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CHRISTENSEN ASSOCIATES ENERGY CONSULTING

2019 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers: *Ex-post* and *Ex-ante* Report

CALMAC Study ID SCE0439

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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 2019. The report provides estimates of *ex-post* load impacts that occurred during events called in 2019 and an *ex-ante* forecast of load impacts for 2020 through 2030 that is based on the IOU's enrollment forecasts and the *ex-post* load impacts estimated for the 2019 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").

In 2019, each utility called at least one full event in 2019. PG&E called five events: one emergency event that was limited to a single subLAP on February 23rd, a test event that was limited to 14 subLAPs on March 12th, one full test event on October 6th, and two re-test events on June 6th and December 8th. Three of the five PG&E events took place on a weekend (February 23rd, October 6th, and December 8th). SCE called a measurement and evaluation event on September 4th. SDG&E called a single event on September 4th, triggered by temperature and system load conditions.

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 October 6th event averaged 173 MW, or 69 percent of enrolled load. This was 99 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 during the three full hours of its September 4th Measurement and Evaluation event was 538 MW, or 79 percent of the total reference load. This was 90 percent of the reduction required to meet the aggregate FSL.

SDG&E's total load impact for its September 4th event averaged 2.9 MW, or 85 percent of enrolled load, representing 96 percent of the reduction required to meet the aggregate FSL.

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 2019. The report provides estimates of *ex-post* load impacts that occurred during events called in 2019 and an *ex-ante* forecast of load impacts for 2020 through 2030 that is based on the IOU's enrollment forecasts and the *ex-post* load impacts estimated for the 2019 program year.

The primary research questions addressed by this evaluation are:

1. What were the BIP load impacts in 2019?
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 2020 through 2030?

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.

All three utilities called at least one full event in 2019. PG&E called five events: one emergency event that was limited to a single subLAP on February 23rd, a test event that was limited to 14 subLAPs on March 12th, one full test event on October 6th, and two re-test events on June 6th and December 8th. Three of the five PG&E events took place on a weekend (February 23rd, October 6th, and December 8th). SCE called a measurement and evaluation event on September 4th. SDG&E called a single event on September 4th, triggered by temperature and system load conditions.

Enrollment

Enrollment in PG&E's BIP increased relative to PY2018, from 480 to 512 in 2019. The sum of enrolled customers' coincident maximum demands was 241.1 MW, or 0.47 MW for the average service agreement during the October 6th Sunday event.[1] The

[1] A customer's coincident maximum demand ("Enrolled Load" in Figures ES.1-3) 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).

Manufacturing industry group contains 43 percent of the enrolled load. 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 484 service accounts on the September 4th, 2019 event day, which is a decrease relative to the 545 enrolled service accounts during PY2018. These accounted for a total of 756.1 MW of maximum demand, or 1.56 MW per service account during the September 4th event day. Manufacturers make up 60 percent of the enrolled load. Figure ES.2 illustrates the distribution of SCE's BIP load across the indicated industry types.

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

[redacted]

SDG&E's enrollment in BIP was five service accounts on its September 4th, 2019 event day, which is up from three service accounts enrolled during PY2018. These accounted for a total of 4.8 MW of maximum demand, or 0.96 MW per service account. Three customers are categorized as part of the Agriculture, Mining, and Construction industry while the remaining two are part of the Manufacturing industry.

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. For instance, the total program load impact for PG&E's October 6th event averaged 173 MW, or 69 percent of enrolled load, representing 99 percent of the reduction required to meet the aggregate FSL. Total load impact for the March 12th event averaged 201 MW, or 82 percent of enrolled load, representing 101 percent of the reduction required to meet the aggregate FSL.

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	2/23/2019	Sat.	116	[redacted]		
2	3/12/2019	Tue.	299	200.5	81.5%	101.1%
3	6/6/2019	Thu.	23	[redacted]		
4	10/6/2019	Sun.	512	172.7	68.6%	99.4%
5	12/8/2019	Sun.	46	[redacted]		

For SCE, the load impact during the three full hours of its September 4th Measurement and Evaluation event was 538 MW, or 79 percent of the total reference load. This was 90 percent of the reduction required to meet the aggregate FSL.

SDG&E's total load impact for its September 4th event averaged 2.9 MW, or 85 percent of enrolled load, representing 96 percent of the reduction required to meet the aggregate FSL.

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 remain constant from 2020 through 2030, with 512 enrolled customers. SCE projects BIP enrollments to decrease between 2020 and 2021, from 464 to 452, and then to remain constant thereafter. SDG&E forecasts BIP enrollments to increase by one each year until 2022 and then remaining constant thereafter with seven customers.

Table ES.2 shows PG&E's aggregate and per-customer *ex-ante* 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 event day, averaged over the resource adequacy window 4 to 9 p.m. Figures ES.3 through ES.4 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.

Table ES.2: Per-customer *Ex-ante* Load Impacts, 2020-2030, *PG&E*

		Aggregate (MWh/h)		Per-Customer (kWh/h)		% Load Impact
Weather Year	Enrollment	Reference	Load Impact	Reference	Load Impact	
Utility 1-in-2	512	333.8	236.1	651.9	461.2	70.7%
Utility 1-in-10	512	335.3	237.2	654.9	463.4	70.8%
CAISO 1-in-2	512	331.8	235.0	648.0	458.9	70.8%
CAISO 1-in-10	512	334.5	236.7	653.4	462.3	70.8%

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

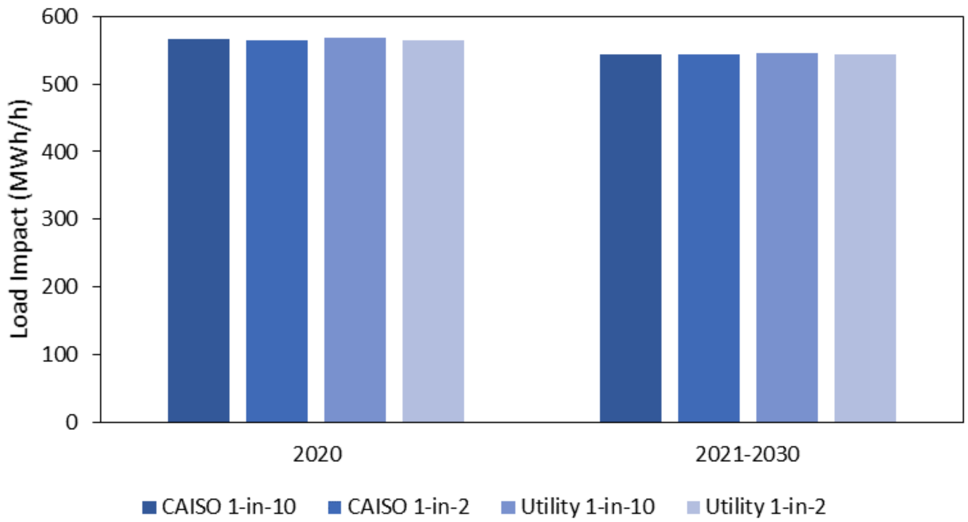
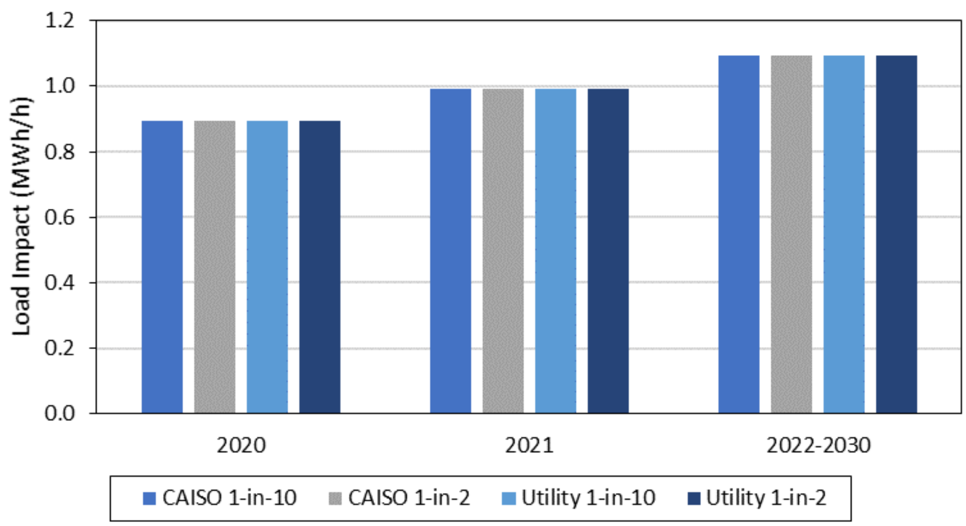


Figure ES.4: Average August *Ex-Ante* Load Impacts by Scenario, 2020-2030, *SDG&E*



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 2019. The report provides estimates of *ex-post* load impacts that occurred during events called in 2019 and an *ex-ante* forecast of load impacts for 2020 through 2030 that is based on the IOU's enrollment forecasts and the *ex-post* load impacts estimated for the 2019 program year.

The primary research questions addressed by this evaluation are:

1. What were the BIP load impacts in 2019?
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 2020 through 2030?

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 2019.

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. Effective January 2013, 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 with a minimum load reduction of 100 kW are eligible for the program. Customers are notified no later than 20 minutes before the event. The monthly incentive payments in 2019 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 were no participants in 2006, three participants in 2007, five participants in 2008, 20 in 2009, 19 customers in 2010, 21 customers in 2011, 11 in 2012,[2] seven participants in 2013 and 2014, five participants in 2015, seven in 2016, six in 2017, three in 2018, and five in 2019.

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).[3]

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 on the October 6, 2019 event day. Enrollment in PG&E's BIP

[2] Previously SDG&E offered a BIP option B which required that participating customer be notified at least three hours before the event but SDG&E discontinued this option in 2012.

[3] 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.

increased relative to PY2018, from 480 to 512.[4] The sum of enrolled customers' coincident maximum demands[5] was 241 MW, or 0.47 MW for the average service agreement. The manufacturing industry group contains over 43 percent of the enrolled load.

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

Industry	Enrolled	Sum of Max MWh/h[6]	Percent of Max MWh/h	Average Max MWh/h[7]
Agriculture, Mining & Construction	268	[redacted]		
Manufacturing	95			
Wholesale, Transport, other utilities	108			
Retail stores	9			
Offices, Hotels, Finance, Services	5			
Other or unknown	27			
Total	**512**	**241.1**	**-**	**0.47**

Table 2.2 shows comparable information on BIP enrollment for SCE. SCE's enrollment in BIP was 484 service accounts on the September 4, 2019 event day, which is a decrease relative to the 545 enrolled service accounts during PY2018. These accounted for a total of 756 MW of maximum demand, or 1.56 MW per service account. Manufacturers make up 60 percent of the enrolled load.

[4] "Enrollment" is defined as the enrollment on the October 6, 2019 event day for PG&E; the September 4, 2019 event day for SCE; and the September 4, 2019 event day for SDG&E.
[5] Customer-level demand ("Sum of Max MW" in the tables) is calculated as the coincident maximum demand on the event days listed in footnote 4—demand during the hour with the highest aggregate demand that day—including the estimated load impacts (*i.e.*, using the reference loads).
[6] "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.
[7] "Ave. Max MW" is calculated as "Sum of Max MW" divided by the "# of Service Accounts."

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	46	[redacted]	[redacted]	[redacted]
Manufacturing	299	456.4	60.4%	1.53
Wholesale, Transport, other utilities	60	[redacted]	[redacted]	[redacted]
Retail stores	48	13.1	1.7%	0.27
Offices, Hotels, Finance, Services	16	[redacted]	[redacted]	[redacted]
Schools	5	[redacted]	[redacted]	[redacted]
Institutional/Government	6	[redacted]	[redacted]	[redacted]
Other (or unknown)	4	[redacted]	[redacted]	[redacted]
Total	**484**	**756.1**	**-**	**1.56**

Table 2.3 shows BIP enrollments for SDG&E. SDG&E's enrollment in BIP was five service accounts on the September 4, 2019 event day. These accounted for a total of 4.8 MW of maximum demand, or 0.96 MW per service account. Three customers were in the Agriculture, mining, and construction industry group while the remaining two were in the manufacturing 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
Agriculture, Mining & Construction	3	4.0	83.4%	1.34
Manufacturing	2	0.8	16.6%	0.40
Total	**5**	**4.8**	**0.0%**	**0.96**

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 majority of PG&E's enrolled load is in Kern or not in an LCA, and 78 percent of SCE's 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	46	[redacted]	[redacted]	[redacted]
Greater Fresno Area	174	12.1	5.0%	0.07
Humboldt	1	[redacted]	[redacted]	[redacted]
Kern	40	[redacted]	[redacted]	[redacted]
North Coast / North Bay	13	[redacted]	[redacted]	[redacted]
Other (blank)	194	146.8	60.9%	0.76
Sierra	23	[redacted]	[redacted]	[redacted]
Stockton	21	[redacted]	[redacted]	[redacted]
Total	**512**	**241.1**	**0.0%**	**0.47**

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	406	592.3	78.3%	1.46
Outside Basin	23	[redacted]	[redacted]	[redacted]
Ventura	55	[redacted]	[redacted]	[redacted]
Total	**484**	**756.1**	**-**	**1.56**

2.3 Event Days

Table 2.6 lists BIP event days and hours for the three IOUs in 2019. PG&E called one emergency event that was limited to a single subLAP on February 23^{rd}, a test event that was limited to 14 subLAPs on March 12^{th}, one full test event on October 6^{th}, and two re-test events on June 6^{th} and December 8^{th}. Three of the five PG&E events took place on a weekend. SCE called a measurement and evaluation event on September 4^{th}. SCE also includes an occurrence where CAISO erroneously dispatched an event in error on September 8^{th} for ten minutes. SDG&E called a single event on September 4^{th}, triggered by temperature and system load conditions.

Table 2.6: BIP Event Days

Date	Day of Week	PG&E	SCE	SDG&E
2/23/2019	Saturday	Emergency Event, 7:00 – 10:00 p.m. (1 subLAP)		
3/12/2019	Tuesday	Test, 6:30 – 9:30 a.m. (14 subLAPs)		
6/6/2019	Thursday	Re-test, 6:30 – 9:30 a.m.		
9/4/2019	Wednesday		M&E Event, 3:20 – 7:00 p.m.	Temp. and System Load 12:00 – 4:00 p.m.
9/8/2019	Sunday		Erroneous Dispatch, 6:30 – 6:40 p.m.	
10/6/2019	Sunday	Test, 5:00 – 7:00 p.m.		
12/8/2019	Sunday	Re-test, 5:00 – 7:00 p.m.		

3. Study Methodology

3.1 Overview

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

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

The models use the level of hourly demand (kW) as the dependent variable and a separate equation is estimated for each enrolled customer. As a result, the coefficients on the event day/hour variables are direct estimates of the *ex-post* load impacts. For example, a BIP hour 15 event coefficient of -100 would mean that the customer reduced load by 100 kWh during hour 15 of that event day relative to its normal usage in that hour. Weekends and holidays were excluded from the estimation database for SCE and SDG&E.[8] Separate weekday and weekend models (without holidays) were estimated for PG&E to provide load impact estimates for both weekday and weekend events.

[8] 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.

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.

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:

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

Because event days did not occur on weekends or holidays for SCE or SDG&E, the exclusion of these data does not affect the model's ability to estimate *ex-post* load impacts.

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[9] (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[10]
e_t	the error term

The $OtherEvt$ variables help the model explain load changes that occur on event days for programs in which the BIP customers are dually enrolled. (In the absence of these variables, any load reductions that occur on such days may be falsely attributed to other included variables, such as weather conditions or day type variables.) The "morning load" variables are included in the same spirit as the day-of adjustment to the 10-in-10 baseline settlement method used in some DR programs. That is, those variables help adjust the reference loads (or the loads that would have been observed in the absence of an event) for factors that affect pre-event usage but are not accounted for by the other included variables.

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.

[9] The *MornLoad* variable is averaged over the hours 1 through 6 for the PG&E weekday model because PG&E's weekday events occurred during hours ending 7 through 10.

[10] The summer pricing season is June through September for SCE, May through October for SDG&E, and May through October for PG&E.

In PY2019, PG&E called weekend events (February 23, October 6, December 8). Separate weekend models were also 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), and notification type (applicable for SCE).

A parallel set of winter models was estimated for each customer, which were used to simulate *ex-ante* reference loads for those months.[11] The structure matches the model described above, with the appropriate month indicators substituted in. A separate model selection process was conducted for the winter models.

3.2.2 Development of Uncertainty-Adjusted Load Impacts

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

Specifically, we added the variances of the estimated load impacts across the customers who are called during the event in question. These aggregations were performed at either the program level, by industry group, 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 10^{th}, 30^{th}, 70^{th}, and 90^{th} 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.

[11] The summer models were estimated over the months May through for September for SCE and SDG&E. The summer period covers February through October for PG&E for the weekday model, and through December 12, 2019 for the weekend model to cover the December 8^{th} event. The *ex-ante* winter models cover all other months.

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.

On a summary level, the average event-hour load impact per enrolled customer was 337 kWh/h for PG&E's October 6th event, 1,122 kWh/h for the three full hours of SCE's event (excluding the partial hour from 3:20 to 4:00 p.m.), and 573 kWh/h for SDG&E's event.

4.1 PG&E Load Impacts

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

Table 4.1 summarizes average event-hour reference loads and load impacts at the program level for each of PG&E's BIP events.[12] The first event was a subLAP-specific emergency events with few service agreements called. March 12th was a test event for 14 subLAPs and October 6th was a program level test event (*i.e.,* all accounts were called). June 6th was a re-test event for the March 12th event, with the same event hours. Similarly, December 8th was a re-test event for the October 6th event, with the same event hours. The highest load impact occurred during the March 12th test event with an average 200.5 MW load impact across the two full event hours. The full program event day, October 6th, had an average event hour load impact of 172.7 MW. The March 12th load impact (200.5 MW) is larger than the October 6th load impact (172.7 MW) despite having fewer called customers because the October 6th event occurred on a Sunday when most customers have lower reference loads than weekdays.

[12] Results are averaged over full event hours only. Therefore, results for the weekday events, March 12th and June 6th, are averaged over the hours 7:00-9:00 a.m., and omit the partial hours 6:30-7:00 a.m. and 9:00-9:30 a.m.

Table 4.1: Average Event-hour Load Impacts by Event, *PG&E*

Event	Date	Day of Week	# Service Agreements	Estimated Reference Load (MWh/h)	Observed Load (MWh/h)	Estimated Load Impact (MWh/h)	% LI[13]
1	2/23/2019	Sat.	116	[redacted]			
2	3/12/2019	Tue.	299	245.9	45.4	200.5	81.5%
3	6/6/2019	Thu.	23	[redacted]			
4	10/6/2019	Sun.	512	251.7	79.0	172.7	68.6%
5	12/8/2019	Sun.	46	[redacted]			

Table 4.2 compares the observed loads and FSLs by event day. During the October 6th event in which all service agreements were called, the observed program load was slightly above the aggregate FSL. 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 called customers in the March 12th event overachieved in aggregate, with a 101 percent FSL achievement rate. Similarly, performance for the program-level test event on October 6th was high at 99 percent. High FSL achievement also occurs for the weekend event because many of the customers' reference loads are already below their FSLs. We will discuss this in more detail with respect to the *ex-ante* forecast.

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	2/23/2019	Sat.	[redacted]		
2	3/12/2019	Tue.	45.4	47.6	101.1%
3	6/6/2019	Thu.	[redacted]		
4	10/6/2019	Sun.	79.0	78.0	99.4%
5	12/8/2019	Sun.	[redacted]		

Table 4.3 summarizes average event-hour BIP load impacts by industry group for the October 6th event day. [redacted]

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

Table 4.3: October 6, 2019 Load Impacts – *PG&E, by Industry Group*

Industry Group	# of Service Agreements	Estimated Reference Load (MWh/h)	Observed Load (MWh/h)	Estimated Load Impact (MWh/h)	% LI
Agriculture, Mining, & Construction	268	[redacted]			
Manufacturing	95				
Wholesale, Transport., & Other Utilities	108				
Retail Stores	9				
Offices, Hotels, Health, Services	5				
Other or Unknown	27				
Total	**512**	**251.7**	**79.0**	**172.7**	**68.6%**

Table 4.4 summarizes the October 6th load impacts by local capacity area (LCA), showing that the highest share of the load impacts came from service agreements not associated with any LCA (112 MW).

Table 4.4: October 6, 2019 Load Impacts – *PG&E, by LCA*

Local Capacity Area	# of Service Agreements	Estimated Reference Load (MWh/h)	Observed Load (MWh/h)	Estimated Load Impact (MWh/h)	% LI
Greater Bay Area	46	[redacted]			
Greater Fresno	174	13.0	6.7	6.3	48.4%
Humboldt	1	[redacted]			
Kern	40				
Northern Coast	13				
Not in any LCA	194	154.3	42.1	112.2	72.7%
Sierra	23	10.2	6.6	3.6	35.5%
Stockton	21	[redacted]			
Total	**512**	**251.7**	**79.0**	**172.7**	**68.6%**

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 October 6, 2019 event day, which was the only event of the program year during which all customers were called.

Table 4.5: BIP Hourly Load Impacts for the October 6, 2019 (Sunday) Event Day, *PG&E*

Hour Ending	Estimated Reference Load (MWh/hour)	Event Day Load (MWh/hour)	Estimated Load Impact (MWh/hour)	Average Temperature (°F)	Uncertainty Adjusted Impact (MWh/hr)- Percentiles 10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	254.6	249.1	5.6	60.8	3.6	4.8	5.6	6.4	7.5
2	252.3	248.5	3.8	59.7	2.2	3.1	3.8	4.4	5.3
3	248.1	245.9	2.2	58.7	0.9	1.7	2.2	2.8	3.5
4	246.5	245.0	1.5	57.3	0.1	0.9	1.5	2.0	2.8
5	245.0	242.9	2.1	56.3	0.9	1.6	2.1	2.6	3.3
6	245.1	244.1	0.9	55.4	-0.2	0.5	0.9	1.4	2.1
7	243.0	244.2	-1.2	54.6	-2.5	-1.7	-1.2	-0.7	0.0
8	241.3	242.2	-0.9	56.2	-2.1	-1.4	-0.9	-0.4	0.4
9	241.9	244.0	-2.1	62.9	-3.3	-2.6	-2.1	-1.6	-0.9
10	240.7	241.1	-0.4	69.1	-1.7	-0.9	-0.4	0.2	1.0
11	241.1	242.3	-1.2	73.5	-2.8	-1.9	-1.2	-0.6	0.3
12	241.9	242.3	-0.5	76.9	-2.2	-1.2	-0.5	0.2	1.2
13	242.9	240.8	2.0	79.4	0.1	1.3	2.0	2.8	3.9
14	245.2	242.6	2.6	82.0	0.5	1.7	2.6	3.4	4.6
15	244.8	244.0	0.8	83.8	-1.3	-0.1	0.8	1.6	2.8
16	245.6	245.7	-0.2	84.7	-2.4	-1.1	-0.2	0.7	2.1
17	247.0	208.6	38.3	84.9	35.8	37.3	38.3	39.3	40.8
18	249.9	80.4	169.6	83.4	166.3	168.2	169.6	170.9	172.8
19	253.5	77.7	175.7	78.9	172.3	174.3	175.7	177.2	179.2
20	255.1	134.4	120.7	75.1	117.4	119.3	120.7	122.1	124.1
21	253.7	175.4	78.3	71.1	75.0	77.0	78.3	79.7	81.7
22	254.4	189.2	65.2	68.7	61.9	63.9	65.2	66.6	68.5
23	255.5	195.1	60.4	66.5	56.9	59.0	60.4	61.8	63.8
24	260.3	198.6	61.8	64.7	58.1	60.3	61.8	63.3	65.4
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	5,949	5,164	785	54.1	701.7	750.9	785.0	819.0	868.2
Event Hours	251.7	79.0	172.7	12.4	170.1	171.6	172.7	173.7	175.2

Figure 4.1 illustrates the hourly reference load, observed load, and estimated load impact for the October 6th event day. 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: BIP Loads for the October 6, 2019 (Sunday) Event Day, *PG&E*

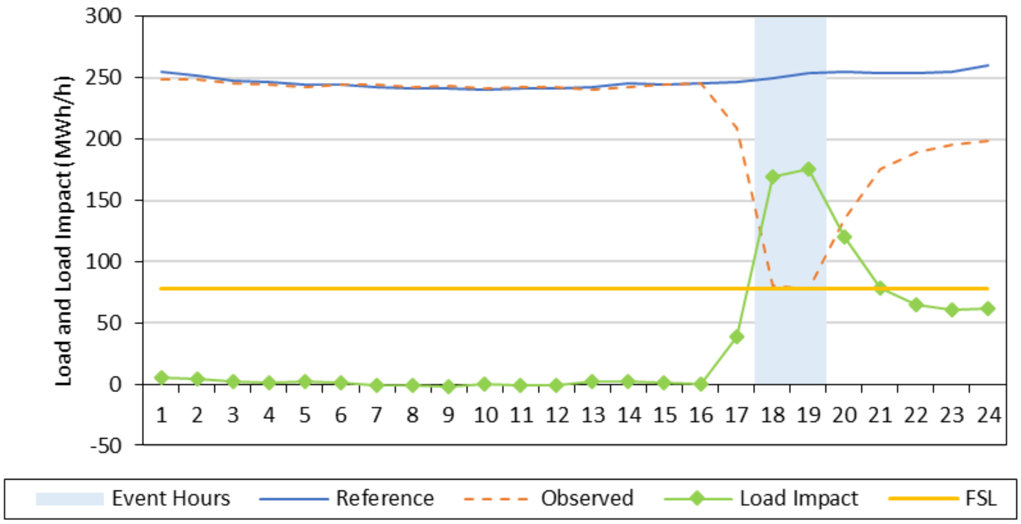
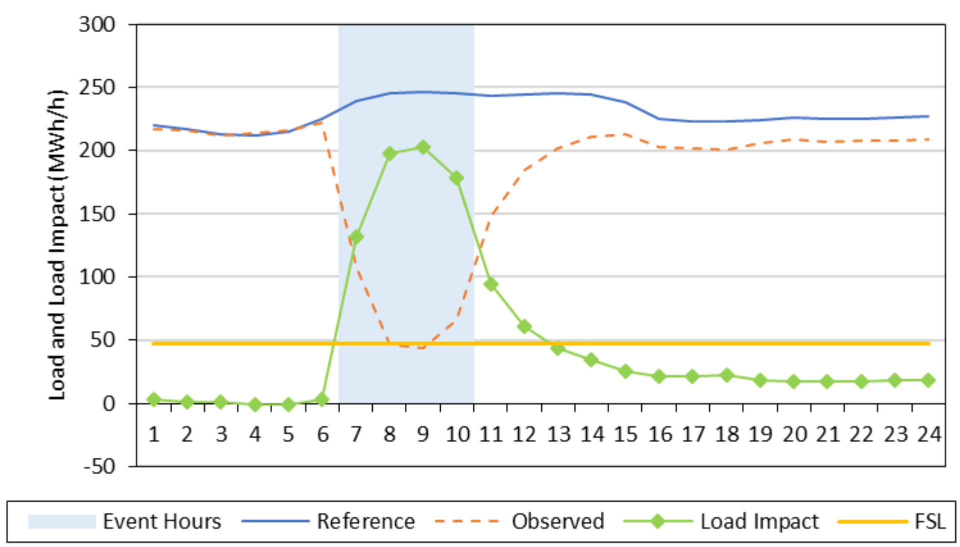


Figure 4.2 illustrates the hourly reference load, load impacts, and FSL for the March 12th test event that was called for earlier hours of the day. The aggregate reference loads of the 299 customers called is similar in magnitude to the 512 called on October 6th because of the difference between weekday and weekend usage.

Figure 4.2: BIP Loads for the March 12, 2019 (Tuesday) Event Day, *PG&E*



4.2 SCE Load Impacts

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

SCE's only BIP event day was September 4, 2019. Table 4.6 shows the average event-hour load impact for that event day by industry group.[14] The total row at the bottom of the table shows the total event-day load impact of 537.5 MW, or 78.5 percent of the reference load. The majority of the program's load impact came from customers in the Manufacturing industry group.

Table 4.6: Average Event-hour 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	46	[redacted]	[redacted]	[redacted]	[redacted]
Manufacturing	299	427.7	80.1	347.6	81.3%
Wholesale, Transport, other utilities	60	[redacted]	[redacted]	[redacted]	[redacted]
Retail stores	48	12.8	12.7	0.1	0.8%
Offices, Hotels, Finance, Services	16	[redacted]	[redacted]	[redacted]	[redacted]
Schools	5	[redacted]	[redacted]	[redacted]	[redacted]
Institutional/Government	6	[redacted]	[redacted]	[redacted]	[redacted]
Other (or unknown)	4	[redacted]	[redacted]	[redacted]	[redacted]
Total	**484**	**684.7**	**147.3**	**537.5**	**78.5%**

Table 4.7 compares the observed loads and FSLs for the September 4th event day. In aggregate, SCE's BIP program achieved 90 percent of the reduction required to meet its FSL.

Table 4.7: Average Event-hour Observed Loads and FSLs, *SCE*

Event	Date	Day of Week	Observed Load (MWh/h)	Firm Service Level (MWh/h)	Estimated LI / LI at FSL
1	9/4/2019	Wednesday	147.3	88.8	90%

Table 4.8 summarizes average hourly load impacts by LCA. The majority of the load impact comes from customers in the LA Basin.

[14] In order to summarize only full-hour load impacts, the tables contain load impacts from 4:00 to 7:00 p.m., omitting the partial hour from 3:20 to 4:00 p.m.

Table 4.8: Average Event-hour 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	406	526.8	120.4	406.4	77.1%
Outside Basin	23	[redacted]			
Ventura	55				
Total	**484**	**684.7**	**147.3**	**537.5**	**81.3%**

4.2.2 Hourly Load Impacts

Table 4.9 presents hourly load impacts for the September 4th BIP event in the manner required by the Protocols.

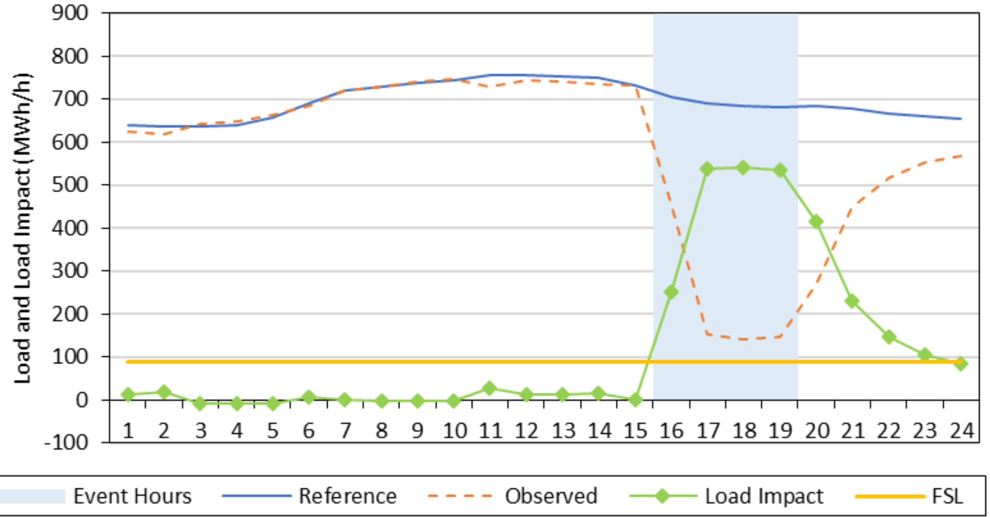
Table 4.9: BIP Hourly Load Impacts for the September 4, 2019 Event Day, *SCE*

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	638.8	625.2	13.6	2%	76.8	9.8	12.1	13.6	15.2	17.4
2	637.7	617.8	19.9	3%	76.2	16.4	18.5	19.9	21.4	23.5
3	635.7	643.8	-8.1	-1%	75.5	-11.6	-9.5	-8.1	-6.7	-4.6
4	639.7	649.2	-9.5	-1%	75.0	-12.9	-10.9	-9.5	-8.1	-6.1
5	655.8	664.0	-8.2	-1%	74.4	-11.3	-9.4	-8.2	-6.9	-5.0
6	689.1	683.7	5.4	1%	73.8	1.7	3.9	5.4	7.0	9.2
7	720.3	719.5	0.7	0%	73.9	-2.5	-0.6	0.7	2.1	3.9
8	728.4	730.0	-1.6	0%	76.5	-4.8	-2.9	-1.6	-0.3	1.6
9	737.9	740.3	-2.4	0%	80.7	-6.0	-3.9	-2.4	-0.9	1.2
10	744.0	746.0	-2.1	0%	85.1	-5.7	-3.6	-2.1	-0.5	1.6
11	756.1	728.0	28.1	4%	88.8	24.0	26.5	28.1	29.8	32.3
12	756.2	742.5	13.6	2%	91.9	9.3	11.8	13.6	15.4	18.0
13	752.1	741.0	11.1	1%	93.9	6.6	9.2	11.1	12.9	15.6
14	749.7	733.5	16.2	2%	95.2	11.7	14.4	16.2	18.0	20.7
15	731.9	730.7	1.2	0%	96.0	-6.1	-1.8	1.2	4.2	8.4
16	705.4	454.7	250.7	36%	94.4	242.9	247.5	250.7	253.8	258.5
17	690.8	153.0	537.8	78%	91.1	529.2	534.3	537.8	541.3	546.4
18	683.0	142.3	540.7	79%	87.5	532.2	537.3	540.7	544.2	549.3
19	680.4	146.6	533.8	78%	84.8	525.1	530.2	533.8	537.4	542.5
20	684.0	268.2	415.8	61%	84.2	407.0	412.2	415.8	419.4	424.6
21	677.7	447.5	230.2	34%	82.3	221.4	226.6	230.2	233.8	239.0
22	665.4	518.0	147.4	22%	80.0	139.0	144.0	147.4	150.9	155.8
23	659.6	554.1	105.5	16%	79.2	96.5	101.8	105.5	109.2	114.5
24	653.7	568.4	85.2	13%	78.0	76.8	81.8	85.2	88.7	93.7
Daily	**16,673**	**13,748**	**2,925**	**18%**	**83.1**	**2,717.2**	**2,840.2**	**2,925.4**	**3,010.6**	**3,133.6**

* The highlighting indicates all hours affected by the event. However, hour-ending 16 was a partial event-hour and is not included in the average event-hour calculations in the report.

Figure 4.3 illustrates the hourly reference load, observed load, and load impact for the September 4th BIP event.

Figure 4.3: BIP Loads for the September 4, 2019 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 single event (September 4, 2019) are summarized in Table 4.10 by industry group. The average load impact over the four-hour event was 2.9 MW, or 84.8 percent of the reference load. Most of the program's load impact came from customers in the Agriculture, Mining, & Construction industry group.

Table 4.10: Average Event-hour Load Impacts – *SDG&E, 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	3	2.6	0.4	2.2	82.9%
Manufacturing	2	0.8	0.1	0.7	91.3%
Total	**5**	**3.4**	**0.5**	**2.9**	**84.8%**

Table 4.11 compares the average observed load to the FSL on the event day. The observed load was near the FSL throughout the event, particularly beginning at 1:00 p.m.

Table 4.11: Average Event-hour Observed Loads and FSLs, *SDG&E*

Event	Date	Day of Week	Observed Load (MWh/h)	Firm Service Level (MWh/h)	Estimated LI / LI at FSL
1	9/4/2019	Wednesday	0.51	0.40	96.2%

4.3.2 Hourly Load Impacts

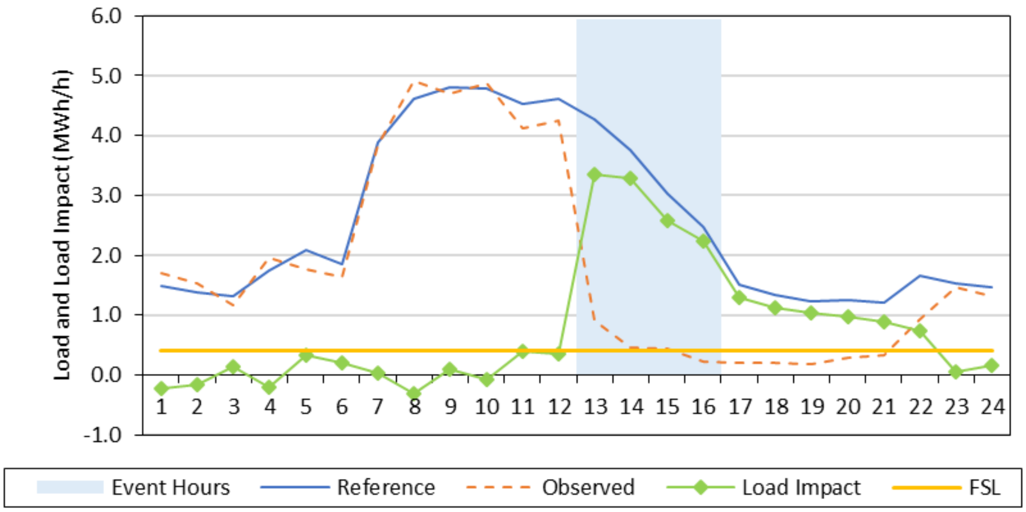
Table 4.12 presents hourly load impacts for the September 4th event day in the manner required by the Protocols.

Table 4.12: BIP Hourly Load Impacts for the September 4, 2019 Event Day, *SDG&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	1.5	1.7	-0.2	77.5	-0.3	-0.2	-0.2	-0.2	-0.1
2	1.4	1.5	-0.2	76.3	-0.2	-0.2	-0.2	-0.1	-0.1
3	1.3	1.2	0.2	76.4	0.1	0.1	0.2	0.2	0.2
4	1.7	2.0	-0.2	73.5	-0.3	-0.2	-0.2	-0.2	-0.1
5	2.1	1.8	0.3	72.1	0.3	0.3	0.3	0.4	0.4
6	1.8	1.6	0.2	71.4	0.2	0.2	0.2	0.2	0.3
7	3.9	3.8	0.0	71.5	-0.1	0.0	0.0	0.1	0.2
8	4.6	4.9	-0.3	70.8	-0.4	-0.3	-0.3	-0.2	-0.2
9	4.8	4.7	0.1	76.0	0.0	0.1	0.1	0.1	0.2
10	4.8	4.9	-0.1	82.5	-0.2	-0.1	-0.1	0.0	0.0
11	4.5	4.1	0.4	87.9	0.3	0.3	0.4	0.4	0.5
12	4.6	4.3	0.4	89.6	0.2	0.3	0.4	0.4	0.5
13	4.3	0.9	3.4	90.4	3.2	3.3	3.4	3.4	3.5
14	3.8	0.5	3.3	92.6	3.2	3.2	3.3	3.4	3.4
15	3.0	0.4	2.6	93.7	2.4	2.5	2.6	2.6	2.7
16	2.5	0.2	2.2	90.7	2.1	2.2	2.2	2.3	2.4
17	1.5	0.2	1.3	82.8	1.2	1.3	1.3	1.3	1.4
18	1.3	0.2	1.1	85.3	1.1	1.1	1.1	1.2	1.2
19	1.2	0.2	1.0	86.5	1.0	1.0	1.0	1.1	1.1
20	1.3	0.3	1.0	83.4	0.9	0.9	1.0	1.0	1.0
21	1.2	0.3	0.9	80.7	0.8	0.9	0.9	0.9	0.9
22	1.7	0.9	0.7	80.2	0.6	0.7	0.7	0.8	0.8
23	1.5	1.5	0.1	78.1	-0.1	0.0	0.1	0.1	0.2
24	1.5	1.3	0.2	77.8	0.0	0.1	0.2	0.2	0.3
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	62	43	18.4	163.2	14.4	16.8	18.4	20.0	22.3
Event Hours	3.4	0.51	2.9	67.4	2.6	2.8	2.9	3.0	3.1

Figure 4.4 illustrates the hourly reference load, observed load, and load impact for the September 4th event day.

Figure 4.4: BIP Loads for the September 4, 2019 Event Day, *SDG&E*



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 and the relevant LCA. 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.

The total number of customer "cells" developed is therefore equal to 24 (= 3 size groups x 8 LCAs).

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

For SDG&E, we do not distinguish the forecast by size or location, so we do not need to develop customer groups.

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 start of the 2020 program year. The load impacts are developed using the historical FSL achievement rates of customers remaining enrolled at the start of the 2020 program year, based on their estimated *ex-post* load impacts during program year 2019.[15]

For each service account, we determine the appropriate size group and LCA. 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.

[15] 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.

2. Simulate reference loads

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

For the summer months, the re-estimated regression equations were similar in design to the *ex-post* load impact equations described in Section 3.2, differing in two ways. First, the *ex-ante* models excluded the morning-usage variables. While these variables are useful for improving accuracy in estimating *ex-post* load impacts for particular events, 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 using information from prior days.[16] 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.

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

[16] 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.[17] 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.[18]

[17] Customer-specific specifications are tested separately for the five SDG&E customers.

[18] 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.[19] 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.

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 needed 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.

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

[19] 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.

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 2020. 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 2030, with separate enrollments provided at the program and portfolio level (which are identical for BIP), by LCA and size group. SCE provided annual enrollments by notice level (15 versus 30 minute) for 2020 through 2030. We assume that the *ex-post* shares of customers by LCA hold throughout the forecast period. The SDG&E enrollment forecast is five in 2020 and is set to increase by one in each year until 2022, at which time enrollment is forecast to remain constant at seven service accounts through 2030. The SDG&E load impact is assumed to increase by 0.1 MW for each newly enrolled customer. SDG&E reference load and FSL is scaled based on recent participants.

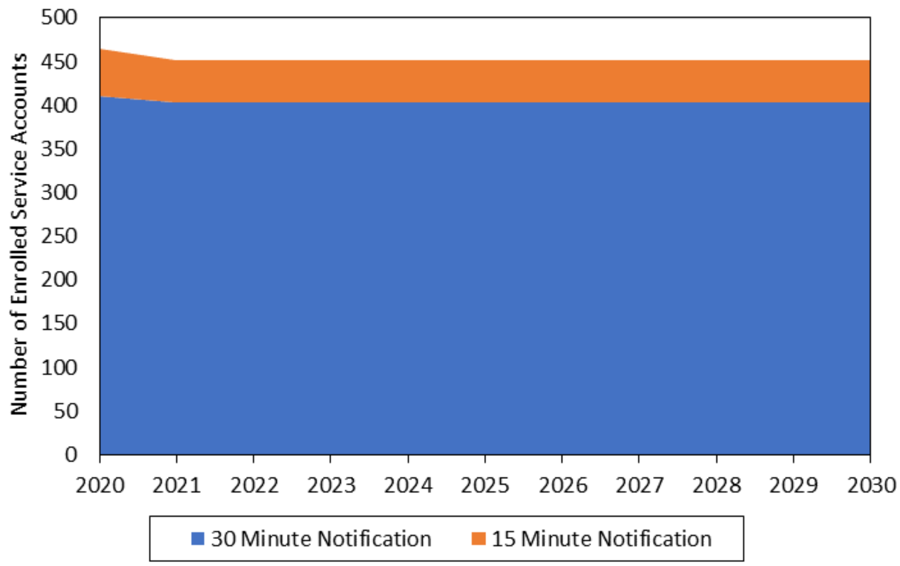
5.3 Enrollment Forecasts

PG&E
PG&E forecasts BIP enrollments to remain constant from 2020 through 2030, with 512 enrolled service agreements. Of these, 288 are in the large customer group (over 200 kW) while the majority of the remaining agreements are in the medium customer group (20 to 200 kW).[20] The total enrollment forecast of 512 is consistent with the 512 service agreements enrolled during the October 6, 2019 BIP event day.

SCE
Figure 5.1 shows SCE's forecast of enrollments by year, broken down by notification time. SCE projects BIP enrollments to decrease between 2020 and 2021, from 464 to 452, and then to remain constant thereafter.

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

Figure 5.1: Number of Enrolled Customers in Each Forecast Year, *SCE*



SDG&E

SDG&E enrollment dropped to four customers by the end of 2019. SDG&E forecasts BIP enrollments to increase by one each year until 2022, at which time enrollment is forecast to remain constant at seven service accounts through 2030.

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 5.2 shows the August 2020 forecast load impacts in a utility-specific 1-in-2 weather year. Event-hour (4:00 to 9:00 p.m.) load impacts average 236 MW, which represents 71 percent of the enrolled reference load. The program-level FSL is 81.7 MW, compared to the average event-hour program load of 97.6 MW. The FSL achievement rate of 94% is lower than the achievement rate of 99% on the October 6, 2019 event day. This occurs because the October 6, 2019 event occurred on a Sunday, when relatively more customers had reference loads below their FSLs. Customers' with reference loads below their FSLs do not contribute a load impact but still contribute to the aggregate FSL, resulting in a larger FSL achievement rate.[21]

[21] Consider, for example, two groups of customers that both achieve a 100% FSL achievement rate. Group 1 has a 100 MW reference load, 20 MW FSL, and therefore 80 MW of load impact. Group 2 has a 15 MW

Figure 5.2: PG&E Hourly Event Day Load Impacts for the August 2020 Event Day in a Utility-Specific 1-in-2 Weather

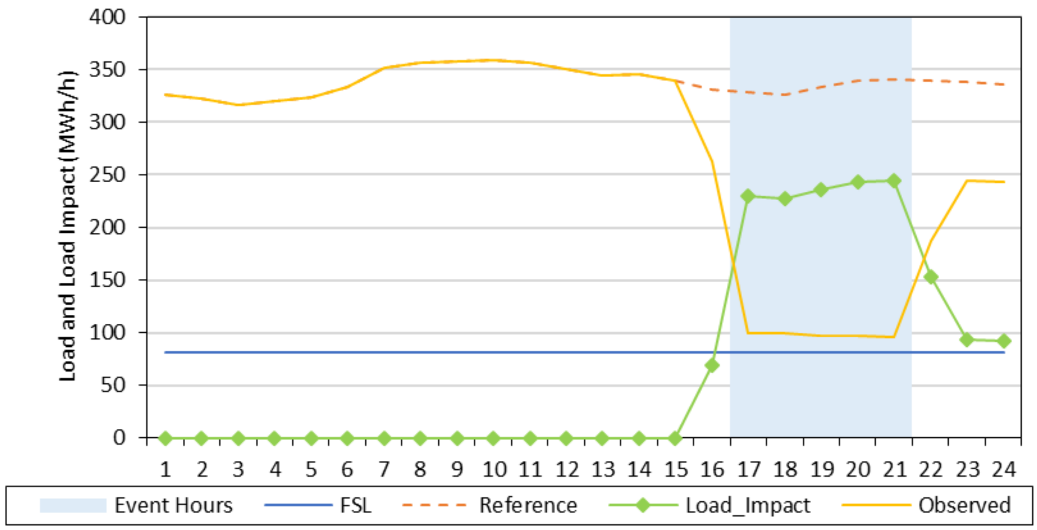


Figure 5.3 shows the share of load impacts by local capacity area, assuming a 2020 August event day in a utility-specific 1-in-2 weather year. [redacted]

reference load, 10 MW FSL, and resulting 5 MW of load impact. The aggregate results would thus be a 115 MW reference load, 30 MW FSL, and 85 MW load impact, resulting in a 100% aggregate FSL achievement rate. Now consider the scenario where Group 2 has a 5 MW reference load, which is below their 10 MW FSL. The aggregate results would then be a 105 MW reference load, the same 30 MW FSL, and 80 MW of load impact (since zero load impact is contributed from Group 2). The FSL achievement rate is larger in this scenario at 107%.

Figure 5.3: Share of PG&E Load Impacts by LCA for the August 2020 Event Day in a Utility-specific 1-in-2 Weather Year

[redacted]

Figure 5.4 illustrates August average event-hour 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. The enrollment forecast does not change across the 2020 to 2030 window, so these load impacts stay constant for August across the forecast years. The differences between the scenarios is minimal because the largest customers are not weather sensitive. (Recall that customers are first sorted according to their weather sensitivity.) The smallest load impact is 235 MW in the CAISO 1-in-2 weather scenario while the largest load impact is 237.2 MW in the Utility 1-in-10 weather scenario.

Figure 5.4: Average August *Ex-ante* Load Impacts by Scenario, 2020-2030, *PG&E*

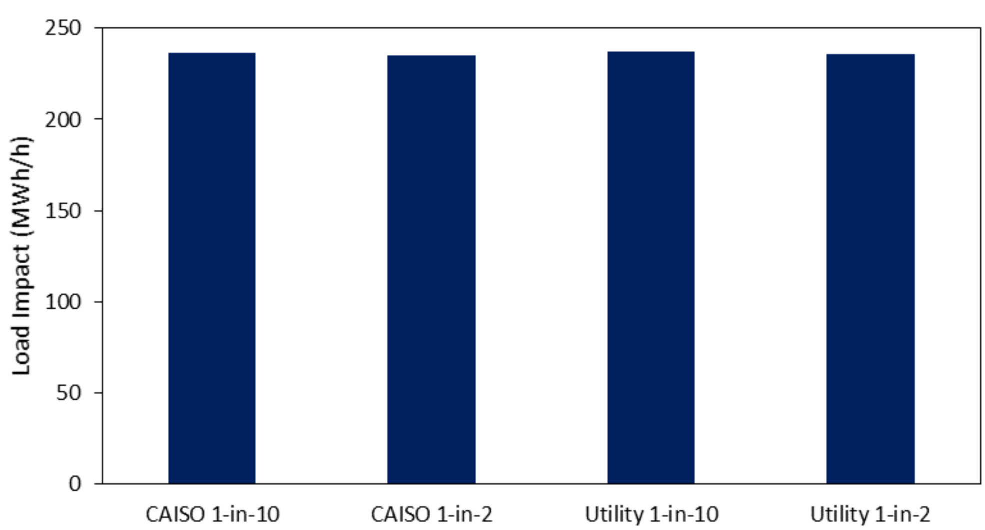


Table 5.2 shows the aggregate and per-customer reference loads and load impacts by weather year (1-in-2 and 1-in-10 for both utility-specific and CAISO-coincident peak conditions) for the August event day.

Table 5.2: Per-customer *Ex-ante* Load Impacts, 2020-2030, *PG&E*

Weather Year	Enrollment	Aggregate (MWh/h)		Per-Customer (kWh/h)		% Load Impact
		Reference	Load Impact	Reference	Load Impact	
Utility 1-in-2	512	333.8	236.1	651.9	461.2	70.7%
Utility 1-in-10	512	335.3	237.2	654.9	463.4	70.8%
CAISO 1-in-2	512	331.8	235.0	648.0	458.9	70.8%
CAISO 1-in-10	512	334.5	236.7	653.4	462.3	70.8%

5.4.2 SCE

Figure 5.5 shows the August 2020 forecast load impacts in a utility-specific 1-in-2 weather year. Event-hour (4:00 to 9:00 p.m.) load impacts average 564 MW, which represents 78 percent of the enrolled reference load. The program-level FSL is 97.8 MW, compared to the average event-hour program load of 155 MW. This performance at the program level is consistent with our estimates for the September 4, 2019 event day that serves as the basis for the *ex-ante* load impacts.

Figure 5.5: SCE Hourly Event Day Load Impacts for the 2020 August Event Day in a Utility-Specific 1-in-2 Weather Year

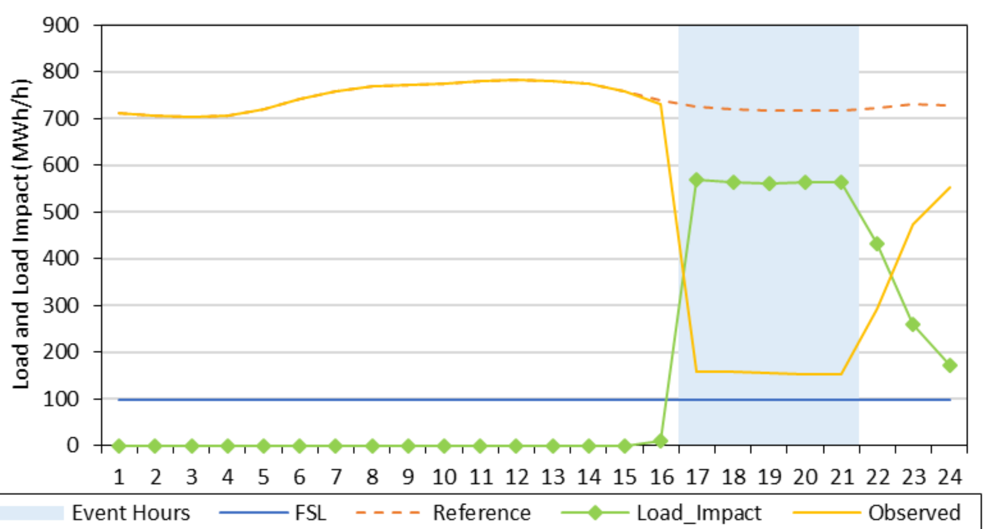


Figure 5.6 shows the share of load impacts by local capacity area for an August 2020 event day in a utility-specific 1-in-2 weather year. LA Basin customers account for the largest share, with 69 percent of the load impacts.

Figure 5.6: Share of SCE Load Impacts by LCA for the August 2020 Event Day in a Utility-specific 1-in-2 Weather Year

[redacted]

Figure 5.7 shows the share of load impacts by notification time, assuming an August 2020 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 5.7: Share of SCE Load Impacts by Notification Time for the August 2020 Event Day in a Utility-specific 1-in-2 Weather Year

[redacted]

Figure 5.8 illustrates August event day load impacts for each forecast scenario, 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 2020 through 2030 (the load impacts are equivalent for the years 2021 through 2030 because of constant enrollment). The load impact is not sensitive to weather conditions, but it decreases slightly after 2020 due to a forecasted reduction in enrollment, at which point it remains constant. The highest average august *ex-ante* load impact forecast in 2020 is 567 MW during the Utility 1-in-10 weather scenario, while the lowest load impact forecast is 564 MW during the Utility 1-in-2 weather scenario.

Figure 5.8: Average August *Ex-ante* Load Impacts by Scenario and Year, *SCE*

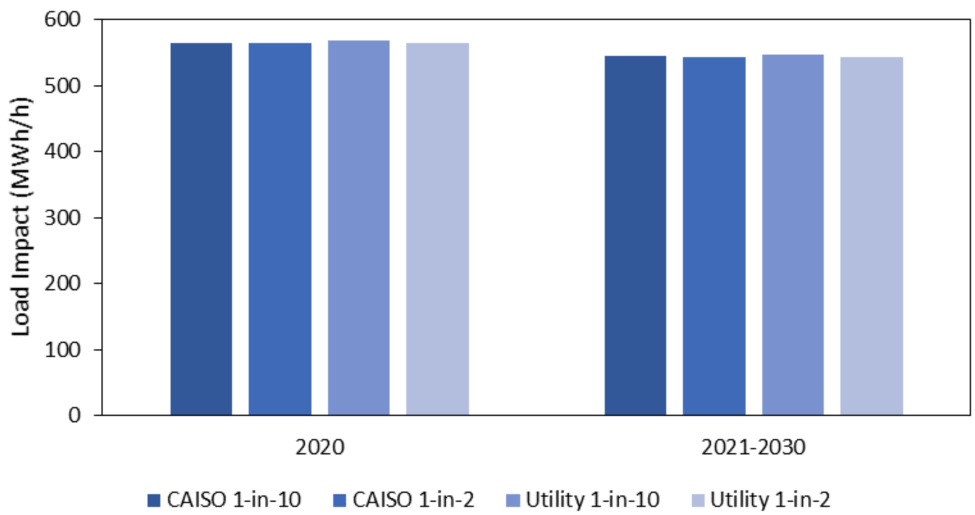


Table 5.3 shows the per-customer reference loads and load impacts by weather year (1-in-2 and 1-in-10 for both utility-specific and CAISO-coincident peak conditions) for the August 2020 event day.

Table 5.3: Per-customer *Ex-ante* August 2020 Load Impacts by Scenario, *SCE*

Weather Year	Reference Load (kWh/h)	Load Impact (kWh/h)	% Load Impact
Utility 1-in-2	1,550	1,216	78%
Utility 1-in-10	1,558	1,223	78%
CAISO 1-in-2	1,551	1,217	78%
CAISO 1-in-10	1,552	1,218	78%

5.4.3 SDG&E

Figure 5.9 shows the load impact forecast for an August 2020 event day in a utility-specific 1-in-2 weather year. The average hourly load impact from 4:00 to 9:00 p.m. is forecast to be 0.89 MW, which represents 68 percent of the enrolled reference load. The average event-hour program load of 0.43 MW is slightly above the program-level FSL of 0.40 MW.

Figure 5.9: SDG&E Hourly Event Day Load Impacts for the August 2020 Event Day in a Utility-Specific 1-in-2 Weather Year

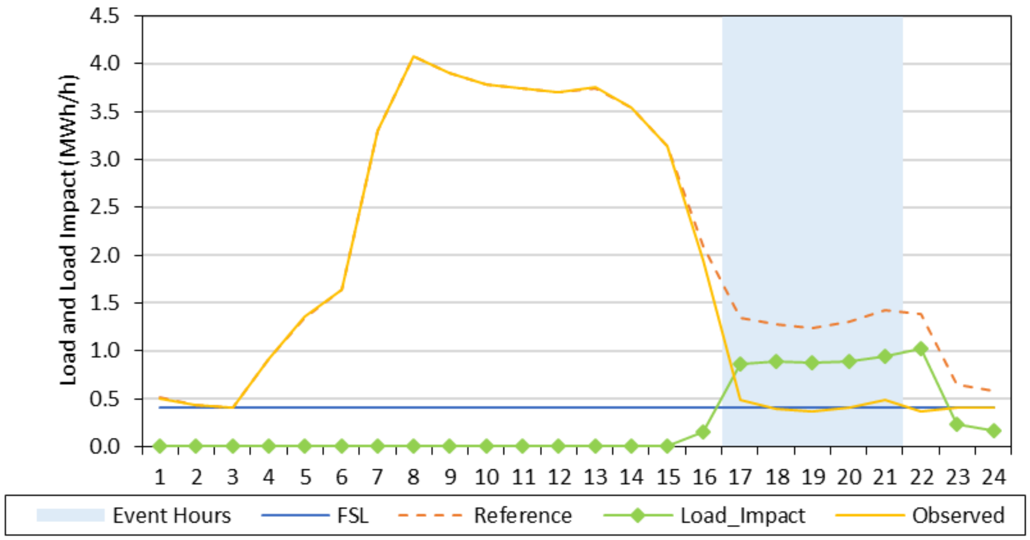


Figure 5.10 illustrates 2020 to 2030 August load impact for each forecast scenario, differentiated by 1-in-2 versus 1-in-10 weather conditions under both utility-specific and CAISO-coincident peak conditions. The enrollment forecast increases by one customer until 2022 and then remains constant. The load impact is assumed to increases by 0.1 MW for each newly enrolled customer. The load impacts are equivalent for each weather scenario because each customer was classified as not weather sensitive.

Figure 5.10: Average August *Ex-ante* Load Impacts by Scenario, 2020-2030, *SDG&E*

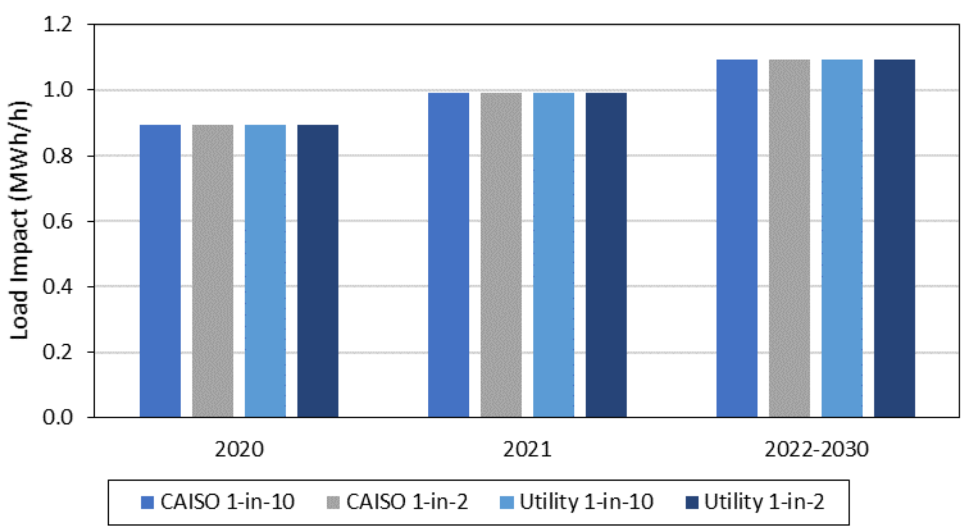


Table 5.4 shows the per-customer reference loads and load impacts by weather condition (1-in-2 and 1-in-10 for both utility-specific and CAISO-coincident peak) for the

2020 August event day. As mentioned above, the complete lack of variation across scenarios is a direct result of none of the customers being classified as sensitive to weather conditions.

Table 5.4: Per-customer *Ex-ante* August 2020 Load Impacts by Scenario, *SDG&E*

Weather Year	Reference Load (kWh/h)	Load Impact (kWh/h)	% Load Impact
Utility 1-in-2	263.6	178.5	67.7%
Utility 1-in-10	263.6	178.5	67.7%
CAISO 1-in-2	263.6	178.5	67.7%
CAISO 1-in-10	263.6	178.5	67.7%

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 2019 program year; and "previous study" refers to the report that was developed following the 2018 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 PY2018 and PY2019. The PY2018 load impacts are based on the six event hours (HE 17-22) on September 26, 2018. The PY2019 load impacts are based on the two event hours (HE 18-19) on October 6, 2019.

Table 6.1: Comparison of *Ex-post* Impacts in PY2018 and PY2019, *PG&E*

Level	Outcome	*Ex-post* PY2018	*Ex-post* PY2019
Total	# Customers	480	512
	Reference (MWh/h)	338	252
	Load Impact (MWh/h)	249	173
Per SAID	Reference (kWh/h)	704	492
	Load Impact (kWh/h)	519	337
	% Load Impact	73.7%	68.6%

There are more service accounts in PY2019; however, reference load is significantly lower because the October 6, 2019 event was called on a Sunday, when the average customer's usage is less than it is on weekdays. For instance, customers that were called for both the PY2018 and PY2019 events had an average reference load of 0.72 MW in PY2018 and 0.56 MW in PY2019. The customers that joined in PY2019 were also smaller, on average, with reference loads of 0.23 MW during the PY2019 event. The FSL achievement rate in of 99% in PY2019, was higher than 95% in PY2018. As mentioned previously, this is a function of a greater proportion of customers in PY2019 having reference loads below their FSLs.

6.1.2 Previous versus current *ex-ante*

In this sub-section, we compare the *ex-ante* forecast prepared following PY2018 (the "previous study") to the *ex-ante* forecast contained in this study (the "current study"). Table 6.2 contains this comparison for the August 2020 utility-specific 1-in-2 typical event day forecast.

Table 6.2: Comparison of *Ex-ante* Impacts from PY2018 and PY2019 Studies, *PG&E*

Level	Outcome	Ex-ante 2020 Typical Event Day, *Previous Study*	Ex-ante 2020 Typical Event Day, *Current Study*
Total	# Customers	421	512
	Reference (MWh/h)	331	334
	Load Impact (MWh/h)	254	239
	FSL (MW)	70	82
Per SAID	Reference (kWh/h)	786	652
	Load Impact (kWh/h)	603	467
	% Load Impact	76.8%	71.6%

While the current study includes 91 additional service agreements, the total reference load only increased by 3 MW while the load impact decreased from 254 MW to 239 MW. The reference load difference is driven by two main factors: 1) customers that remained on the program in both years used less during PY2019, and 2) newly enrolled customers are, on average, smaller in terms of usage. Specifically, customers that were enrolled in BIP during PY2018 and PY2019 exhibited less usage in PY2019 which resulted in an aggregate reference load reduction of 12 MW in the PY2019 analysis. For newly enrolled customers, the average reference load was about 0.37 MW, which is lower than the 0.72 MW reference load for customers that remained on the program in both years. A greater proportion of smaller customers results in a smaller per-customer reference load. These differences result in a lower reference loads that, when combined with an increase in the FSL, contributes to a smaller *ex-ante* load impact for the current study.

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

Table 6.3 provides a comparison of the *ex-ante* forecast of 2019 load impacts prepared following PY2018 and the *ex-post* PY2019 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 weekend October 6, 2019 event day.[22]

The aggregate forecast from the previous study and the current *ex-post* load impacts are not the same because the enrollment numbers increased more than was forecasted in the previous study. The reference loads and load impacts (total and per-customer) are difficult to compare because the *ex-ante* forecasts an average weekday event; however, the PY2019 *ex-post* represents an event that was called on a Sunday, when loads were significantly less than the average weekday. Consequently, the *ex-post* reference loads and load impacts are significantly less than the PY2018 *ex-ante* forecast. The *ex-post* FSL achievement rate of 99% is higher than the *ex-ante* forecast FSL achievement rate of 97%; which is also a consequence of more customers having lower reference loads, even below their FSLs, during the Sunday event.

[22] The weekday events PG&E called do not provide a suitable comparison with the previous study *ex-ante* forecast because not all BIP customers were called. Moreover, but less important, the weekday event hours were earlier in the day (6:30 – 9:30 a.m.) than is typical.

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

Level	Outcome	*Ex-ante* 2019 Typical Event Day, Previous Study	*Ex-post* PY2019
Total	# Customers	421	512
	Reference (MWh/h)	331	252
	Load Impact (MWh/h)	254	173
Per SAID	Reference (kWh/h)	786	492
	Load Impact (kWh/h)	603	337
	% Load Impact	76.8%	68.6%

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 2020 typical event day with utility-specific 1-in-2 weather conditions. The enrollments are expected to remain constant at 512 customers. The *ex-post* reference loads are lower because they represent the weekend event day, October 6, 2019, while the *ex-ante* forecast represents an average weekday event. A greater proportion of customers have *ex-ante* reference loads above their FSL. As a result, the *ex-ante* aggregate and per-customer load impacts are larger, even with a higher aggregate FSL.

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

Level	Outcome	*Ex-post* PY2019	*Ex-ante* 2020 Typical Event Day, Current Study
Total	# Customers	512	512
	Reference (MWh/h)	252	334
	Load Impact (MWh/h)	173	239
	FSL (MWh/h)	78	82
Per SAID	Reference (kWh/h)	492	652
	Load Impact (kWh/h)	337	467
	% Load Impact	68.6%	71.6%

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	49.0 degrees on 2/23/2019, 47.9 degrees on 3/12/2019, 64.0 degrees on 6/6/2019, 81.2 degrees on 10/6/2019, 55.0 degrees on 12/8/2019, during event hours.	93.0 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 20-22 on 2/23/2019 HE 7-10 on 3/12/2019, HE 7-10 on 6/6/2019, HE 18-19 on 10/6/2019, HE 18-19 on 12/8/2019.	HE 17-21.	Periods corresponding to larger reference loads result in larger load impacts.
Event Day of the Week	Weekend events: 2/23/2019, 10/6/2019, and 12/8/2019.	Average Weekday.	Weekend events correspond with lower customer reference loads which result in lower load impacts. Aggregate FSL achievement rates are also higher during weekend events because a greater proportion of customers are below their FSL.
% of resource dispatched	All on the 10/6/2019 event.	Assume all customers are called.	None. The *ex-ante* method assumes that all enrolled customers are dispatched.
Enrollment	512 customers during the 10/6/2019 event day.	512 customers.	None. The enrollment forecast matches *ex-post.*
Methodology	Customer-specific regressions using own within-subject analysis.	Reference loads are simulated from customer-specific regressions. Load impacts are based on customer-level performance on the most recent event day that a customer has reference loads above their FSL.	Possible difference between simulated *ex-ante* and estimated *ex-post* reference loads. In this case, however, the aggregate differences are minimal for the average weekday.

6.2 SCE

6.2.1 Previous versus current *ex-post*

Table 6.6 compares *ex-post* load impacts for the typical event day between PY2018 and PY2019. Only one BIP event was called in each year: September 27, 2018; and September 4, 2019. Both events were called during the hours 3:20 to 7 p.m.; though we summarize results over the event window of 4 to 7 p.m.

There were 484 enrolled and 479 called customers during the PY2019 event day (five customers were exempt). The enrollment decreased from 545 customers in PY2018. The aggregate reference loads and load impacts also decreased during PY2019. There are a number of contributing factors that result in the PY2019 load impact decreasing by 106 MW (643 MW minus 537 MW). First, there were 73 customers that de-enrolled from BIP that contributed 26 MW to the load impact during PY2018. Second, there were five enrolled customers but exempt from the PY2019 event. [redacted] Third, the load impact decreased by 15 MW for customers that remained on the program during both years; however, their reference loads were also 13 MW lower in PY2019. Additionally, their FSL increased from 70 to 87 MW. [redacted]

Table 6.6: Comparison of *Ex-post* Impacts in PY2018 and PY2019, *SCE*

Level	Outcome	*Ex-post* PY2018	*Ex-post* PY2019
Total	# Customers	545	479
	Reference (MWh/h)	815	685
	Load Impact (MWh/h)	643	537
Per SAID	Reference (kWh/h)	1,495	1,430
	Load Impact (kWh/h)	1,180	1,122
	% Load Impact	78.9%	78.5%

6.2.2 Previous versus current *ex-ante*

In this sub-section, we compare the *ex-ante* forecast prepared following PY2018 (the "previous study") to the *ex-ante* forecast contained in this study (the "current study"). Table 6.7 represents the forecast for the August 2020 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 PY2018 and PY2019 Studies, *SCE*

Level	Outcome	Ex-ante 2020 Typical Event Day, *Previous Study*	Ex-ante 2020 Typical Event Day, *Current Study*
Total	# Customers	480	464
	Reference (MWh/h)	765	716
	Load Impact (MWh/h)	598	562
	FSL (MWh/h)	80	98
Per SAID	Reference (kWh/h)	1,593	1,542
	Load Impact (kWh/h)	1,246	1,211
	% Load Impact	78.2%	78.5%

The enrollments numbers decreased by 16 customers between the previous and current studies. Similarly, the aggregate reference load decreased 49 MW. [redacted] The aggregate load impact decreased by 36 MW in the current *ex-ante* analysis, which is a result of the lower reference loads and an increase of 18 MW to the FSL. The percentage load impacts are similar; however, the per-customer reference loads and load impacts are slightly smaller in the current study.

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

Table 6.8 provides a comparison of the *ex-ante* forecast of 2019 load impacts prepared following PY2018 and the PY2019 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 September 4, 2019 event day, averaged over only full event hours (HE 17-19).

The forecast percentage load impact was quite close to the *ex-post* estimates; however, the per-customer reference loads and load impacts were smaller. While some of this is caused by customers that left the program, [redacted] The forecasted FSL was 82 MW whereas the *ex-post* FSL was 89 MW.

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

Level	Outcome	*Ex-ante* 2019 Typical Event Day, Previous Study	*Ex-post PY2019*
Total	# Customers	492	479
	Reference (MWh/h)	790	685
	Load Impact (MWh/h)	619	537
Per SAID	Reference (kWh/h)	1,606	1,430
	Load Impact (kWh/h)	1,257	1,122
	% Load Impact	78.3%	78.5%

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 event day, September 4, 2019, and the *ex-ante* load impact represents the 2020 typical event day in a utility-specific 1-in-2 weather year.

The forecast calls for a reduction in enrollment of fifteen customers.[23] Notice, however, that the forecasted aggregate reference loads and load impacts are larger. [redacted] The percentage load impact is similar between the *ex-post* and *ex-ante* analyses.

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

Level	Outcome	Ex-post PY2019	Ex-ante 2020 Typical Event Day, Current Study
Total	# Customers	479	464
	Reference (MWh/h)	685	716
	Load Impact (MWh/h)	537	562
	FSL (MWh/h)	89	98
Per SAID	Reference (kWh/h)	1,430	1,542
	Load Impact (kWh/h)	1,122	1,211
	% Load Impact	78.5%	78.5%

Table 6.10 lays out all the potential sources of differences between the *ex-post* and *ex-ante* load impacts, but it is using the single event hour FSL achievement rate that primarily accounts for the differences, as explained above.

[23] Specifically, there were twenty customers that de-enrolled and five customers that were exempt from *ex-post*, resulting in a net decrease of fifteen customers. The twenty customers that left had an average August load of 2,272 kWh per-customer.

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

Factor	*Ex-post*	*Ex-ante*	Expected Impact
Weather	87.8 degrees Fahrenheit during event window.	87.6 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 16-19, results summarized over only full event hours HE 17-19.	HE 17-21 in Nov-Mar.	The slightly later *ex-post* event window tends toward slightly lower reference loads and load impacts relative to the *ex-ante* window.
% of resource dispatched	All but five customers were called.	Assume all customers are called.	[redacted]
Enrollment	479 customers during the *ex-post* event day.	464 customers in August 2020.	[redacted]
Methodology	Customer-specific regressions using own within-subject analysis.	Reference loads are simulated from customer-specific regressions. Load impacts are based on the customer-specific load impacts from the PY2019 event day during HE 18-19.	Using only *ex-post* full event hours' FSL achievement rate provides a larger *ex-ante* load impact than if using that of the average event hour.

6.3 SDG&E

6.3.1 Previous versus current *ex-post*

Table 6.11 compares *ex-post* load impacts between PY2018 and PY2019. The PY2018 load impacts are based on the August 9, 2018 event while the PY2019 load impacts are based on September 4, 2019 event; both events have event hours-ending 13 through 16.

Enrollment has increased from three to five customers. While the difference in enrollment numbers increases aggregate loads and load impacts, the customers that were in the program for both years also had slightly larger reference loads and load impacts during the PY2019 event.

Table 6.11: Comparison of *Ex-post* Impacts in PY2018 and PY2019, *SDG&E*

Level	Outcome	*Ex-post* PY2018	*Ex-post* PY2019
Total	# Customers	3	5
	Reference (MWh/h)	2.3	3.4
	Load Impact (MWh/h)	1.2	2.9
Per SAID	Reference (kWh/h)	758.6	676.1
	Load Impact (kWh/h)	409.3	573.5
	% Load Impact	53.9%	84.8%

6.3.2 Previous versus current *ex-ante*

In this sub-section, we compare the *ex-ante* forecast prepared following PY2018 (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 typical event day.

The enrollment forecast is lower in the current study which also results in lower reference loads and load impacts. Nonetheless, the per-customer reference loads and load impacts are slightly larger in the current study, because of the slightly higher observed loads during PY2019. The percentage load impact is similar between both years.

Table 6.12: Comparison of *Ex-ante* Impacts from PY2018 and PY2019 Studies, *SDG&E*

Level	Outcome	Ex-ante 2020 Typical Event Day, *Previous Study*	Ex-ante 2020 Typical Event Day, *Current Study*
Total	# Customers	7	5
	Reference (MWh/h)	1.5	1.3
	Load Impact (MWh/h)	1.0	0.9
	FSL (MWh/h)	0.6	0.4
Per SAID	Reference (kWh/h)	219.6	263.6
	Load Impact (kWh/h)	143.6	178.5
	% Load Impact	65.4%	67.7%

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

Table 6.13 compares the *ex-ante* forecast prepared following PY2018 to the PY2019 *ex-post* load impact estimates contained in this report for the September 4, 2019 event day. The *ex-ante* load impacts are based on the typical event day in a utility-specific 1-in-

2 weather year. The earlier event hours in the *ex-post* analysis (HE 13-16 vs HE 14-18) contributes to larger per-customer load impacts because the larger enrolled customers have greater loads during the earlier hours and curtail to their FSL around hour-ending 17. Even when comparing similar hours, however, the PY2019 customer loads are slightly higher.

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

Level	Outcome	*Ex-ante* 2019 Typical Event Day, Previous Study	*Ex-post* *PY2019*
Total	# Customers	6	5
	Reference (MWh/h)	1.3	3.4
	Load Impact (MWh/h)	0.9	2.9
Per SAID	Reference (kWh/h)	219.6	676.1
	Load Impact (kWh/h)	143.6	573.5
	% Load Impact	65.4%	84.8%

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

Table 6.14 shows a comparison of *ex-post* and *ex-ante* load impacts. Enrollment remains the same.[24] The decreased reference loads and load impacts is caused by the RA window of 4 to 9 p.m. corresponding to a period when most of the customers are already operating at or near their FSLs. The *ex-ante* forecast is based on the *ex-post* FSL achievement (*i.e.*, observed loads) relative to the FSL during event hours. In terms of achievement relative to the FSL, the *ex-post* and *ex-ante* load impacts match by design. However, the forecast reference loads may differ from the *ex-post* event-hour reference loads for various reasons. For instance, forecast reference loads are lower partly due to a difference in event windows, as the historical event was earlier than the *ex-ante* event window (hours-ending 13 to 16 vs. 17 to 21, respectively). The later *ex-ante* window includes hours with relatively low loads, which reduces the load impact because the FSL does not change across hours.

[24] One customer de-enrolled after the *ex-post* event. Regardless, SDG&E assumes enrollment to increase by one each year until 2022, afterwards enrollment remains constant.

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

Level	Outcome	Ex-post PY2019	Ex-ante 2020 Typical Event Day, Current Study
Total	# Customers Reference (MWh/h) Load Impact (MWh/h) FSL (MWh/h)	5 3.4 2.9 0.40	5 1.3 0.9 0.40
Per SAID	Reference (kWh/h) Load Impact (kWh/h) % Load Impact	676.1 573.5 84.8%	263.6 178.5 67.7%

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	92 degrees Fahrenheit during HE 13 to 16 on the September 4th event day	84 degrees Fahrenheit during HE 17 to 21 on utility-specific 1-in-2 typical event day	Program load is not very weather sensitive, so a small effect.
Event window	HE 13 to 16	HE 17 to 21.	Reference loads are substantially lower during 4 to 9 p.m., dragging down the average *ex-ante* reference loads and load impacts relative to *ex-post*.
% of resource dispatched	All	All	None
Enrollment	5 service accounts	5 service accounts	One larger customer de-enrolled after *ex-post*. *The ex-ante* forecast scales reference loads so the incremental customers will have lower reference loads than the de-enrolled customer. Afterwards, no increase in per-customer reference load or load impacts because results are scaled by enrollments.
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.

7. Recommendations

BIP continues to perform well, with its customers providing substantial load impacts with short notice. PG&E called three weekend events, which performed well in regard to the FSL achievement rate. Forecasts are built for the average weekday and are, consequently, not well suited for providing an estimate of the expected load impact for weekend events. The mismatch is driven by differences in usage between weekdays and weekends. SDG&E may want to consider calling earlier events to ensure that its customers are capable of consistently meeting their obligation during hours in which their loads are above their FSL. However, this decision is likely offset by the need to call events during the RA window.

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_2019_BIP_Ex_Post
BIP Study Appendix D	SCE 2019 BIP *Ex-Post*
BIP Study Appendix E	SDG&E 2019 BIP *Ex-Post*
BIP Study Appendix F	6.b PGE_2019_BIP_Ex_Ante
BIP Study Appendix G	SCE 2019 BIP *Ex-Ante*
BIP Study Appendix H	SDG&E 2019 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 provides the number of customers that are categorized as weather sensitive by industry group and utility. Customer weather sensitivity was evaluated for weekdays and weekends for PG&E because of the weekend *ex-post* events called.[25] The proportion of PG&E customers classified as non-weather sensitive was 68% for weekdays and 77% for weekends. The proportion customers classified as non-weather sensitive was 56% and 100% for SCE and SDG&E, respectively. The proportion of weather sensitive customers is largest in the retail industry group.

[25] The total number of customers included in the weekday models was less than the weekend models because not all enrolled customers were called for the weekday events.

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

WEEKDAY

Industry Type	Weather Sensitive	Non-Weather Sensitive	Total	Share Weather Sensitive
1. Agriculture, Mining, Construction	54	84	138	39%
2. Manufacturing	13	60	73	18%
3. Wholesale, Transportation, Utilities	17	54	71	24%
4. Retail	9	0	9	100%
5. Offices, Hotels, Health, Services	3	1	4	75%
8. Other	1	4	5	20%
Total	**97**	**203**	**300**	**32%**

WEEKEND

Industry Type	Weather Sensitive	Non-Weather Sensitive	Total	Share Weather Sensitive
1. Agriculture, Mining, Construction	58	210	268	22%
2. Manufacturing	13	82	95	14%
3. Wholesale, Transportation, Utilities	28	81	109	26%
4. Retail	9	0	9	100%
5. Offices, Hotels, Health, Services	2	3	5	40%
8. Other	9	18	27	33%
Total	**119**	**394**	**513**	**23%**

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	8	38	46	17%
2. Manufacturing	103	196	299	34%
3. Wholesale, Transportation, Utilities	29	31	60	48%
4. Retail	46	2	48	96%
5. Offices, Hotels, Health, Services	15	1	16	94%
6. Schools	5	0	5	100%
7. Entertainment, Other Services, Government	4	2	6	67%
8. Other or unknown	1	3	4	25%
Total	**211**	**273**	**484**	**44%**

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

Industry Type	Weather Sensitive	Non-Weather Sensitive	Total	Share Weather Sensitive
1. Agriculture, Mining, Construction	0	3	3	0%
2. Manufacturing	0	2	2	0%
Total	**0**	**5**	**5**	**0%**

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.[26] The tests are conducted using average-customer data by industry group and weather-sensitivity. Separate model specifications were tested for weather sensitive and non-weather sensitive customers. Model variations for weather sensitive customers include 17 combinations of weather-related variables for *ex-post* and 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)[27]; heat index (HI)[28]; cooling degree hours (CDH)[29], including both a 60 and 65 degree Fahrenheit threshold; the 3-hour moving average of CDH; cooling degree days (CDD)[30], 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.

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[26] 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.

[27] THI = T – 0.55 x (1 – HUM) x (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").

[28] 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.

[29] 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.

[30] 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, Monday X Hour, Friday X Hour, Morningload X Hour
2	Month X Hour
3	Month X Hour, Morningload X Hour
4	Month X Hour, Monday X Hour, Friday 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 (for SCE and SDG&E), and event days for programs in which BIP customers are dually enrolled (*e.g.*, CPP). For the most part, the selection involved selecting the hottest qualifying days. Table A.6 lists the event-like non-event days selected with a separate set of dates selected for PG&E weekend events.

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

PG&E		SCE	SDG&E
Weekday	Weekend	Weekday	Weekday
3/1/2019	2/9/2019	6/11/2019	7/23/2019
3/11/2019	2/24/2019	6/12/2019	7/24/2019
3/14/2019	3/10/2019	7/22/2019	7/25/2019
3/21/2019	6/1/2019	7/24/2019	7/26/2019
3/29/2019	6/29/2019	7/26/2019	8/26/2019
6/14/2019	6/30/2019	7/30/2019	8/30/2019
6/20/2019	7/6/2019	8/5/2019	9/5/2019
6/26/2019	8/17/2019	8/26/2019	9/6/2019
7/1/2019	9/21/2019	8/30/2019	
9/10/2019			
9/18/2018			

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 for PG&E bifurcates the results by weekday and weekend.

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

WEEKDAY

Group	Industry Type	Selected Specification	MPE	MAPE	Number of Customers
Weather Sensitive	1. Agriculture, Mining, Construction	6	1.1%	2.7%	54
	2. Manufacturing	6	6.6%	10.0%	13
	3. Wholesale, Transportation, Utilities	6	0.8%	2.7%	17
	4. Retail	1	0.1%	1.1%	9
	5. Offices, Hotels, Health, Services	3	-0.8%	3.8%	3
	8. Other	3	-1.1%	3.3%	1
Non-Weather Sensitive	1. Agriculture, Mining, Construction	1	-0.4%	1.6%	84
	2. Manufacturing	5	-0.5%	4.1%	60
	3. Wholesale, Transportation, Utilities	3	1.7%	9.3%	54
	5. Offices, Hotels, Health, Services	3	70.3%	95.6%	1
	8. Other	3	6.2%	16.3%	4

WEEKEND

Group	Industry Type	Selected Specification	MPE	MAPE	Number of Customers
Weather Sensitive	1. Agriculture, Mining, Construction	5	1.6%	2.4%	58
	2. Manufacturing	15	0.2%	9.0%	13
	3. Wholesale, Transportation, Utilities	7	-1.1%	8.1%	28
	4. Retail	11	-0.1%	0.9%	9
	5. Offices, Hotels, Health, Services	16	-0.1%	2.7%	2
	8. Other	5	0.0%	5.5%	9
Non-Weather Sensitive	1. Agriculture, Mining, Construction	3	0.3%	5.4%	210
	2. Manufacturing	5	0.3%	5.3%	82
	3. Wholesale, Transportation, Utilities	1	0.9%	10.7%	81
	5. Offices, Hotels, Health, Services	1	2.8%	52.7%	3
	8. Other	2	0.2%	9.6%	18

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	11	1.7%	9.4%	8
	2. Manufacturing	2	0.0%	1.1%	103
	3. Wholesale, Transportation, Utilities	16	-0.4%	4.0%	29
	4. Retail	12	-0.2%	1.0%	46
	5. Offices, Hotels, Health, Services	1	0.0%	2.9%	15
	6. Schools	10	0.1%	1.8%	5
	7. Entertainment, Other Services, Government	16	-1.3%	5.1%	4
	8. Other or unknown	17	0.0%	2.9%	1
Non-Weather Sensitive	1. Agriculture, Mining, Construction	3	0.7%	1.1%	38
	2. Manufacturing	1	0.3%	3.0%	196
	3. Wholesale, Transportation, Utilities	3	-1.3%	5.8%	31
	4. Retail	1	0.5%	4.5%	2
	5. Offices, Hotels, Health, Services	5	-1.1%	12.8%	1
	6. Schools	n/a	n/a	n/a	n/a
	7. Entertainment, Other Services, Government	2	2.8%	16.6%	2
	8. Other or unknown	5	9.0%	10.6%	3

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

Group	Industry Type	Selected Specification	MPE	MAPE	Number of Customers
Non-Weather Sensitive	1. Agriculture, Mining, Construction	3, 4, & 5[31]	81.9%	101.0%	3
	2. Manufacturing	2	3.2%	16.9%	2

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.

[31] A separate regression specification was chosen for each SDG&E customer, instead of a specification choice by industry group, because of the low number of customers.

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%	81
	2. Manufacturing	4	3.8%	13.8%	20
	3. Wholesale, Transportation, Utilities	5	1.3%	7.0%	37
	4. Retail	5	0.5%	1.6%	9
	5. Offices, Hotels, Health, Services	1	-0.6%	3.7%	4
	8. Other	4	0.0%	3.6%	10
Non-Weather Sensitive	1. Agriculture, Mining, Construction	0	-0.8%	2.3%	187
	2. Manufacturing	2	-1.8%	3.9%	74
	3. Wholesale, Transportation, Utilities	1	3.3%	8.9%	72
	4. Retail	n/a	n/a	n/a	n/a
	5. Offices, Hotels, Health, Services	1	71.8%	98.1%	1
	8. Other	2	-1.8%	12.6%	17

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%	8
	2. Manufacturing	4	-0.3%	2.1%	103
	3. Wholesale, Transportation, Utilities	6	-0.4%	4.2%	29
	4. Retail	4	0.0%	1.5%	46
	5. Offices, Hotels, Health, Services	5	-0.4%	4.2%	15
	6. Schools	1	3.6%	9.1%	5
	7. Entertainment, Other Services, Government	4	-2.5%	5.5%	4
	8. Other or unknown	5	-3.0%	5.7%	1
Non-Weather Sensitive	1. Agriculture, Mining, Construction	1	1.6%	1.7%	38
	2. Manufacturing	2	-0.4%	3.3%	196
	3. Wholesale, Transportation, Utilities	1	-1.7%	5.7%	31
	4. Retail	1	19.4%	27.5%	2
	5. Offices, Hotels, Health, Services	2	-3.1%	15.9%	1
	6. Schools	n/a	n/a	n/a	n/a
	7. Entertainment, Other Services, Government	1	2.8%	16.6%	2
	8. Other or unknown	1	22.6%	32.3%	3

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

Group	Industry Type	Selected Specification	MPE	MAPE	Number of Customers
Non-Weather Sensitive	1. Agriculture, Mining, Construction	1 & 2	82.1%	105.3%	3
	2. Manufacturing	1	3.2%	16.9%	2

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
	Weekday	Weekend		
7	0.0%			
8	0.0%			
9	0.0%			
10	0.0%			
13				0.0%
14				20.0%
15				0.0%
16				0.0%
17		0.0%	0.6%	
18		0.0%	8.5%	
19		0.0%	8.5%	
20		0.0%		
21		0.0%		
22		0.0%		
Average Event Hour	**0.0%**	**0.0%**	**5.9%**	**5.0%**

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.4 illustrate each utility's average predicted and observed loads across the event-like days using the specification chosen (by industry and weather sensitivity) for each customer. In each figure, the solid line represents the observed load and the dashed line represents the load predicted by the statistical model. These figures show that the predicted loads are quite close to the observed loads for the event-like non-event days.

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

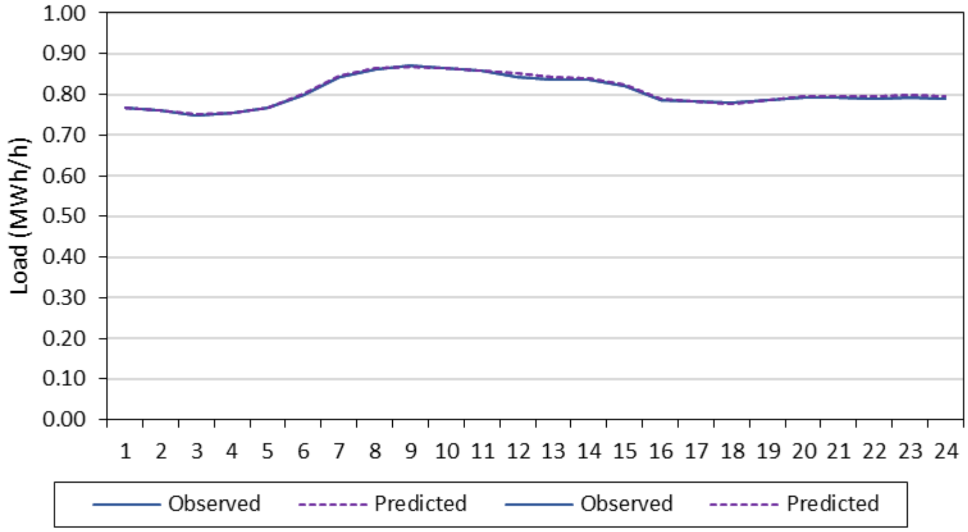


Figure A.2 Average Predicted and Observed Loads on Weekend Event-like Days, *PG&E*

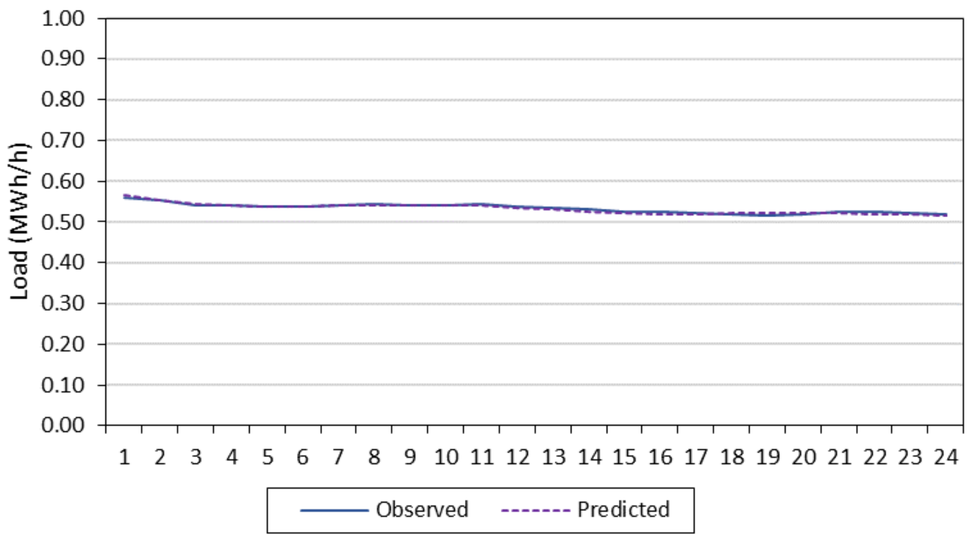


Figure A.3: Average Predicted and Observed Loads on Event-like Days, *SCE*

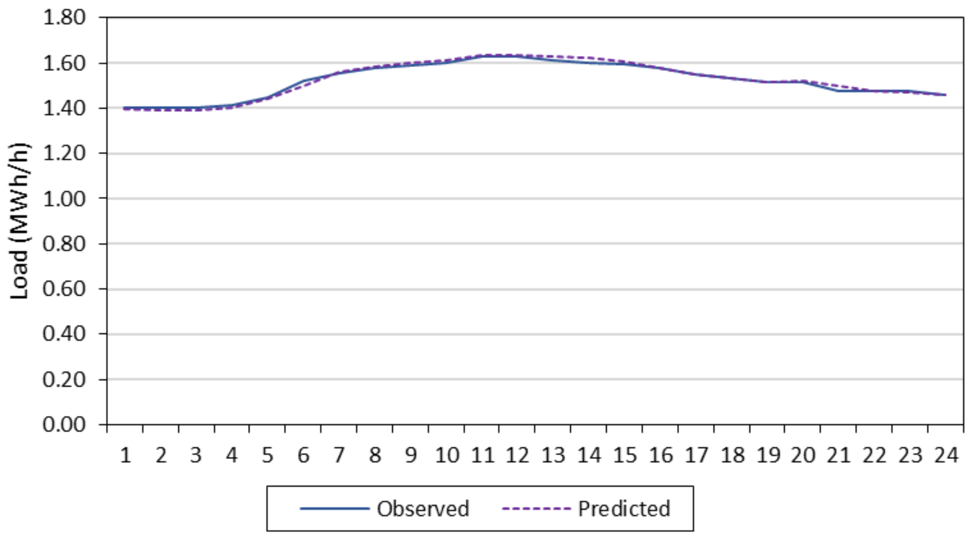
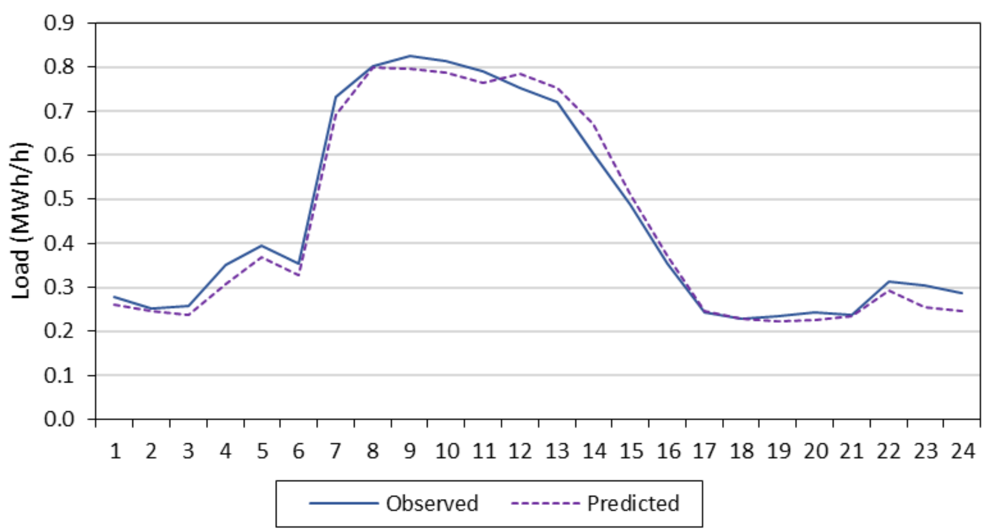


Figure A.4: Average Predicted and Observed Loads on Event-like Days, *SDG&E*



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. 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. The notes following each table indicate the included hours.

PG&E called multiple events in 2019, including weekdays and weekends. No FSL achievement is applicable when a customer's reference load was below their FSL. For PG&E, we use a customer's FSL achievement for the last event day that they were called and had their reference load above their FSL. Table B.1 summarizes the FSL achievement rate by event groups, which are assembled by similar event types and hours. Event Group 1 represents February 23rd, Event Group 2 represents March 12th and June 6th, and Event Group 2 represents October 6th and December 8th. The FSL achievement rate are calculated over only full event hours, thus excluding partial event hours.

Table B.1: September 26, 2019 Over/Under Performance – PG&E BIP,
by Industry Group and Event Hour

Event Group	Industry Group	Count	Percent Over/Under Performance			
			Hour Before Event	First Hour of Event	Remaining Hours of Event	Hour After Event
1	1. Agriculture, Mining, Construction	25	[redacted]	[redacted]	[redacted]	[redacted]
	2. Manufacturing	2	[redacted]	[redacted]	[redacted]	[redacted]
	3. Wholesale, Transportation, Utilities	4	[redacted]	[redacted]	[redacted]	[redacted]
2	1. Agriculture, Mining, Construction	41	[redacted]	[redacted]	[redacted]	[redacted]
	2. Manufacturing	35	-1.9%	95.3%	93.7%	12.4%
	3. Wholesale, Transportation, Utilities	7	[redacted]	[redacted]	[redacted]	[redacted]
	5. Offices, Hotels, Health, Services	1	[redacted]	[redacted]	[redacted]	[redacted]
	8. Other	4	[redacted]	[redacted]	[redacted]	[redacted]
3	1. Agriculture, Mining, Construction	200	[redacted]	[redacted]	[redacted]	[redacted]
	2. Manufacturing	57	[redacted]	[redacted]	[redacted]	[redacted]
	3. Wholesale, Transportation, Utilities	98	[redacted]	[redacted]	[redacted]	[redacted]
	4. Retail	9	[redacted]	[redacted]	[redacted]	[redacted]
	5. Offices, Hotels, Health, Services	4	[redacted]	[redacted]	[redacted]	[redacted]
	8. Other	23	[redacted]	[redacted]	[redacted]	[redacted]

Note: Event Group 1 represents the 2/23/19 event, Event Group 2 represents the 3/12/19 and 6/6/19 events, and Event Group 3 represents the 10/6/19 and 12/8/19 events.
"n/a" indicates that the total reference load is below FSL during period.

Table B.2: September 4, 2019 Over/Under Performance – SCE BIP,
by Industry Group and Event Hour

Industry Group	Percent Over/Under Performance Hour Before Event (HE 15)	First Hour of Event (HE 16)	Remainder Hours of Event (HE 17-19)	Hour After Event (HE 20)
1. Agriculture, Mining, Construction	[redacted]	[redacted]	[redacted]	[redacted]
2. Manufacturing	1.5%	32.9%	76.1%	54.2%
3. Wholesale, Transportation, Utilities	[redacted]	[redacted]	[redacted]	[redacted]
4. Retail	-0.2%	1.9%	1.0%	-1.3%
5. Offices, Hotels, Health, Services	[redacted]	[redacted]	[redacted]	[redacted]
6. Schools	[redacted]	[redacted]	[redacted]	[redacted]
7. Institutional/Government	[redacted]	[redacted]	[redacted]	[redacted]
8. Other	[redacted]	[redacted]	[redacted]	[redacted]

Note: HE 16 is a partial event hour because the event began at 3:20 p.m.)
"n/a" indicates that the total reference load is below FSL during period.

Table B.3: September 4, 2019 Over/Under Performance – SDG&E BIP,
by Industry Group and Event Hour

Industry Group	Percent Over/Under Performance Hour Before Event (HE 12)	First Hour of Event (HE 13)	Remainder Hours of Event (HE 14-16)	Hour After Event (HE 17)
1. Agriculture, Mining, Construction	10.6%	85.4%	103.5%	190.0%
2. Manufacturing	-1.0%	92.4%	94.1%	102.2%