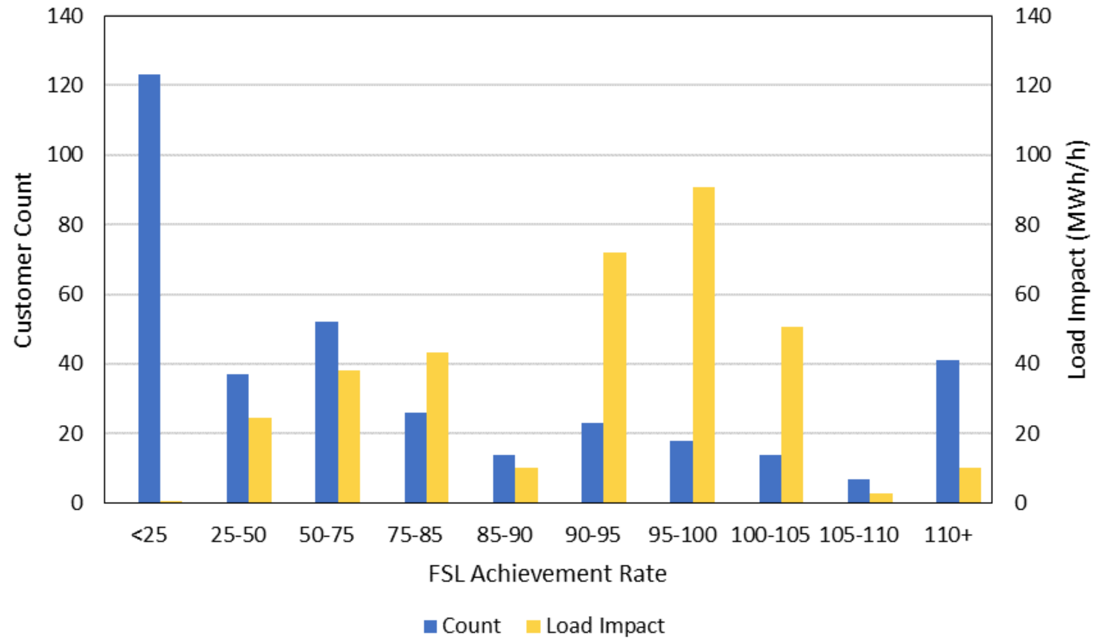
Table 4.12: BIP Hourly Load Impacts for the Typical Event Day, *SCE*

Hour Ending	Estimated Reference Load (MW)	Observed Event Day Load (MW)	Estimated Load Impact (MW)	Load Impact (%)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact - Percentiles				
						10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	626.5	641.0	-14.4	-2%	77.2	-18.4	-16.0	-14.4	-12.8	-10.5
2	626.0	630.4	-4.3	-1%	76.1	-7.8	-5.8	-4.3	-2.9	-0.8
3	629.5	635.7	-6.2	-1%	74.9	-9.7	-7.6	-6.2	-4.7	-2.6
4	638.9	625.0	13.9	2%	73.2	10.4	12.5	13.9	15.4	17.5
5	652.6	647.5	5.0	1%	72.3	1.9	3.7	5.0	6.3	8.2
6	669.6	672.9	-3.3	0%	71.3	-7.2	-4.9	-3.3	-1.7	0.7
7	680.8	674.8	6.0	1%	70.4	1.8	4.3	6.0	7.8	10.3
8	679.7	659.8	19.9	3%	69.7	16.7	18.6	19.9	21.2	23.1
9	678.1	667.7	10.4	2%	70.1	5.5	8.4	10.4	12.4	15.3
10	679.2	682.9	-3.7	-1%	73.0	-8.0	-5.5	-3.7	-2.0	0.5
11	680.1	685.5	-5.4	-1%	77.2	-10.4	-7.4	-5.4	-3.3	-0.3
12	677.3	676.4	0.9	0%	80.8	-4.1	-1.1	0.9	3.0	5.9
13	674.4	680.6	-6.1	-1%	83.6	-11.1	-8.2	-6.1	-4.1	-1.1
14	670.1	677.5	-7.5	-1%	86.3	-13.0	-9.7	-7.5	-5.2	-2.0
15	657.4	660.7	-3.3	0%	89.2	-8.6	-5.5	-3.3	-1.1	2.1
16	644.5	649.6	-5.1	-1%	90.4	-10.2	-7.2	-5.1	-3.0	0.0
17	625.3	612.6	12.7	2%	91.1	7.5	10.6	12.7	14.8	17.8
18	615.8	599.5	16.3	3%	91.0	11.3	14.3	16.3	18.3	21.3
19	609.8	584.8	25.1	4%	90.2	19.6	22.8	25.1	27.3	30.5
20	610.0	537.7	72.3	12%	88.1	66.7	70.0	72.3	74.6	77.9
21	616.0	272.2	343.8	56%	85.0	338.1	341.5	343.8	346.1	349.5
22	636.7	386.9	249.8	39%	84.1	244.1	247.5	249.8	252.2	255.5
23	638.8	465.9	172.9	27%	80.5	167.7	170.8	172.9	175.0	178.1
24	633.9	525.0	108.8	17%	78.1	102.9	106.4	108.8	111.3	114.7
Daily	**15,551**	**14,553**	**999**	**6%**	**80.2**	**866.0**	**944.4**	**998.7**	**1,053.0**	**1,131.4**

* The highlighting indicates all hours affected by the event. There are no full event hours so hours-ending 20 and 21 are highlighted in green to denote that they are partial hours.

Figure 4.4 illustrates the FSL achievement rate distribution and the load impacts by group for all SCE customers on the July 20th partial-hour event day. Despite the fact that we would not expect to observe full FSL compliance given the data limitations and the fact that customers with a 30-minute response option were not required to respond until the last four minutes of the event, 23 percent of the customers still had an FSL achievement rate above 95 percent.

Figure 4.4: FSL Achievement Rates and Load Impacts on the Typical Event Day, *SCE*



5. EX-ANTE LOAD IMPACT FORECAST

5.1 Ex-ante Load Impact Requirements

The DR Load Impact Evaluation Protocols require that hourly load impact forecasts for event-based DR resources must be reported at the program level and by LCA for the following scenarios:

- For a typical event day in each year; and
- For the monthly system peak load day in each month for which the resource is available;

under both:

- 1-in-2 weather conditions for both utility-specific and CAISO-coincident load conditions, and
- 1-in-10 weather conditions for both utility-specific and CAISO-coincident load conditions;

at both:

- the program level (i.e., in which only the program in question is called), and
- the portfolio level (i.e., in which all demand response programs are called).

5.2 Description of Methods

This section describes the methods used to develop the relevant groups of customers, to develop reference loads for the relevant customer types and event-day types, and to develop load impacts for a typical event day.

5.2.1 Development of Customer Groups

For PG&E's program, customer accounts were assigned to one of three size groups, the relevant LCA, and SubLAP. The three size groups were the following:

- Small – maximum demand less than 20 kW;
- Medium – maximum demand between 20 and 200 kW;
- Large – maximum demand greater than 200 kW.

For SCE, customers are assigned to one of three LCAs, the relevant SubLAP, and by participation option (15 minutes notice or 30 minutes notice).

5.2.2 Development of Reference Loads and Load Impacts

Reference loads and load impacts for all of the above factors were developed in the following series of steps:

1. Define data sources;
2. Estimate ex-ante regressions and simulate reference loads by service account and scenario;
3. Calculate historical FSL achievement rates from ex-post results;
4. Apply achievement rates to the reference loads; and
5. Scale the reference loads using enrollment forecasts.

Each of these steps is described below.

1. Define data sources

The reference loads are developed using data for customers enrolled in BIP at the end of the 2023 program year. The load impacts are developed using the historical FSL achievement rates of customers remaining enrolled at the end of the 2023 program year, based on their estimated ex-post load impacts during program year 2022, as it contained the most recent full event day for both PG&E and SCE.[18]

For each service account, we determine the appropriate size group, LCA, and SubLAP. Although BIP customers may be dually enrolled in some other DR programs, the BIP obligation takes precedence on event days, so *program-specific* scenarios (in which each

[18] Current program year loads are used to simulate references loads and load impacts. We assume that the current year provides the most up-to-date information regarding customers' usage behavior, as opposed to averaging across multiple years.

DR program is assumed to be called in isolation) are identical to *portfolio-level* scenarios (in which all DR programs are assumed to have been called) for this program.

2. Simulate reference loads

In order to develop reference loads, we first re-estimated regression equations for each enrolled customer account using data for the current program year. The resulting estimates were used to simulate reference loads for each service account under the various scenarios required by the Protocols (e.g., the typical event day in a utility-specific 1-in-2 weather year).

For the summer months, the re-estimated regression equations were similar in design to the ex-post load impact equations described in Section 3.2, differing in two ways. First, the ex-ante models excluded the morning-usage variables. While these variables are useful for improving the accuracy of ex-post load impact estimates, they complicate the use of the equations in ex-ante simulation. That is, they would require a separate simulation of the level of the morning load. The second difference between the ex-post and ex-ante models is that the ex-ante models do not use weather variables that incorporate information from prior days.[19] The primary reason for this is that the ex-ante weather days were not selected based on weather from the prior day, restricting the use of lagged weather variables to construct the ex-ante scenarios.

Because BIP events may be called in any month of the year, we estimated separate regression models to allow us to simulate winter reference loads. The winter model is shown below. This model is estimated separately from the summer ex-ante model. It only differs from the summer model in two ways: it includes different weather variables; and the month dummies relate to a different set of months. Table 5.1 describes the terms included in the equation.

$$
\begin{aligned}
Q_t \;=\; & \sum_{i=1}^{24}(b_i^h \times h_{i,t}) + \sum_{Evt=1}^{E}\sum_{i=1}^{24}(b_{i,Evt}^{BIP} \times h_{i,t} \times BIP_t) + \sum_{DR}\sum_{i=1}^{24}(b_i^{DR} \times h_{i,t} \times OtherEvt_{i,t}^{DR}) \\
& + \sum_{i=1}^{24}(b_i^{Weather} \times h_{i,t} \times Weather_t) + \sum_{j=2}^{5}(b_j^{DTYPE} \times DTYPE_{j,t}) \\
& + \sum_{i=2}^{24}(b_i^{MON} \times h_{i,t} \times MON_t) + \sum_{i=2}^{24}(b_i^{FRI} \times h_{i,t} \times FRI_t) \\
& + \sum_{j=2-4,11-12}(b_j^{MONTH} \times MONTH_{j,t}) + e_t
\end{aligned}
$$

[19] In particular, where CDH60 and CDH60_MA24, the 24-hour moving average of CDH60, are used together for summer ex-post regressions, only CDH60 is used for the ex-ante models. Similarly, where CDH60_MA3, the three-hour moving average, is used for ex-post regressions, CDH60 is used for the ex-ante analysis. See Appendix A for weather variable details.

Table 5.1: Descriptions of Terms included in the Ex-ante Regression Equation

Variable Name	Variable Description
Q_t	the demand in hour *t* for a customer enrolled in BIP prior to the last event date
The various *b*'s	the estimated parameters
$h_{i,t}$	an indicator variable for hour *i*, equal to one when *t* corresponds to hour *i* of a given day
BIP_t	an indicator variable for program event days
E	the number of program event days that occurred during the program year
$OtherEvt_{i,t}^{DR}$	an indicator variable for event day *DR* of other demand response programs in which the customer is enrolled (e.g. *DR* = CPP Event 1, CPP Event 2, ...)
$Weather_t$	the weather variables selected using our model screening process
$DTYPE_{j,t}$	a series of indicator variables for each day of the week
MON_t, FRI_t,	indicator variables for Monday and Friday
$MONTH_{j,t}$	a series of indicator variables for each month
e_t	the error term

Similar to the ex-post analysis, we tested a variety of weather variables included in the above regression equation to determine the best specification for explaining usage on event-like non-event days. Each specification is tested separately by customer group, defined by industry group and weather sensitivity. This process and its results are explained in Appendix A.

Once these models were estimated, we simulated 24-hour load profiles for each required scenario. The typical event day was assumed to occur in August. In 2014, two sets of 1-in-2 and 1-in-10 weather years were introduced in the load impact analyses. The sets are differentiated according to whether they correspond to utility-specific conditions or CAISO-coincident conditions. The weather conditions used in prior evaluations corresponded to the utility-specific scenarios.

3. Calculate forecast load impacts

Each service account's FSL achievement rate is defined as the estimated load impact divided by the difference between the reference load and the FSL. A result of 100 percent implies that the customer dropped its load exactly to its FSL. Values greater than 100 percent imply event-day loads lower than the FSL, and values less than 100 percent imply event-day loads higher than the FSL.[20]

The achievement rates are based on the estimates for the most recent observed event day where the customers' reference load was above their FSL.[21,22] In consultation with

[20] It is not possible to calculate an achievement rate for customers with reference loads below their FSLs throughout an event period—the event effectively has no effect on them.

[21] The most recent event for both PG&E and SCE was September 6th, 2022 as there were no full event days with full event hours called in PY2023.

[22] Customers with reference loads below their FSL do not provide any information regarding how they would respond to an event in which their reference loads are above their FSL. Therefore, if a customer's reference load is not above their FSL for the latest event that they were called, then we evaluate whether their reference load was higher than their FSL during their previous event, if

the utilities, we determined that using a longer time period (e.g., three years of ex-post load impacts) was not appropriate for this program. Specifically, as customers experience events, they are re-tested if they fail to meet their obligation (i.e., reduce load to the FSL). If they continue to fail, their FSL is increased to the point at which the customer is expected to be able to comply. Therefore, the most recent load impact estimates should provide a good indication of customer performance going forward. In addition, some program design changes make older load impacts less relevant as predictors of future performance. For example, an increased excess energy charge for non-compliance (and a higher excess energy charge for failing to comply during re-test events) may make more recent performance rates higher than performance rates in the more distant past.

In consultation with the IOUs we deemed it appropriate to use the PY2022 typical event day (September 6th, 2022) impacts as the basis for our ex-ante forecasts. Attempting to use the partial-event hour impacts from the current ex-post evaluation would not accurately reflect program performance.

From these customer-level forecasts of reference loads and load impacts, we form results for any given sub-group of customers (e.g., customers over 200 kW in size in the Greater Bay Area), by summing the reference loads and load impacts across the relevant customers.

Because the forecast event window (5:00 to 10:00 p.m. for March, April, and May and 4:00 to 9:00 p.m. for all other months) differs from the historical event window (which can vary across utilities and event days), we need to adjust the historical load impacts for use in the ex-ante study. Load impacts are assumed to be zero until the hour prior to the beginning of the event, at which time we apply the customer's historical FSL performance rate to the forecast window to best represent the pattern of customer response given the limitations of the observed events.[23] We develop forecast load impacts through the end of the event day because customer load reductions often persist well after the end of the event hours.

The uncertainty-adjusted load impacts (i.e., the 10th, 30th, 50th, 70th, and 90th percentile scenarios of load impacts) are based on the standard errors associated with the estimated load impacts from the event day used to determine the customer's event-day achievement rate, scaled to account for the difference between observed and forecast enrollments. The square of these standard errors (i.e., the variance) is added across customers within each required subgroup. Each uncertainty-adjusted scenario is then calculated under the assumption that the load impacts are normally distributed with a mean equal to the total estimated load impact and a variance based on the standard errors in the estimated load impacts. The uncertainty-adjusted load impacts for the

applicable, and so forth. If a customer does not have their reference load above their FSL for any event, then the average program FSL achievement rate is assumed.

[23] For PG&E, FSL achievement rates are capped at 100% for dually enrolled ELRP customers if the last historical event was also an ELRP event day. For SCE, when producing Portfolio-level load impacts, FSL achievement rates are capped at 100% for dually enrolled ELRP customers if the last historical event was also an ELRP event day. For Program-level load impacts, SCE FSL achievement rates are not capped for dually enrolled customers because FSL achievement rates greater than 100% is not uncommon.

average event hour are based on the same event-hour standard errors used in the ex-post study.

4. Apply achievement rates to reference loads for each event scenario.
In this step, the customer-specific FSL achievement rates are applied to the reference loads for each scenario to produce all of the required estimated event-day loads and load impacts. For customers for which an achievement rate cannot be calculated because either their reference loads were below their FSLs or they are newly enrolled customers, the average achievement rate across all customers is used. The FSL achievement rate is assumed to be 100% for customers that change their FSL in the beginning of 2024.

5. Apply forecast enrollments to produce program-level load impacts.
The utilities provided enrollment forecasts. PG&E provided monthly enrollments through 2034, with separate enrollments provided at the program and portfolio level (which are identical for BIP), by LCA, SubLAP, and size group. SCE provided annual enrollments for 2024 through 2034. We assume that the ex-post shares of customers by notice level (15 versus 30 minute), LCA, and SubLAP hold throughout the forecast period.

5.3 Enrollment Forecasts

PG&E
PG&E forecasts BIP enrollments to decrease from 249 in ex-post to 191 at the beginning of 2024, and then increase steadily until it reaches 330 customers by the end of 2034. Of the 191 customers enrolled at the beginning of 2024, 135 are in the large customer group (over 200 kW), 45 are in the medium customer group (20 to 200 kW), and the remainder are classified as small.

SCE
SCE projects that there will be 325 BIP customers by April 2024 and that enrollment will remain constant through 2034. Of these, 284 customers are forecasted to be enrolled in the BIP-30 program and the remaining 41 customers are enrolled in the BIP-15 program.

5.4 Reference Loads and Load Impacts

For each utility and program type, we provide the following summary information: the hourly profile of reference loads and load impacts for an August event day; the level of load impacts across years; and the distribution of load impacts by local capacity area.

Together, these figures provide a useful indication of the anticipated changes in the forecast load impacts across the various scenarios represented in the Protocol tables.

All tables required by the Protocols are provided in an Appendix.

5.4.1 PG&E

Figure 5.1 shows the August 2024 forecast load impacts in a utility-specific 1-in-2 weather year. Event-hour (4:00 to 9:00 p.m.) load impacts average 144 MW, which represents 74 percent of the enrolled reference load. The program-level FSL is 50 MW, compared to the average event-hour program load of 51 MW. The FSL achievement rate of 99% is slightly higher than the achievement rate during the 2022 event.

Figure 5.1: PG&E Hourly Event Day Load Impacts for the August 2024 Event Day in a Utility-Specific 1-in-2 Weather Year

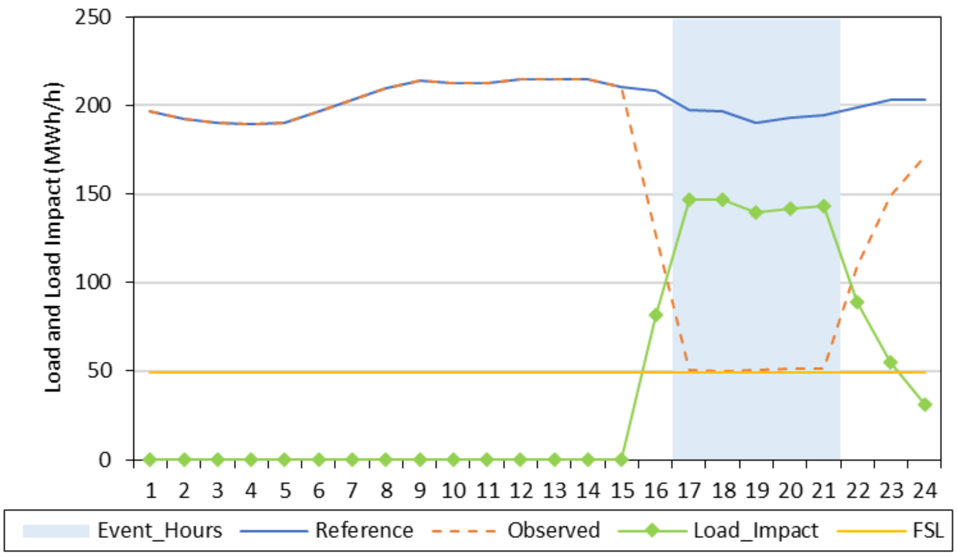


Figure 5.2 shows the share of load impacts by local capacity area, assuming a 2024 August event day in a utility-specific 1-in-2 weather year. [redacted]

Figure 5.2: Share of PG&E Load Impacts by LCA for the August 2024 Event Day in a Utility-specific 1-in-2 Weather Year

[redacted]

Figure 5.3 illustrates August average event-hour load impact for each forecast scenario and year, differentiated by 1-in-2 versus 1-in-10 weather conditions under both utility-specific and CAISO-coincident peak conditions. The differences in load impacts between weather scenarios is minimal because the largest customers are not weather sensitive.

(Recall that customers are first sorted according to their weather sensitivity.) Impacts increase consistently over the course of the forecast due to a steadily increasing enrollment forecast. Impacts also increase by 2 MW after 2027 due to the end of ELRP.[24]

Figure 5.3: Average August Ex-ante Load Impacts by Scenario and Year, *PG&E*

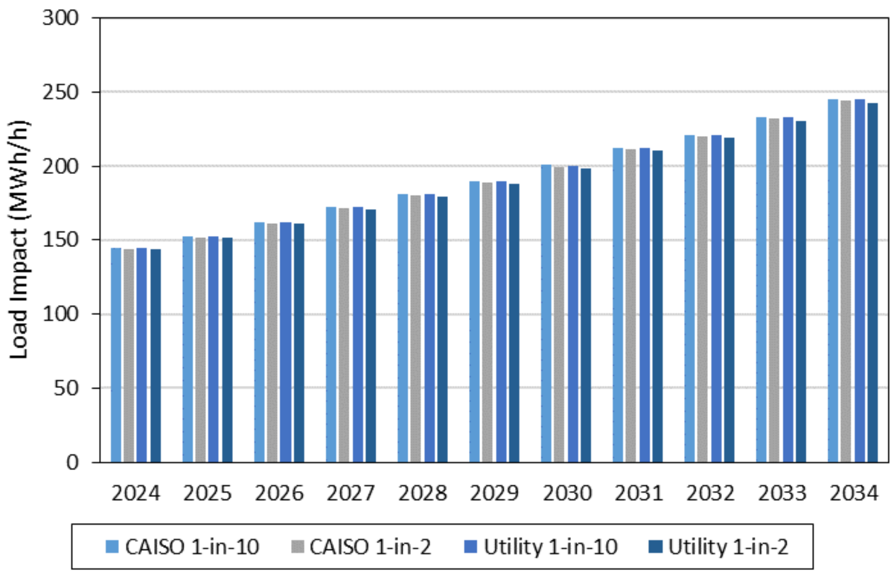


Table 5.2 shows the aggregate and per-customer reference loads and load impacts by weather year (1-in-2 and 1-in-10 for both utility-specific and CAISO-coincident peak conditions) for the August 2024 event day.

Table 5.2: Ex-ante August 2024 Load Impacts by Scenario, *PG&E*

Weather Year	Enrollment	Aggregate (MWh/h)		Per-Customer (kWh/h)		% Load Impact
		Reference	Load Impact	Reference	Load Impact	
Utility 1-in-2	195	194.3	143.5	996.6	735.9	73.8%
Utility 1-in-10	195	195.6	144.6	1003.2	741.7	73.9%
CAISO 1-in-2	195	195.0	144.1	999.9	738.9	73.9%
CAISO 1-in-10	195	195.7	144.7	1003.4	741.8	73.9%

[24] The BIP ex-post ad ex-ante load impact is capped at a 100% FSL achievement rate for customers that are dually enrolled in BIP and ELRP. Any load impact above the 100% FSL achievement rate is credited towards ELRP. After the end of ELRP in December 2027, BIP load impacts are allowed to exceed the 100% FSL achievement rate for customers who have demonstrated the ability to surpass this threshold prior to enrollment in ELRP.

5.4.2 SCE

Figure 5.4 shows the August 2024 forecast load impacts in a utility-specific 1-in-2 weather year.[25] Event-hour (4:00 to 9:00 p.m.)[26] load impacts average 417 MW, which represents 71 percent of the 585 MW reference load. The program-level FSL of 170 MW, compared to the average event-hour program load of 168 MW, results in an FSL achievement rate of 101%. The FSL achievement rate is higher than in the PY2022 ex-post typical event day because the customers that remained enrolled in BIP for the ex-ante forecast had higher performance than those that were de-enrolled. Additionally, the ex-post event had an FSL achievement rate of 103% during the second and third full event hours. A longer ex-ante event window results in more event hours when customers achieve the higher FSL achievement rate.

Figure 5.4: SCE Hourly Event Day Load Impacts for the August 2024 Event Day in a Utility-Specific 1-in-2 Weather Year

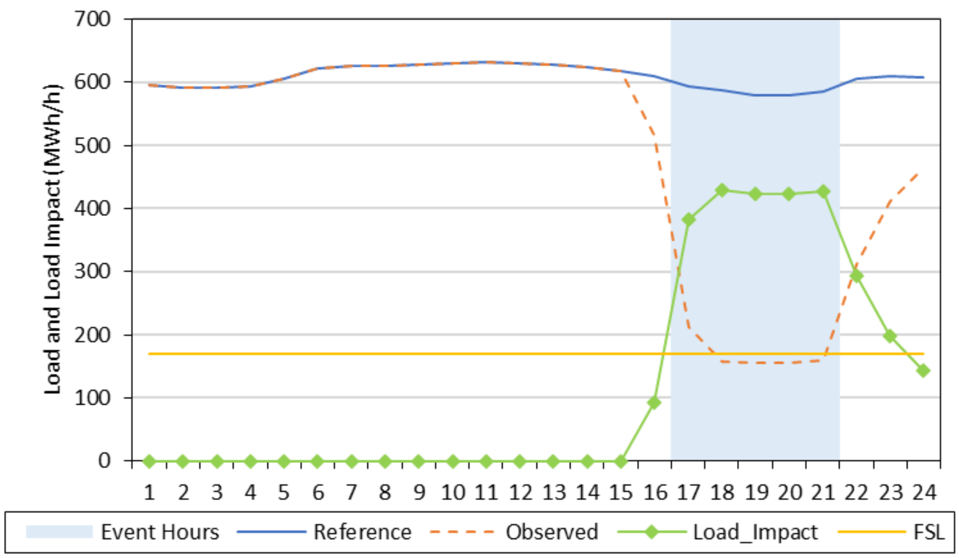


Figure 5.5 shows the share of load impacts by local capacity area for an August 2024 event day in a utility-specific 1-in-2 weather year. LA Basin customers account for the largest share, with 69 percent of the load impacts.

[25] The following section presents the program-level BIP ex-ante forecast. A portfolio level forecast is provided in the ex-ante table generators. Portfolio impacts represent the load impacts attributed to BIP on days in which both a BIP event and an ELRP event are called. To calculate portfolio impacts we cap FSL achievement rates at 100% for dually enrolled customers when both programs are called. All impacts above 100% are attributed to ELRP for those customers and not represented in BIP portfolio forecasts.

[26] The event window is from 5:00 PM to 10:00 PM during March, April, and May.

Figure 5.5: Share of SCE Load Impacts by LCA for the August 2024 Event Day in a Utility-specific 1-in-2 Weather Year

[redacted]

Figure 5.6 shows the share of load impacts by notification time, assuming an August 2024 event day in a utility-specific 1-in-2 weather year. Customers required to reduce demand to their FSL within 15 minutes of a Notice of Interruption make up 13 percent of customers but account for 35 percent of the load impacts.

Figure 5.6: Share of SCE Load Impacts by Notification Time for the August 2024 Event Day in a Utility-specific 1-in-2 Weather Year

[redacted]

Figure 5.7 illustrates August event day load impacts for each forecast scenario by year, differentiated by 1-in-2 versus 1-in-10 weather conditions under both utility-specific and CAISO-coincident peak conditions. The load impacts are constant over the forecast period 2024-2034 due to the steady enrollment forecast. The load impact is not sensitive to weather conditions. For example, the minimum and maximum load impacts are 415 MW and 421 MW, respectively.

Figure 5.7: Average August Ex-ante Load Impacts by Scenario and Year, *SCE*

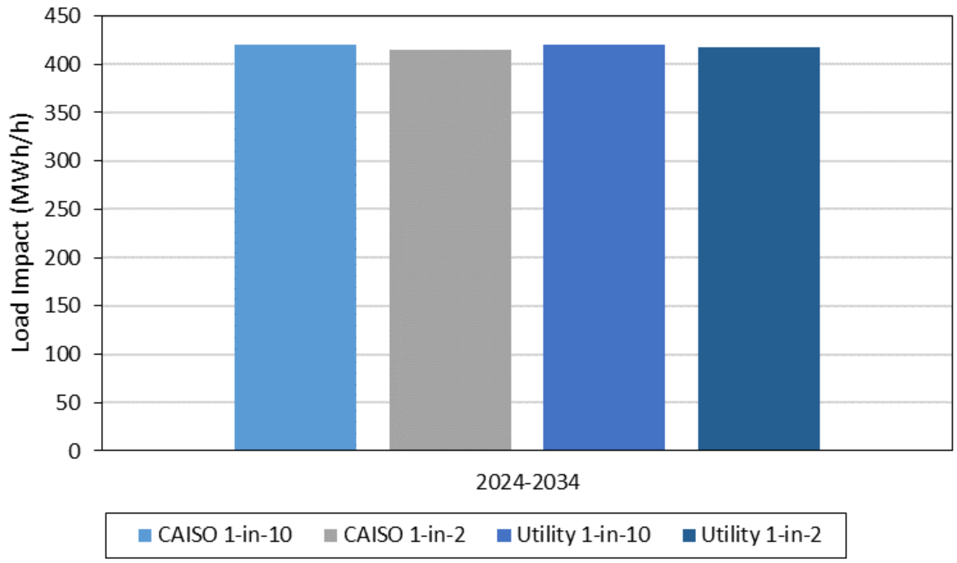


Table 5.3 shows the per-customer reference loads and load impacts by weather year (1-in-2 and 1-in-10 for both utility-specific and CAISO-coincident peak conditions) for the August 2024 event day.

Table 5.3: Per-customer Ex-ante August 2024 Load Impacts by Scenario, *SCE*

Weather Year	Reference Load (kWh/h)	Load Impact (kWh/h)	% Load Impact
Utility 1-in-2	1,800	1,283	71%
Utility 1-in-10	1,811	1,294	71%
CAISO 1-in-2	1,793	1,277	71%
CAISO 1-in-10	1,813	1,295	71%

6. COMPARISONS OF RESULTS

In this section, we present several comparisons of load impacts for each utility. Due to the nature of the typical events this program year we do not feel that it is appropriate to compare last year's ex-post event to this year's event as it is not reasonable to compare partial-hour impacts to full-hour impacts. This also renders the comparison of last year's ex-ante forecast to this year's ex-post event moot. Additionally, we compare last year's ex-post event to this year's ex-ante as it is the most relevant basis for comparison because the PY 2022 event is that basis for the current ex-ante forecast. The comparisons in this section are as follows:

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

In the above "current study" refers to this report, which is based on findings from the 2023 program year; and "previous study" refers to the report that was developed following the 2022 program year. Ex-post reference loads and load impacts are averaged over the associated event window (excluding partial event hours). Ex-ante reference loads and load impacts are averaged over the Resource Adequacy (RA) window (i.e., HE 17-21).

6.1 PG&E

6.1.1 Previous versus current ex-ante

In this sub-section, we compare the ex-ante forecast prepared following PY2022 (the "previous study") to the ex-ante forecast contained in this study (the "current study"). Table 6.1 contains this comparison for the August 2024 utility-specific 1-in-2 typical event day forecast.

Table 6.1: Comparison of Ex-ante Impacts from PY2022 and PY2023 Studies, *PG&E*

Level	Outcome	Ex-ante 2024 Typical Event Day, *Previous Study*	Ex-ante 2024 Typical Event Day, *Current Study*
Total	# Customers	240	195
	Reference (MWh/h)	231	194
	Load Impact (MWh/h)	169	144
	FSL (MW)	57	50
Per SAID	Reference (kWh/h)	961	999
	Load Impact (kWh/h)	702	739
	% Load Impact	73.1%	73.9%

PG&E BIP enrollment decreased by 49 customers, from 240 to 191 customers in January of 2024, and is expected to increase to 195 by August of 2024. The aggregate reference load decreased by 37 MW. The per-customer reference loads and load impacts are slightly higher in the PY2023 forecast because customers who leave the program tend to be smaller than average. Forecast reference loads were similar for customers that remain on the program for both years of the ex-ante analysis. The FSL achievement rate was forecast to be 97% in the PY2022 ex-ante analysis. In the PY2023 ex-ante analysis, the FSL achievement rate was forecast to be 99% due to higher performing customers remaining on the program.

6.1.2 Current ex-post versus current ex-ante

Table 6.2 compares the most recent full ex-post and current ex-ante load impacts. The most recent full ex-post event was the September 6th, 2022 event which we use as the basis for our ex-ante forecast. The ex-ante load impacts in the table represent the 2024 typical event day with utility-specific 1-in-2 weather conditions. The enrollments decreased from 258 during September of PY2022 to 191 in January of PY2024 with enrollments forecasted to increase to 195 by August of PY2024. The aggregate FSL achievement rate increases from roughly 98% in the ex-post analysis to 99% in the ex-ante forecast. The average per-customer reference loads and load impacts are significantly higher in the ex-ante forecast because customers that remain on the program are larger, on average, than customers that left [redacted].

Table 6.2: Comparison of Previous Ex-post and Current Ex-ante Impacts, *PG&E*

Level	Outcome	Ex-post Typical Event Day, *PY2022*	Ex-ante 2024 Typical Event Day, Current Study
Total	# Customers	258	195
	Reference (MWh/h)	203	194
	Load Impact (MWh/h)	149	144
	FSL (MWh/h)	51	50
Per SAID	Reference (kWh/h)	787	999
	Load Impact (kWh/h)	577	739
	% Load Impact	73.4%	73.9%

Table 6.3 documents the various potential sources of differences between the ex-post and ex-ante load impacts.

Table 6.3: PG&E Ex-post versus Ex-ante Factors

Factor	Ex-post	Ex-ante	Expected Impact
Weather	Event hour temperature of 96 degrees Fahrenheit.	93 degrees Fahrenheit during event hours on utility-specific 1-in-2 typical event day.	Little to no impact because most customers are categorized as not weather sensitive.
Event window	HE 19-20 on 9/6/2022.	HE 17-21.	Periods corresponding to larger reference loads result in larger load impacts. Reference loads are similar between these periods.
Event Day of the Week	Monday Event.	Average Weekday.	This can have an impact on reference loads. Mondays tend to have lower reference loads than average weekday loads. Higher ex-ante average weekday loads results in higher load impacts. Weekend events would have lower reference loads with lower load impacts albeit likely higher FSL achievement rates.
% of resource dispatched	All customers dispatched.	Assume all customers are called.	Similar load impacts. The ex-ante method assumes that all enrolled customers are dispatched.
Enrollment	258 customers during 2022 event days.	195 customers.	Lower enrollment reduces the aggregate reference load and load impact; however, the per-customer reference load and FSL achievement rate are higher due to size and performance of remaining customers.
Methodology	Customer-specific regressions using own within-subject analysis.	Reference loads are simulated from customer-specific regressions. Load impacts are based on customer-level performance on the most recent event day that a customer has reference loads above their FSL.	Possible difference between simulated ex-ante and estimated ex-post reference loads. In this case, however, the aggregate differences are minimal for the average weekday.

6.2 SCE

6.2.1 Previous versus current ex-ante

In this sub-section, we compare the ex-ante forecast prepared following PY2022 (the "previous study") to the ex-ante program level forecast contained in this study (the “current study”). Table 6.4 represents the forecast for the August 2024 utility-specific 1-in-2 typical event day. The results are averaged over the RA window, 4 to 9 p.m.

Table 6.4: Comparison of Ex-ante Impacts from PY2022 and PY2023 Studies, *SCE*

Level	Outcome	Ex-ante 2024 Typical Event Day, *Previous Study*	Ex-ante 2024 Typical Event Day, *Current Study*
Total	# Customers	332	325
	Reference (MWh/h)	611	584
	Load Impact (MWh/h)	500	416
	FSL (MWh/h)	118	170
Per SAID	Reference (kWh/h)	1,840	1,797
	Load Impact (kWh/h)	1,507	1,280
	% Load Impact	81.9%	71.2%

The enrollment numbers decreased by 7 customers between the previous and current studies. The total reference load and load impacts are lower in the current study because of the reduced number of customers. Per-customer reference loads and load impacts also decrease because a handful of larger-than-average customers left BIP after the January 2024 open enrollment period and no large customers are forecasted to join the program. Additionally, 7 large customers increased their FSLs by over 40 MW, which decreases the forecasted load impacts as customers have a smaller obligation to reduce during events that are called. Program-level FSL Achievement remains constant at 101% as the customers that remain on the program across years are high performers.

6.2.2 Previous ex-post versus current ex-ante

Table 6.5 compares the ex-post impacts from PY2022 and ex-ante load impacts from this study, where the ex-post impacts are based on the September 6th, 2022, event day and the ex-ante load impact represents the 2024 typical event day in a utility-specific 1-in-2 weather year. Again, we use the PY2022 ex-post typical event as the basis for comparison because it is the last full BIP event and is used as the basis for our ex-ante forecast.

Table 6.5: Comparison of Previous Ex-post and Current Ex-ante Impacts, *SCE*

Level	Outcome	Ex-post Typical Event Day, *PY2022*	Ex-ante 2024 Typical Event Day, *Current Study*
Total	# Customers	343	325
	Reference (MWh/h)	592	584
	Load Impact (MWh/h)	487	416
	FSL (MWh/h)	122	170
Per SAID	Reference (kWh/h)	1,727	1,797
	Load Impact (kWh/h)	1,419	1,280
	% Load Impact	82.2%	71.2%

The forecast calls for a reduction in enrollment of 18 customers. There is some amount of program churn across the two years as 56 customers have de-enrolled since the PY2022 event occurred and 38 customers have joined. Per customer reference load is larger due to many small customers leaving the program. However, per customer load impacts are smaller primarily due to customers raising their FSLs by 48 MW which contributes to an additional decrease in both load impacts and the impact percentage. The FSL achievement rate is forecasted to be 101% which is higher than the 99% FSL achievement rate in the PY2022 ex-post event. Additional impact comes from longer event hours during the ex-ante RA window where the FSL achievement rate is higher, as described below.

The FSL achievement rate is 99% in ex-post and 101% in ex-ante. The increased FSL achievement rate is reflective of a longer RA window than the ex-post event. That is, the FSL achievement rate was 103% in ex-post by the second hour of the event, while the average over all event hours is 99% due to the first full event hour FSL achievement rate being 89%. The ex-ante achievement rate has more hours following the second event hour (i.e., HE 18-21) that are assumed to remain at 103%, thus increasing the entire event average.

Table 6.6 lays out all the potential sources of differences between the ex-post and ex-ante load impacts.

Table 6.6: SCE Ex-post versus Ex-ante Factors

Factor	Ex-post	Ex-ante	Expected Impact
Weather	Event hour temperatures ranging from 85 to 94 degrees Fahrenheit.	Temperatures ranging from 84 to 93 degrees Fahrenheit.	Higher temperatures result in higher references loads for weather sensitive customers. There is some impact on total reference load although it does not affect the majority of the program due to the lack of weather sensitivity for most customers.
Event window	HE 18-20 on 9/6/2022.	HE 17-21.	The slightly earlier ex-ante event window tends toward slightly higher reference loads and load impacts relative to the ex-post window.
Event Day of the Week	Tuesday event following holiday.	Average Weekday.	Tuesday ex-post event following Labor Day had lower reference loads than the average weekday that serves as the basis for ex-ante. Ex-ante reference loads will thus be larger and have larger load impacts than ex-post.
% of resource dispatched	All customers were called.	Assume all customers are called.	None.
Enrollment	343 customers enrolled during the 9/6/2022 event.	325 customers in August 2024.	Lower enrollment reduces the aggregate reference load and load impact; per customer reference load increases as customers who leave the program are smaller on average than those who remained or joined.
Methodology	Customer-specific regressions using own within-subject analysis.	Reference loads are simulated from customer-specific regressions. Load impacts are based on customer-level performance on the most recent event day that a customer has reference loads above their FSL.	Possible difference between simulated ex-ante and estimated ex-post reference loads. In this case, however, the aggregate differences are minimal for the average weekday.

7. RECOMMENDATIONS

Neither PG&E nor SCE called full events that lasted for at least a full clock hour in PY2023. This led to artificially low ex-post load impact estimates because load data are not available with sufficient granularity to reflect the abbreviated events and because some customers had not yet moved beyond their notification period by the end of the event. We are confident that it is reasonable to use ex-post estimates from PY2022 as the basis for the current ex-ante forecast because the PY2022 results relatively recent performance and few customers have joined the program since PY2022 (we assume program-average performance for customers without ex-post estimates). However, we recommend that both PG&E and SCE utilities to call full-hour, full-dispatch events during PY2024 if possible so the ex-ante forecast in that evaluation has a more current basis.

APPENDICES

The following Appendices accompany this report. Appendix A is the validity assessment associated with our ex-post load impact evaluation. Normally we provide an Appendix B which contains the FSL achievement rates for each utility, by industry group. We do not include these figures in our report this year as they are not illustrative of program performance due to the data limitations discussed in the report. In future years when there are full event hours it makes sense to continue producing these tables. The additional appendices are Excel files that can produce the tables required by the Protocols. The Excel file names are listed below.

BIP Study Appendix C	6a. PGE_2023_BIP_Ex_Post
BIP Study Appendix D	PY2023_SCE_BIP_Ex_Post_Load_Impacts
BIP Study Appendix E	6b. PGE_2023_BIP_Ex_Ante
BIP Study Appendix F	PY2023_SCE_BIP_Ex_Ante_Load_Impacts

APPENDIX A. VALIDITY ASSESSMENT

A.1 Customer Weather Sensitivity

Customer-specific regressions are implemented to categorize customers as weather sensitive or not. Weather sensitive customers change usage in response to changes in the weather, while non-weather sensitive customers do not. Determining which customers are non-weather sensitive allows for a more parsimonious regression model by not including weather variables as explanatory variables for these customers. The following regression specification is used to determine whether a customer is weather sensitive:

$$Q_t = b^{Weather} \times Weather_t + \sum_{i=2}^{5}\left(b_i^{DTYPE} \times DTYPE_{i,t}\right) + \sum_{i=7}^{9}\left(b_i^{MONTH} \times MONTH_{i,t}\right) + \sum_{i=1}^{EVT}\left(b_i^{EVT} \times EVT_{i,t}\right) + e_t$$

where Q_t represents the average customer usage during hours-ending 13 through 20 on day t in the summer months of June through September. $DTYPE_{i,t}$ represents the day of week, while $MONTH_{i,t}$ represents each month. The $EVT_{i,t}$ variables control for any event days a customer faces (BIP, CPP, etc.). The variable of importance is $Weather_t$, which is defined as CDD55, CDD60, or CDD65, each as a separate regression. The regression is estimated for each customer and weather specification. A customer is identified as weather sensitive if the weather coefficient ($b^{Weather}$) is positive and statistically significant for any of the three separate weather specifications. Tables A.1 through A.5 provide the number of customers that are categorized as weather sensitive by industry group and utility. We separately categorize customers as weather sensitive by weekday and weekend/holiday. Additionally, we separately classify customers who provided voluntary reductions for SCE on weekends as we exclude morning load variables from their customer specific regressions in order to not capture the effects of their voluntary reduction on reference loads. The proportion of PG&E customers classified as non-weather sensitive was 78% on weekdays. The proportion of SCE customers classified as non-weather sensitive was 75% (although non-voluntary reducers were 89% non-weather sensitive on the weekend event).

Table A.1: Weather Sensitive Customer Count by Industry Type, PG&E Weekday

Industry Type	Weather Sensitive	Non-Weather Sensitive	Total	Share Weather Sensitive
1. Agriculture, Mining, Construction	25	74	99	25%
2. Manufacturing	7	51	58	12%
3. Wholesale, Transportation, Utilities	23	44	67	34%
4. Retail	1	0	1	100%
5. Offices, Hotels, Health, Services	0	1	1	0%
6. Schools	1	0	1	100%
8. Other	0	1	1	0%
Total	**57**	**171**	**228**	**25%**

Table A.2: Weather Sensitive Customer Count by Industry Type, SCE Weekday

Industry Type	Weather Sensitive	Non-Weather Sensitive	Total	Share Weather Sensitive
1. Agriculture, Mining, Construction	6	25	31	19%
2. Manufacturing	77	150	227	34%
3. Wholesale, Transportation, Utilities	20	49	69	30%
4. Retail	2	0	2	100%
5. Offices, Hotels, Health, Services	4	2	6	67%
6. Schools	1	0	1	100%
7. Entertainment, Other Services, Government	0	1	1	0%
8. Other	7	7	14	50%
Total	**117**	**234**	**351**	**34%**

A.2 Model Specification Tests

A range of model specifications were tested before arriving at the model used in the ex-post load impact analysis. A separate set of specifications was also tested to be used in the ex-ante load impact analysis.[27] The tests are conducted using average-customer data by industry group and weather-sensitivity. Separate model specifications were tested for weather sensitive and non-weather sensitive customers. Model variations for weather sensitive customers include 17 combinations of weather-related variables for ex-post and

[27] Recall that the ex-ante set of specifications eliminate the use of morning load variables as well as weather variables using information from prior days.

7 combinations for ex-ante; and 5 different specifications of non-weather-related variables for non-weather sensitive customers.

The basic structure of the model for weather sensitive customers is shown in Section 3.2.1 for ex-post and Section 5.2.2 for ex-ante. The weather variables include: temperature-humidity index (THI)[28]; heat index (HI)[29]; cooling degree hours (CDH)[30], including both a 60 and 65 degree Fahrenheit threshold; the 3-hour moving average of CDH; cooling degree days (CDD)[31], including both a 60 and 65 degree Fahrenheit threshold; the one-day lag of cooling degree days, and the average of the temperatures in degrees Fahrenheit during the first 17 hours of the day (Mean17). A list of the combinations of these variables that we tested for weather sensitive customers is provided in Table A.3, including 17 specifications for the ex-post analysis and 7 for ex-ante analysis.

Table A.3: Weather Variables Included in the Tested Specifications for Weather Sensitive Customers

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

The model specifications tested for non-weather sensitive customers do not include any weather variables but have different combinations of non-weather-related variables. The

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

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

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

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

variables include combinations of indicator variables and interactions of month, hour, Monday, Friday, and morning load. A list of the five combinations of these variables is shown in Table A.4, where an "X" between two variables represents the interaction of these two variables. Each specification includes the following variables in common: hour indicators, day type indicators, and events interacted with hour indicators. For the ex-ante analysis, we exclude the specifications with the morning load variable. The morning load variable is also excluded when estimating ex-post event that are consecutive event days or if customers were requested to provide voluntary reductions before an event.

Table A.4: Variables Included in the Tested Specifications for Non-Weather Sensitive Customers

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

The model variations are evaluated according to two primary validation tests:

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

2. Performance on *synthetic* event days (e.g., event-like non-event days that are treated as event days in estimation), to test for "event" coefficients that demonstrate statistically significant bias, as opposed to expected non-significance, since customers have no reason to modify usage on days that are not actual events. This is an extension of the previous test. The same test days are used, with a set of hourly "synthetic" event variables included in addition to the rest of the specification to test whether non-zero load impacts are estimated for these days. A successful test involves synthetic event load impact coefficients that are not statistically significantly different from zero.

A.2.1 Selection of Event-Like Non-Event Days

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

We selected days according to the average typical event-hours, omitting holidays, weekends, event days for programs in which BIP customers are dually enrolled (e.g., CPP), Flex Alert days, and Public Safety Power Shutoff days. For the most part, the selection involved selecting the hottest qualifying days. Table A.5 lists the event-like non-event days selected.

Table A.5: List of Event-Like Non-Event Days by IOU

PG&E	SCE
6/30/2023	7/14/2023
7/14/2023	7/19/2023
7/25/2023	7/25/2023
8/23/2023	7/26/2023
8/29/2023	7/27/2023
8/30/2023	8/16/2023
9/13/2023	8/29/2023
10/5/2023	8/30/2023
10/6/2023	

A.2.2 Results from Tests of Alternative Weather Specifications

For each industry group, we tested 17 different sets of weather variables for weather sensitive customers and five different specifications for non-weather sensitive customers. The aggregate load used in conducting these tests was constructed separately for each industry group and weather sensitivity categorization. Only customers who were called on at least one event day are included.

The tests are conducted by estimating one model for every industry, weather sensitivity, specification (17 for weather sensitive customers, 5 for non-weather sensitive customers), and event-like day. Each model excludes one event-like day from the estimation model and uses the estimated parameters to predict the usage for that day. The MPE and MAPE are calculated across the event windows of the withheld days.

Tables A.6 and A.7 summarize for each utility the mean percentage error (MPE), mean absolute percentage error (MAPE), and number of customers in the sub-group for each industry by weather sensitivity type for specifications in the ex-post analysis.

Table A.6: Specification Test Results for the Ex-Post analysis, PG&E Weekday

Group	Industry Type	Selected Specification	MPE	MAPE	Number of Customers
Weather Sensitive	1. Agriculture, Mining, Construction	17	0%	3%	25
	2. Manufacturing	17	0%	8%	7
	3. Wholesale, Transportation, Utilities	17	0%	7%	23
	4. Retail	17	-1%	3%	1
	5. Offices, Hotels, Health, Services	n/a	n/a	n/a	0
	6. Schools	8	0%	7%	1
	8. Other	n/a	n/a	n/a	0
Non-Weather Sensitive	1. Agriculture, Mining, Construction	5	0%	2%	74
	2. Manufacturing	5	0%	2%	51
	3. Wholesale, Transportation, Utilities	3	12%	13%	44
	4. Retail	n/a	n/a	n/a	0
	5. Offices, Hotels, Health, Services	4	64%	90%	1
	6. Schools	n/a	n/a	n/a	0
	8. Other	2	19%	39%	1

Table A.7: Specification Test Results for the Ex-Post analysis, SCE Weekday

Group	Industry Type	Selected Specification	MPE	MAPE	Number of Customers
Weather Sensitive	1. Agriculture, Mining, Construction	3	0%	7%	6
	2. Manufacturing	6	-1%	2%	77
	3. Wholesale, Transportation, Utilities	6	6%	13%	20
	4. Retail	10	0%	2%	2
	5. Offices, Hotels, Health, Services	6	2%	5%	4
	6. Schools	3	0%	4%	1
	7. Entertainment, Other Services, Government	n/a	n/a	n/a	0
	8. Other or unknown	6	-1%	7%	7
Non-Weather Sensitive	1. Agriculture, Mining, Construction	5	0%	1%	25
	2. Manufacturing	4	2%	5%	150
	3. Wholesale, Transportation, Utilities	4	0%	3%	49
	4. Retail	n/a	n/a	n/a	0
	5. Offices, Hotels, Health, Services	4	0%	1%	2
	6. Schools	n/a	n/a	n/a	0
	7. Entertainment, Other Services, Government	5	16%	25%	1
	8. Other or unknown	3	2%	11%	7

Tables A.8 and A.9 summarize for each utility the mean percentage error (MPE), mean absolute percentage error (MAPE), and customer count of the winning specification (as shown in Tables A.4 and A.5) for each industry by weather sensitivity type for specifications included in the ex-ante analysis.

Table A.8: Specification Test Results for the Ex-Ante analysis, PG&E

Group	Industry Type	Selected Specification	MPE	MAPE	Number of Customers
Weather Sensitive	1. Agriculture, Mining, Construction	5	3%	3%	36
	2. Manufacturing	5	11%	12%	13
	3. Wholesale, Transportation, Utilities	5	-11%	12%	24
	4. Retail	4	1%	1%	4
	5. Offices, Hotels, Health, Services	5	1%	4%	1
	6. Schools	5	2%	4%	1
	8. Other	2	-1%	11%	1
Non-Weather Sensitive	1. Agriculture, Mining, Construction	0	0%	4%	73
	2. Manufacturing	1	0%	3%	61
	3. Wholesale, Transportation, Utilities	1	1%	5%	56
	4. Retail	n/a	n/a	n/a	0
	5. Offices, Hotels, Health, Services	0	3%	57%	2
	6. Schools	n/a	n/a	n/a	0
	8. Other	0	12%	19%	1

Table A.9: Specification Test Results for the Ex-Ante analysis, SCE

Group	Industry Type	Selected Specification	MPE	MAPE	Number of Customers
Weather Sensitive	1. Agriculture, Mining, Construction	2	0%	9%	7
	2. Manufacturing	4	-1%	3%	88
	3. Wholesale, Transportation, Utilities	5	5%	5%	26
	4. Retail	4	-1%	3%	2
	5. Offices, Hotels, Health, Services	6	1%	4%	4
	6. Schools	1	-5%	11%	1
	7. Entertainment, Other Services, Government	n/a	n/a	n/a	0
	8. Other or unknown	6	0%	6%	4
Non-Weather Sensitive	1. Agriculture, Mining, Construction	0	5%	14%	27
	2. Manufacturing	2	2%	5%	171
	3. Wholesale, Transportation, Utilities	0	3%	4%	45
	4. Retail	n/a	n/a	n/a	0
	5. Offices, Hotels, Health, Services	0	1%	2%	1
	6. Schools	n/a	n/a	n/a	0
	7. Entertainment, Other Services, Government	0	16%	33%	1
	8. Other or unknown	2	2%	8%	8

A.2.3 Synthetic Event Day Tests

For the specification selected using the testing described in Section A.2.2, we conducted an additional test. The selected specification was estimated on the aggregate customer data by industry and weather sensitivity (averaged across all applicable customers), including a set of 24 hourly "synthetic" event-day variables. These variables equaled one on the days listed in Table A.5, with a separate estimate for each hour of the day.

If the model produces synthetic event-day coefficients that are not statistically significantly different from zero, the test provides some added confidence that our actual event-day coefficients are not biased. That is, the absence of statistically significant results for the synthetic event days indicates that the remainder of the model is capable of explaining the loads on those days.

Table A.10 presents the results of this test, showing the percentage of statistically significant synthetic event-day coefficients for each hour during the relevant event windows. The synthetic event-day load impacts are estimated using the chosen model specification shown in Tables A.6 through A.9. The "Average Event Hour" row at the bottom of the table shows the percentage of statistically significant estimates across all event hours. The model does not perform as well for the first partial hour for SCE or the lone partial hour for PG&E which is unsurprising considering customers were only responding for a fraction of the hour.

Table A.10: Percentage of Statistically Significant Synthetic Event-Day Estimated Load Impacts

Hour	PG&E	SCE
20	-	43%
21	19%	0%
Average Event Hour	19%	21.5%

A.3 Comparison of Predicted and Observed Loads on Event-like Days

The model specification tests are based on the ability of the model to predict program load on event-like non-event days. Figures A.1 and A.2 illustrate each utility's average predicted and observed loads across the event-like days using the specification chosen (by industry and weather sensitivity) for each customer. In each figure, the solid line represents the observed load and the dashed line represents the load predicted by the statistical model. These figures show that the predicted loads are quite close to the observed loads for the event-like non-event days.

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

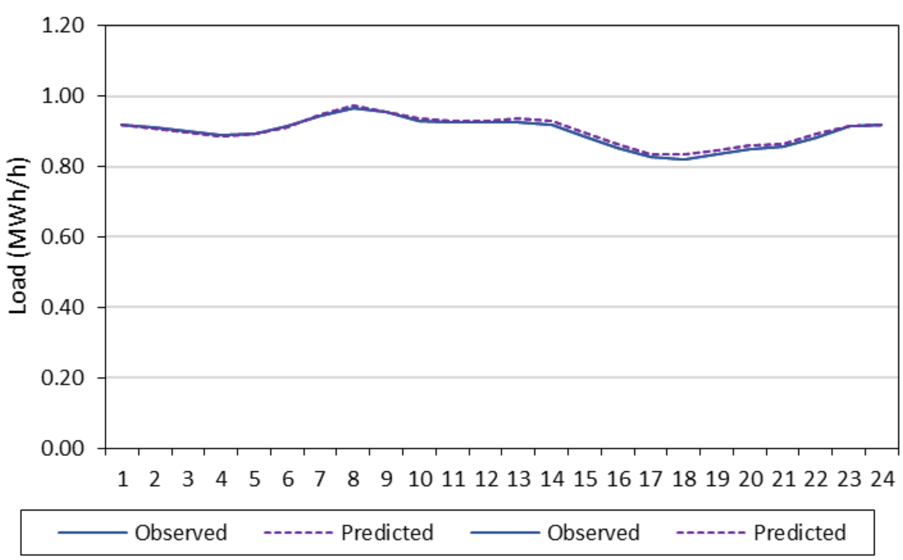


Figure A.2: Average Observed & Predicted Loads on Weekday Event-like Days, *SCE*