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2021 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers: Ex-post and Ex-ante Report

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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"), Southern California Edison ("SCE"), and San Diego Gas and Electric Company ("SDG&E") in 2021. The report provides estimates of ex-post load impacts that occurred during events called in 2021 and an ex-ante forecast of load impacts for 2022 through 2032 that is based on the IOU's enrollment forecasts and the ex-post load impacts estimated for the 2021 program year.

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").

All three utilities called one event in 2021 with varying event hours. PG&E and SCE called the event on July 9th, while SDG&E called it on June 17th. All three events were called on a weekday.

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.

The total program load impact for PG&E's event day, was 155 MW, or 65 percent of enrolled load. This was 84 percent of the reduction required to meet the aggregate FSL, calculated as the estimated load impact divided by the load impact that would have occurred if customers had (in aggregate) exactly attained their FSL.

For SCE, the load impact was 409 MW during July 9th event, representing a 74 percent decrease of the reference load. This was 94 percent of the reduction required to meet the aggregate FSL.

[redacted]

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"), Southern California Edison ("SCE"), and San Diego Gas and Electric Company ("SDG&E") in 2021. The report provides estimates of ex-post load impacts that occurred during events called in 2021 and an ex-ante forecast of load impacts for 2022 through 2032 that is based on the IOU's enrollment forecasts and the ex-post load impacts estimated for the 2021 program year.

The primary research questions addressed by this evaluation are:

1. What were the BIP load impacts in 2021?
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 2022 through 2032?

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 investor-owned utilities ("IOUs"). The programs consist of an interruptible tariff available to both customers and aggregators with a minimum demand.

Each utility called one event in 2021. PG&E called its event on July 9th. The event was called as a transmission emergency event from 6:32-8:32 PM. The event took place on a Friday.

SCE also called its event on Friday July 9th. The SCE event was called to ensure program reliability. The lone event lasted from 5:50-8:53 PM.

SDG&E called its event on Thursday June 17th. The event was triggered by temperature and system load conditions. The event lasted from 6-8 PM.

Enrollment

Enrollment in PG&E's BIP decreased relative to PY2020, from 494 to 310. The sum of enrolled customers' coincident maximum demands was 275.4 MW, or 0.89 MW for the

average service agreement.[1] [redacted] Figure ES.1 illustrates the distribution of BIP load across the indicated industry types.

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

[redacted]

SCE's enrollment in BIP was 344 service accounts during the typical 2021 event day, which is a decrease relative to the 469 enrolled service accounts during PY2020. These accounted for a total of 594.3 MW of maximum demand, or 1.73 MW per service account during the July 9th event day. Manufacturers make up 57 percent of the enrolled load. Figure ES.2 illustrates the distribution of SCE's BIP load across the indicated industry types.

[1] A customer's coincident maximum demand ("Enrolled Load" in Figures ES.1-2) 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).

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

[redacted]

[redacted]

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

Table ES.1 summarizes the number of customers called, load impact, percentage load impact, and FSL achievement rate by event for PG&E. The total program load impact for PG&E's July 9th event averaged 155 MW, or 65 percent of enrolled load, representing 84

percent of the reduction required to meet the aggregate FSL across the 293 customers who were called for the event.

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	7/9/2021	Fri.	293	155	65%	84%
Typical Event Day			**293**	**155**	**65%**	**84%**

Table ES.2 displays a summary of load impact results for the July 9th SCE BIP event. The load impact was 409 MW, representing a 74 percent decrease relative to the reference load. This was 93.7 percent of the reduction required to meet the aggregate FSL.

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	7/9/2021	Fri.	344	409	74%	94%
Typical Event Day			**344**	**409**	**74%**	**94%**

[redacted]

Table ES.3: Summary of Event-hour Load Impact by Event, *SDG&E*

Event	Date	Day of Week	# Service Agreements	Estimated Load Impact (MWh/h)	% LI	Estimated LI / LI at FSL
1	6/17/2021	Fri.	[redacted]			
Typical Event Day						

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.

PG&E forecasts BIP enrollments to increase from 263 customers in January of 2022 to 362 customers by the end of 2032. SCE predicts enrollments to remain constant at 341 service accounts from 2022 through 2032. SDG&E forecasts BIP enrollments to remain at one customer until 2032.

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. Figures ES.4 and ES.5 show the ex-ante load impacts for SCE and SDG&E, respectively. The ex-ante load impacts illustrate the lack of weather sensitivity at the aggregate level.

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

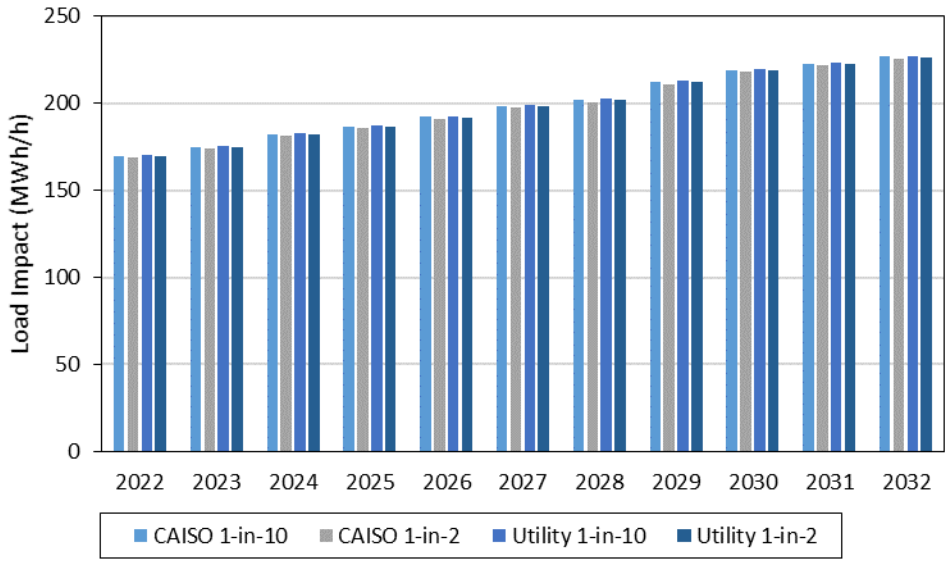


Figure ES.4: Average August Ex-Ante Load Impacts by Year and Scenario, *SCE*

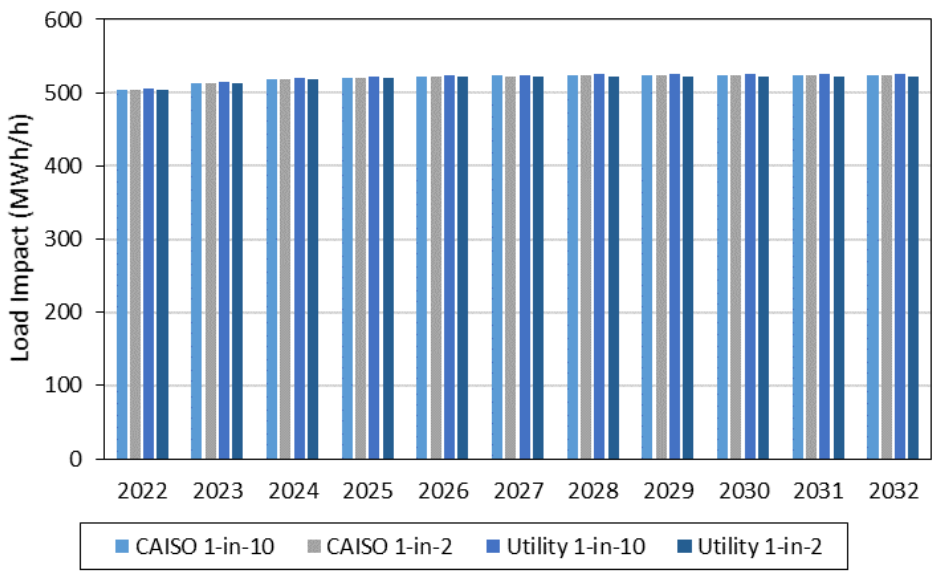


Figure ES.5: Average August Ex-Ante Load Impacts by Scenario, *SDG&E*

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"), Southern California Edison ("SCE"), and San Diego Gas and Electric Company ("SDG&E") in 2021. The report provides estimates of ex-post load impacts that occurred during events called in 2021 and an ex-ante forecast of load impacts for 2022 through 2032 that is based on the IOU's enrollment forecasts and the ex-post load impacts estimated for the 2021 program year.

The primary research questions addressed by this evaluation are:

1. What were the BIP load impacts in 2021?
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 2022 through 2032?

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. Appendix B shows the FSL achievement rate by industry group.

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 2021.

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 events can be operated year-round, with 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 a substantial excess energy charge on any power used above their contracted amount, or FSL. This potential energy charge has resulted in a high compliance rate. PG&E may require a customer that fails to reduce its load down to or below its FSL to re-test, modify its FSL, de-enroll from the program, or successfully comply with the re-test.

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.

SDG&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 2021 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.

Participation in SDG&E's program has been low, consistent with the California Public Utilities Commission ("Commission" or "CPUC") direction to focus marketing efforts on price responsive programs. There was one participant in 2021.

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).[2]

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 PY2020, from 494 to 310.[3] The sum of enrolled customers' coincident maximum demands[4] was 275.4 MW, or 0.89 MW for the average service agreement. The manufacturing industry group contains 46 percent of the enrolled load.

[2] 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, 3 in SCE's service territory, and 1 representing SDG&E's entire service territory. In addition, PG&E has many accounts that are not located within any specific LCA.

[3] "Enrollment" is defined as the enrollment on the (August 17th and 18th) typical event day in PY2020 compared to the July 9th event day in PY2021.

[4] 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[5]	Percent of Max MWh/h	Average Max MWh/h[6]
Agriculture, Mining & Construction	126			
Manufacturing	76			
Wholesale, Transport, other utilities	99	51.9	18.9%	0.52
Retail stores	4			
Offices, Hotels, Finance, Services	3			
Schools	1			
Other or unknown	1			
Total	**310**	**275.4**	**-**	**0.89**

Table 2.2 shows comparable information on BIP enrollment for SCE. SCE's enrollment in BIP was 344 service accounts on the July 9, 2021 event day, which is a decrease relative to the 469 enrolled service accounts during PY2020. These accounted for a total of 594.3 MW of maximum demand, or 1.73 MW per service account. Manufacturers make up 57 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			
Manufacturing	228	339.8	57.2%	1.49
Wholesale, Transport, other utilities	51			
Retail stores	3			
Offices, Hotels, Finance, Services	5			
Schools	1			
Institutional/Government	3			
Other (or unknown)	22			
Total	**344**	**594.3**	**-**	**1.73**

Table 2.3 shows BIP enrollments for SDG&E. SDG&E's enrollment in BIP was one service account during the June 17th event. This account totaled 1.3 MW of maximum demand. The single customer is a part of the Agriculture, Mining & Construction industry group.

Table 2.3: BIP Enrollees by Industry Group, *SDG&E*

Industry	Enrolled	Sum of Max MWh/h	Percent of Max MWh/h	Average Max MWh/h

[5] "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.
[6] "Ave. Max MW" is calculated as "Sum of Max MW" divided by the "# of Service Accounts."

[redacted]

Tables 2.4 and 2.5 show BIP enrollment by local capacity area for PG&E and SCE, respectively. (SDG&E consists of a single LCA.) The greatest portion of PG&E's enrolled load is in the "Other" LCA category. For SCE, 68.1% percent of enrolled load is in the LA Basin.

Table 2.4: 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	38	[redacted]		
Greater Fresno Area	90			
Humboldt	2			
Kern	27			
North Coast / North Bay	11			
Other (blank)	104	86.1	31.3%	0.83
Sierra	17	[redacted]		
Stockton	21			
Total	**310**	**275.4**	**-**	**0.89**

Table 2.5: 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	281	404.9	68.1%	1.44
Outside Basin	14	[redacted]		
Ventura	48			
Total	**344**	**594.3**	**-**	**1.73**

2.3 Event Days

Table 2.6 lists BIP event days and hours for the three IOUs in 2021. PG&E called one transmission emergency event, which occurred on a Friday. SCE called one local reliability event which occurred on a Friday. SDG&E called one event triggered by temperature and system load conditions, which took place on a Thursday.

Table 2.6: BIP Event Days

Date	Day of Week	PG&E	SCE	SDG&E
6/17/2021	Thursday			Temp. & Sys. Load 6:00 – 8:00 p.m.
7/9/2021	Friday	Transmission Emergency 6:32 – 8:32 p.m.	Reliability 5:50 – 8:53 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. Weekends and holidays were excluded from the estimation database.[7]

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 and its results are explained in Appendix A.

[7] Including weekends and holidays would require the addition of variables to capture the fact that load levels and patterns on weekends and holidays can differ greatly from those of non-holiday weekdays. Because event days did not occur on weekends or holidays in PY2021, the exclusion of these data does not affect the model's ability to estimate ex-post load impacts.

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[8]
e_t	the error term

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

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 an event) for factors that affect pre-event usage but are not accounted for by the other included variables.[9]

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.

In PY2021, no weekend events were called. Therefore, no separate weekend models were estimated to account for different usage behavior on weekends. The weekend regression specification only differs by including the appropriate day type indicator variables (i.e., Sunday).

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 SubLAP (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.[10] 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.

[9] 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.

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

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, or by LCA, 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 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 using a metric of estimated *average hourly load impacts* by event and for the average event. 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.

Each utility called one event in 2021. On a summary level for the typical event day, the average event-hour load impact per enrolled customer was 531 kWh/h for PG&E, 1,188 kWh/h for SCE, and [redacted].

4.1 PG&E Load Impacts

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

PG&E called a transmission emergency event on July 9th from 6:32 to 8:32 p.m. Table 4.1 summarizes average event-hour reference loads and load impacts at the program level.[11] The average estimated reference load across event hours was 238 MW. The load impact was 155 MW during the full event hour, resulting in a percentage load impact of

[11] Results are averaged over full event hours only, i.e., partial event hours are omitted.

65 percent. There were 293 customers called while 310 customers were enrolled at the time of the event.

Table 4.1: 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[12]
1	7/9/2021	Fri.	293	238	83	155	65%
Typical Event Day			**293**	**238**	**83**	**155**	**65%**

Table 4.2 compares the observed loads and FSLs for the July 9th 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 4.1) 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 (an observed load above the FSL). The FSL achievement rate on July 9th was 84%.

Table 4.2: 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	7/9/2021	Fri.	83	53	84%
Typical Event Day			**83**	**53**	**84%**

Table 4.3 summarizes average event-hour BIP load impacts by industry group for the typical event day. [redacted]

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

Table 4.3: 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					
Manufacturing					
Wholesale, Transport, Other Utilities	96	43.7	10.3	33.5	76.5%
Retail					
Offices, Hotels, Finance, Services					
Schools					
Other or Unknown					
Total	**293**	**238.2**	**82.73**	**155.50**	**65.3%**

Table 4.4 summarizes the typical event day load impacts by local capacity area (LCA), showing that the highest share of the load impacts came from service agreements not currently categorized under any LCA (53.8 MW).

Table 4.4: 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	31				
Greater Fresno	90				
Kern	26				
Northern Coast	4				
Other	104	76.6	22.7	53.8	70.3%
Sierra	17				
Stockton	21				
Total	**293**	**238.2**	**82.7**	**155.5**	**65.3%**

4.1.2 Hourly Load Impacts

Table 4.5 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 9th event where 293 customers were called.

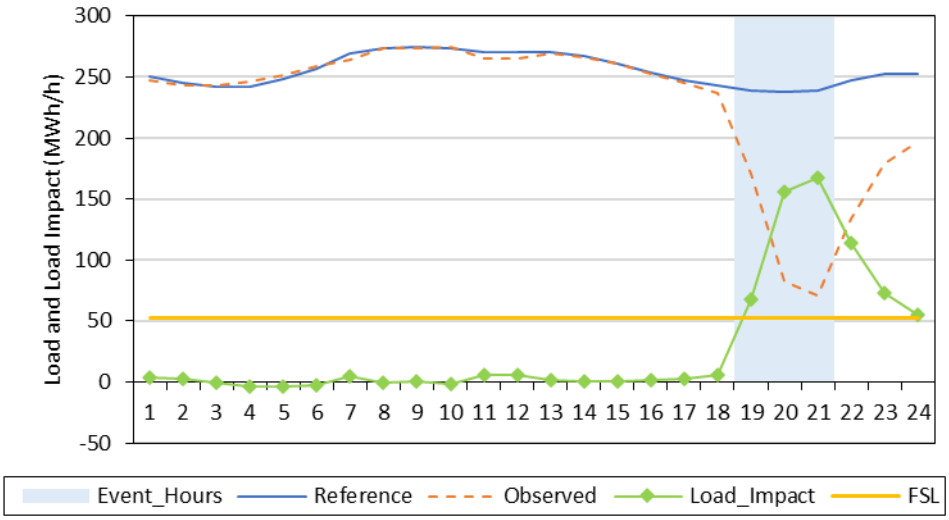
Table 4.5: BIP Hourly Load Impacts for the Typical Event Day, *PG&E*

Hour Ending	Estimated Reference Load (MWh/hour)	Observed Event Day Load (MWh/hour)	Estimated Load Impact (MWh/hour)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (MWh/hr)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	250.6	247.2	3.5	81.7	1.8	2.8	3.5	4.1	5.1
2	245.7	243.3	2.4	80.1	1.1	1.9	2.4	3.0	3.8
3	242.6	243.3	-0.7	78.1	-2.0	-1.2	-0.7	-0.2	0.5
4	242.4	245.8	-3.4	76.3	-4.7	-3.9	-3.4	-2.9	-2.2
5	248.0	251.1	-3.1	75.0	-4.2	-3.6	-3.1	-2.7	-2.1
6	256.7	259.3	-2.6	73.8	-3.6	-3.0	-2.6	-2.2	-1.5
7	269.2	264.1	5.1	73.9	4.0	4.6	5.1	5.5	6.2
8	273.3	273.3	-0.1	76.6	-1.3	-0.6	-0.1	0.4	1.2
9	274.3	273.5	0.7	81.0	-0.7	0.1	0.7	1.3	2.1
10	273.3	274.4	-1.0	86.1	-2.7	-1.7	-1.0	-0.4	0.6
11	270.8	265.3	5.5	90.9	3.8	4.8	5.5	6.1	7.1
12	270.6	264.7	5.9	95.0	4.2	5.2	5.9	6.7	7.7
13	270.9	268.9	2.0	98.0	0.3	1.3	2.0	2.7	3.8
14	267.0	266.3	0.7	100.2	-0.9	0.0	0.7	1.3	2.2
15	261.0	260.6	0.5	102.2	-1.1	-0.2	0.5	1.1	2.0
16	253.8	252.4	1.4	103.1	-0.2	0.7	1.4	2.1	3.0
17	247.8	245.4	2.5	103.8	0.9	1.8	2.5	3.1	4.1
18	242.7	237.3	5.4	103.0	3.8	4.8	5.4	6.1	7.0
19	239.0	171.1	67.9	101.3	66.3	67.2	67.9	68.5	69.5
20	238.2	82.7	155.5	95.6	153.8	154.8	155.5	156.2	157.1
21	239.0	71.4	167.6	91.6	166.0	166.9	167.6	168.2	169.1
22	247.7	133.6	114.2	88.5	112.3	113.4	114.2	114.9	116.0
23	252.3	178.8	73.5	85.5	71.5	72.7	73.5	74.3	75.5
24	252.1	196.8	55.3	83.2	53.4	54.5	55.3	56.1	57.3
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	6,129	5,470	658	326.7	585.8	628.7	658.4	688.2	731.1
Event Hours	238.2	82.7	155.5	20.6	147.2	152.1	155.5	158.9	163.8

* The highlighting indicates all hours affected by the event. However, hour-ending 19 and 21 were partial event-hours and are not included in the average event-hour calculations in the report.

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 4.1 illustrates the hourly reference load, observed load, and estimated load impact for the typical event day.

Figure 4.1: BIP Loads for the Typical Event Day, *PG&E*



During the July 9th event, some SubLaps received late notifications due to an error with PG&E's notification system. Customers within those SubLaps received notifications around 7 p.m. instead of 6 p.m. As a result, 68 customers began curtailing loads around 7:30 p.m. instead of 6:30 p.m. Figure 4.2 illustrates the aggregate reference load, load impact, and FSL for the 225 customers called on time for the July 9th BIP event. Whereas Figure 4.3 illustrates the reference load, load impact, and FSL for the 68 customers who were notified of the event approximately one hour. Customers who were called on time reduced their load by approximately 91 MW and had an 87% FSL achievement rate during hour ending 20. Customers notified one hour later begin to decrease usage almost exactly one hour later than their counterparts. Customers who were called late reduced their load by approximately 83 MW and had a 99% FSL achievement rate during hour ending 21. The late notification lowers average FSL achievement and load impacts during the ex-post event window as many customers did not start responding until an hour after the event technically started and we report results for the full event hour (HE 20).

Figure 4.2: BIP Loads for the Typical Event Day (Regular Notification), *PG&E*

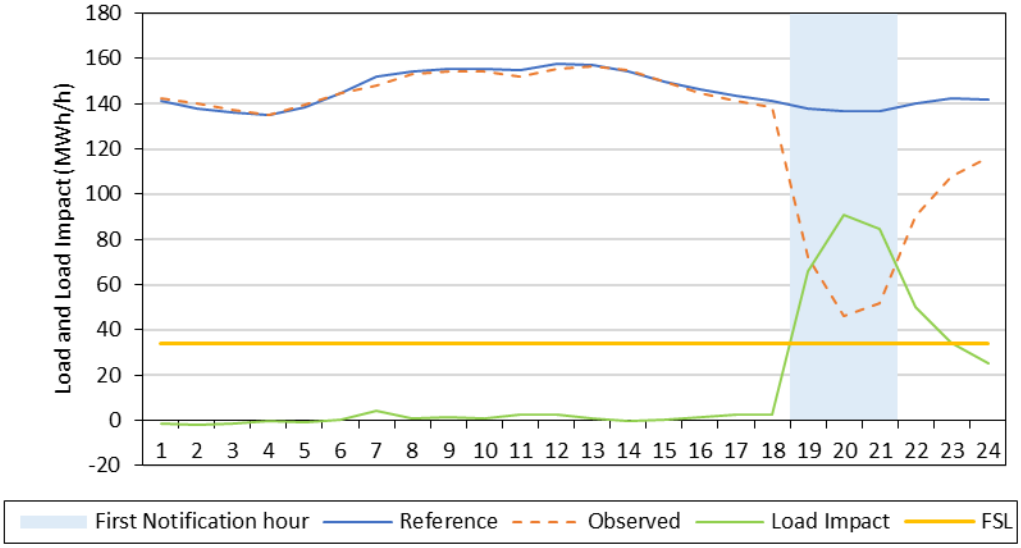
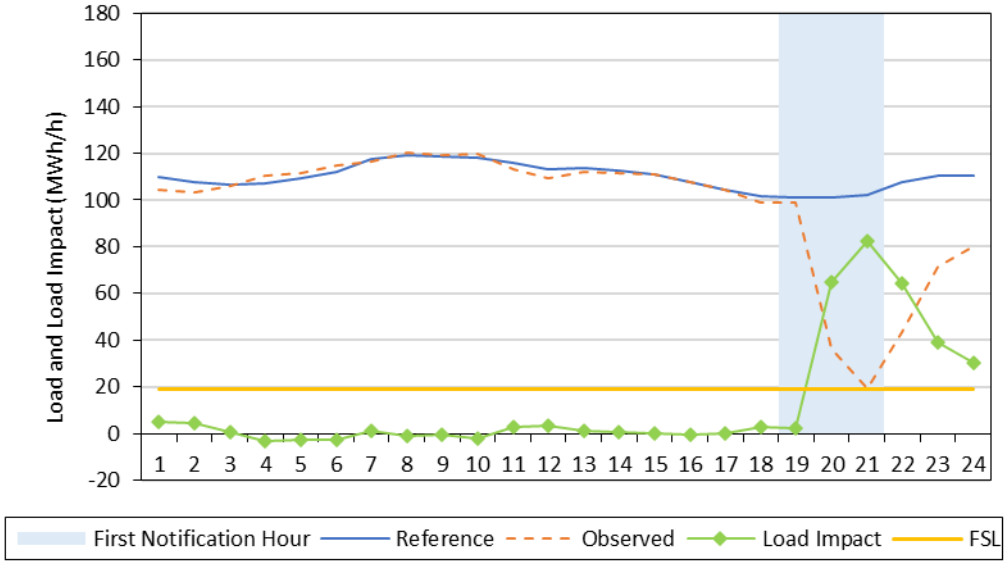


Figure 4.3: BIP Loads for the Typical Event Day (Late Notification), *PG&E*



4.2 SCE Load Impacts

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

SCE called one event in 2021 on July 9th from 5:50 to 8:53 p.m. Table 4.6 displays the average full event-hour reference loads and load impacts for the single weekday event.[13] The event was called as a program reliability check. All 344 enrolled BIP

[13] Results are averaged over full event hours only, i.e., partial event hours are omitted.

customers were called, accounting for 551 MW of reference load. The load impact was 409 MW, or 74% of the reference load.

Table 4.6: 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[14]
1	7/9/2021	Fri.	344	551.4	142.9	408.5	74%
Typical Event Day			**344**	**551.4**	**142.9**	**408.5**	**74%**

Table 4.7 provides the SCE BIP event day observed loads compared to the FSL and FSL achievement rate. The program FSL was 115 MW and the FSL achievement rate was 94% over the two full event hours.

Table 4.7: 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	7/9/2021	Fri.	142.9	115	94%
Typical Event Day			**142.9**	**115**	**94%**

Table 4.8 shows the average event-hour load impact by industry group for the typical event day (July 9th).[15] The total row at the bottom of the table shows the total event-day load impact of 408.5 MW, or 74.1 percent of the reference load. Most of the program's load impact came from customers in the Manufacturing industry group.

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

[15] In order to summarize only full-hour load impacts, the tables contain load impacts from 6 to 8 p.m., omitting the partial hours from 5:50 to 6:00 p.m. and 8:00 to 8:53 p.m.

Table 4.8: 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				
Manufacturing	228	306.5	78.1	228.4	74.5%
Wholesale, Transport, other utilities	51				
Retail stores	3				
Offices, Hotels, Finance, Services	5				
Schools	1				
Institutional/Government	3				
Other (or unknown)	22				
Total	**344**	**551.4**	**142.9**	**408.5**	**74.1%**

Table 4.9 summarizes average hourly load impacts by LCA. The majority of the load impact comes from customers in the LA Basin.

Table 4.9: 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	282	368.8	107.4	261.5	71%
Outside Basin	14				
Ventura	48				
Total	**344**	**551.4**	**142.9**	**408.5**	**74%**

4.2.2 Hourly Load Impacts

Table 4.10 presents hourly load impacts for the typical event day (July 9th) in the manner required by the Protocols.

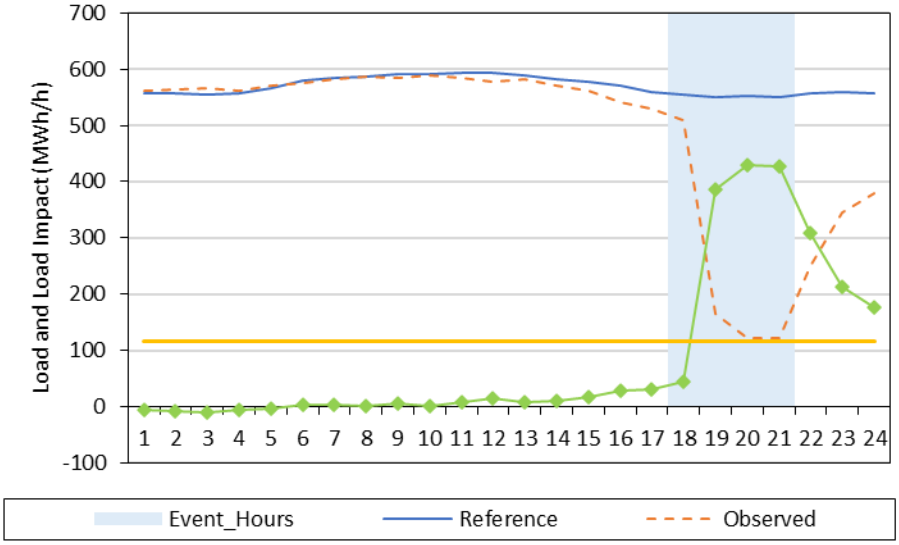
Table 4.10: BIP Hourly Load Impacts for the Typical Event Day, *SCE*

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	557.3	562.3	-5.0	-1%	75.1	-8.5	-6.4	-5.0	-3.5	-1.4
2	556.5	563.8	-7.2	-1%	74.5	-10.5	-8.6	-7.2	-5.9	-3.9
3	554.0	565.0	-11.0	-2%	74.0	-13.8	-12.2	-11.0	-9.9	-8.2
4	556.6	561.0	-4.4	-1%	73.7	-6.9	-5.4	-4.4	-3.4	-1.9
5	566.3	569.5	-3.2	-1%	72.9	-5.5	-4.1	-3.2	-2.3	-1.0
6	578.8	575.1	3.7	1%	72.3	1.4	2.8	3.7	4.6	6.0
7	585.1	582.4	2.7	0%	72.6	-0.1	1.5	2.7	3.8	5.5
8	587.1	586.2	0.9	0%	74.9	-2.2	-0.4	0.9	2.2	4.1
9	590.2	583.5	6.7	1%	78.3	3.4	5.3	6.7	8.1	10.1
10	591.4	589.3	2.1	0%	82.1	-1.5	0.6	2.1	3.6	5.7
11	592.8	585.4	7.4	1%	85.5	3.6	5.9	7.4	8.9	11.1
12	594.3	578.6	15.7	3%	87.5	11.6	14.0	15.7	17.4	19.8
13	590.0	582.2	7.7	1%	88.4	3.2	5.9	7.7	9.6	12.3
14	581.5	571.0	10.6	2%	89.9	6.0	8.7	10.6	12.4	15.2
15	578.3	560.7	17.6	3%	91.7	12.8	15.6	17.6	19.6	22.4
16	570.8	541.5	29.3	5%	92.2	24.1	27.2	29.3	31.4	34.4
17	559.8	530.0	29.9	5%	91.7	24.8	27.8	29.9	31.9	34.9
18	555.8	510.3	45.5	8%	90.3	40.1	43.3	45.5	47.8	51.0
19	551.2	164.5	386.7	70%	86.3	380.8	384.3	386.7	389.1	392.5
20	551.7	121.3	430.4	78%	83.0	424.5	428.0	430.4	432.8	436.3
21	550.7	122.6	428.1	78%	79.8	422.4	425.8	428.1	430.5	433.9
22	557.5	248.5	309.0	55%	78.1	303.3	306.7	309.0	311.3	314.7
23	559.6	345.3	214.2	38%	77.1	208.8	212.0	214.2	216.5	219.7
24	556.6	379.5	177.0	32%	75.9	171.6	174.8	177.0	179.3	182.5
Daily	**13,674**	**11,580**	**2,094**	**15%**	**81.2**	**1,940.7**	**2,031.5**	**2,094.4**	**2,157.3**	**2,248.2**

* The highlighting indicates all hours affected by the event. However, hour-ending 18 and 21 were partial event-hours and are not included in the average event-hour calculations in the report.

Figure 4.4 illustrates the hourly reference load, observed load, and load impact for the typical event day. The event hours are represented with blue shading with the edge hours as partial event hours.

Figure 4.4: BIP Loads for the Typical Event Day, *SCE*



4.3 SDG&E Load Impacts

4.3.1 Average Event-hour Load Impacts

Average event-hour reference loads and load impacts for SDG&E's BIP event are summarized in Table 4.11. There was only one customer enrolled at the time of the June 17th event. The event took place on a Thursday and lasted from 6-8 PM. The event was called in response to temperature and system load conditions. [redacted]

Table 4.11: Average Event-hour Load Impacts by Event, *SDG&E*

Event	Date	Day of Week	# Service Agreements Called	Estimated Reference Load (MWh/h)	Observed Load (MWh/h)	Estimated Load Impact (MWh/h)	% LI[16]
1	6/17/2021	Thu.	[redacted]				
Typical Event Day							

Table 4.12 compares the average observed load to the FSL on the event day. [redacted]

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

Table 4.12: Average Event-hour Observed Loads and FSLs by Event, *SDG&E*

Event	Date	Day of Week	Estimated Reference Load (MWh/h)	Observed Load (MWh/h)	Firm Service Level (MWh/h)	Estimated LI / LI at FSL
1	7/9/2021	Thu.	[redacted]			
Typical Event Day						

4.3.2 Hourly Load Impacts

Table 4.13 presents hourly load impacts for the typical event day in the manner required by the Protocols.

Table 4.13: BIP Hourly Load Impacts for the Typical Event Day, *SDG&E*

[redacted]

Figure 4.5 illustrates the hourly reference load, observed load, and load impact for the typical event day. During the event hours, the observed load and reference load are below the FSL. The majority of curtailable load occurs during the middle of the day, whereas reference loads approach the FSL and below during later hours.

Figure 4.5: BIP Loads for the Typical Event Day, *SDG&E*

[redacted]

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).

For SDG&E, we do not distinguish the forecast by size or location.

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 2021 program year. The load impacts are developed using the historical FSL achievement rates of customers remaining enrolled at the end of the 2021 program year, based on their estimated ex-post load impacts during program year 2021.[17]

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 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

[17] 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.

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.[18] 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.

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

[18] 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.[19] 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]

[19] Customer-specific specifications are tested at an individual level for SDG&E customers.

[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.

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] In consultation with 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.

For SDG&E, the load impact is based on one customer that was enrolled during the ex-post event. Their observed loads during the ex-post event are used to forecast ex-ante "observed" loads during event hours. The load impact is calculated as the difference between the simulated ex-ante reference load and the simulated "observed load".[22]

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 (4:00 to 9:00 p.m. for all 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. We develop forecast load impacts through the end of the event day because customers load reductions often persist well after the end of the event hours.[23]

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

[21] 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 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.

[22] This assumption reflects the pattern we have observed for this customer across previous evaluations.

[23] For PG&E, we use the FSL achievement rate for the first full event hour after being notified for each customer in order to prevent notification delays from lowering the ex-ante forecast.

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 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 2022. The ex-post FSL achievement rates for each utility are summarized in Appendix B, with the results differentiated by industry group (and hour relative to the called event window).

5. Apply forecast enrollments to produce program-level load impacts.
The utilities provided enrollment forecasts. PG&E provided monthly enrollments through 2032, 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 2022 through 2032. We assume that the ex-post shares of customers by notice level (15 versus 30 minute), LCA, and SubLAP hold throughout the forecast period. [redacted]

5.2.3 Methodology for COVID-19 Adjustments to the Ex-Ante Forecast

BIP customers, on average, exhibited a reduction in load as a response to the COVID-19 pandemic which began in March 2020. As a result, the methodology described above for estimating ex-ante reference loads and load impacts requires an adjustment to account for how COVID will affect customer usage over the forecast period. First, we estimate the effect COVID had on each customer's hourly reference loads, comparing pre-COVID versus PY21 loads. Second, we adjust the magnitude of the COVID effect over time based on utility-provided assumptions regarding the expected evolution of the COVID effect during the forecast period. Consequently, the load impacts are also adjusted because they are calculated based upon the FSL achievement rate relative to the reference load. Further details are provided below.

The following regression specification is estimated for each customer and hour separately to capture the effect COVID had on consumption:

$$Q_d = \beta_0 + \beta_1 \times COVID_d + \beta_2 \times CDD65_d + \beta_3 \times HDD65_d + \Sigma_m (\beta_{4,m} \times MONTH_{d,m}) + \beta_5 \times MON_d + \beta_5 \times FRI_d + e_d$$

Table 5.2: Descriptions of Terms included in the COVID Regression Equation

Variable Name	Variable Description
Q_d	the hourly demand on day *d* for a customer enrolled in BIP
The various *b*'s	the estimated parameters
$COVID_d$	an indicator variable for if day *d* is during the COVID-19 pandemic (i.e., post March 2020)
$CDD65_d$	average cooling degree days[24]
$HDD65_d$	average heating degree days[25]
$MONTH_d$	a series of indicator variables for each month
MON_d, FRI_d,	indicator variables for Monday and Friday
e_d	the error term

Table 5.2 provides a description of the variables in the model. Customer non-holiday weekday load data covering the period October 2018 through September 2021 is used to provide sufficient pre-COVID information.[26] The variable of importance, *COVID*, provides an estimate of each customer's PY21 load change in response to the pandemic. The estimated coefficient for *COVID*, β_1, provided the magnitude of the COVID-19 effect and is used to adjust ex-ante reference loads for the various levels of COVID specified in the utility's forecasts.

Each utility provided assumptions regarding how to adjust the magnitude of the COVID effect over time. The magnitude of the pandemic effect on customer usage lessens over time. Therefore, COVID-affected reference loads will approach the non-COVID reference load according to each utility COVID transition assumptions. SCE assumes the COVID effect decreases by half each year until it reaches zero percent in 2031. The percentage assumptions are applied to the magnitude of the COVID effect in its respective period. For example, a 1 MW COVID-related usage decrease is reduced to 0.5 MW when 50 percent of the COVID effect is assumed. PG&E provided us with a COVID forecast but has chosen to withhold the details from the load impact evaluations. For each utility, the

[24] 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.

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

[26] A greater period of data is required to not confound the COVID effect with usage that occurs during summer months. Therefore, it is important to have at least of full year of data before the pandemic began in March 2020. The maximum amount of data available is used for customers that had less than the full two-year period. Specific days that have an effect on customer usage are removed from the analysis (e.g., program events, public safety power shutoffs, FLEX alert).

COVID effects are estimated and applied at a customer level. SDG&E, for PY2021, assumes no COVID-19 adjustment because the program appears to have returned to pre-COVID-19 levels.

Table 5.3: COVID-19 Transition Path Assumption, *SCE*

Year	Commercial & Industrial
2021	50.0%
2022	25.0%
2023	12.5%
2024	6.2%
2025	3.1%
2026	1.6%
2027	0.8%
2028	0.4%
2029	0.2%
2030	0.1%
2031	0.0%

Figures 5.1 through 5.2 illustrates the magnitude of the estimated COVID-19 effect on June 2022 ex-ante program reference loads for PG&E and SCE, respectively.[27] The "Pre-COVID" solid blue line indicates the reference load assuming that COVID-19 were no longer in effect; while the "With COVID" dashed purple line indicates the reference load with an adjustment for COVID-19 (using the estimated COVID-19 magnitude and transition path described above). Over time, the reference loads move closer to "pre-Covid" levels. The aggregate COVID effect on program load is an increase of 0.9 MW for PG&E during the RA window (i.e., hour-ending 17 through 21), representing a 0.4 percent increase. The COVID-related reduction for SCE is 17 MW, or three percent, during the RA window.

[27] Customers that remain enrolled in BIP and are used as the basis for the ex-ante analysis are included in the COVID estimates. Newly enrolled BIP customers without pre-COVID-19 data do not have COVID-19 effects estimated.

Figure 5.1: Ex-Ante Aggregate June 2022 Load with COVID-19 Adjustment, *PG&E*

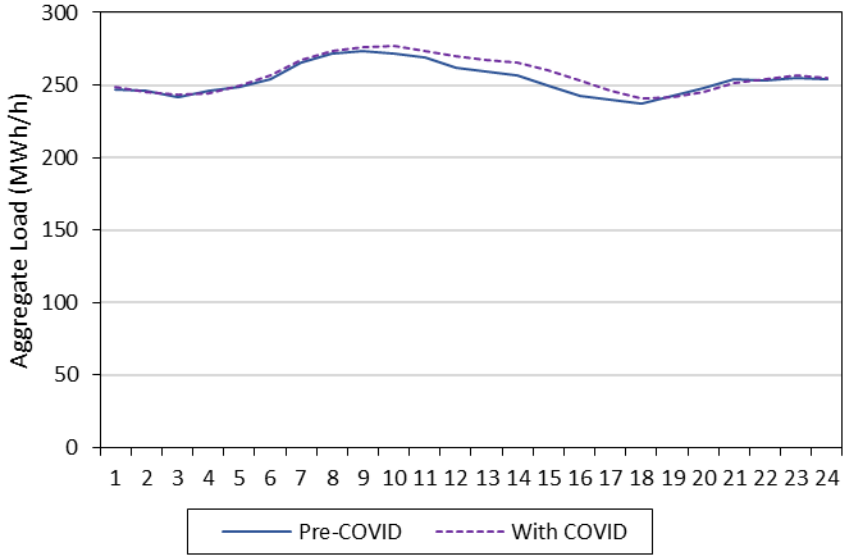
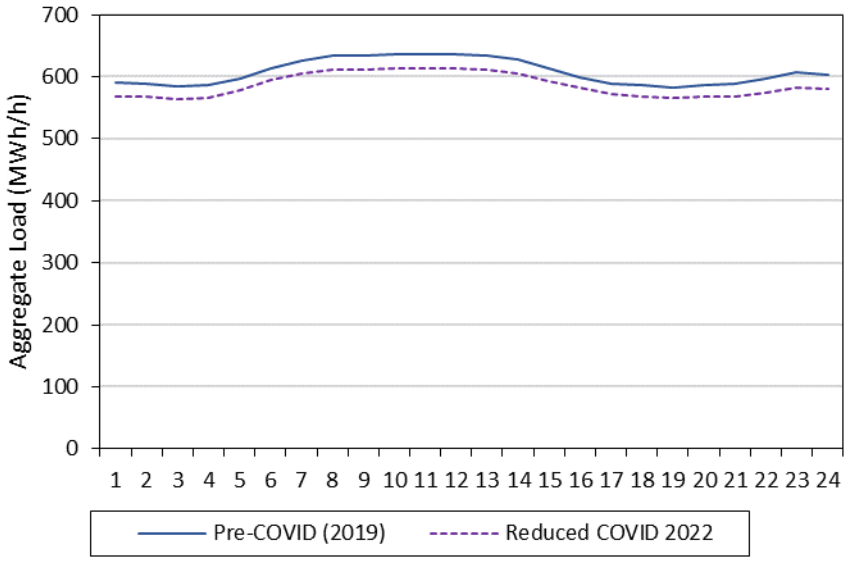


Figure 5.2: Ex-Ante Aggregate June 2022 Load with COVID-19 Adjustment, *SCE*



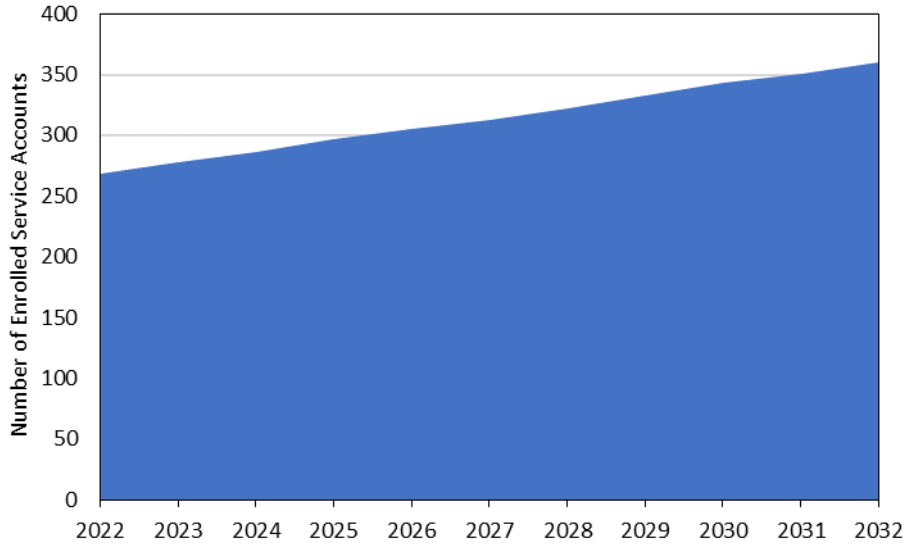
5.3 Enrollment Forecasts

PG&E

Figure 5.3 shows PG&E's forecast of enrollments by year. PG&E forecasts BIP enrollments to decrease from 310 in ex-post to 263 at the beginning of 2022, and then steadily increase to 362 by the end of 2032. Of these, 190 are in the large customer group (over 200 kW) while the majority of the remaining accounts are in the medium customer group (20 to 200 kW).[28]

[28] Only three customers are forecasted to be enrolled in the small customer group (below 20 kW) in 2022.

Figure 5.3: Number of Enrolled Customers in Each Forecast Year, *PGE*



SCE
SCE projects 341 BIP enrollments by April 2022, remaining constant through 2032. Of these, 297 customers are forecasted to be enrolled in the BIP-30 program and the remaining 44 customers are enrolled in the BIP-15 program.

SDG&E
SDG&E had one customer enrolled during 2021. SDG&E forecasts BIP enrollments to remain at one customer until 2032.

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 5.4 shows the August 2022 forecast load impacts in a utility-specific 1-in-2 weather year. Event-hour (4:00 to 9:00 p.m.) load impacts average 170 MW, which represents 64 percent of the enrolled reference load. The program-level FSL is 54 MW, compared to the average event-hour program load of 66 MW. The FSL achievement rate of 93% is higher than the achievement rate during the 2021 event. There were 68 customers who received late notification to the PY2021 ex-post event. We use their FSL achievement rate from hour-ending 21 as opposed to the FSL achievement rate from

hour-ending 20 to forecast future load impacts. As a result, the FSL achievement rate and load impacts are higher in ex-ante than the ex-post event.

Figure 5.4: PG&E Hourly Event Day Load Impacts for the August 2022 Event Day in a Utility-Specific 1-in-2 Weather Year

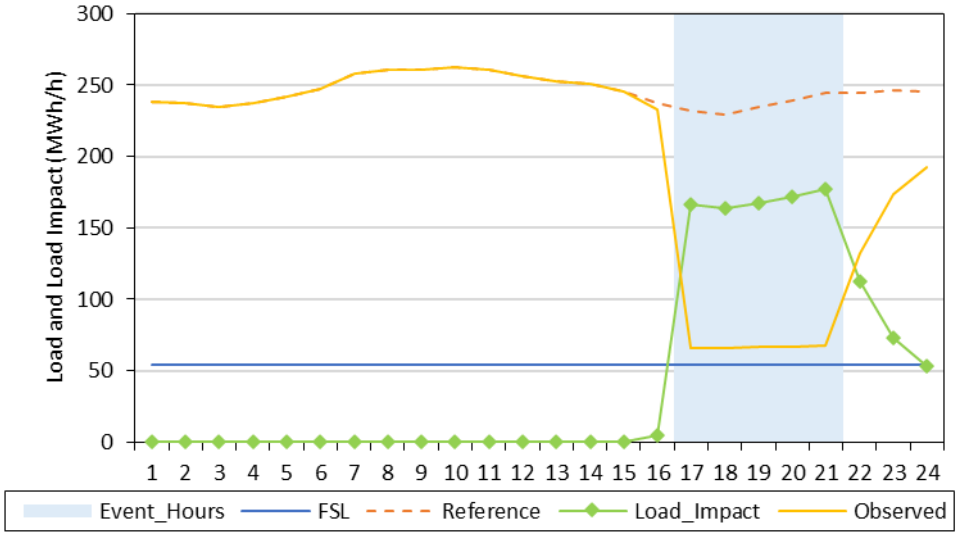


Figure 5.5 shows the share of load impacts by local capacity area, assuming a 2021 August event day in a utility-specific 1-in-2 weather year. [redacted]

Figure 5.5: Share of PG&E Load Impacts by LCA for the August 2022 Event Day in a Utility-specific 1-in-2 Weather Year

Figure 5.6 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 enrollment forecast increases over time, resulting in aggregate load impacts that also increase. 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.) Additionally, there is a small reduction in the per-customer load impact from 2022 through 2023 due to the reference loads decreasing slightly as the estimated COVID effect goes away (since the COVID effect resulted in larger reference loads).

Figure 5.6: Average August Ex-ante Load Impacts by Scenario and Year, *PG&E*

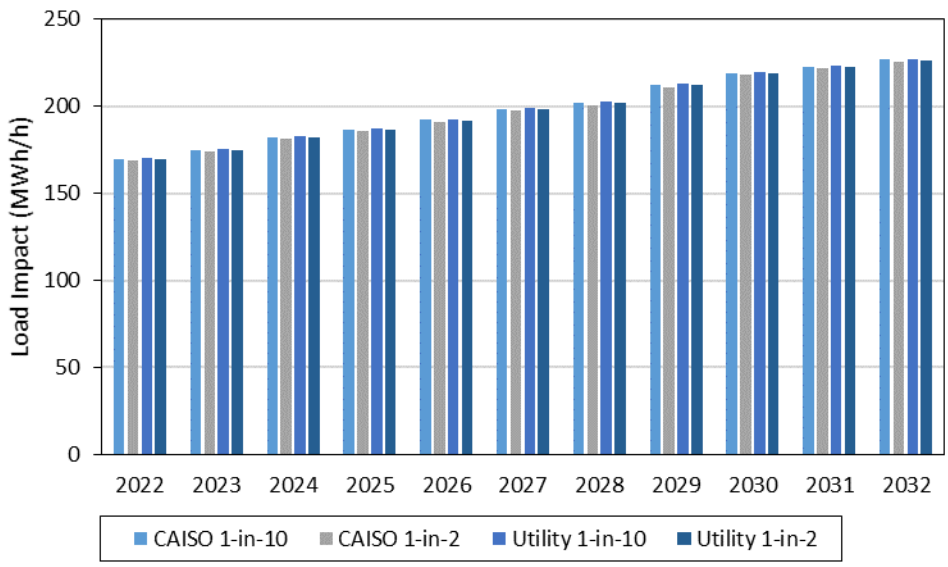


Table 5.4 shows the aggregate and per-customer reference loads and load impacts by weather year (1-in-2 and 1-in-10 for both utility-specific and CAISO-coincident peak conditions) for the August 2022 event day.

Table 5.4: Per-customer Ex-ante August 2022 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	268	236.0	169.5	880.7	632.6	71.8%
Utility 1-in-10	268	236.6	170.0	882.9	634.4	71.9%
CAISO 1-in-2	268	235.1	168.8	877.4	629.7	71.8%
CAISO 1-in-10	268	236.4	169.7	882.0	633.0	71.8%

5.4.2 SCE

Figure 5.7 shows the August 2022 forecast load impacts in a utility-specific 1-in-2 weather year. Event-hour (4:00 to 9:00 p.m.) load impacts average 503 MW, which represents 82 percent of the 616 MW reference load. The program-level FSL of 112 MW, compared to the average event-hour program load of 113 MW, results in an FSL achievement rate of 100%. The FSL achievement rate is higher than shown in our ex-post summary 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 100% during the second full event hour. A longer ex-ante event window results in more event hours when customers achieve the higher 100% FSL achievement rate.

Figure 5.7: SCE Hourly Event Day Load Impacts for the August 2022 Event Day in a Utility-Specific 1-in-2 Weather Year

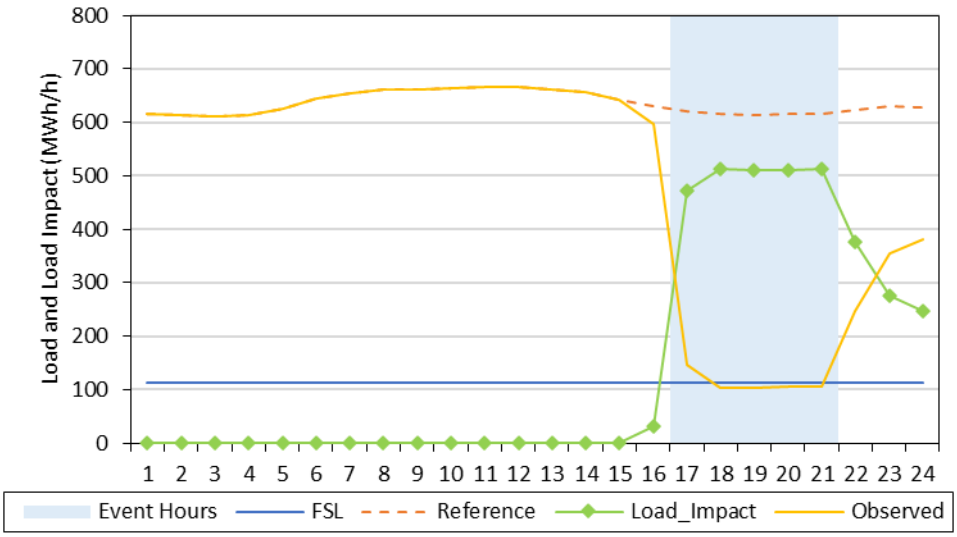


Figure 5.8 shows the share of load impacts by local capacity area for an August 2022 event day in a utility-specific 1-in-2 weather year. LA Basin customers account for the largest share, with 68 percent of the load impacts.

Figure 5.8: Share of SCE Load Impacts by LCA for the August 2022 Event Day in a Utility-specific 1-in-2 Weather Year

[redacted]

Figure 5.9 shows the share of load impacts by notification time, assuming an August 2022 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 [redacted]

Figure 5.9: Share of SCE Load Impacts by Notification Time for the August 2022 Event Day in a Utility-specific 1-in-2 Weather Year

Figure 5.10 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. These load impacts are shown for forecast years 2022 through 2032. The load impact is not sensitive to weather conditions. For example, the minimum and maximum load impacts in 2022 are 503 MW and 505 MW, respectively. The load impact increases over time to a maximum of 523 MW because reference loads increase as the estimated effect of COVID diminishes over ten years.

Figure 5.10: Average August Ex-ante Load Impacts by Scenario and Year, *SCE*

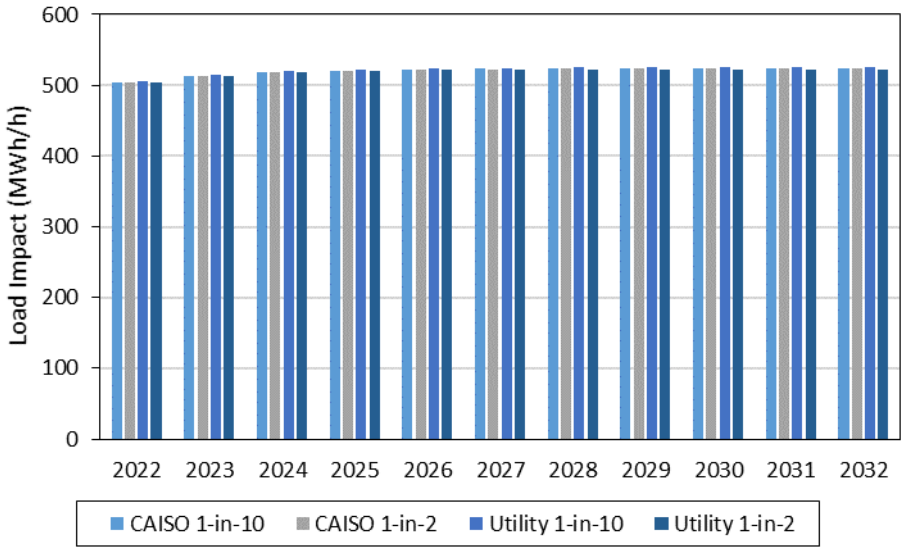


Table 5.5 shows the per-customer reference loads and load impacts by weather year (1-in-2 and 1-in-10 for both utility-specific and CAISO-coincident peak conditions) for the August 2022 event day.

Table 5.5: Per-customer Ex-ante August 2022 Load Impacts by Scenario, *SCE*

Weather Year	Reference Load (kWh/h)	Load Impact (kWh/h)	% Load Impact
Utility 1-in-2	1,806	1,476	82%
Utility 1-in-10	1,813	1,481	82%
CAISO 1-in-2	1,807	1,477	82%
CAISO 1-in-10	1,808	1,477	82%

5.4.3 SDG&E

Figure 5.11 shows the load impact forecast for an August 2022 event day in a utility-specific 1-in-2 weather year. [redacted]

Figure 5.11: SDG&E Hourly Event Day Load Impacts for the August 2022 Event Day in a Utility-Specific 1-in-2 Weather Year

[redacted]

Figure 5.12 illustrates 2022 to 2032 August load impact for each forecast scenario, differentiated by 1-in-2 versus 1-in-10 weather conditions under both utility-specific and CAISO-coincident peak conditions. [redacted]

Figure 5.12: Average August Ex-Ante Load Impacts by Scenario and Year, *SDG&E*

[redacted]

Table 5.6 shows the per-customer reference loads and load impacts by weather condition (1-in-2 and 1-in-10 for both utility-specific and CAISO-coincident peak) for the August 2022 event day. [redacted]

Table 5.6: Per-customer Ex-ante August 2022 Load Impacts by Scenario, *SDG&E*

Weather Year	Reference Load (kWh/h)	Load Impact (kWh/h)	% Load Impact
Utility 1-in-2	[redacted]		
Utility 1-in-10			
CAISO 1-in-2			
CAISO 1-in-10			

6. Comparisons of Results

In this section, we present several comparisons of load impacts for each utility:

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

In the above "current study" refers to this report, which is based on findings from the 2021 program year; and "previous study" refers to the report that was developed following the 2020 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-post

Table 6.1 shows the average event-hour reference loads and load impacts for PY2020 and PY2021. The PY2020 load impacts are based on the three full event hours (HE 17-19) during the typical event day (which is an average of the August 17th and 18th, 2020 event days). The PY2021 load impacts are based on the one full event hour (HE 20) on July 9th.

Table 6.1: Comparison of Ex-post Impacts in PY2020 and PY2021, *PG&E*

Level	Outcome	Ex-post PY2020	Ex-post PY2021
Total	# Customers	494	293
	Reference (MWh/h)	294	238
	Load Impact (MWh/h)	202	155
Per SAID	Reference (kWh/h)	595	813
	Load Impact (kWh/h)	408	531
	% Load Impact	68.6%	65.3%

There are fewer service accounts in PY2021, resulting in a lower aggregate reference load and load impact. However, the per-customer results are higher in PY2021 since de-enrolling customers were smaller on average. The percentage load impact is similar between program years. The FSL achievement rate was 93% in PY2020 and 84% in PY2021. (The FSL achievement rate over the three weekday events in PY2020 ranged from 83% to 93%.) Customers that remained on the program in both years exhibited a reduction in FSL achievement rate (106% vs 84%). The aggregate reference loads and FSL increased for these customers by 10 MW and 4 MW, respectively. A significant portion of the difference between the load Impacts and FSL achievement rate in PY2020 and PY2021 was that 68 customers were notified of the event an hour late, delaying their response by one hour. While customers with a late notification had a 100% FSL achievement rate in hour-ending 21, ex-post results are provided for the full event hour-ending 20. [redacted]

6.1.2 Previous versus current ex-ante

In this sub-section, we compare the ex-ante forecast prepared following PY2020 (the "previous study") to the ex-ante forecast contained in this study (the "current study"). Table 6.2 contains this comparison for the August 2022 utility-specific 1-in-2 typical event day forecast.

Table 6.2: Comparison of Ex-ante Impacts from PY2020 and PY2021 Studies, *PG&E*

Level	Outcome	Ex-ante 2022 Typical Event Day, *Previous Study*	Ex-ante 2022 Typical Event Day, *Current Study*
Total	# Customers	308	268
	Reference (MWh/h)	240	236
	Load Impact (MWh/h)	187	170
	FSL (MW)	56	54
Per SAID	Reference (kWh/h)	780	881
	Load Impact (kWh/h)	608	633
	% Load Impact	78.1%	71.8%

PG&E BIP enrollment decreased by 39 customers, from 308 to 268 customers. The aggregate reference load decreased by 4 MW. There were 58 customers accounting for 32 MW of reference load that were included in the PY2020 forecast, but left BIP prior to the creation of the PY2022 forecast. In addition, 14 customers accounting for 25 MW of reference load joined BIP in between the two forecasts. The forecast reference loads were similar for customers that remain in both years of the ex-ante analysis. The FSL achievement rate is forecast to be 93% which is higher than PY2021 ex -post estimates. However, the PY2020 forecast FSL achievement rate was 102% which is significantly higher than that of the PY2021 ex-ante forecast. As mentioned above, the reduced FSL achievement in PY2022 was driven by reduced performance from a few large customers.

6.1.3 Previous ex-ante versus current ex-post

Table 6.3 provides a comparison of the ex-ante forecast of 2021 load impacts prepared following PY2020 and the ex-post PY2021 load impacts estimated as part of this study. The ex-ante forecast shown in the table represents the typical event day during a utility-specific 1-in-2 weather year. The ex-post load impacts are based on the typical event day in 2021.

Table 6.3: Comparison of Previous Ex-ante and Current Ex-post Impacts, *PG&E*

Level	Outcome	Ex-ante 2021 Typical Event Day, Previous Study	Ex-post *PY2021*
Total	# Customers	308	293
	Reference (MWh/h)	234	238
	Load Impact (MWh/h)	183	155
Per SAID	Reference (kWh/h)	761	813
	Load Impact (kWh/h)	593	531
	% Load Impact	78.0%	65.3%

The aggregate load impact forecast from the previous study is 28 MW higher than the current ex-post load impacts. The PY2020 enrollment forecast of 308 customers is similar to the 310 customers enrolled in ex-post, although only 293 customers were called during the PY2021 event. The PY2021 aggregate and per-customer reference loads are larger because of the COVID effect diminished by a greater magnitude than was assumed in PY2020 for customers that remained on the program. The PY2020 forecast FSL achievement rate of 102% was higher than the ex-post FSL achievement rate of 84%. As mentioned above, of the customers that were part of the PY2020 ex-ante analysis and the PY2021 ex-post analysis, there were a few customers with significant load impact reductions in PY2021 that resulted in lower aggregate performance. Part of the lower ex-post FSL achievement rate is because almost one quarter of the program was called late to the event which lowered ex-post performance. Using hour-ending 20 for customers with a regular notification and hour-ending 21 for customers that had a late notification, the combined load impacts would be 173 MW for the PY2021 ex-post event.

6.1.4 Current ex-post versus current ex-ante

Table 6.4 compares the ex-post and ex-ante load impacts from this study. The ex-ante load impacts in the table represent the 2022 typical event day with utility-specific 1-in-2 weather conditions. The enrollments decreased from 310 to 268. (The table reflects the 293 called customers in PY2021 rather than the 310 enrolled customers.) The aggregate FSL achievement rate increases from roughly 84% in PY2020 to 93% in PY2021. We see increased impacts and FSL achievement due to our different forecast methodology for customers who were notified late of the July 9th event. Specifically, the ex-post event represents results for the full event hour, HE 20, but FSL achievement rates for HE 21 were used for customers that received a late notification of the event. The average per-customer reference load is larger in the ex-ante forecast because customers that remain on the program are larger, on average, than customers that left. COVID-19 has a de minimis effect on reference loads for the remaining BIP PG&E customers.

Table 6.4: Comparison of Current Ex-post and Current Ex-ante Impacts, *PG&E*

Level	Outcome	Ex-post PY2021	Ex-ante 2022 Typical Event Day, Current Study
Total	# Customers	293	268
	Reference (MWh/h)	238	236
	Load Impact (MWh/h)	155	170
	FSL (MWh/h)	53	54
Per SAID	Reference (kWh/h)	813	881
	Load Impact (kWh/h)	531	633
	% Load Impact	65.3%	71.8%

Table 6.5 documents the various potential sources of differences between the ex-post and ex-ante load impacts.

Table 6.5: 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 20 on 7/9/2021.	HE 17-21.	Periods corresponding to larger reference loads result in larger load impacts. Reference loads are similar between these periods. The FSL achievement rate for HE 21 is used for customers that received late notification of the event, resulting in a large ex-ante load impact.
Event Day of the Week	Friday event.	Average Weekday.	This is not expected to have any major impacts on forecast load impacts. If weekend events are called in future years reference loads are likely to be lower while FSL achievement rates are likely to be higher.
% of resource dispatched	Only 293 out of 310 customers were called to the lone event.	Assume all customers are called.	Larger load impacts. The ex-ante method assumes that all enrolled customers are dispatched.
Enrollment	310 customers during 2021 event days.	268 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.
COVID-19	Slightly higher reference loads because of COVID-19.	Reference loads decrease over time to a non-COVID level as the effect of COVID is reduced.	Little to no impact. Load impacts reduce over time as reference loads approach a non-COVID usage level, which is slightly lower for PG&E BIP customers.

6.2 SCE

6.2.1 Previous versus current ex-post

Table 6.6 compares ex-post load impacts between the August 14th event day in PY2020 and the July 9th event day in PY2021. Eight BIP events were called in PY2020 compared to one event called in PY2021. The August 14th event day is used as a comparison as it was non-consecutive Friday event with all customers called. The PY2021 event was called during the hours 5:50 to 8:53 p.m. while the PY2020 event was called from 5:10 to 8:35 p.m.

Table 6.6: Comparison of Ex-post Impacts in PY2020 and PY2021, *SCE*

Level	Outcome	Ex-post Previous Study	Ex-post Current Study
Total	# SAIDs	469	344
	Reference (MWh)	640	551
	Load Impact (MWh/h)	484	409
	FSL (MW)	105	115
Per SAID	Reference (kWh/h)	1,366	1,603
	Load Impact (kWh/h)	1,032	1,188
	% Load Impact	75.6%	74.1%

Enrollment decreased from 469 accounts to 344, resulting in lower aggregate reference loads and load impacts. The per-customer reference load is larger in PY2021 because customers that remained enrolled on BIP were larger, on average. The aggregate load impact decreased by 75 MW. There were 139 customers that left BIP, accounting for 38 MW in PY2020. There were 14 new customers providing a 1 MW load impact in PY2021. For customers that remained in both program-year events, their load impact decreased by 77 MW in 2021. This reduction, however, is a result of 89 MW lower reference loads on July 9th and a 10 MW increase to their FSL. Overall, these customers had a higher FSL achievement rate of 93% in PY2021, compared to the 90% on the PY2020 August 14th event. The aggregate FSL achievement rate is 94% in PY2021.

6.2.2 Previous versus current ex-ante

In this sub-section, we compare the ex-ante forecast prepared following PY2020 (the "previous study") to the ex-ante forecast contained in this study (the "current study"). Table 6.7 represents the forecast for the August 2022 utility-specific 1-in-2 typical event day. The results are averaged over the RA window, 4 to 9 p.m.

Table 6.7: Comparison of Ex-ante Impacts from PY2020 and PY2021 Studies, *SCE*

Level	Outcome	Ex-ante 2022 Typical Event Day, *Previous Study*	Ex-ante 2022 Typical Event Day, *Current Study*
Total	# Customers	359	341
	Reference (MWh/h)	653	614
	Load Impact (MWh/h)	510	502
	FSL (MWh/h)	112	112
Per SAID	Reference (kWh/h)	1,818	1,800
	Load Impact (kWh/h)	1,421	1,471
	% Load Impact	78.2%	81.7%

The enrollment numbers decreased by 18 customers between the previous and current studies. The total forecast reference load is lower in the current study because of customers that left the program, whereas per-customer reference load remains similar. Customers that were on the program in both years have similar forecast reference loads, indicating that the estimated COVID-19 effect was consistent between years. The reference loads for SCE will increase over time as the effect of COVID diminishes. The aggregate load impact increased by 5 MW because the FSL achievement rate increased from 94% to 100%. The ex-ante load impacts are directly calculated from ex-post achievement rates and PY2021 had higher a higher FSL achievement rate than PY2020, as mentioned above.

6.2.3 Previous ex-ante versus current ex-post

Table 6.8 provides a comparison of the ex-ante forecast of 2021 load impacts prepared following PY2020 and the PY2021 load impacts estimated as part of this study. The ex-ante forecast shown in the table represents the typical event day during a utility-specific 1-in-2 weather year. The ex-post load impacts are based on the July 9th, 2021 event day, averaged over only full event hours (HE 19-20).

Table 6.8: Comparison of Previous Ex-ante and Current Ex-post Impacts, *SCE*

Level	Outcome	Ex-ante 2021 Typical Event Day, Previous Study	Ex-post *PY2021*
Total	# Customers	351	344
	Reference (MWh/h)	627	551
	Load Impact (MWh/h)	488	409
	FSL (MW)	109	115
Per SAID	Reference (kWh/h)	1,786	1,603
	Load Impact (kWh/h)	1,391	1,188
	% Load Impact	77.9%	74.1%

The FSL achievement rate was 94% in the previous forecast and during the PY2021 ex-post event. Thus, the differences in load impacts are a result of enrollments, reference

loads, and changes in FSL. The enrollment decrease reduces the aggregate reference load and load impact. The per-customer reference load was lower in ex-post, partially due to customers not adjusting back to pre-COVID levels as much as was assumed in the PY2020 ex-ante analysis. Lastly, the FSL increased from 109 MW to 115 MW resulting in lower load impact and percentage load impacts.

6.2.4 Current ex-post versus current ex-ante

Table 6.9 compares the ex-post and ex-ante load impacts from this study, where the ex-post impacts are based on the July 9th, 2021, event day and the ex-ante load impact represents the 2022 typical event day in a utility-specific 1-in-2 weather year.

Table 6.9: Comparison of Current Ex-post and Current Ex-ante Impacts, *SCE*

Level	Outcome	Ex-post PY2021	Ex-ante 2022 Typical Event Day, Current Study
Total	# Customers	344	341
	Reference (MWh/h)	551	614
	Load Impact (MWh/h)	409	502
	FSL (MWh/h)	115	112
Per SAID	Reference (kWh/h)	1,603	1,800
	Load Impact (kWh/h)	1,188	1,471
	% Load Impact	74.1%	81.7%

The forecast calls for a reduction in enrollment of three customers. There are roughly similar numbers of customers leaving and joining the program. Loads are scaled to enrollments based on customers remaining on the program that have load data. The per-customer reference load increases as a result of scaling since customers who remained on BIP were larger than the those that left, though this effect is relatively minor (about 8 MW). Another 40 MW of the increased reference load comes from our assumption that the effect of COVID-19 will diminish over time, resulting in increased reference loads. Lastly, the July 9th event day had lower loads during pre-event hours than other similar days (of about 15 MW).
The aggregate reference load and load impact is also greater. Reference loads increased in ex ante because of scaling, COVID-19, and because the July 9th event day had lower loads than other days.

The FSL achievement rate is 94% in ex-post and 100% in ex-ante. The increased FSL achievement rate is reflective of a higher achievement for customers that remain on the program. It is also higher since the RA window covers a longer period. The FSL achievement rate was 100% in ex-post by the second hour of the event, while the average over both event hours is 94%. The ex-ante achievement rate has more hours following the second event hour (i.e., HE 18-21) that are assumed to remain at 100%, thus increasing the entire event average.

Table 6.10 lays out all the potential sources of differences between the ex-post and ex-ante load impacts.

Table 6.10: SCE Ex-post versus Ex-ante Factors

Factor	Ex-post	Ex-ante	Expected Impact
Weather	Event hour temperatures ranging from 83 to 86 degrees Fahrenheit.	87 degrees Fahrenheit during event hours on utility-specific 1-in-2 Aug typical event day.	Higher temperatures result in higher references loads for weather sensitive customers. There is little effect on the load impact because most responsive customers are categorized as not weather sensitive.
Event window	HE 19-20 on 7/9/2021,	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	Friday event.	Average Weekday.	This is not expected to have any major impacts on forecast load impacts. If weekend events are called in future years reference loads are likely to be lower while FSL achievement rates are likely to be higher.
% of resource dispatched	All customers were called	Assume all customers are called.	None.
Enrollment	344 customers enrolled during the lone event.	341 customers in August 2021.	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.
COVID-19	Lower reference loads because of COVID-19.	Reference loads increase over time to a non-COVID level as the effect of COVID is reduced.	Load impacts increase over time as reference loads approach a non-COVID usage level.

6.3 SDG&E

6.3.1 Previous versus current ex-post

Table 6.11 compares ex-post load impacts between PY2020 and PY2021. The PY2020 load impacts are based on the PY2020 typical event day (i.e., August 14th, 19th, and 20th) while the PY2021 load impacts are based on the lone June 17th event day. Calculations for both years take place over hours ending 19-20.

Table 6.11: Comparison of Ex-post Impacts in PY2020 and PY2021, *SDG&E*

Level	Outcome	Ex-post PY2020	Ex-post PY2021
Total	# Customers Reference (MWh/h) Load Impact (MWh/h)	[redacted]	
Per SAID	Reference (kWh/h) Load Impact (kWh/h) % Load Impact		

[redacted]

6.3.2 Previous versus current ex-ante

In this sub-section, we compare the ex-ante forecast prepared following PY2020 (the "previous study") to the ex-ante forecast contained in this study (the "current study"). Table 6.12 presents this comparison for the ex-ante forecasts of the utility-specific 1-in-2 August 2022 typical event day.

Table 6.12: Comparison of Ex-ante Impacts from PY2020 and PY2021 Studies, *SDG&E*

Level	Outcome	Ex-ante 2022 Typical Event Day, *Previous Study*	Ex-ante 2022 Typical Event Day, *Current Study*
Total	# Customers Reference (MWh/h) Load Impact (MWh/h) FSL (MWh/h)	[redacted]	
Per SAID	Reference (kWh/h) Load Impact (kWh/h) % Load Impact		

[redacted]

6.3.3 Previous ex-ante versus current ex-post

Table 6.13 compares the ex-ante forecast prepared following PY2020 to the PY2021 ex-post load impact estimates contained in this report for the typical event day. The ex-ante load impacts are based on the typical event day in a utility-specific 1-in-2 weather year. The majority of the difference in load impacts derives from the decrease in enrollments. [redacted]

Table 6.13: Comparison of Previous Ex-ante and Current Ex-post Impacts, *SDG&E*

Level	Outcome	Ex-ante 2021 Typical Event Day, Previous Study	Ex-post PY2021
Total	# Customers Reference (MWh/h) Load Impact (MWh/h)	[redacted]	
Per SAID	Reference (kWh/h) Load Impact (kWh/h) % Load Impact		

6.3.4 Current ex-post versus current ex-ante

Table 6.14 shows a comparison of ex-post and ex-ante load impacts. SDG&E assumes enrollment to remain at one customer through 2032. [redacted]

Table 6.14: Comparison of Current Ex-post and Current Ex-ante Impacts, *SDG&E*

Level	Outcome	Ex-post PY2021	Ex-ante 2022 Typical Event Day, Current Study
Total	# Customers Reference (MWh/h) Load Impact (MWh/h) FSL (MWh/h)	[redacted]	
Per SAID	Reference (kWh/h) Load Impact (kWh/h) % Load Impact		

Table 6.15 below describes the factors that differ between the ex-post and ex-ante load impacts for SDG&E.

Table 6.15: SDG&E BIP Ex-post versus Ex-ante Factors, Typical Event Day

Factor	Ex-post	Ex-ante	Expected Impact
Weather	Event hour temperatures ranging from 78 to 91 degrees Fahrenheit, 83 degrees Fahrenheit for the typical event day.	90 degrees Fahrenheit during HE 17 to 21 on utility-specific 1-in-2 typical event day	The single customer is non-weather sensitive so there is little expected effect.
Event window	HE 19-20 on 6/17/2021,	HE 17 to 21.	Little impact because reference loads are somewhat higher during the ex-ante window. Note, however, that their usage is below the FSL before event or RA window occurs.
% of resource dispatched	All	All	None.
Enrollment	1 service account	1 service account	None.
Methodology	Customer-specific regressions using own within-subject analysis.	Reference loads are simulated from customer-specific regressions.	Possible difference between simulated ex-ante and estimated ex-post reference loads. In this case, however, the aggregate differences are minimal.
COVID-19	Reference loads do not appear affected as a result of COVID-19.	Reference loads use ex-post load data, assuming no COVID-19 effects remain.	None. No COVID-19 effect is assumed.

7. Recommendations

BIP continues to perform well, with its customers providing substantial load impacts with short notice. Each utility called one weekday event with strong response from customers. Each utility saw large decreases in enrollment which contributed to a decrease in overall load impacts.

Appendices

The following Appendices accompany this report. Appendix A is the validity assessment associated with our ex-post load impact evaluation. Appendix B contains the FSL achievement rates for each utility, by industry group. 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	6.a PG&E_2021_BIP_Ex_Post
BIP Study Appendix D	SCE 2021 BIP Ex-Post
BIP Study Appendix E	SDG&E 2021 BIP Ex-Post
BIP Study Appendix F	6.b PGE_2021_BIP_Ex_Ante
BIP Study Appendix G	SCE 2021 BIP Ex-Ante
BIP Study Appendix H	SDG&E 2021 BIP Ex-Ante

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.3 provide the number of customers that are categorized as weather sensitive by industry group and utility. Customer weather sensitivity was evaluated for weekdays only for all three utilities as no weekend events were called. The proportion of PG&E customers classified as non-weather sensitive was 83%. The proportion of SCE customers classified as non-weather sensitive was 69%. [redacted]

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

Industry Type	Weather Sensitive	Non-Weather Sensitive	Total	Share Weather Sensitive
1. Agriculture, Mining, Construction	15	105	120	13%
2. Manufacturing	10	60	70	14%
3. Wholesale, Transportation, Utilities	22	74	96	23%
4. Retail	2	1	3	67%
5. Offices, Hotels, Health, Services	1	2	3	33%
6. Schools	1	0	1	100%
8. Other	0	0	0	0
Total	**51**	**242**	**293**	**17%**

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

Industry Type	Weather Sensitive	Non-Weather Sensitive	Total	Share Weather Sensitive
1. Agriculture, Mining, Construction	5	26	31	16%
2. Manufacturing	69	159	228	30%
3. Wholesale, Transportation, Utilities	19	32	51	37%
4. Retail	3	0	3	100%
5. Offices, Hotels, Health, Services	5	0	5	100%
6. Schools	1	0	1	100%
7. Entertainment, Other Services, Government	2	1	3	67%
8. Other	4	18	22	18%
Total	**108**	**236**	**344**	**31%**

Table A.3: Weather Sensitive Customer Count by Industry Type, SDG&E

Industry Type	Weather Sensitive	Non-Weather Sensitive	Total	Share Weather Sensitive
[redacted]				

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.[29] The tests are conducted using average-customer data by industry group and weather-sensitivity. Separate model specifications were

[29] 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.

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 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)[30]; heat index (HI)[31]; cooling degree hours (CDH)[32], including both a 60 and 65 degree Fahrenheit threshold; the 3-hour moving average of CDH; cooling degree days (CDD)[33], 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.4, including 17 specifications for the ex-post analysis and 7 for ex-ante analysis.

[30] 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").

[31] 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.

[32] 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.

[33] 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.

Table A.4: 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 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.5, 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.

Table A.5: 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.6 lists the event-like non-event days selected.

Table A.6: List of Event-Like Non-Event Days by IOU

PGE	SCE	SDGE
6/16/2021	6/28/2021	6/14/2021
7/8/2021	7/2/2021	6/21/2021
7/23/2021	7/7/2021	7/1/2021
7/29/2021	7/8/2021	7/7/2021
7/30/2021	7/21/2021	7/16/2021
8/10/2021	8/3/2021	7/23/2021
8/11/2021	8/4/2021	8/3/2021
8/27/2021	8/5/2021	8/4/2021
	8/13/2021	

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.7 through A.9 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 (specified in Tables A.4 and A.5) for specifications in the ex-post analysis.

Table A.7: Specification Test Results for the Ex-Post analysis, PG&E

Group	Industry Type	Selected Specification	MPE	MAPE	Number of Customers
Weather Sensitive	1. Agriculture, Mining, Construction	5	0.7%	2.6%	15
	2. Manufacturing	6	-0.1%	5.5%	10
	3. Wholesale, Transportation, Utilities	17	0.8%	6.7%	22
	4. Retail	5	0.3%	1.4%	2
	5. Offices, Hotels, Health, Services	16	-1.4%	5.8%	1
	6. Schools	3	1.9%	3.4%	1
	8. Other	n/a	n/a	n/a	n/a
Non-Weather Sensitive	1. Agriculture, Mining, Construction	5	0.1%	1.6%	105
	2. Manufacturing	3	0.8%	3.5%	60
	3. Wholesale, Transportation, Utilities	5	4.8%	7.3%	74
	4. Retail	4	0.4%	4.5%	1
	5. Offices, Hotels, Health, Services	2	141.8%	185.7%	2
	8. Other	n/a	n/a	n/a	n/a

Table A.8: Specification Test Results for the Ex-Post analysis, SCE

Group	Industry Type	Selected Specification	MPE	MAPE	Number of Customers
Weather Sensitive	1. Agriculture, Mining, Construction	17	0.0%	2.9%	5
	2. Manufacturing	3	1.4%	10.2%	69
	3. Wholesale, Transportation, Utilities	5	0.1%	16.5%	19
	4. Retail	7	0.0%	1.7%	3
	5. Offices, Hotels, Health, Services	8	0.6%	3.5%	5
	6. Schools	3	0.0%	4.6%	1
	7. Entertainment, Other Services, Government	15	-2.9%	4.5%	2
	8. Other	6	-0.9%	3.0%	4
Non-Weather Sensitive	1. Agriculture, Mining, Construction	3	0.3%	3.3%	26
	2. Manufacturing	5	0.7%	3.7%	159
	3. Wholesale, Transportation, Utilities	3	-0.9%	6.7%	32
	4. Retail	n/a	n/a	n/a	0
	5. Offices, Hotels, Health, Services	n/a	n/a	n/a	0
	6. Schools	n/a	n/a	n/a	n/a
	7. Entertainment, Other Services, Government	4	-2.0%	32.8%	1
	8. Other or unknown	3	-0.9%	5.4%	18

Table A.9: Specification Test Results for the Ex-Post analysis, SDG&E

Group	Industry Type	Selected Specification	MPE	MAPE	Number of Customers
[redacted]					

Tables A.10 through A.12 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.[34]

[34] The ex-ante model specification tests are provided for customers included in the PY2021 ex-ante analysis. The specification tests provide results that come from the PY2019 study which serves as the basis for estimating pre-COVID reference loads.

Table A.10: 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	1	0.2%	3.4%	24
	2. Manufacturing	4	3.8%	13.8%	10
	3. Wholesale, Transportation, Utilities	5	1.3%	7.0%	24
	4. Retail	5	0.5%	1.6%	4
	5. Offices, Hotels, Health, Services	1	-0.6%	3.7%	1
	8. Other	4	0.0%	3.6%	3
Non-Weather Sensitive	1. Agriculture, Mining, Construction	0	-0.8%	2.3%	82
	2. Manufacturing	2	-1.8%	3.9%	58
	3. Wholesale, Transportation, Utilities	1	3.3%	8.9%	51
	4. Retail	n/a	n/a	n/a	0
	5. Offices, Hotels, Health, Services	1	71.8%	98.1%	1
	8. Other	2	-1.8%	12.6%	5

Table A.11: 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	6.0%	8.5%	3
	2. Manufacturing	4	-0.3%	2.1%	64
	3. Wholesale, Transportation, Utilities	6	-0.4%	4.2%	16
	4. Retail	4	0.0%	1.5%	2
	5. Offices, Hotels, Health, Services	5	-0.4%	4.2%	3
	6. Schools	1	3.6%	9.1%	1
	7. Entertainment, Other Services, Government	4	-2.5%	5.5%	0
	8. Other or unknown	5	-3.0%	5.7%	5
Non-Weather Sensitive	1. Agriculture, Mining, Construction	1	1.6%	1.7%	28
	2. Manufacturing	2	-0.4%	3.3%	159
	3. Wholesale, Transportation, Utilities	1	-1.7%	5.7%	26
	4. Retail	1	19.4%	27.5%	0
	5. Offices, Hotels, Health, Services	2	-3.1%	15.9%	1
	6. Schools	n/a	n/a	n/a	0
	7. Entertainment, Other Services, Government	1	2.8%	16.6%	1
	8. Other or unknown	1	22.6%	32.3%	6

Table A.12: Specification Test Results for the Ex-Ante analysis, SDG&E

Group	Industry Type	Selected Specification	MPE	MAPE	Number of Customers
[redacted]					

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.6, 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.13 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.7 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. As the table shows, the models perform quite well on this test.

Table A.13: Percentage of Statistically Significant Synthetic Event-Day Estimated Load Impacts

Hour	Percent Statistically Significant		
	PG&E	SCE	SDG&E
18		0%	
19	0%	0%	0%
20	0%	0%	0%
21	0%	1%	
Average Event Hour	**0.0%**	**0.1%**	**0.0%**

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 through A.3 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. The predicted load for SDG&E are relatively poor during the middle of the day; however, only one customer is represented and the prediction versus observed loads are nearly identical during the RA window (HE 17-21).

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

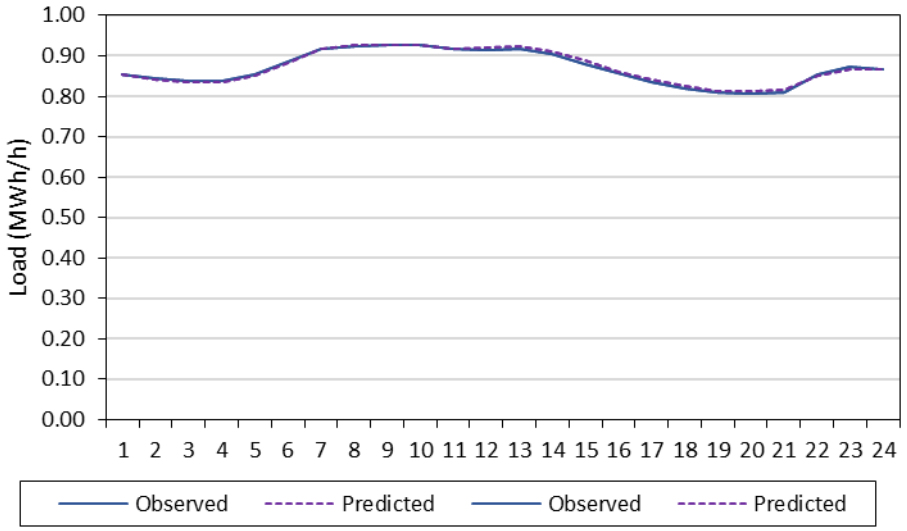


Figure A.2: Average Observed & Predicted Loads on Weekday Event-like Days, *SCE*

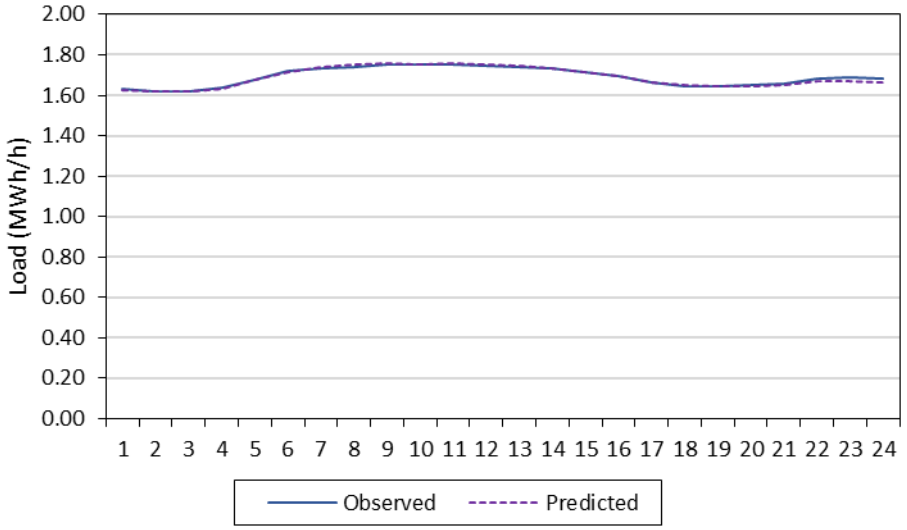


Figure A.3: Average Observed & Predicted Loads on Weekday Event-like Days, *SDG&E*

Appendix B. FSL Achievement by Industry Group

This appendix contains tables showing the FSL achievement by industry group and hour (relative to the called event window) for the events used as the basis for the ex-ante load impacts.[35] FSL achievement is defined as the estimated ex-post load impact divided by the difference between the reference load and the FSL. The denominator represents the load impact required to exactly meet the customer's BIP obligation. Because BIP events do not always begin and end on the hour, the hours before and after the event are not always well-defined. Partial event hours are therefore not considered for the first or remainder event hour FSL achievement rate calculations. We use a customer's FSL achievement for the last weekday event day that they were called and had their reference load above their FSL (since no FSL achievement is applicable when a customer's reference load was below their FSL). Tables B.1 through Table B.3 summarize the FSL achievement rate by industry group for each utility. The term "n/a" indicates when a group's reference load is already below the FSL.

[35] Only customers that remain enrolled in BIP for ex-ante are included.

Table B.1: Ex-Post Event Day Over/Under Performance – PG&E BIP,
by Industry Group and Event Hour

Industry Group	Count	Percent Over/Under Performance			
		Hour Before Event	First Hour of Event	Remaining Hours of Event	Hour After Event
1. Agriculture, Mining, Construction	120				
2. Manufacturing	70				
3. Wholesale, Transportation, Utilities	95	11%	85%	85%	35%
4. Retail	3				
5. Offices, Hotels, Health, Services	3				
6. Schools	1				
8. Other	0				

Table B.2: Ex-Post Event Day Over/Under Performance – SCE BIP,
by Industry Group and Event Hour

Industry Group	Count	Percent Over/Under Performance			
		Hour Before Event	First Hour of Event	Remaining Hours of Event	Hour After Event
1. Agriculture, Mining, Construction	31				
2. Manufacturing	223	6%	83%	96%	54%
3. Wholesale, Transportation, Utilities	42				
4. Retail	2				
5. Offices, Hotels, Health, Services	4				
6. Schools	1				
7. Institutional/Government	1				
8. Other	23				

Table B.3: Ex-Post Event Day Over/Under Performance – SDG&E BIP,
by Industry Group and Event Hour

Industry Group	Count	Percent Over/Under Performance			
		Hour Before Event	First Hour of Event	Remaining Hours of Event	Hour After Event