

Public Version. Redactions in 2020 Statewide Load Impact
Evaluation of California Capacity Bidding Programs and
Appendices



2020 STATEWIDE LOAD IMPACT EVALUATION OF CALIFORNIA CAPACITY BIDDING PROGRAMS

Ex-Post and Ex-Ante Load Impacts

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Report prepared for:
PACIFIC GAS & ELECTRIC COMPANY
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SOUTHERN CALIFORNIA EDISON

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ABSTRACT

This report documents the Program Year 2020 (PY2020) load impact evaluation of the aggregator-based demand response (DR) programs operated by the three California investor-owned utilities (IOUs) Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E). The scope of this evaluation covers the statewide Capacity Bidding Program (CBP) operated by all three IOUs. The primary goals of this evaluation are to 1) estimate the ex-post load impacts for PY2020 and 2) estimate ex-ante load impacts for years 2021 through 2031.

As part of these programs, DR aggregators contract with customers to act on their behalf in all aspects of the DR program, including receiving notices from the utility, arranging for load reductions on event days, receiving incentive payments, and paying penalties (if warranted) to the utility. Each aggregator forms a “portfolio” of individual service accounts, whose aggregated load reductions participate as a single resource for the DR programs' IOUs. Depending on their contractual arrangement with the IOU, aggregators can enroll and nominate customer service accounts in various product types, including day-ahead (DA) and day-of¹ (DO) notifications and triggers. The terms and conditions of service can vary widely, depending on individual contracts and tariffs negotiated between aggregators and IOUs, and contracts between aggregators and customers.

The number of nominated customer service accounts² on a single event day ranged from less than one service account to over 1,600, depending on the product type. Some programs and notice types called events on as few as 15 days in 2020, while others called events on up to 39 days, including several events called for various combinations of distribution-based geographical locations or Sub-Load Aggregation Points (Sub-LAPs). These local, or Sub-LAP, events may occur when the IOU does not need the entire nominated load reduction, as in localized distribution events, or based upon CAISO awards.

AEG estimated hourly ex-post load impacts for each program³, product⁴, and event during 2020, using regression analysis of individual customer-level hourly load, weather, and event data. The estimated load impacts are reported by IOU, event day, program, and product type (e.g., DA 1-4 Hours and DO 1-4 Hours). Load impacts for the average event day are also reported by industry type and CAISO local capacity area (LCA) where relevant.

Estimated aggregate load impacts for an average non-residential CBP DA event were 10.0 MW for PG&E, 3.9 MW for SCE, and 0.4 MW for SDG&E. Aggregate load impacts for non-residential CBP with DO notice ■■■ MW for SCE and 2.2 MW for SDG&E, on average.

¹ Starting in PY2018, DO products are no longer offered by PG&E.

² PG&E refers to these as service agreements.

³ “Program” refers to each IOU’s notification type by customer class. For example, SDG&E’s Non-residential CBP Day Of notification is a program. SCE and SDG&E both have Non-residential Day Ahead and Non-residential Day Of programs, while PG&E has the Day Ahead program for both Residential and Non-residential customers.

⁴ “Product” refers to different product offerings within each program. For example, the PG&E Day Ahead program has 3 products offerings: Elect, Elect+, and Prescribed.

AEG developed ex-ante load impact forecasts by combining enrollment forecasts provided by the IOUs, and per-customer load impacts generated from analysis of current and prior ex-post load impact estimates. The forecast numbers of nominated customer service accounts and aggregate ex-ante load impacts presented in the report reflect several program changes expected to take place beginning in 2021.

EXECUTIVE SUMMARY

This report describes the load impact evaluation of aggregator demand response (DR) programs offered by Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E), the three California investor-owned utilities (IOUs). Aggregators are non-utility entities that contract with eligible utility customers to act on their behalf in all aspects of the DR program, including the receipt of notices of DR events from the utility, the receipt of incentive payments, and the payment of penalties to the utility. Each aggregator forms a portfolio of individual customers who participate as a group to provide load reduction during DR events.

This evaluation only covers the Capacity Bidding Program (CBP). All three IOUs eliminated the Aggregator Managed Portfolio (AMP) program offering in 2018. The CBP programs offered by each IOU differ slightly in program features and operation. However, in all programs, third-party aggregators enroll customers under their own contracts for DR or load reduction capacity; the IOUs are not involved in the contracts between the aggregators and the participating customers.

The primary goals of the 2020 impact evaluation are as follows:

- Estimate hourly ex-post load impacts for each product and IOU for PY2020.
- Estimate hourly ex-ante load impacts for each product and IOU for years 2021 through 2031.

In the following subsections, we present the program description, the evaluation methodology, PY2020 ex-post load impacts, ex-ante load impacts, and our key findings.

Program Description

CBP is a statewide price-responsive program launched in 2007. In CBP, aggregators are entities that contract with eligible residential⁵ and non-residential utility customers to act on their behalf in all aspects of the demand response program, including the receipt of notices (day-ahead, DA, or day-of, DO) from the utility under this program, the receipt of incentive payments, and the payment of penalties to the utility. Each aggregator forms a portfolio of individual customers who then participate on an aggregate basis to provide load reduction during events. The aggregators enroll participants under the terms of their own contracts to provide the load reduction capacity. The utilities are not directly involved in the contracts between the aggregators and the participating customers. A few customers are enrolled as individual participants in CBP and are classified as self-aggregated. Participating aggregators must have Internet access. Enrolled customers must have a qualifying interval meter and receive Bundled, Direct Access, or Community Choice Aggregation service.⁶ Customers enrolled in CBP may participate in another DR program, so long as it is an energy-only program (i.e., cannot have a capacity payment component) and does not have the same notification type (DA or DO).

CBP provides monthly capacity payments (\$/kW) to aggregators based on the nominated kW load, the specific operating month, the event duration, and the event notice option. Delivered

⁵ Since PY2018, the program was open to residential customer enrollment.

⁶ PG&E's partial standby, net-metered, and Automated Demand Response (AutoDR) customers are also eligible.

capacity determines performance. A penalty is assessed if a CBP aggregator's delivered capacity is less than 50% for SCE and SDG&E or less than 60% for PG&E. CBP aggregators receive the full monthly capacity payment following their nominations but no energy payments in the absence of events.⁷ Additional energy payments (\$/kWh) are made to the aggregator⁸ based on the measured kWh reductions (relative to the program baseline) achieved during an event.⁹

For PG&E, CBP events are determined by California Independent System Operator (CAISO) market awards. Events may also be called when the DA market price is greater than \$95/MWh, when PG&E forecasts that capacity may not be adequate, or when forecasted temperatures exceed the threshold for a Sub-LAP. Events can be called on non-holiday weekdays in May through October, between 1 PM and 9 PM, with a maximum of five events and 30 event hours per month (or more under the Elect and Elect+ options).

For SCE, CBP events are also determined by CAISO market awards. Events can be called on any non-holiday weekday year-round, between 3 PM and 9 PM, with a maximum of five events and 30 event hours per month.

For SDG&E, CBP events are triggered when market prices go above a given price threshold. Events can be called on non-holiday weekdays in May through October, between 11 AM and 7 PM or 1 PM and 9 PM, with a maximum of 24 event hours per month. Effective May 1, 2019, the maximum number of events called per month is limited to six event days with a maximum number of three consecutive days.

Number of Accounts

Since the IOUs continued to utilize localized events in PY2020, it is essential to distinguish total nomination (i.e., total enrollment) versus event nomination (i.e., event participation).¹⁰ Table E-1 presents the total number of nominated accounts for an average summer month¹¹ in PY2020 by notification type and utility. These counts would be comparable to participation counts during system-level events.

Table E-1 Summary of Nominated Accounts, Average Summer Month

Utility	Nominated Accounts	
	Day Ahead	Day Of
PG&E	1,155	-
SCE	387	312
SDG&E	23	158

⁷ Customers participating directly receive up to 80% of the available capacity payment; aggregators receive 100% of the capacity payment for the load reduction received. Note that all of PG&E and SCE's CBP customers participate through an aggregator.

⁸ Customers participating directly receive any additional energy payments directly.

⁹ PG&E and SDG&E's energy payments are made to bundled customers; SCE's energy payment calculation is based upon all types of customers including bundled, DA, and CCA.

¹⁰ In this report, we refer to the total enrolled customers and their associated impact as the nomination or nominated load. For a specific event, nomination refers to number of customers that were actually called, or dispatched, and the impact that was delivered on a given event. We recognize that this terminology might be confusing and, at PG&E's request, have made a recommendation to clarify definitions and terminology in future reports.

¹¹ A summer month is defined as months between May through October.

Evaluation Methods

For non-residential participants, AEG used customer-specific hourly regression models as the primary evaluation method for both the ex-post and ex-ante load impact analysis. Customer-specific regressions allow for granularity in the results and can readily be used to control for variables such as weather, geography, and time, as well as for unobservable customer-specific effects. For residential participants, AEG used aggregate hourly regression models since residential participants do not typically have highly variable loads. Paired with a matched control group approach, this allowed for effective use of aggregate models, which have higher statistical power with more customers included in the model. Because the CBP events are called only on isolated days over the program year, and participants face identical rates on all other days, a regression model is well-suited to estimating the effect of events relative to usage on non-event days.

The regression models capture variation in hourly customer loads as a function of several primary factors:

- Weather, using hourly weather variables such as cooling and heating degree days.
- Seasonal patterns, such as month of the year, day of the week, and interactions between seasonal and other variables.
- Events, including CBP event days and events called in other DR programs across the three IOUs.
- Daily fluctuations in load unrelated to other variables, captured by an appropriate load adjustment, such as an average load in the morning or evening.

After developing a set of hourly regression models to estimate the ex-post impacts, AEG used the same models to predict the ex-ante impacts under the Utility and CAISO 1-in-2 and 1-in-10 weather scenarios. AEG estimated load impacts for all five hours of the Resource Adequacy (RA) window, developing IOU-specific adjustments based on historical performance on events called for longer durations for each IOU and program.

Results

PY2020 Events

Table E-2 summarizes the number of event days by notification type and utility for the PY2020 evaluation period.¹²

¹² The PY2020 evaluation period is May 1 through Oct. 31, 2020 for PG&E and SDG&E and is Nov. 1, 2019 – Oct. 31, 2020 for SCE.

Table E-2 Number of PY2020 Event Days by Notice Type

Utility	Nov 2019-Apr 2020		May 2020-Oct 2020	
	Day Ahead	Day Of	Day Ahead	Day Of
PG&E	n/a	n/a	28	n/a
SCE	6	10	24	29
SDG&E	n/a	n/a	27	24

Ex-Post Impacts

Table E-3 summarizes the PY2020 ex-post load impacts and nominated capacity by IOU and program. The data presented are for the average summer event day.¹³ Table E-4 through Table E-6 shows the PY2020 ex-post load impacts and nominated capacity for each IOU by program and event day.

Note that in the following tables, we show the number of event nominations, which is dependent on being called to an event. Low counts are not indicative of low enrollment, rather an indication of necessity. Meeting capacity nominations, on the other hand, is the correct measure of the program's success. Meeting nominations means that aggregators and customers were able to curtail their load when asked to do so. None of the programs, on average, were successful in meeting or exceeding capacity nominations in PY2020.

Table E-3 Summary of PY2020 Ex-Post Impacts and Nominated Capacity: Average Summer Event Day

Utility	Day Ahead				Day Of			
	Nominated Accounts	Nominated Capacity (MW)	Aggregate Impact (MW)	% Delivered	Nominated Accounts	Nominated Capacity (MW)	Aggregate Impact (MW)	% Delivered
PG&E	1,155	■	■	64%	-	-	-	-
SCE	387	6.0	3.9	65%	312	■	■	67%
SDG&E	23	0.6	0.4	71%	158	2.9	2.2	74%

¹³ The average event day is defined as the average of all events called regardless of nomination count or Sub-LAP count. If multiple event windows were called on the same day, the multiple event windows are combined to give each event day equal weight. The average event day is calculated using aggregate-level results. The accompanying nomination count is calculated as a simple average of the nominated counts of each event day. For combined products (e.g. PG&E DA is a combination of Elect DA and Prescribed DA), the average event day aggregate-level results and nominated counts are summed. The corresponding per-participant impacts are calculated from the summed values.

Table E-4 Summary of PY2020 PG&E Ex-Post Impacts and Nominated Capacity

Event	Residential Day Ahead				Non-Residential Day Ahead			
	# of Accts	Per Customer Impact (kW)	Aggregate Impact (MW)	Nominated Capacity (MW)	# of Accts	Per Customer Impact (kW)	Aggregate Impact (MW)	Nominated Capacity (MW)
Jun 3, 2020	664	■	■	■	20	■	■	■
Jul 13, 2020	-	-	-	-	7	■	■	■
Jul 28, 2020	-	-	-	-	9	■	■	■
Jul 29, 2020	671	■	■	■	9	■	■	■
Jul 30, 2020	-	-	-	-	604	16.0	9.6	18.1
Jul 31, 2020	671	■	■	■	337	71.4	24.1	22.1
Aug 11, 2020	209	■	■	■	-	-	-	-
Aug 13, 2020	666	■	■	■	9	■	■	■
Aug 14, 2020	666	■	■	■	834	20.2	16.8	23.5
Aug 17, 2020	666	■	■	■	841	18.8	15.8	23.6
Aug 18, 2020	666	■	■	■	727	18.0	13.1	18.6
Aug 19, 2020	666	■	■	■	929	32.0	29.7	32.9
Aug 20, 2020	457	■	■	■	-	-	-	-
Aug 24, 2020	666	■	■	■	-	-	-	-
Aug 25, 2020	666	■	■	■	-	-	-	-
Sep 8, 2020	664	■	■	■	241	24.6	5.9	8.0
Sep 9, 2020	664	■	■	■	8	■	■	■
Sep 14, 2020	-	-	-	-	7	■	■	■
Sep 28, 2020	455	■	■	■	8	■	■	■
Sep 29, 2020	663	■	■	■	8	■	■	■
Sep 30, 2020	662	■	■	■	971	28.8	28.0	40.5
Oct 1, 2020	659	■	■	■	707	■	■	■
Oct 13, 2020	662	■	■	■	1	■	■	■
Oct 14, 2020	663	■	■	■	1	■	■	■
Oct 15, 2020	663	■	■	■	613	17.9	11.0	11.0
Oct 16, 2020	-	-	-	-	714	■	■	■
Oct 20, 2020	-	-	-	-	1	■	■	■
Oct 21, 2020	-	-	-	-	9	■	■	■

Table E-5 Summary of PY2020 SCE Ex-Post Impacts and Nominated Capacity

Event	Day Ahead				Day Of			
	# of Accts	Per Customer Impact (kW)	Aggregate Impact (MW)	Nominated Capacity (MW)	# of Accts	Per Customer Impact (kW)	Aggregate Impact (MW)	Nominated Capacity (MW)
Nov 4, 2019	3	■	■	■	1	■	■	■
Nov 5, 2019	3	■	■	■	1	■	■	■
Nov 6, 2019	3	■	■	■	1	■	■	■
Nov 7, 2019	3	■	■	■	1	■	■	■
Nov 8, 2019	3	■	■	■	1	■	■	■
Dec 2, 2019	3	■	■	■	1	■	■	■
Dec 11, 2019	-	-	-	-	1	■	■	■
Feb 3, 2020	-	-	-	-	15	■	■	■
Feb 4, 2020	-	-	-	-	15	■	■	■
Feb 6, 2020	-	-	-	-	15	■	■	■
May 28, 2020	295	4.2	1.2	2.9	326	5.9	1.9	4.6
Jun 2, 2020	351	16.4	5.8	5.7	433	17.3	7.5	5.0
Jun 3, 2020	351	12.0	4.2	5.7	467	■	■	■
Jun 4, 2020	351	16.4	5.8	5.7	467	■	■	■
Jun 10, 2020	292	18.3	5.3	4.7	394	■	■	■
Jul 9, 2020	403	17.1	6.9	6.2	397	14.0	5.6	4.6
Jul 10, 2020	403	11.4	4.6	6.2	359	■	■	■
Jul 13, 2020	403	11.4	4.6	6.2	428	■	■	■
Jul 27, 2020	403	17.1	6.9	6.2	397	14.0	5.6	4.6
Jul 28, 2020	-	-	-	-	69	22.9	1.6	1.2
Jul 29, 2020	-	-	-	-	31	■	■	■
Jul 30, 2020	-	-	-	-	31	■	■	■
Jul 31, 2020	-	-	-	-	31	■	■	■
Aug 3, 2020	382	22.8	8.7	6.4	444	11.7	5.2	5.9
Aug 12, 2020	382	22.8	8.7	6.4	408	11.7	4.8	5.5
Aug 13, 2020	382	8.3	3.2	6.4	444	8.0	3.6	5.9
Aug 14, 2020	382	8.8	3.4	6.4	444	8.2	3.7	5.9
Aug 17, 2020	382	8.8	3.4	6.4	444	8.2	3.7	5.9
Aug 18, 2020	-	-	-	-	36	11.8	0.4	0.5
Sep 3, 2020	413	17.4	7.2	6.5	307	■	■	■
Sep 4, 2020	413	10.3	4.2	6.5	307	■	■	■

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Event	Day Ahead				Day Of			
	# of Accts	Per Customer Impact (kW)	Aggregate Impact (MW)	Nominated Capacity (MW)	# of Accts	Per Customer Impact (kW)	Aggregate Impact (MW)	Nominated Capacity (MW)
Sep 8, 2020	413	10.5	4.4	6.5	307	■	■	■
Sep 9, 2020	413	17.4	7.2	6.5	307	■	■	■
Sep 10, 2020	413	23.8	9.8	6.5	307	■	■	■
Oct 1, 2020	412	7.8	3.2	5.9	294	■	■	■
Oct 2, 2020	412	6.6	2.7	5.9	294	■	■	■
Oct 5, 2020	412	13.5	5.6	5.9	294	■	■	■
Oct 6, 2020	412	13.5	5.6	5.9	294	■	■	■
Oct 7, 2020	412	14.8	6.1	5.9	294	■	■	■

Table E-6 Summary of PY2020 SDG&E Ex-Post Impacts and Nominated Capacity¹⁴

Event	Day Ahead				Day Of			
	# of Accts	Per Customer Impact (kW)	Aggregate Impact (MW)	Nominated Capacity (MW)	# of Accts	Per Customer Impact (kW)	Aggregate Impact (MW)	Nominated Capacity (MW)
Jun 2, 2020	7	50.2	0.4	0.3	-	-	-	-
Jun 3, 2020	11	49.6	0.5	0.5	101	27.0	2.7	2.4
Jul 10, 2020	20	12.7	0.3	0.4	110	23.6	2.6	2.3
Jul 13, 2020	20	12.7	0.3	0.4	110	23.6	2.6	2.3
Jul 29, 2020	24	28.3	0.7	0.6	110	23.6	2.6	2.3
Jul 30, 2020	24	15.2	0.4	0.6	175	16.2	2.8	3.2
Jul 31, 2020	24	15.2	0.4	0.6	175	16.2	2.8	3.2
Aug 3, 2020	20	29.7	0.6	0.4	-	-	-	-
Aug 14, 2020	24	29.5	0.7	0.6	175	14.2	2.5	3.2
Aug 17, 2020	24	24.9	0.6	0.6	175	10.1	1.8	3.2
Aug 18, 2020	24	24.9	0.6	0.6	175	10.7	1.9	3.2
Aug 19, 2020	24	29.5	0.7	0.6	175	14.2	2.5	3.2
Aug 21, 2020	24	15.3	0.4	0.6	175	15.0	2.6	3.2
Aug 27, 2020	4	0.0	0.0	0.2	175	14.0	2.4	3.2
Sep 4, 2020	24	10.1	0.2	0.7	152	14.5	2.2	3.2
Sep 8, 2020	24	13.8	0.3	0.7	152	20.1	3.1	3.2
Sep 9, 2020	20	24.7	0.5	0.5	-	-	-	-
Sep 16, 2020	24	20.6	0.5	0.7	-	-	-	-

¹⁴ All impacts shown are for HE19 (6 PM to 7 PM), which is the common hour between all SDG&E events.

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Event	Day Ahead				Day Of			
	# of Accts	Per Customer Impact (kW)	Aggregate Impact (MW)	Nominated Capacity (MW)	# of Accts	Per Customer Impact (kW)	Aggregate Impact (MW)	Nominated Capacity (MW)
Sep 17, 2020	24	14.1	0.3	0.7	-	-	-	-
Sep 18, 2020	24	-0.5	0.0	0.7	-	-	-	-
Sep 29, 2020	-	-	-	-	152	12.5	1.9	3.2
Sep 30, 2020	4	7.4	0.0	0.2	152	10.6	1.6	3.2
Oct 1, 2020	20	19.4	0.4	0.4	129	8.7	1.1	2.2
Oct 2, 2020	20	18.6	0.4	0.4	-	-	-	-
Oct 5, 2020	20	11.8	0.2	0.4	-	-	-	-
Oct 6, 2020	20	11.8	0.2	0.4	129	14.7	1.9	2.2
Oct 7, 2020	20	11.7	0.2	0.4	-	-	-	-
Oct 12, 2020	-	-	-	-	70	6.4	0.4	0.8
Oct 13, 2020	20	18.6	0.4	0.4	129	10.3	1.3	2.2
Oct 14, 2020	-	-	-	-	129	8.4	1.1	2.2
Oct 15, 2020	-	-	-	-	59	17.1	1.0	1.4
Oct 19, 2020	-	-	-	-	70	6.4	0.4	0.8
Oct 20, 2020	-	-	-	-	59	24.5	1.4	1.4

Ex-Ante Impacts

Table E-7 summarizes the 11-year enrollment and load forecast by utility, customer class, notification type, and year in August.

Table E-7 2021-2031 Forecast for August

Utility	Customer Class	Notice	Number of Service Accounts			Aggregate Impact (MW)		
			2021	2023	2025-2031 (Each Year)	2021	2023	2025-2031 (Each Year)
PGE	Residential	Day Ahead	8,247	16,494	16,494	2.4	4.9	4.9
	Non-Residential	Day Ahead	2,049	2,258	2,258	40.5	44.7	44.7
SCE	Non-Residential	Day Ahead	410	410	410	2.6	2.6	2.6
		Day Of	380	380	380			
SDG&E	Non-Residential	Day Ahead	18	19	20	0.2	0.2	0.2
		Day Of	164	170	177	1.5	1.5	1.6

We describe each IOU's 2021-2031 forecast as follows:

- PG&E uses a nomination-based forecast, which assumes growth through 2022 and holds the forecast constant across the remainder of the forecast horizon (2023-2031). The enrollment forecast follows accordingly, assuming per customer load impacts remains constant.

- SCE's enrollment forecasts for both CBP DA and DO are derived from the average nominations during each season in PY2020, incorporating known and anticipated PY2021 participation. SCE also assumes a constant enrollment forecast for both non-residential CBP DA and DO throughout the 2021-2031 forecast horizon. For this filing, SCE assumes zero residential CBP participation. The CPUC has not ruled on SCE's Mid-Cycle advice filing, so the parameters of SCE's residential CBP cannot yet be determined.
- SDG&E's enrollment forecast for the DA and DO products assumes the customer enrollment will increase by 2% per year starting in 2021 through 2025 due to the CBP program improvements proposed by SDG&E. In addition, SDG&E forecasts that the customer enrollment in the CBP DO program will increase by another 1% per year starting in 2021 through 2025 due to growth in the Technical Incentives (TI) program. Therefore, total DO enrollment is expected to increase by 3% per year starting in 2021 through 2025 due to program improvements and growth in TI. The enrollment forecasts for the DA and DO products after 2025 and through 2031 show a flat trend at the 2025 values. The forecast listed in Table E-7 for DO includes new enrollments in the Technical Incentives (TI) program. SDG&E's forecast does not include a residential forecast.

Table E-8 summarizes the aggregate load impact forecasts for an August peak day in 2021 by IOU and program for each weather scenario. Note that since CBP impacts are inherently nomination-driven, not weather-driven, we assumed constant per-customer load impacts across the weather scenarios. The per-customer impacts are also estimated to remain constant across the months of May through October, i.e., constant nominations through the season. However, since participant usage can be weather-dependent, the weather scenarios do affect the estimated reference load. This results in varying percent impacts across the months and weather scenarios.

Table E-8 Summary of Average RA Window Ex-Ante Impacts, August Peak Day, 2021

Utility	Customer Class	Notice	# of Accts	Per Customer (kW)	Aggregate Impact (MW)	Percent Impact (%)			
						Utility Peak		CAISO Peak	
						1-in-2	1-in-10	1-in-2	1-in-10
PGE	Residential	Day Ahead	8,247	0.3	2.4	20.7%	19.7%	21.3%	21.0%
	Non-Residential	Day Ahead	2,049	19.8	40.5	15.3%	15.0%	15.5%	15.2%
SCE	Non-Residential	Day Ahead	410	6.2	2.6	7.0%	7.0%	7.0%	7.0%
		Day Of	380	■	■	■	■	■	■
SDG&E	Non-Residential	Day Ahead	18	11.8	0.2	9.9%	9.6%	9.7%	9.8%
		Day Of	164	9.1	1.5	9.5%	9.3%	9.4%	9.4%

The ex-ante load impact forecasts are developed by combining enrollment forecasts provided by the utilities, per-customer load impacts generated from analysis of current and prior ex-post load impact estimates. The forecasted numbers of nominated customer service accounts and aggregate load impacts reflect any anticipated program changes in future years.

Key Findings

In PY2020, we have the following key findings:

1. CBP remains a more time and geographically-targeted DR program, utilizing localized events. However, all three IOUs, due to market conditions, called more consistent events through the PY2020 season.
 - PG&E's CBP program, like in PY2019, dispatched many localized events with 1 to 14 Sub-LAPs called and 1 to 1,647 participants nominated. PG&E called several system-level events, utilizing all 14 Sub-LAPs and both residential and non-residential participants. Similar to PY2019, PG&E called most events between 6 PM to 7 PM (HE19).
 - Similar to PY2019, SCE called mostly system-level events. The variability in event characteristics (Sub-LAP and participant count) is due to the variability in monthly nominations across the two seasons (summer v. non-summer).
 - Similar to SCE, SDG&E mostly system-level events, also experiencing some variability in nominations in the DO 1-9 Hour product. SDG&E also called most events between 3 PM to 7 PM (HE16-HE19) and 6 PM to 8 PM (HE19-HE20) for the 11 AM to 7 PM and 1 PM to 9 PM dispatch windows, respectively.
2. None of the CBP programs successfully met/exceeded their capacity nominations during dispatches on a summer typical event day.
 - PG&E's DA program is the largest contributor with 10.1 MW reductions, on average, but was not successful in meeting its average nominated capacity of 18.1 MW.
 - SCE's DA non-summer season successfully exceeded MW nominations but did not see the same success in the summer season. SCE's DO program did not succeed in meeting its nominated capacity in either season on a typical event day.
 - SDG&E's DA and DO programs were not successful in meeting nominated capacities, on typical event days. However, both programs were able to exceed nominations under the 1-9 Hour products.
3. Participation adjusts to fill aggregator nominations. Comparisons of PY2020 load impacts¹⁵ to previous program years show that the participant population consistently changes from year-to-year. PY2020 electric usage saw shifts in all customer classes, but aggregator recruitment determines the appropriate customers capable of curtailing load when needed.

Recommendations

AEG has the following recommendations for future research and evaluation related to the Capacity Bidding Programs.

- [Reevaluate the definition of the average event day.](#) The current definition, consistent across all IOUs, includes all events called calculating the average, regardless of participant

¹⁵ See "Comparison to Ex-Post Impacts" subsection for each IOU in Ex-Post Results (Section 4) for IOU-specific comparisons.

count and event timing. Results for the most prevalent event hour¹⁶ are presented. In PY2020, a number of events were called in “outlier” hours, i.e., PG&E’s September 14th event on HE15. Although only a handful, these outlier events, by definition, are included in the average but are not represented in the reported event hour. As more outlier events are dispatched, it is likely that certain exclusions may be considered and applied as appropriate.

- **Clearly differentiate between nominated customers and dispatched customers.** In future evaluation reports PG&E suggests, and AEG agrees, that the terminology should be updated to more clearly differentiate between customers nominated on a monthly or seasonal basis and those actually called, or dispatched, for individual events. This includes the differentiation between nominated load and delivered load. In this report, we refer to the total enrolled customers and their associated impact as the nomination or nominated load. For a specific event, nomination refers to number of customers that were called, or dispatched, and the impact that was delivered on a given event.

¹⁶ PG&E and SDG&E show HE19. SCE show HE18 and HE20 for non-summer and summer estimates, respectively.

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1

INTRODUCTION

This report documents the load impact evaluation of the Capacity Bidding Program (CBP), the aggregator-based DR program operated by Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E) for PY2020.

Research Objectives

This study's key objectives are to estimate both ex-post and ex-ante impacts for each investor-owned utility's (IOU) CBP program. More specifically:

- Ex-post impacts are estimated for the average customer and all customers in aggregate for each hour of each event day and the average event day for each IOU's CBP products¹⁷ and programs¹⁸. These results are presented at the program level and separately for each product offering. They are also provided for each customer class¹⁹, each industry group, each LCA, each size group, each aggregator, for AutoDR, and for dually enrolled DR participants.²⁰ For Residential participants, they are provided for each LCA and by CARE status.
- Ex-ante impacts are estimated for each year over an 11-year²¹ time horizon, based on each IOU's and CAISO's 1-in-2 and 1-in-10 weather conditions for a typical event day and each monthly system peak day. These results are presented at the program level. The impacts are provided for the average customer and all customers in aggregate for the resource adequacy (RA) window (4 PM to 9 PM). As applicable, they will also be provided for each LCA, each size group, and each busbar.

Key Issues for PY2020 Analysis

In PY2020, all three IOUs made changes to their programs, as discussed in Section 2. These changes did not impact the overall methodology. Our analysis approach incorporated the following changes:

- We included PG&E Residential ex-post and ex-ante impact estimates in the analysis.

¹⁷ "Product" refers to different product offerings within each program. For example, the PG&E Day Ahead program has 3 products offerings: Elect, Elect+, and Prescribed.

¹⁸ "Program" refers to each IOU's notification type by customer class. For example, SDG&E's Non-residential CBP Day Of notification is a program. SCE and SDG&E both have Non-residential Day Ahead and Non-residential Day Of programs, while PG&E has the Day Ahead program for both Residential and Non-residential customers.

¹⁹ Defined as residential v. non-residential.

²⁰ Some sub-categories of data are only available in the confidential versions of the Excel-based Protocol table generators that accompany the confidential reports.

²¹ PG&E and SDG&E has requested a PY2020 back cast as part of the ex-ante impact analysis.

- We added monthly average events to the ex-post analysis. These primarily served as summaries to provide insight into reporting. They did not replace the CPUC LI Protocol requirement, which is the average for the program year.
- We modified assumptions on estimated RA window impacts in the ex-ante analysis. These modifications simulate the shape of the impacts across the 5-hour RA window based on historical events called for longer durations for each IOU and program.

Also, we worked collaboratively with the IOUs to determine the most appropriate approach for addressing COVID-19 effects within the analysis. In this case, because CBP is an aggregator nomination-based program, which often results in dramatic changes in the underlying participant population from year to year, we determined the most appropriate approach was not to make any assumptions or adjustments to reflect COVID-19 conditions.

Report Organization

The remainder of this report is organized into the following sections:

- Section 2 describes the CBP programs as each IOU implements them. The section also presents information regarding the total number of accounts nominated in each program, at each utility, by industry.
- Section 3 describes the methods used to estimate the ex-post and ex-ante impacts for the 2020 program year.
- Section 4 presents the ex-post impact results.
- Section 5 presents the ex-ante impact results.
- Section 6 presents key findings and recommendations.

2

PROGRAM DESCRIPTIONS AND RESOURCES

This section describes the CBP programs as each IOU implements them. We also present information regarding the total number of accounts nominated in each program and at each utility by industry.

Program Description

The Capacity Bidding Program (CBP) is a statewide price-responsive program launched in 2007. It is available at the three IOUs: PG&E, SCE, and SDG&E, although each IOU's program differs slightly in program features and operations.

In CBP, aggregators are entities that contract with eligible residential²² and non-residential utility customers to act on their behalf in all aspects of the demand response program, including the receipt of notices (day-ahead, DA, or day-of, DO) from the utility, the receipt of incentive payments, and the payment of penalties to the utility. Each aggregator forms a portfolio of individual customers who then participate on an aggregate basis to provide load reduction during events. The aggregators enroll participants under the terms of their own contracts to provide the load reduction capacity. The utilities are not directly involved in the contracts between the aggregators and the participating customers. A few customers are enrolled as individual participants in CBP and are classified as self-aggregated. Participating aggregators must have Internet access. Enrolled customers must have a qualifying interval meter and receive Bundled, Direct Access, or Community Choice Aggregation service.²³ Customers enrolled in CBP may participate in another DR program, so long as it is an energy-only program (i.e., cannot have a capacity payment component) and does not have the same notification type (DA or DO).

CBP provides monthly capacity payments (\$/kW) to aggregators based on the nominated kW load, the specific operating month, the event duration, and the event notice option. Delivered capacity determines performance. If a CBP aggregator's delivered capacity is less than 50% for SCE and SDG&E or less than 60% for PG&E, the aggregator is assessed a penalty. If no events are called, CBP aggregators receive the full monthly capacity payment following their nominations, but no energy payments.²⁴ Additional energy payments (\$/kWh) are made to the aggregator²⁵ based on the measured kWh reductions (relative to the program baseline) achieved when an event is called.²⁶

The following describes each IOU's different product offerings in PY2020:

²² Since PY2018, the program was open to residential customer enrollment.

²³ PG&E's partial standby, net-metered, and Automated Demand Response (AutoDR) customers are also eligible.

²⁴ Customers participating directly receive up to 80% of the available capacity payment; aggregators receive 100% of the capacity payment for the load reduction received. Note that all of PG&E and SCE's CBP customers participate through an aggregator.

²⁵ Customers participating directly receive any additional energy payments directly.

²⁶ PG&E and SDG&E's energy payments are made to bundled customers; SCE's energy payment calculation is based upon all types of customers including bundled, DA, and CCA.

PG&E

As of PY2018, PG&E's CBP only offers day-ahead notification. It has three options: Prescribed, Elect, and Elect+. For all three options, aggregators nominate a monthly capacity amount. Under the Prescribed option, PG&E sets the CAISO market bid price and dispatch strategy within specified operating hours (1-4 hours and 2-6 hours). Under the Elect option, aggregators set their own CAISO market bid price within specified operating hours (1-4 hours, 2-6 hours, and 1-8 hours). The Elect+ option is similar to Elect, but an aggregator can participate in additional hours outside the minimum specified operating hours (1-4 hours, 2-6 hours, and 1-24 hours). As of PY2020, PG&E CBP events may only be called between 1 PM to 9 PM. Events are called Monday through Friday, excluding holidays, during May through October, with a maximum of five events and 30 hours per month (or possibly more hours under Elect and Elect+ Options if the participants so choose).

SCE

Effective May 1, 2018, SCE's CBP offers both DA and DO notifications only for 1-6 hour durations. Effective January 19, 2020, the CBP dispatch window was changed to 3 PM to 9 PM to better align with the RA window (4 PM to 9 PM). SCE CBP events may be called Monday through Friday, excluding holidays, year-round, with a maximum of 5 events and 30 hours per month. Like PG&E, SCE CBP events are determined by CAISO market awards.

SDG&E

SDG&E currently offers four CBP products. There are two DA 2-4 hour products, one with operating hours of 11 AM - 7 PM and the other with operating hours of 1 PM - 9 PM. Similarly, there are two DO 2-4 hour products, one with operating hours of 11 AM - 7 PM and the other with operating hours of 1 PM - 9 PM. SDG&E CBP events may be called Monday through Friday, excluding holidays, from May through October, with a maximum of 24 hours per month. Effective May 1, 2019, the maximum number of events called per month is limited to six, with the maximum number of consecutive days called limited to three. Effective in PY2019, SDG&E no longer allows dual DR enrollment in CBP. Customers who were dually enrolled before October 1, 2018, were grandfathered in.

SDG&E has the following program triggers:

- Effective December 15, 2018, Day Ahead Product: SDG&E may call an event whenever the day-ahead market price is equal to or greater than \$80/MWh or as utility system conditions warrant. The day-ahead market price is defined as California Independent System Operator (CAISO) DLAP or applicable pnode SDGE-APND day-ahead market locational marginal price (DAM LMP).
- Effective July 1, 2018, Day Of Product: SDG&E may call an event whenever the forecasted real-time price is equal to or greater than \$95/MWh for Day Of 11 AM to 7 PM; \$110/MWh for Day Of 1 PM to 9 PM or as utility system conditions warrant. Real-time price is defined as the CAISO DLAP or applicable pnode SDGE-APND average hourly real-time market locational marginal price (LMP).

Table 2-1 summarizes the product types for SDG&E.

Table 2-1 SDG&E Product Types

Product	Hours	Minimum Duration per Event	Maximum Duration per Event	Maximum Cumulative Event Duration per Operational Month	Maximum Events per Day	Maximum Events per Month
Day Ahead	11 AM to 7 PM	2 hours	4 hours	24	1	6
2 to 4 hours	1 PM to 9 PM	2 hours	4 hours	24	1	6
Day Of	11 AM to 7 PM	2 hours	4 hours	24	1	6
2 to 4 hours	1 PM to 9 PM	2 hours	4 hours	24	1	6

To characterize the distribution of PY2020 non-residential participation, Table 2-3 presents the number of nominated²⁷ service accounts for each IOU, size group, and industry segment. Since nominations vary by month, we use the number of service accounts nominated at any point in PY2020, i.e., the maximum nomination count. For reference, Table 2-2 presents the eight industry-type definitions and corresponding NAICS codes.

Table 2-2 Non-Residential Industry Type Definitions

Industry Type	NAICS Codes
1. Agriculture, Mining & 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. Institutional/Government	71, 81, 92
8. Other/Unknown	N/A

²⁷ In this report, we refer to the total enrolled customers and their associated impact as the nomination or nominated load. For a specific event, nomination refers to number of customers that were actually called, or dispatched, and the impact that was delivered on a given event. We recognize that this terminology might be confusing and, at PG&E's request, have made a recommendation to clarify definitions and terminology in future reports.

Table 2-3 CBP Non-Residential Nominated Service Accounts, by Utility, Size, and Industry Group, PY2020

Utility	Industry Type	Size			Total
		Below 20 kW	20 kW to 199.99 kW	Above 200 kW	
PG&E	1. Agriculture, Mining & Construction	7	56	39	102
	2. Manufacturing	-	-	7	7
	3. Wholesale, Transport, Other Utilities	6	57	41	104
	4. Retail Stores	56	493	229	778
	5. Offices, Hotels, Finance, Services	6	17	9	32
	6. Schools	-	-	1	1
	7. Institutional/Government	3	32	-	35
	8. Other/Unknown	5	1	-	6
	Total	83	656	326	1,065
SCE	1. Agriculture, Mining & Construction	3	15	4	22
	2. Manufacturing	-	1	6	7
	3. Wholesale, Transport, Other Utilities	5	34	32	71
	4. Retail Stores	40	746	154	940
	5. Offices, Hotels, Finance, Services	2	23	3	28
	6. Schools	-	-	1	1
	7. Institutional/Government	-	2	1	3
	8. Other/Unknown	-	3	-	3
	Total	50	824	201	1,075
SDG&E	1. Agriculture, Mining & Construction	-	2	2	4
	2. Manufacturing	-	-	1	1
	3. Wholesale, Transport, Other Utilities	-	-	-	-
	4. Retail Stores	3	107	63	173
	5. Offices, Hotels, Finance, Services	-	7	7	14
	6. Schools	-	-	-	-
	7. Institutional/Government	-	13	-	13
	8. Other/Unknown	-	-	-	-
	Total	3	129	73	205

Program Changes

This section presents the fundamental changes implemented in PY2020 and planned for future program years.

PG&E

- Effective for the PY2020 season, PG&E removed the 100-kW resource requirement per LSE and the 11 AM to 7 PM dispatch window.
- PG&E had Residential participation in PY2020, which included around 700 customers.
- Effective March 8, 2021, PG&E received approval on the following changes for PY2021:
 - Implement a 5-in-10 baseline option for residential customers.
 - Change the nomination deadline to the 15th of the month before the operating month.
 - Change the bidding deadline for the Elect and Elect+ offering to three days before the trade day.
 - Remove the 100-kW minimum requirement per sub-LAP for resource nomination.
 - Increase the maximum number of events per month from five to six.
- PG&E is also proposing the following changes for PY2021:
 - Decrease the price bid cap for Elect offering, which is currently capped at \$1000.
 - Introduce the option for resources to participate on weekends.

SCE

- Effective January 19, 2020, the CBP dispatch window was changed to 3 PM to 9 PM to better align with the RA window (4 PM to 9 PM).
- SCE proposes that Residential CBP is implemented as a full program with a 5-in-10 baseline.

SDG&E

- SDG&E proposes adding Residential CBP as a pilot program and is looking for approval to implement in PY2021. Due to system limitations, SDG&E will limit the number of residential enrollments

3

STUDY METHODS

This section presents the methods used to estimate the ex-post and ex-ante impacts for CBP, the aggregator-based DR program operated by the three IOUs.

Ex-Post Impact Analysis

The PY2020 ex-post analysis was explicitly designed to meet each of the following goals:

- To develop hourly and daily load impact estimates for each event in the 2020 program year.
- To provide these estimates by various segments: IOU, program, LCA, industry group, Automated Demand Response (AutoDR) and TA&TI participation, CARE participation²⁸, and notification type.
- To estimate the distribution of load impacts by customer segment for the average event.

Because CBP is implemented somewhat differently within each IOU's territory, the ex-post analysis was conducted independently for each IOU to account for those differences in the modeling and analysis. However, the same basic methodology was employed across all three IOUs to balance the consistency of results with modifications to account for differences in implementation and rate design. With the addition of PG&E's Residential participation in PY2020, it is important to highlight the key differences in the approach used for the two customer classes.

The Residential program analysis utilized a matched control group and aggregate hourly regression models. Residential participants do not typically have highly variable loads. Paired with a matched control group approach, this allows for effective use of aggregate models, which have higher statistical power with more customers included in the model. While the models were estimated at the aggregate level, impacts were calculated at the participant level, allowing for ease of aggregation to various segments of interest.

The Non-Residential programs analyses continued to utilize customer-specific hourly regression models. Given the goals of the project and the potential differences across service territories, customer-specific regressions offered the most flexible, consistent, and appropriate solution for several reasons:

- The individual customer impacts can be added together to estimate impacts at any level, including, but not limited to, utility, program, aggregator, LCA, NAICS, or notification type.
- They can be easily used to control for variation in load due to weather conditions, geography, and time-related variables (day of the week, month, hour, etc.).

²⁸ For PG&E Residential participants.

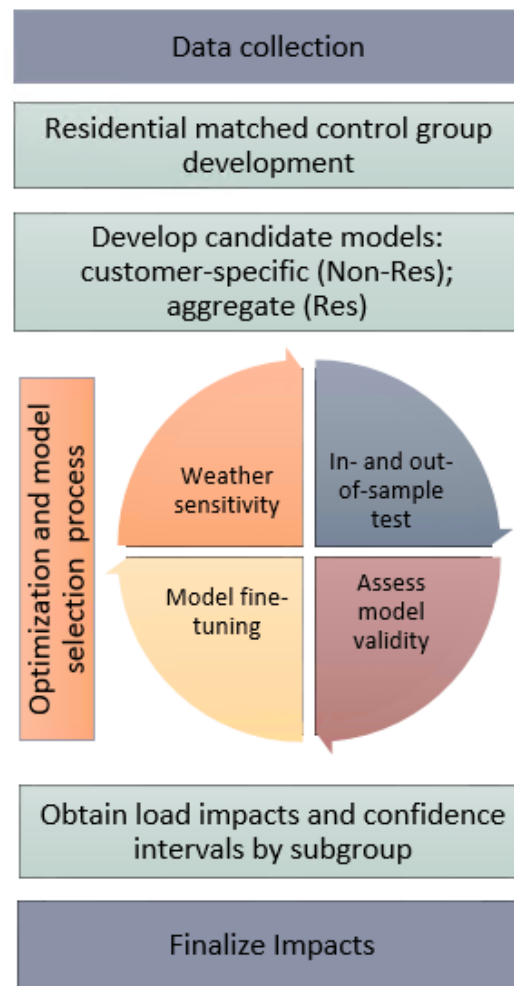
- Because impacts are estimated for each customer separately, they also control for unobservable customer-specific effects that are more difficult to account for in aggregate regression models.
- Commercial and industrial customers often vary significantly from one another in load shape, weather response, and overall size. Customer-specific regressions allow us to capture differences between customers; therefore, they can better model changes in energy usage than an aggregated model.
- Because the events are called only on isolated days over the program year, and on all other days the participants face similar TOU rates, the data conforms to a repeated-measures design. A repeated-measures design means that all participants are subjected to the treatment simultaneously, repeatedly throughout the study. In this case, the control is defined as an absence of the treatment or the non-event days.

It is not practical to develop models individually for thousands of participants; therefore, AEG used a candidate model optimization process to select the best model for each participant. Figure 3-1 illustrates a high-level overview of the approach AEG used to develop ex-post impacts, as applicable. For example, the matched control group development was only utilized in the Residential analysis. The following subsections describe the analysis process in more detail.

Data Collection and Validation

AEG constructed an extensive database of different types of utility information, including, but not limited to, interval usage data, weather data, DR event data, notification data, aggregator nomination data, and settlement data. We then checked and validated all the interval data using algorithms we have developed and enhanced over time. Our validation process included carefully checking the interval data for zero intervals, missing intervals, peaks, valleys, and erroneous intervals. Using our experience working with C&I usage data, we established rules to omit intervals from the analysis. We excluded all event days from the omission rules since event days are inherently different from a customer's normal usage and are more likely to be flagged for omission.

Figure 3-1 Ex-Post Analysis Approach



With the addition of Residential participants in PY2020, AEG adjusted the omission rules for the residential participants since zero intervals in residential is more likely to indicate missing data or power outages.

Event-like Days Selection

The selection of comparable non-event days, or event-like days, is essential to several evaluation activities. Event-like days were used in the Residential analysis's matched control group development and the out-of-sample testing in model optimization.

The event-like days included 5 to 15 days comparable to called event days in weather, day of the week, and month of the year. We used a Euclidean distance metric²⁹ (similar to what we describe in matched control group development) to select days that are as similar as possible to actual event days using multiple weather-based criteria.

Residential Matched Control Group Development

To create the matched control group in the PG&E Residential analysis, we used a Stratified Euclidean Distance Matching (SEDM) technique. The basic steps were as follows:

Step 1 is to define both the participant and non-participant populations and the treatment and pre-treatment periods for each participant. Once the participant and non-participant populations are identified, both populations can be assigned to strata or filters that are categorical in nature. For PG&E Residential participants, we used CARE-status, net metering status, and LCA as key filters. This ensured that customers with similar usage characteristics were matched to one another, capturing some of the unobservable attributes that affect the way customers use energy.

Step 2 is to perform the one-to-one match based on hourly demand data of comparable event-like days. To determine how close each participant is to a potential match, we used a Euclidean distance metric. The Euclidean distance is defined as the square root of the sum of the squared differences between the matching variables. Any number of relevant variables could be included in the Euclidean distance. For this one-to-one match, we included three demand variables:

- The average demand on event-like days during the event window,
- The demand on event-like days during the typical system peak hour (HE18),
- And the average demand on event-like days during the hours outside the event window.

We then weighted the variables to reflect the relative importance of the estimates, with typical system peak hour having the most weight and the average demand outside the typical event window having the least weight. The Euclidean distance for this set of variables can be calculated using the equation below.

²⁹ We included three weather variables in the Euclidean distance metrics calculation to select similar non-event days: (1) daily maximum temperature; (2) daily minimum temperatures; and (3) average daily temperature. We will work with each IOU to determine which weather variables are best suited for selecting days that are most similar to event days. In PY2019, the Euclidean distance metric used was calculated by the following equation:

$$ED = \sqrt{(MaxTemp_{event} - MaxTemp_{non-event})^2 + (MinTemp_{event} - MinTemp_{non-event})^2 + (MeanTemp_{event} - MeanTemp_{non-event})^2}$$

$$ED = \sqrt{w_1(avgevent_{Ti} - avgevent_{Ci})^2 + w_2(systempeak_{Ti} - systempeak_{Ci})^2 + w_3(avgnonevent_{Ti} - avgnonevent_{Ci})^2}$$

After calculating the distance metric within each group for each possible combination of participant and control customer, the control customer with the smallest distance is matched to each participant without replacement. We can then select the closest matches³⁰ for each of our participants, creating a one-to-one match of control customers to participants. Once the matching process is complete, we validate the match by using the appropriate t-tests and visual inspection of the event-like day load shapes.

Develop Candidate Regression Models

After collecting the data required for the evaluation, the next step was to develop a set of candidate models. We developed a set of candidate models for both residential and non-residential participants based on our knowledge and experience working with both customer classes and our modeling approach for both customer classes, i.e., aggregate models for residential participants and customer-specific models for non-residential participants.

In general, we think of regression models as being made up of building blocks, which are in turn made up of one or more explanatory variables. These different sets of variables can be combined in different ways to represent different types of customers. The blocks can be generally categorized into either “baseline” variables or “impact” variables and could be made up of a single variable (e.g., cooling degree hours, CDH) or a group of variables (e.g., days of the week). The baseline portion of the model explains variation in usage unrelated to DR events, while the impact portion explains the variation in usage related to a DR event.³¹ Table 3-1 presents the different explanatory variables used to create candidate models for the CBP participants.

³⁰ The closest match is defined by a control customer with an ED with the smallest distance to a participant’s ED. If two or more participants share the same closest match, the participant that is “worst off” will “win” its closest match. This is determined by checking the ED’s for the second closest matches for each participant.

³¹ Any unexplained variation will end up in the error term.

Table 3-1 Explanatory Variables Included in Candidate Regression Models

Variable Name	Variable Description
Baseline Variables	
Weather _{i,d}	Weather-related variables including average daily temperature, cooling degree hour (CDH) terms with base value of 70, heating degree hour (HDH) with base value of 60, and lagged versions of various weather-related variables
Month _{i,d}	A series of indicator variables for each month
DayOfWeek _{i,d}	A series of indicator variables for each day of the week
OtherEvt _{i,d}	Equals one on event days of other demand response programs in which the customer is enrolled
AvgLoad _{i,d}	The average of each day's load in specified window ³²
Impact Variables	
P _{i,d}	An indicator variable for aggregator program event days
P * Month _{i,d}	An indicator variable for aggregator program event days interacted with the month
P*EventHour _{i,d}	An indicator variable for aggregator program event days interacted with an indicator for the hour the event is called
P*EventWindow _{i,d}	An indicator variable for aggregator program event days interacted with an indicator for the window the event is called

With the different variables presented above, sets of candidate models were created that represent a wide variety of customers and their impacts. Each IOU has customized sets of candidate models, but in general, the candidate models fit into two basic categories:

- Weather-sensitive models include weather effects and calendar effects. These models are less likely to require a load adjustment since much of the day-to-day variation in load is captured by weather terms.
- Non-weather sensitive models include the load adjustment and calendar effects.

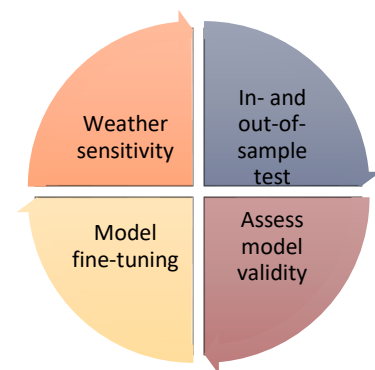
Optimization and Model Selection Process

Our optimization process incorporates the validation of the hourly regression models. The hourly regression models are designed to:

- Accurately predict the actual participant load on event days, and
- Accurately predict the reference load, or what participants would have used on event days in the absence of an event.

To meet these two specific goals, our optimization process included a four-part cycle consisting of the following steps:

Figure 3-2 Optimization Process



³² The specified window can be one or more of the following: 4AM – 10 AM; 10 AM – 1 PM; 10 AM – 2 PM; 10 PM – 12 AM.

(1) assessing weather sensitivity; (2) in-sample and out-of-sample testing; (3) assessing model validity; and, (4) model fine-tuning.

1. **Assess Weather Sensitivity.** To increase efficiency in the model selection process, we first evaluated weather sensitivity by performing p-value tests on coefficient estimates on weather variables. This test determined if each customer/subgroup will optimize using weather-sensitive or non-weather-sensitive models. The initial step of assigning customers to one of these two groups streamlines the model optimization process by limiting the number of candidate models each customer is exposed to. Note that this step was not performed in the residential analysis, and we assumed that residential usage is weather-sensitive, on average.
2. **In-Sample and Out-of-Sample Testing.** We used in-sample tests to show how well each model performs on the actual event days. We used out-of-sample tests to show how well each of the candidate models could predict a customer's/subgroup's load on non-event days that were as similar as possible to actual event days. The in-sample test measures a candidate model's ability to estimate the event-day impacts, and the out-of-sample test measures a candidate model's ability to estimate the reference load.
 - To perform the in-sample test, we fitted each candidate model to the entire data set. The results of these fitted models are used to predict the usage on event days. Then we assessed the accuracy and bias of the predictions by calculating the mean absolute percent error (MAPE)³³ and mean percent error (MPE)³⁴, respectively. We refer to these metrics as the in-sample MAPE and MPE.
 - To perform the out-of-sample test, we first identified the out-of-sample event-like days as several days that are similar to event days. For efficiency and consistency, we used the same event-like days used in matched control group development. After identifying the event-like days, event-like days are removed from the analysis dataset, and the candidate models are fitted to the remaining data. Lastly, we assessed the accuracy and bias of the predictions by calculating the MAPE and MPE, respectively. Similarly, we refer to these metrics as the out-of-sample MAPE and MPE.

These two tests resulted in several in-sample and out-of-sample metrics. Recall that the goal of the tests is to find the best model for each customer/subgroup in terms of its ability to predict the reference load and the actual load for each subgroup. Therefore, for each customer/subgroup, we combined the two tests into a single metric, giving each candidate model a single metric. The metric is defined as follows:

$$\mathbf{metric}_{ic} = (0.4 * MAPE_{in}) + (0.4 * MAPE_{out}) + (0.1 * abs(MPE_{in})) + (0.1 * abs(MPE_{out}))$$

Once we have a single metric for each customer/subgroup and candidate model combination, we selected the best model for each customer/subgroup by choosing the model specification with the smallest overall metric.

³³ The mean absolute percent error (MAPE) is defined as: $MAPE = \frac{100\%}{n} \sum_{h=1}^n \left| \frac{Actual_h - Estimate_h}{Actual_h} \right|$

³⁴ The mean percent error (MPE) is defined as: $MPE = \frac{100\%}{n} \sum_{h=1}^n \frac{Actual_h - Estimate_h}{Actual_h}$

3. **Assessing Model Validity.** After selecting the best model for each subgroup by minimizing the smallest overall metric, AEG assessed model validity at the program level. We did this by calculating the weighted average MAPE and MPE at the program level. For both metrics, we like them to be low or very close to zero to be able to say that all the customer/subgroup best models collectively deliver good levels of accuracy and bias. We describe the steps in more detail and go over program metrics in the model validity subsection (see Appendix B).
4. **Model Fine-Tuning.** We also routinely use visual inspection of the results as a simple but highly effective tool. We looked for specific aspects of the segment-level predicted and reference load shapes to determine how well the models perform during the inspection. We used observations derived from these inspections to make necessary edits to the model specifications obtained from the optimization process. For example:
 - We checked to ensure that the reference load is closely aligned with the actual and predicted loads during the early morning and late evening hours when there is likely to be little effect from the event. Large differences can indicate that there is a problem with the reference load over or underestimating usage in the absence of the program.
 - We closely examined the reference load for odd increases or decreases that could indicate an effect that is not properly being captured in the model.
 - We also looked for bias both visually and mathematically. Identification of bias and its source often allows us to adjust the models to capture and isolate the bias-inducing effects within the model specification.

Obtain Load Impacts and Confidence Intervals by Subgroup

After developing a set of candidate models, a single “best” model was selected for each customer/subgroup.

Below are examples of two final models, one for a weather-sensitive customer and one for a non-weather-sensitive customer. For both types of models, the model specification is identical for each hour of the day.

Simple weather-sensitive example:

$$kwh_{i,d} = \alpha_{i,d} + Month_{i,d} + Weather_{i,d} + P_{i,d} + (P_{i,d} * Month_{i,d}) + (P_{i,d} * EventHour_{i,d}) + \varepsilon_{i,d} \quad (3.1)$$

where:

$kwh_{i,d}$ is the customer’s consumption in hour i on day d .

$\alpha_{i,d}$ is the intercept.

$\varepsilon_{i,d}$ is the error for participant in hour i on day d .

and, all other terms are defined in Table 3-1 above.

Simple non-weather-sensitive example:

$$kwh_{i,d} = \alpha_{i,d} + MornLoad_{i,d} + DayofWeek_{i,d} + P_{i,d} + \varepsilon_{i,d} \quad (3.2)$$

where:

$kwh_{i,d}$ is the customer's consumption in hour i on day d .

$\alpha_{i,d}$ is the intercept.

$\varepsilon_{i,d}$ is the error for participant in hour i on day d .

and, all other terms are defined in Table 3-1 above.

After the "best" model was selected for each customer, we calculate the customer-specific impact as follows:

- We obtained the actual and predicted load on each hour and day based on each customer's best model specification.
- We used the estimated coefficients and the baseline portion of the model to predict what this customer would have used each day and hour if there had been no events. We call this prediction the reference load.
- We calculated the difference between the reference load (the estimate based on the baseline variables) and the predicted load (the estimate based on the baseline + impacts variables) on each event day. This difference represents our estimated load impact.
- To show the actual observed load (and avoid confusion associated with the predicted load), we re-estimated the reference load as the sum of the observed load and the load impact.

Aggregation of Impacts

Because we estimated an impact for each customer, the model results are easily aggregated to represent impacts of the required subpopulations of participants for the three IOUs. In some cases, we needed to apply average per-customer impacts as a proxy for the "actual" impacts realized by one or more customers on a given event day because part of their data was missing. In these cases, we determined the aggregate impact for a particular grouping based on the per-customer average of the customers with valid data in the grouping and the total nominated accounts associated with that grouping for the given event.

It is important to note that the per-customer average may differ depending on the group or subgroup because of the different types and sizes of customers in the grouping. Therefore, during events where average per-customer data was used as a proxy for one or more customers, the sum of the individual subgroup totals may not exactly add up to the total for the larger groupings or populations of customers.

Consider the following hypothetical example:

- Subgroup #1 in Product A:
 - 24 nominated customers
 - 23 with sufficient valid data to estimate impacts
 - Aggregate impact for 23 customers = 2,300 kW

- Average per-customer impact for the subgroup would be calculated with the aggregated data for the 23 customers: $2,300 \text{ kW} / 23 \text{ customers} = 100 \text{ kW per customer}$
- Aggregate impact for all 24 nominated customers: $100 \text{ kW/customer} \times 24 \text{ customers} = 2,400 \text{ kW}$
- Subgroup #2 in Product A:
 - 76 nominated customers, all with sufficient valid data to estimate impacts
 - Aggregate impact for 76 customers: 6,460 kW
 - Average per-customer impact: $6,460 \text{ kW} / 76 \text{ customers} = 85 \text{ kW per customer}$
- Total for Product A:
 - 100 nominated customers
 - 99 with sufficient valid data to estimate impacts
 - Aggregate impact for 99 customers = $2,300 \text{ kW} + 6,460 \text{ kW} = 8,760 \text{ kW}$
 - Average per-customer impact for the subgroup would be calculated with the aggregated data for the 99 customers: $8,760 \text{ kW} / 99 \text{ customers} = 88.48 \text{ kW per customer}$
 - Aggregate for all 100 nominated customers: $88.48 \text{ kW/customer} \times 100 \text{ customers} = 8,848 \text{ kW}$
- Sum of Subgroup #1 plus Subgroup #2 = $2,400 \text{ kW} + 6,460 \text{ kW} = 8,860 \text{ kW}$, which does not equal the Total for Product A of 8,848 kW

Uncertainty

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

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 MS Excel-based Protocol table generator), we estimated the standard error of the average event hour using the standard errors associated with each impact estimate within the entire event window. This is a more straightforward approach compared to what we've done in past evaluations. Although it is a more conservative estimate since it does not allow us to consider the covariances between the event hours, a comparison of the results from the two methodologies shows that the differences are not

substantial. We first employed this approach in PY2018 and recommended the use of this more straightforward approach in future evaluations.

Calculating Impacts for an Average Event Day

We defined the average event day consistently across the three IOUs. We defined the average event day as the average of all events called regardless of nomination count or Sub-LAP count for each product and subgroup. If multiple event windows were called on the same day, the multiple event windows are combined to give each event day equal weight. The average event day is calculated using aggregate-level results. The accompanying nomination count is calculated as a simple average of the nominated counts of each event day. This is done at the product level.

For combined products (e.g., PG&E DA is a combination of Elect DA and Prescribed DA), the average event day aggregate-level results and nominated counts are summed. The corresponding per-participant impacts are calculated from the summed values.

As in previous years, different service accounts were nominated for each event; therefore, the average is necessarily made up of different customer groups across different days. These differences in customer groups can prove problematic when attempting to sum average impacts and customer counts across the multiple combinations of subgroups presented as part of this analysis. The approach we used to determine the average involved taking the average of each subgroup's aggregate impact. Another option would be to create the averages first at the lowest level of disaggregation and then sum them to the desired aggregation level. Though both approaches are equally valid, they often result in slightly different values. Therefore, when viewing the average event day impact results in Chapter 4, one may notice that the sum of the subgroup level impacts does not always equal the program level impacts.

Estimating Incremental Impacts for Technology-Enabled Participants

AEG did not perform this analysis this year. In previous program years, only SDG&E's AutoDR and TA/TI participants have shown statistically significant incremental impacts. In PY2020, SDG&E did not have CBP participants that are also enrolled in AutoDR or TA/TI.

Ex-Ante Impact Analysis

The ex-ante analysis's primary goal is to produce an annual 11-year³⁵ forecast (2021 through 2031) of the load impacts expected from the CBP programs.

We developed the ex-ante forecasts using the following general steps:

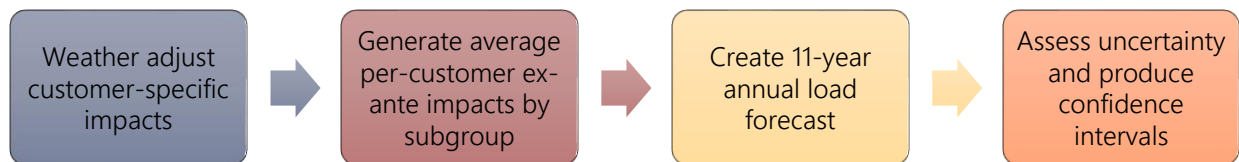
- AEG first provided the IOUs with the appropriate weather-adjusted, per-customer impacts for each subgroup.
- The IOUs used the per-customer impacts, along with contractual MW agreements and adjustments based on historical load reduction performance and/or the latest development of the program, to determine the enrollment forecasts.

³⁵ PG&E and SDG&E has requested a PY2020 back cast as part of the ex-ante impact analysis.

- AEG then used the enrollment forecasts and the per-customer ex-ante impacts to develop the 11-year annual load impact forecasts for the participant populations and subgroups.

Figure 3-3 provides an overview of the ex-ante analysis approach, which includes four primary steps after assembling the required data: 1) prediction of weather-adjusted impacts for each customer; 2) generation of per-customer average impacts by subgroup; 3) creation of annual load impact forecasts over the next 11 years; and 4) an assessment of uncertainty and the development of confidence intervals.

Figure 3-3 Ex-Ante Analysis Approach



Weather-Adjusted Impacts for Each Customer

The first step in the ex-ante analysis is to use the customer-specific regression models to predict weather-adjusted, per-customer average impacts for each IOU and each of the appropriate subgroups. This step produced a set of impacts under each of the different weather scenarios (monthly peak day and typical event day for 1-in-2 weather year and 1-in-10 weather year for each of the three IOUs and CAISO). It is important to note that the CBP impacts are inherently nomination-driven, not weather-responsive. As a result, per-customer kW impacts estimated are the same across all weather scenarios. However, since some customer the reference loads are weather-sensitive, percent impacts will vary across the weather scenarios.

To estimate weather-adjusted impacts, we carried out the following steps:

1. We began with the coefficients estimated in the customer-specific regression models developed for the ex-post analysis for each customer.
2. Then, we replaced the actual weather, from the program year, with the 1-in-2 and 1-in-10 weather data to predict a customer's load for each scenario, assuming no events are called. The result is a weather-adjusted reference load for each customer for each weather scenario required.
3. Next, we determined the most prevalent event hour called for each customer. In PY2020, this varied³⁶ for all three IOUs. Using the regression model of the selected hour, we estimated the non-weather dependent load impact using a linear combination of the coefficients of the impact variables.

³⁶ PG&E and SDG&E used HE19. SCE used HE18 and HE20 for non-summer and summer estimates, respectively.

4. We then develop the shape of the impacts across the 5-hour window based on historical events called for longer durations for each IOU and program. We express the shape as the percent of the maximum impact in each subsequent event hour.
5. We applied this event shape to the impacts estimated in step 3 to develop a load impact estimate for all hours of the Resource Adequacy window, which is HE17 through HE21 year-round as of PY2020.³⁷
6. Finally, we calculated the predicted load for each scenario by adding the estimated load impact to the weather-adjusted reference load.

In Table 3-2 below, we present an example of the impact degradation shape for SCE's DA and DO programs in both summer and non-summer seasons.

Table 3-2 Example: SCE Ex-Ante impact Degradation Shape by Product

Program	Season	Percent of Maximum Impact				
		HE17	HE18	HE19	HE20	HE21
Day Ahead	Non-Summer	86%	100%	72%	44%	16%
	Summer	100%	79%	61%	58%	48%
Day Of	Non-Summer	100%	90%	34%	75%	19%
	Summer	100%	71%	57%	41%	50%

Generation of Per-Customer Average Impacts by Subgroup

Once weather-adjusted impacts have been predicted for each customer for each of the desired day types, we average the individual impacts and generate per-customer average impacts by subgroup. For example, the average impact for a particular LCA is the average of the impacts predicted for each customer in that LCA. At this stage, we also worked with the IOUs to determine the best way to account for participation between notification types to ensure that they are not double-counted in the per-customer averages.

Since CBP is a capacity-payment program, the IOUs allocate to CBP the full load impacts from CBP participants dually enrolled in other DR or energy-payment programs. The CBP impacts do not require adjustments to account for dual participation in other programs.

Creation of 11-Year Annual Load Impact Forecasts

AEG provided the IOUs with the per-customer average ex-ante impacts by year and subgroup. The IOUs used the per-customer impacts—along with contractual MW adjusted by historical performance relative to the aggregator's MW nomination and/or anticipated program changes—to determine the enrollment forecasts. AEG used the current PY2020 enrollment to create weather-adjusted impacts for PY2020³⁸ and the PY2021-PY2031 enrollment forecasts to create the annual forecast of load impacts over the next 11 years.

³⁷ IOU-specific adjustments to the assumptions will be discussed in Section 5, alongside the ex-ante results.

³⁸ The PY2020 back cast requested by PG&E and SDG&E.

Uncertainty Estimates and Confidence Intervals

Confidence intervals are provided for each hour as well as for an average event hour. Uncertainty in the ex-ante forecasts comes from modeling error, both from the customer-specific regressions and from the weather adjustment to the 1-in-2 and 1-in-10 weather years. Though there is also error in the enrollment forecast, the confidence intervals do not include the enrollment forecast uncertainty.

4

EX-POST RESULTS

This section presents the PY2020 ex-post impacts for each program, and by segment, for CBP, the aggregator-based DR program operated by the three IOUs.

Overview of Results

In 2020, all three IOUs offered CBP Day Ahead (DA) products. SCE and SDG&E offered CBP Day Of (DO) products. Table 4-1 presents the PY2020 average summer event day impacts by product offering and IOU, both at the per-customer level and in aggregate.

Table 4-1 Statewide CBP Impacts Summary, Average Summer Event Day PY2020

Utility	Product	Accounts	Nominated Capacity (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)	
				Reference Load	Impact	Reference Load	Impact
PG&E	Residential DA	■	■	■	■	■	■
	Non-Residential DA	531	15.6	120.5	18.9	64.1	10.0
SCE	Day Ahead	387	6.0	90.7	10.1	35.1	3.9
	Day Of	■	■	■	■	■	■
SDG&E	Day Ahead	23	0.6	121.3	18.0	2.8	0.4
	Day Of	158	2.9	115.4	13.8	18.3	2.2

Note that the average event day is calculated using all events regardless of participant count and event timing. For PG&E and SDG&E, the results shown are for the joint event hour HE19 or 6 PM – 7 PM, which is the hour wherein all events overlap. For SCE, the joint event hour is HE20 or 7 PM – 8 PM. In the next sections, we present total enrollment and participation in each event to show the distribution of events represented by the averages shown above.

PG&E

Events for PG&E

We present a summary of the 2020 events for PG&E's CBP program by product offering: Elect DA³⁹ (Residential and Non-Residential) and Prescribed DA (Non-Residential). The Elect DA Residential participants experienced 21 event days and were nominated to participate in one product: Elect DA 1-4 Hour. The Elect DA Non-Residential participants experienced 15 event days and were nominated to participate in two products: Elect DA 1-4 Hour and Elect DA 2-6 Hour. The Prescribed DA participants experienced a total of 17 event days, participating only in one product: Prescribed DA 1-4 Hour.

³⁹ Note that no aggregators chose to participate in the Elect+ product offering in PY2020.

In PY2020, most events were localized, meaning that most events were called for only some Sub-LAPs. Table 4-3 below shows the number of Sub-LAPs, the event windows called, and the number of accounts nominated⁴⁰ on each event day. For reference, Table 4-2 presents the total monthly enrollment for the DA program, which would be comparable to participation counts of a system-level event. As mentioned earlier, the average event day is defined as the average of all events called in PY2020 regardless of event window and number of Sub-LAPs called. We present impacts for the average event day on the joint event hour, HE19, which is the hour when all event windows overlap.

Table 4-2 PG&E Day Ahead Monthly Enrollment and MW Nominations

Month	Residential DA		Non-Residential DA	
	Enrolled Accounts	Nominated Capacity (MW)	Enrolled Accounts	Nominated Capacity (MW)
May	0	0.0	817	23.3
June	672	■	846	30.3
July	679	■	998	42.1
August	676	■	1,029	43.9
September	575	■	979	40.6
October	675	■	807	18.8
Average Summer	563	■	913	33.2

Table 4-3 PG&E Event Summary

Date	Day of Week	# of Sub-LAPs	Event Hours (HE)	# Accounts		
				Elect DA (Res)	Elect DA (Non-Res)	Prescribed DA (Non-Res)
Avg. Event	-	14	19	623	525	7
Jun 3, 2020	Wednesday	3	18-20, 20-20	672	20	-
Jul 13, 2020	Monday	1	21-21	-	7	-
Jul 28, 2020	Tuesday	2	20-20	-	-	9
Jul 29, 2020	Wednesday	3	19-20, 20-20	679	-	9
Jul 30, 2020	Thursday	10	19-20, 20-20	-	595	9
Jul 31, 2020	Friday	5	19-20, 20-20	679	337	-
Aug 11, 2020	Tuesday	1	20-20	213	-	-
Aug 13, 2020	Thursday	3	19-20	676	-	9
Aug 14, 2020	Friday	13	18-21, 19-20	676	825	9

⁴⁰ Recall that the number of nominated customers on a given event can be, and often is, different than the total number of customers nominated in a given month or season. The number of customers nominated for each event represents only those dispatched and the kW impact is the delivered load.

Date	Day of Week	# of Sub-LAPs	Event Hours (HE)	# Accounts		
				Elect DA (Res)	Elect DA (Non-Res)	Prescribed DA (Non-Res)
Aug 17, 2020	Monday	14	18-20, 18-21, 19-20	676	832	9
Aug 18, 2020	Tuesday	11	17-20, 18-19, 18-20, 18-21, 19-19	676	718	9
Aug 19, 2020	Wednesday	13	19-19, 19-20	676	920	9
Aug 20, 2020	Thursday	1	19-19	463	-	-
Aug 24, 2020	Monday	2	19-19	676	-	-
Aug 25, 2020	Tuesday	2	19-20	676	-	-
Sep 8, 2020	Tuesday	6	19-19, 19-20	676	233	8
Sep 9, 2020	Wednesday	3	19-19	676	-	8
Sep 14, 2020	Monday	1	15-15	-	7	-
Sep 28, 2020	Monday	2	18-20, 19-19	463	-	8
Sep 29, 2020	Tuesday	3	18-20	676	-	8
Sep 30, 2020	Wednesday	14	17-20, 18-19, 19-19	676	963	8
Oct 1, 2020	Thursday	13	17-20, 18-19, 19-19	675	707	-
Oct 13, 2020	Tuesday	3	19-19	675	-	1
Oct 14, 2020	Wednesday	3	18-19, 19-19	675	-	1
Oct 15, 2020	Thursday	11	18-18, 18-19	675	612	1
Oct 16, 2020	Friday	14	18-19, 19-19	-	714	-
Oct 20, 2020	Tuesday	1	18-18	-	-	1
Oct 21, 2020	Wednesday	2	19-19	-	9	-

Summary Load Impacts

Table 4-4 shows the average summer event day impacts for Elect DA, Prescribed DA, and overall CBP, both at the per-customer level and aggregate. Table 4-5 shows the average monthly and overall program performance by customer class, including the percent of delivered nominations. On average, none of the product offerings performed well, with participants failing to meet their nominated capacity. We discuss this in more detail below.

Table 4-4 PG&E Non-Residential Impacts Summary, Average Event Day PY2020

Product	Accounts	Nominated Capacity (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact
			Reference Load	Impact	Reference Load	Impact	
Elect DA 1-4 Hour	483	14.5	127.5	20.3	61.6	9.8	16%
Elect DA 2-6 Hour	41	■	■	■	■	■	■
All Non-Residential Elect	525	15.2	120.5	18.9	63.2	9.9	16%
Prescribed DA 1-4 Hour	7	■	■	■	■	■	■
All Non-Residential CBP	531	15.6	120.5	18.9	64.1	10.0	16%

Table 4-5 PG&E Impacts Summary, Monthly Performance

Month	Residential DA				Non-Residential DA			
	Nominated Accounts	Nominated Capacity (MW)	Aggregate Impact (MW)	% Delivered	Nominated Accounts	Nominated Capacity (MW)	Aggregate Impact (MW)	% Delivered
May	-	-	-	-	-	-	-	-
June*	664	■	■	■	20	■	■	103%
July*	671	■	■	■	326	13.8	11.3	81%
August	592	■	■	■	833	24.6	19.1	78%
September	622	■	■	■	445	17.1	11.3	66%
October	662	■	■	■	512	9.4	7.9	83%
Overall	623	■	■	■	531	15.6	10.0	64%

*Results show HE20 instead of HE19

The overall aggregate impact for the non-residential CBP participants was 10.0 MW in PY2020, which fell short of its nominated capacity by 5.6 MW or 36%. This shortfall is similar across all products. Interestingly, while the products fell short of their nominations on a typical day, on some individual event days (presented in subsequent tables), they were able to successfully meet nominations. The majority of the overall impacts are concentrated in the Elect DA 1-4 product with 9.8 out of 10 MW and 483 out of 531 participants.

In PY2020, only one aggregator participated in PG&E's Residential CBP. Thus, all CBP Residential impacts are marked confidential.

Comparison of Ex-Post Impacts

Table 4-6 and Table 4-7 present the comparison of current ex-post impacts to previous ex-post impacts and current ex-post impacts to prior ex-ante impacts, respectively. These comparisons give the reader a sense of how the program has performed over time and how the program has performed relative to the most recent forecast.

Table 4-6 PG&E: Current Ex-Post v. Previous Ex-Post, Average Event Day

Customer Class	Year	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Residential	2018	-	-	-	-	-	-	-
	2019	-	-	-	-	-	-	-
	2020	623	■	■	■	■	■	86
Non-Residential	2018	197	350.7	44.8	69.1	8.8	13%	77
	2019	241	312.6	40.8	75.3	9.8	13%	85
	2020	531	120.5	18.9	64.1	10.0	16%	85

Table 4-6 above presents the ex-post impacts over time. PG&E's non-residential program has increased in participants, total impacts, and percent impacts over the past three years. However, average customer size and per customer impact has fallen over the same time by more than 60%. These changes represent a shift in the type and quantity of customers that are participating in the program to a higher number of smaller, more responsive customers.

In Table 4-7 below, we present the PY2020 ex-post impacts compared to PY2019 ex-ante impacts. Non-residential participants' ex-post impacts were also significantly lower. However, in this case, lower than expected enrollment was the main driver of differences.

Table 4-7 PG&E Current Ex-Post (Average Event Day) v. Prior Ex-Ante (PG&E 1-in-2, Typical Event Day, 2020)

Customer Class	Estimate	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Residential	PY2019 Ex-Ante	5,000	-	0.4	-	2.0	-	-
	Current Ex-Post	623	■	■	■	■	■	86
Non-Residential	PY2019 Ex-Ante	1,503	190.9	24.0	286.9	36.0	13%	89
	Current Ex-Post	531	120.5	18.9	64.1	10.0	16%	85

Impacts by Event Day

Table 4-8 through Table 4-10 present the average event hour impacts for the Elect DA and Prescribed DA participants, respectively. The impacts are presented both at the average per-customer level and in aggregate. For event days with multiple event windows, the values shown in this table represent the average event hour using only the hours that the multiple event windows have in common.

Table 4-8 PG&E Residential Elect Day Ahead: Impacts by Event

Event	# of Accts	Nominated Capacity (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Avg. Event	623							86
Jun 3, 2020	664							89
Jul 29, 2020	671							77
Jul 31, 2020	671							76
Aug 11, 2020	209							85
Aug 13, 2020	666							93
Aug 14, 2020	666							99
Aug 17, 2020	666							86
Aug 18, 2020	666							93
Aug 19, 2020	666							88
Aug 20, 2020	457							79
Aug 24, 2020	666							84
Aug 25, 2020	666							81
Sep 8, 2020	664							82
Sep 9, 2020	664							70
Sep 28, 2020	455							90
Sep 29, 2020	663							81
Sep 30, 2020	662							90
Oct 1, 2020	659							90
Oct 13, 2020	662							83
Oct 14, 2020	663							87
Oct 15, 2020	663							90

Table 4-9 PG&E Non-Residential Elect Day Ahead: Impacts by Event

Event	# of Accts	Nominated Capacity (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Avg. Event	525	14.8	120.5	18.9	63.2	9.9	16%	85
Jun 3, 2020	20							62
Jul 13, 2020	7							60
Jul 30, 2020	595	17.6	121.7	16.1	72.4	9.6	13%	79
Jul 31, 2020	337	22.1	127.5	71.4	43.0	24.1	56%	96
Aug 14, 2020	825	22.9	126.3	20.4	104.2	16.8	16%	98
Aug 17, 2020	832	23.1	124.0	18.9	103.2	15.7	15%	89

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Event	# of Accts	Nominated Capacity (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Aug 18, 2020	718	18.1	131.1	18.2	94.1	13.1	14%	95
Aug 19, 2020	920	32.4	123.7	31.9	113.8	29.3	26%	90
Sep 8, 2020	233	■	■	■	■	■	■	77
Sep 14, 2020	7	■	■	■	■	■	■	68
Sep 30, 2020	963	40.1	124.9	28.6	120.3	27.6	23%	88
Oct 1, 2020	707	■	■	■	■	■	■	89
Oct 15, 2020	612	■	■	■	■	■	■	90
Oct 16, 2020	714	■	■	■	■	■	■	86
Oct 21, 2020	9	■	■	■	■	■	■	81

In PY2020, the Elect DA product offering called several localized events and several system events in August and September. Elect DA did not meet or exceed the nominated capacity on average. The residential participants did not meet the nominated capacity for any events, while non-residential participants called to respond to events were able to do so for only 2 out of 15 events.

Table 4-10 PG&E Prescribed Day Ahead: Impacts by Event

Event	# of Accts	Nominated Capacity (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Avg. Event	7	■	■	■	■	■	■	82
Jul 28, 2020	9	■	■	■	■	■	■	72
Jul 29, 2020	9	■	■	■	■	■	■	72
Jul 30, 2020	9	■	■	■	■	■	■	71
Aug 13, 2020	9	■	■	■	■	■	■	88
Aug 14, 2020	9	■	■	■	■	■	■	97
Aug 17, 2020	9	■	■	■	■	■	■	80
Aug 18, 2020	9	■	■	■	■	■	■	88
Aug 19, 2020	9	■	■	■	■	■	■	83
Sep 8, 2020	8	■	■	■	■	■	■	75
Sep 9, 2020	8	■	■	■	■	■	■	64
Sep 28, 2020	8	■	■	■	■	■	■	91
Sep 29, 2020	8	■	■	■	■	■	■	73
Sep 30, 2020	8	■	■	■	■	■	■	83
Oct 13, 2020	1	■	■	■	■	■	■	81
Oct 14, 2020	1	■	■	■	■	■	■	85
Oct 15, 2020	1	■	■	■	■	■	■	91
Oct 20, 2020	1	■	■	■	■	■	■	81

Table 4-11 and Table 4-12 present the impacts for an average event day by Industry and Local Capacity Area (LCA).⁴¹

Table 4-11 PG&E Impacts by Industry and Product Offering, Non-Residential

Industry		# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Ref. Load	Impact	Ref. Load	Impact		
Elect DA	Agriculture, Mining & Construction	25	186.9	122.2	4.7	3.1	65%	96
	Manufacturing	3	■	■	■	■	■	90
	Wholesale, Transport, other utilities	23	139.4	81.4	3.2	1.9	58%	94
	Retail stores	447	■	■	■	■	■	84
	Offices, Hotels, Finance, Services	17	148.5	4.7	2.5	0.1	3%	83
	Schools	1	■	■	■	■	■	77
	Institutional/Government	26	■	■	■	■	■	92
	Other or unknown	5	■	■	■	■	■	92
	Total Elect DA	525	120.5	18.9	63.2	9.9	16%	85
Total Prescribed DA		7	■	■	■	■	■	82
Total CBP DA		197	531	120.5	18.9	64.1	10.0	16%

⁴¹ The results in Table 4-11 and Table 4-12 are for an average event day. Note that the total for the program does not always exactly equal the total of the individual segments (industry or LCAs). This is because different groups of customers are called for each event, and in some cases, no customers in a segment are called. The average for that segment will reflect only those events where customers in that segment were called. The total program is the average across all events, regardless of which groups of customers are called for each event. Because the total program and the individual segments are averaged across different events, the total program may not exactly match the sum of the individual segments.

Table 4-12 PG&E Impacts by LCA and Product Offering

Local Capacity Area		# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Ref. Load	Impact	Ref. Load	Impact		
Total Res Elect DA		623	■	■	■	■	■	86
Non-Res Elect DA	Greater Bay Area	281	121.8	11.7	34.2	3.3	10%	83
	Greater Fresno Area	147	105.2	25.7	15.5	3.8	24%	97
	Humboldt	7	■	■	■	■	■	64
	Kern	43	171.2	33.7	7.3	1.4	20%	99
	Northern Coast	65	■	■	■	■	■	89
	Sierra	62	137.2	23.1	8.5	1.4	17%	92
	Stockton	32	■	■	■	■	■	94
	Other	126	105.4	22.0	13.3	2.8	21%	91
	Total Non-Res Elect DA	525	120.5	18.9	63.2	9.9	16%	85
Total Prescribed DA		7	■	■	■	■	■	82
Total Non-Res CBP		531	120.5	18.9	64.1	10.0	16%	85

Hourly Load Impacts

Figure 4-1 through Figure 4-3 illustrate the per-customer hourly profiles of the estimated reference load, observed load, and estimated load impacts (in kW) for PG&E's Elect DA and Prescribed DA product offerings, respectively, on an average event day. The hours highlighted in the blue-green show the hours wherein at least one group is called. The common event hour, HE19, is highlighted by the vertical dotted line. The data underlying the figures are available in the MS Excel-based Protocol table generators that are included as appendices to this report.

Figure 4-1 PG&E Residential Elect Day Ahead: Average Hourly Per-Customer Impact, 2020

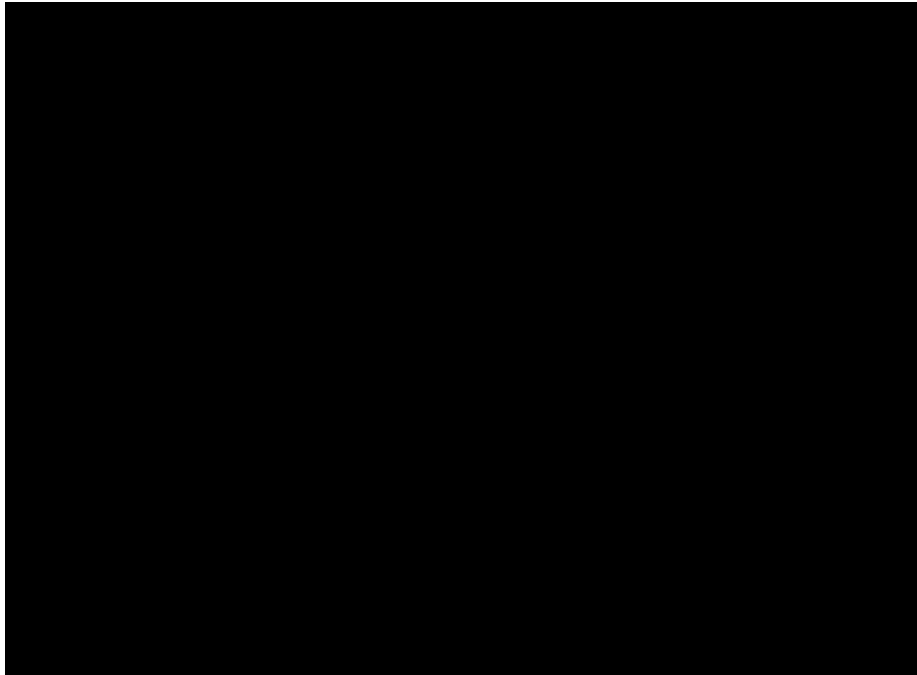


Figure 4-2 PG&E Non-Residential Elect Day Ahead: Average Hourly Per-Customer Impact, 2020

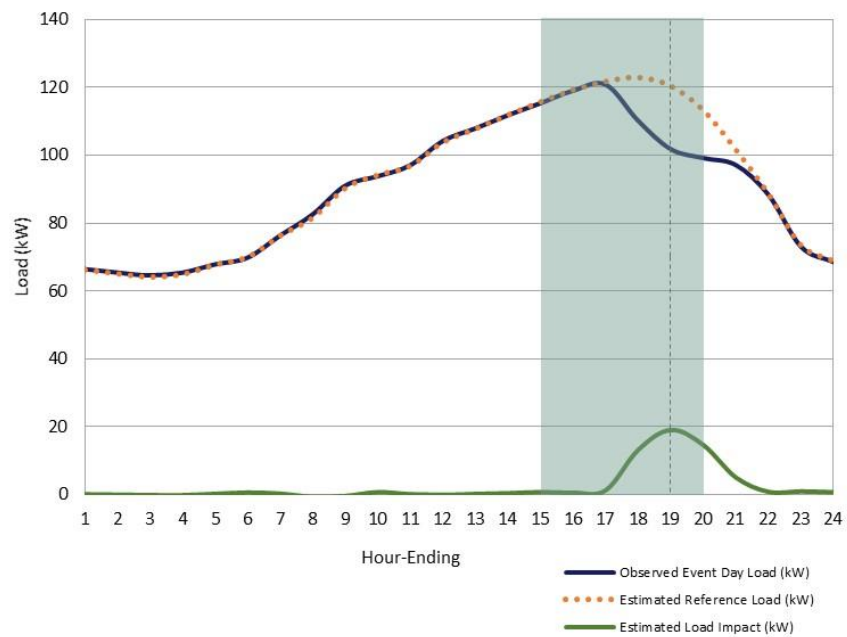
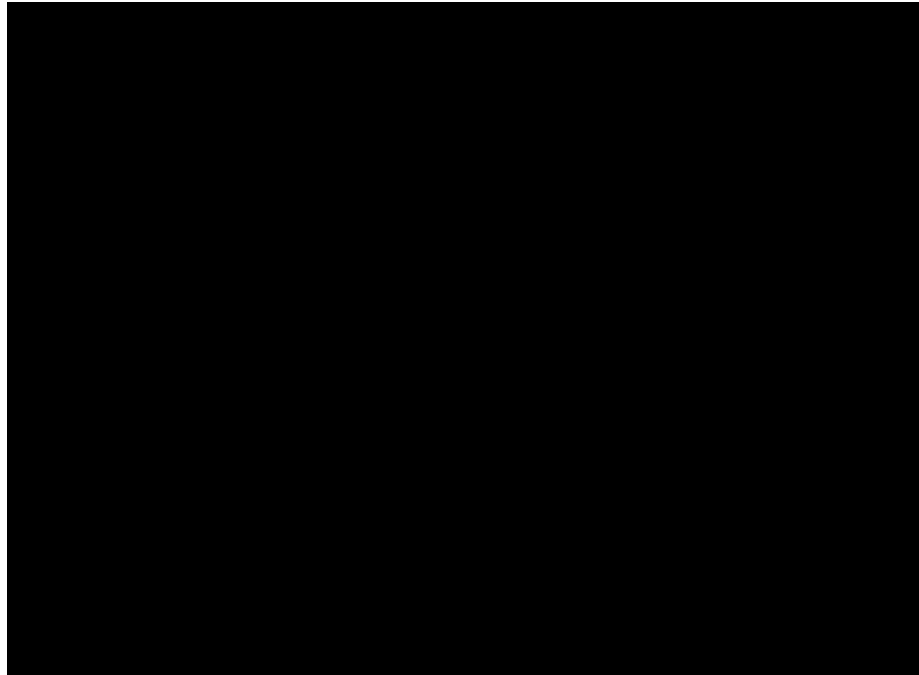


Figure 4-3 PG&E Prescribed Day Ahead: Average Hourly Per-Customer Impact, 2020



Load Impacts of AutoDR Participants

The Automated Demand Response (AutoDR) program provides customers incentives to invest in energy management technologies that will enable their equipment or facilities to reduce demand automatically in response to a physical signal sent from the utility. It encourages customers to expand their energy management capabilities by participating in DR programs using automated electric controls and management strategies.

In PY2020, only the Elect DA product offering recruited AutoDR participants. Table 4-13 shows the per-customer and aggregate ex-post impacts by event day for the AutoDR participants for the Elect DA product offering. For comparison, we include the aggregate load shed test, which is the confirmed number of MW that AutoDR customers are able to reduce during an event.

Table 4-13 PG&E Elect Day Ahead: AutoDR Participant Impacts by Event

Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Aggregate Load Shed Test (MW)	Temp (F)
		Reference Load	Impact	Reference Load	Impact			
Avg. Event	124	177.1	38.9	22.0	4.8	22%	4.9	86
Jun 3, 2020	7							61
Jul 13, 2020	1							60
Jul 30, 2020	114	191.9	28.0	21.9	3.2	15%	5.3	78
Jul 31, 2020	101	167.3	117.0	16.9	11.8	70%	6.6	98
Aug 14, 2020	174	210.6	46.0	36.6	8.0	22%	7.3	98
Aug 17, 2020	175	204.7	43.5	35.8	7.6	21%	7.3	88

Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Aggregate Load Shed Test (MW)	Temp (F)
		Reference Load	Impact	Reference Load	Impact			
Aug 18, 2020	153	211.7	46.4	32.4	7.1	22%	6.5	94
Aug 19, 2020	223	169.4	50.3	37.8	11.2	30%	10.3	90
Sep 8, 2020	46	■	■	■	■	■	■	76
Sep 14, 2020	1	■	■	■	■	■	■	68
Sep 30, 2020	238	160.5	57.6	38.2	13.7	36%	10.6	88
Oct 1, 2020	85	■	■	■	■	■	■	88
Oct 15, 2020	78	■	■	■	■	■	■	91
Oct 16, 2020	86	■	■	■	■	■	■	86

Load Impacts of CARE Participants

In Table 4-14, we present the results for the residential CARE participants on each event. CARE customers represented about 27% of the participants on an average event day, and with only 169 participants, their aggregate impact is less than ■. On a per-customers basis, they are very similar to an average participant both in terms of their reference load and their percent impacts with an average reference load of ■ and an average percent impact of ■.

Table 4-14 PG&E Elect Day Ahead: Residential CARE Participant Impacts by Event⁴²

Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
		Reference Load	Impact	Reference Load	Impact		
Avg. Event	169	■	■	■	■	■	88
Jun 3, 2020	185	■	■	■	■	■	93
Jul 29, 2020	185	■	■	■	■	■	86
Jul 31, 2020	185	■	■	■	■	■	85
Aug 11, 2020	127	■	■	■	■	■	85
Aug 13, 2020	184	■	■	■	■	■	93
Aug 14, 2020	184	■	■	■	■	■	99
Aug 17, 2020	184	■	■	■	■	■	86
Aug 18, 2020	184	■	■	■	■	■	94
Aug 19, 2020	184	■	■	■	■	■	88
Aug 20, 2020	57	■	■	■	■	■	79
Aug 24, 2020	184	■	■	■	■	■	85
Aug 25, 2020	184	■	■	■	■	■	81
Sep 8, 2020	183	■	■	■	■	■	83
Sep 9, 2020	183	■	■	■	■	■	70

⁴² The small negative impacts are most likely a modeling artifact resulting from an imperfect quantification of weather effects and/or omitted variable bias. We have no reason to think that customers are actually increasing their load in response to events.

Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
		Reference Load	Impact	Reference Load	Impact		
Sep 28, 2020	57	■	■	■	■	■	91
Sep 29, 2020	183	■	■	■	■	■	81
Sep 30, 2020	183	■	■	■	■	■	90
Oct 1, 2020	182	■	■	■	■	■	90
Oct 13, 2020	183	■	■	■	■	■	84
Oct 14, 2020	184	■	■	■	■	■	88

SCE

Events for SCE

We present summaries of the PY2020⁴³ events for SCE's CBP program for DA and DO products. The DO participants experienced a total of 39 event days over the course of the program year, while DA participants experienced 30 event days. As in previous years, events were called using a wide variety of event hours, with events starting as early as 2 PM (HE15)⁴⁴ and as late as 9 PM (HE21) and most events ending at 7 PM (HE19) or 8 PM (HE20). Table 4-16 below shows the number of Sub-LAPs, the event windows called, and the number of accounts nominated on each event day.

Table 4-15 presents the total monthly enrollment for the DA and DO programs, which would be comparable to participation counts of a system-level event. Note that SCE mostly system-level events in PY2020, with participation counts varying due to monthly nominations.

Similar to PG&E, the average event day is defined as the average of all events called in PY2020 regardless of event window and number of Sub-LAPs called. Since SCE's CBP is a year-round program, we define two average event days: summer and non-summer. The average summer event day is the average of all events called in months May through October. The average non-summer event day is the average of all events called in months November through April. We present impacts for the average event days on the joint event hours HE18 and HE20 for non-summer and summer, respectively.

⁴³ SCE's PY2020 evaluation period is from Nov. 1, 2019 through Oct. 31, 2020.

⁴⁴ Events called prior to the change in the dispatch window effective January 19, 2020.

Table 4-15 SCE Monthly Enrollment and MW Nominations

Month	Day Ahead		Day Of	
	Enrolled Accounts	Nominated Capacity (MW)	Enrolled Accounts	Nominated Capacity (MW)
November	3	■	1	■
December	3	■	1	■
January	3	■	1	■
February	53	■	17	■
March	157	■	3	■
April	180	■	3	■
Avg. Non-Summer	67	■	4	■
May	527	12.2	357	5.4
June	351	5.7	467	■
July	403	6.2	428	■
August	382	6.4	444	5.9
September	413	6.5	307	■
October	412	5.9	294	■
Avg. Summer	415	7.1	383	5.4

Table 4-16 SCE Event Summary

Date	Day of Week	# of Sub-LAPs	Event Hours (HE)	# Accounts	
				Day Ahead	Day Of
Avg. Non-Summer Event	-	3	18	3	5
Avg. Summer Event	-	6	20	387	312
Nov 4, 2019	Monday	2	15-19, 19-19	3	1
Nov 5, 2019	Tuesday	2	17-19	3	1
Nov 6, 2019	Wednesday	2	17-19	3	1
Nov 7, 2019	Thursday	2	17-19	3	1
Nov 8, 2019	Friday	2	17-19	3	1
Dec 2, 2019	Monday	2	18-18, 18-19	3	1
Dec 11, 2019	Wednesday	1	18-18	-	1
Feb 3, 2020	Monday	1	19-19	-	15
Feb 4, 2020	Tuesday	1	19-19	-	15
Feb 6, 2020	Thursday	1	19-19	-	15
May 28, 2020	Thursday	5	20-20	295	326
Jun 2, 2020	Tuesday	6	20-20	351	433
Jun 3, 2020	Wednesday	6	19-20, 19-21	351	467
Jun 4, 2020	Thursday	6	20-20	351	467

Date	Day of Week	# of Sub-LAPs	Event Hours (HE)	# Accounts	
				Day Ahead	Day Of
Jun 10, 2020	Wednesday	4	20-20	292	394
Jul 9, 2020	Thursday	6	20-20	403	397
Jul 10, 2020	Friday	6	19-20	403	359
Jul 13, 2020	Monday	6	19-20	403	428
Jul 27, 2020	Monday	6	20-20	403	397
Jul 28, 2020	Tuesday	1	20-20	-	69
Jul 29, 2020	Wednesday	1	19-20	-	31
Jul 30, 2020	Thursday	1	18-21	-	31
Jul 31, 2020	Friday	1	18-21	-	31
Aug 3, 2020	Monday	6	20-20	382	444
Aug 12, 2020	Wednesday	6	20-20	382	408
Aug 13, 2020	Thursday	6	18-21	382	444
Aug 14, 2020	Friday	6	16-21	382	444
Aug 17, 2020	Monday	6	16-21	382	444
Aug 18, 2020	Tuesday	1	16-21	-	36
Sep 3, 2020	Thursday	6	19-19, 19-20	413	307
Sep 4, 2020	Friday	6	16-21, 17-21	413	307
Sep 8, 2020	Tuesday	6	16-21, 17-21	413	307
Sep 9, 2020	Wednesday	6	19-19, 19-20	413	307
Sep 10, 2020	Thursday	6	19-19	413	307
Oct 1, 2020	Thursday	6	16-20, 17-20	412	294
Oct 2, 2020	Friday	6	17-20, 18-19	412	294
Oct 5, 2020	Monday	6	18-19	412	294
Oct 6, 2020	Tuesday	6	18-19	412	294
Oct 7, 2020	Wednesday	6	18-19, 19-19	412	294

Summary Load Impacts

Table 4-17 shows the average event day impacts for DA and DO programs and overall CBP for both non-summer and summer seasons, both at the per-customer level and in aggregate. Table 4-18 shows the average monthly and overall program performance by program and season, including the percent of delivered nominations. On average, SCE's CBP participants did not meet their nominated capacity in PY2020. We discuss this in more detail below.

Table 4-17 SCE Impacts Summary, Average Event Day PY2020

Product & Season	Accounts	Nominated Capacity (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact
			Reference Load	Impact	Reference Load	Impact	
Non-Summer DA	3	■	■	■	■	■	■
Non-Summer DO	5	■	■	■	■	■	■
Total Non-Summer	8	■	■	■	■	■	■
Summer DA	387	6.0	90.7	10.1	35.1	3.9	11%
Summer DO	312	■	■	■	■	■	■
Total Summer	699	10.3	95.0	9.8	66.4	6.8	10%

The overall aggregate impact for the summer season was 6.8 MW in PY2020, which fell short of its nominated capacity by 3.5 MW or 34%. This shortfall is similar across both products. Interestingly, while the products fell short of their nominations on a typical day, SCE showed relative success in June, July, and September (presented in subsequent tables). In both products, they were able to successfully meet nominations with delivery above 85% of nominated capacity.

Table 4-18 SCE Impacts Summary, Monthly Performance

Month	Day Ahead				Day Of			
	Nominated Accounts	Nom Capacity (MW)	Aggregate Impact (MW)	% Delivered	Nominated Accounts	Nom Capacity (MW)	Aggregate Impact (MW)	% Delivered
November	3	■	■	■	1	■	■	■
December	3	■	■	■	1	■	■	■
January	-	-	-	-	-	-	-	-
February*	-	-	-	-	15	■	■	■
March	-	-	-	-	-	-	-	-
April	-	-	-	-	-	-	-	-
Avg. Non-Summer	3	■	■	■	5	■	■	■
May	295	2.95	1.25	42%	326	4.6	1.9	42%
June	336	5.41	5.23	97%	440	■	■	■
July	403	6.20	5.47	88%	218	■	■	■
August	382	6.38	5.13	80%	370	4.9	3.3	66%
September**	413	6.46	7.03	109%	307	■	■	■
October**	412	5.85	3.73	64%	294	■	■	■
Avg. Summer	387	5.95	3.89	65%	312	■	■	■

* Results show HE19 instead of HE18

**Results show HE19 instead of HE20

Comparison of Ex-Post Impacts

In Table 4-19 and Table 4-20 below, we present the comparison of current ex-post impacts to previous ex-post impacts and current ex-post impacts to prior ex-ante impacts. These comparisons give the reader a sense of how the program has performed over time and how the program has performed relative to the most recent forecast.

Table 4-19 SCE: Current Ex-Post v. Previous Ex-Post, Average Summer Event Day

Product	Year	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Day Ahead	2018	43	432.1	47.9	18.7	2.1	11%	81
	2019	262	86.7	10.3	22.7	2.7	12%	86
	2020	387	90.7	10.1	35.1	3.9	11%	80
Day Of	2018	214	175.8	22.8	37.6	4.9	13%	83
	2019	151	132.9	15.8	20.1	2.4	12%	87
	2020	312	■	■	■	■	■	78

Table 4-19 above presents the ex-post impacts over time. SCE's non-residential program has varied in participants, total impacts, and percent impacts over the past three years. However, the average per customer impacts and percent impacts have remained relatively stable.

In Table 4-20 below, we present the PY2020 ex-post impacts compared to PY2019 ex-ante impacts. Day Ahead ex-post impacts were very comparable to last year's ex-ante forecast, even slightly exceeding the forecast at both the per customer and MW level. Day Of ex-post impacts, on the other hand, were lower than the ex-ante forecast by about 30 percent.

Table 4-20 SCE Current Ex-Post (Average Summer Event Day) v. Prior Ex-Ante (SCE 1-in-2, Typical Event Day, 2020)

Product	Estimate	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Day Ahead	PY2019 Ex-Ante	384	■	■	■	■	■	89
	Current Ex-Post	387	90.7	10.1	35.1	3.9	11%	80
Day Of	PY2019 Ex-Ante	233	■	■	■	■	■	89
	Current Ex-Post	312	■	■	■	■	■	78

Impacts by Event Day

Table 4-21 to Table 4-24 below show the average event-hour impacts for the two CBP products, summer, and non-summer. Impacts are included for each event, both at the average per-customer level, and in aggregate. For event days with multiple event windows, the values shown in this table represent the average event hour using only the hours that the multiple event

windows have in common. The tables include results for the average summer event and average non-summer event.

The DA product non-summer offering, overall, was able to meet capacity nominations, while the summer offering was able to do so in 11 out of 24 events. Similar to DA, the DO product offering, overall, was not able to meet capacity nominations, unable to do so in any non-summer events, and in 13 of 29 summer events.

Table 4-21 SCE Day Ahead 1-6 Hour: Non-Summer Impacts by Event

Event	# of Accts	Nominated Capacity (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Avg. Non-Summer	3	■	■	■	■	■	■	78
Nov 4, 2019	3	■	■	■	■	■	■	74
Nov 5, 2019	3	■	■	■	■	■	■	82
Nov 6, 2019	3	■	■	■	■	■	■	85
Nov 7, 2019	3	■	■	■	■	■	■	76
Nov 8, 2019	3	■	■	■	■	■	■	82
Dec 2, 2019	3	■	■	■	■	■	■	59

Table 4-22 SCE Day Ahead 1-6 Hour: Summer Impacts by Event

Event	# of Accts	Nominated Capacity (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Avg. Summer	387	6.0	90.7	10.1	35.1	3.9	11%	80
May 28, 2020	295	2.9	47.4	4.2	14.0	1.2	9%	76
Jun 2, 2020	351	5.7	76.2	16.4	26.7	5.8	22%	77
Jun 3, 2020	351	5.7	83.9	12.0	29.4	4.2	14%	79
Jun 4, 2020	351	5.7	80.5	16.4	28.3	5.8	20%	81
Jun 10, 2020	292	4.7	80.0	18.3	23.4	5.3	23%	85
Jul 9, 2020	403	6.2	86.5	17.1	34.9	6.9	20%	78
Jul 10, 2020	403	6.2	108.8	11.4	43.8	4.6	10%	82
Jul 13, 2020	403	6.2	95.6	11.4	38.5	4.6	12%	88
Jul 27, 2020	403	6.2	87.8	17.1	35.4	6.9	20%	78
Aug 3, 2020	382	6.4	99.6	22.8	38.0	8.7	23%	79
Aug 12, 2020	382	6.4	101.4	22.8	38.7	8.7	22%	80
Aug 13, 2020	382	6.4	101.8	8.3	38.9	3.2	8%	85
Aug 14, 2020	382	6.4	118.3	8.8	45.2	3.4	7%	91
Aug 17, 2020	382	6.4	113.6	8.8	43.4	3.4	8%	89
Sep 3, 2020	413	6.5	103.9	17.4	42.9	7.2	17%	80

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Event	# of Accts	Nominated Capacity (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Sep 4, 2020	413	6.5	107.9	10.3	44.6	4.2	10%	84
Sep 8, 2020	413	6.5	95.5	10.5	39.4	4.4	11%	82
Sep 9, 2020	413	6.5	96.2	17.4	39.8	7.2	18%	79
Sep 10, 2020	413	6.5	100.7	23.8	41.6	9.8	24%	80
Oct 1, 2020	412	5.9	104.2	7.8	42.9	3.2	8%	93
Oct 2, 2020	412	5.9	100.5	6.6	41.4	2.7	7%	92
Oct 5, 2020	412	5.9	95.6	13.5	39.4	5.6	14%	86
Oct 6, 2020	412	5.9	96.6	13.5	39.8	5.6	14%	83
Oct 7, 2020	412	5.9	95.5	14.8	39.3	6.1	15%	80

Table 4-23 SCE Day Of 1-6 Hour: Non-Summer Impacts by Event⁴⁵

Event	# of Accts	Nominated Capacity (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Avg. Non-Summer	5	■	■	■	■	■	■	62
Nov 4, 2019	1	■	■	■	■	■	■	66
Nov 5, 2019	1	■	■	■	■	■	■	64
Nov 6, 2019	1	■	■	■	■	■	■	66
Nov 7, 2019	1	■	■	■	■	■	■	63
Nov 8, 2019	1	■	■	■	■	■	■	61
Dec 2, 2019	1	■	■	■	■	■	■	59
Dec 11, 2019	1	■	■	■	■	■	■	60
Feb 3, 2020	15	■	■	■	■	■	■	58
Feb 4, 2020	15	■	■	■	■	■	■	58
Feb 6, 2020	15	■	■	■	■	■	■	57

Table 4-24 SCE Day Of 1-6 Hour: Summer Impacts by Event

Event	# of Accts	Nominated Capacity (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Avg. Summer	312	■	■	■	■	■	■	78
May 28, 2020	326	4.6	52.1	5.9	17.0	1.9	11%	78
Jun 2, 2020	433	5.0	53.3	17.3	23.1	7.5	32%	77

⁴⁵ The small negative impacts are most likely a modeling artifact resulting from an imperfect quantification of weather effects and/or omitted variable bias. We have no reason to think that customers are actually increasing their load in response to events.

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Event	# of Accts	Nominated Capacity (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Jun 3, 2020	467	■	■	■	■	■	■	78
Jun 4, 2020	467	■	■	■	■	■	■	79
Jun 10, 2020	394	■	■	■	■	■	■	85
Jul 9, 2020	397	4.6	74.9	14.0	29.7	5.6	19%	79
Jul 10, 2020	359	■	■	■	■	■	■	80
Jul 13, 2020	428	■	■	■	■	■	■	87
Jul 27, 2020	397	4.6	75.1	14.0	29.8	5.6	19%	79
Jul 28, 2020	69	1.2	117.2	22.9	8.1	1.6	20%	89
Jul 29, 2020	31	■	■	■	■	■	■	67
Jul 30, 2020	31	■	■	■	■	■	■	65
Jul 31, 2020	31	■	■	■	■	■	■	69
Aug 3, 2020	444	5.9	78.4	11.7	34.8	5.2	15%	79
Aug 12, 2020	408	5.5	79.1	11.7	32.3	4.8	15%	81
Aug 13, 2020	444	5.9	77.5	8.0	34.4	3.6	10%	84
Aug 14, 2020	444	5.9	83.9	8.2	37.2	3.7	10%	91
Aug 17, 2020	444	5.9	84.0	8.2	37.3	3.7	10%	89
Aug 18, 2020	36	0.5	100.2	11.8	3.6	0.4	12%	80
Sep 3, 2020	307	■	■	■	■	■	■	79
Sep 4, 2020	307	■	■	■	■	■	■	83
Sep 8, 2020	307	■	■	■	■	■	■	81
Sep 9, 2020	307	■	■	■	■	■	■	77
Sep 10, 2020	307	■	■	■	■	■	■	79
Oct 1, 2020	294	■	■	■	■	■	■	92
Oct 2, 2020	294	■	■	■	■	■	■	90
Oct 5, 2020	294	■	■	■	■	■	■	85
Oct 6, 2020	294	■	■	■	■	■	■	82
Oct 7, 2020	294	■	■	■	■	■	■	79

Table 4-25 and Table 4-26 present the impacts by Industry for an average non-summer event day and average summer event day, respectively. Table 4-27 and Table 4-28 present the impacts by LCA for an average non-summer event day and average summer event day, respectively.^{46 47}

Table 4-25 SCE CBP Impacts by Industry and Notice, Non-Summer

Industry	# of Acct	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
		Ref. Load	Impact	Ref. Load	Impact		
Total Day Ahead	3	■	■	■	■	■	78
Retail stores	3	■	■	■	■	■	59
Offices, Hotels, Finance, Services	8	■	■	■	■	■	59
DO Schools	1	■	■	■	■	■	63
Institutional/Government	2	■	■	■	■	■	60
Other or unknown	2	■	■	■	■	■	60
Total Day Of	5	■	■	■	■	■	62
Total Non-Summer CBP	8	■	■	■	■	■	62

⁴⁶ The results in Table 4-25 through Table 4-28 are for an average event day. Note that the total for the program does not always exactly equal the total of the individual segments (industry or LCAs). This is because different groups of customers are called for each event, and in some cases, no customers in a segment are called. The average for that segment will reflect only those events where customers in that segment were called. The total program is the average across all events, regardless of which groups of customers are called for each event. Because the total program and the individual segments are averaged across different events, the total program may not exactly match the sum of the individual segments.

⁴⁷ The small negative impacts in segment-level results are most likely a modeling artifact resulting from an imperfect quantification of weather effects and/or omitted variable bias. We have no reason to think that customers are actually increasing their load in response to events.

Table 4-26 SCE CBP Impacts by Industry and Notice, Summer

Industry	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
		Ref. Load	Impact	Ref. Load	Impact		
Agriculture, Mining & Construction	3	■	■	■	■	■	73
Manufacturing	2	■	■	■	■	■	87
Wholesale, Transport, other utilities	3	■	■	■	■	■	87
DA Retail stores	378	71.6	7.2	27.1	2.7	10%	80
Offices, Hotels, Finance, Services	1	■	■	■	■	■	85
Institutional/Government	3	■	■	■	■	■	69
Other or unknown	2	■	■	■	■	■	68
Total Day Ahead	387	90.7	10.1	35.1	3.9	11%	80
Agriculture, Mining & Construction	15	■	■	■	■	■	91
Manufacturing	3	■	■	■	■	■	87
Wholesale, Transport, other utilities	2	■	■	■	■	■	87
DO Retail stores	289	80.5	9.4	23.3	2.7	12%	78
Offices, Hotels, Finance, Services	5	■	■	■	■	■	77
Schools	1	■	■	■	■	■	67
Institutional/Government	2	■	■	■	■	■	75
Other or unknown	1	■	■	■	■	■	74
Total Day Of	312	■	■	■	■	■	78
Total Summer CBP	699	95.0	9.8	66.4	6.8	10%	86

Table 4-27 SCE CBP Impacts by LCA and Notice, Non-Summer

Local Capacity Area	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
		Ref. Load	Impact	Ref. Load	Impact		
Total Day Ahead	3	■	■	■	■	■	78
LA Basin	15	■	■	■	■	■	59
DO Ventura / Big Creek	1	■	■	■	■	■	63
Total Day Of	5	■	■	■	■	■	62
Total Non-Summer CBP	8	■	■	■	■	■	12%

Table 4-28 SCE CBP Impacts by LCA and Notice, Summer

Local Capacity Area		# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Ref. Load	Impact	Ref. Load	Impact		
DA	LA Basin	285	91.1	10.6	26.0	3.0	12%	79
	Outside LA Basin	31	■	■	■	■	■	86
	Ventura / Big Creek	71	92.3	8.1	6.5	0.6	9%	82
	Total Day Ahead	387	90.7	10.1	35.1	3.9	11%	80
DO	LA Basin	273	68.7	8.2	18.7	2.2	12%	79
	Outside LA Basin	25	■	■	■	■	■	84
	Ventura / Big Creek	65	■	■	■	■	■	80
	Total Day Of	312	■	■	■	■	■	78
Total Summer CBP		699	100.5	95.0	9.8	66.4	6.8	10%

We show the event day impacts for two additional geographical areas in SCE's service territory: South of Lugo and Southern Orange County in Appendix C.

Hourly Load Impacts

Figure 4-4 through Figure 4-7 illustrate the per-customer hourly profiles of the estimated reference load, observed load, and estimated load impacts (in kW) for each of the SCE CBP products on an average event day. The hours highlighted in the blue-green show the hours wherein at least one group is called. The joint event hour is highlighted by the vertical dotted line. The data underlying the figures are available in the Excel-based Protocol table generators that are included as appendices to this report.

Figure 4-4 exhibits the issues encountered in the ex-post impact analysis, where the regression models are not predicting as well as is satisfactory. This is due to having very few participants (3 customers during each event) with very erratic loads. This is not the case for DA summer and both DO summer and non-summer, where we see the reference load lining up well with the observed load during non-event hours.

Figure 4-4 SCE Day-Ahead 1-6 Hour: Average Hourly Per-Customer Impact, Non-Summer 2020

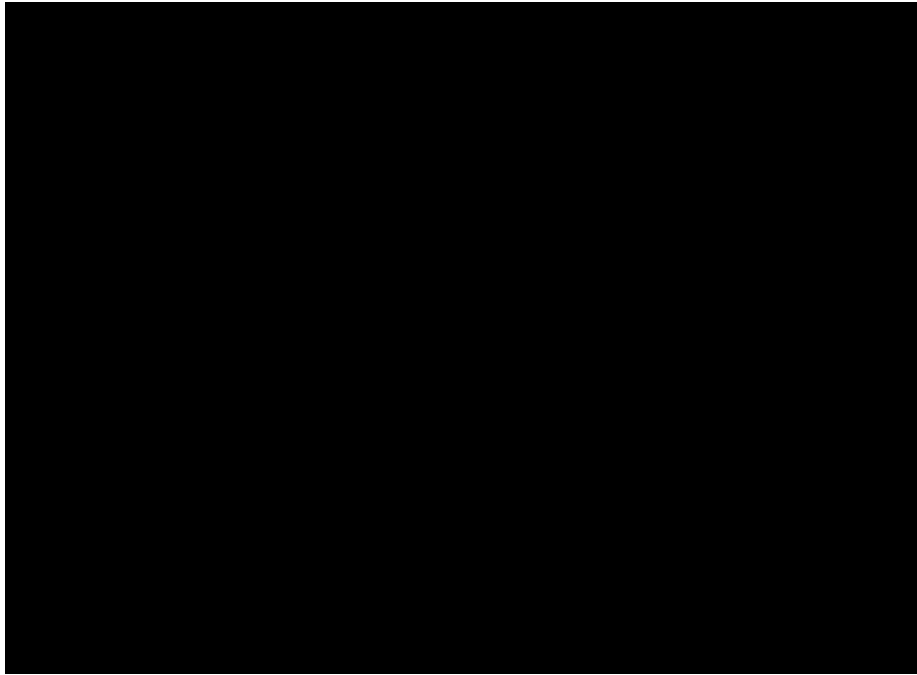


Figure 4-5 SCE Day-Ahead 1-6 Hour: Average Hourly Per-Customer Impact, Summer 2020

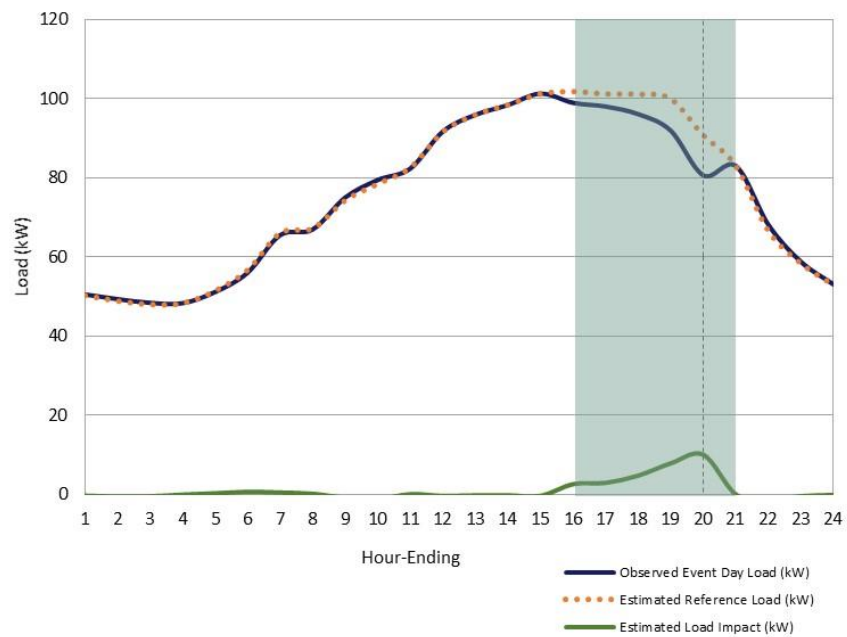


Figure 4-6 SCE Day-Of 1-6 Hour: Average Hourly Per-Customer Impact, Non-Summer 2020

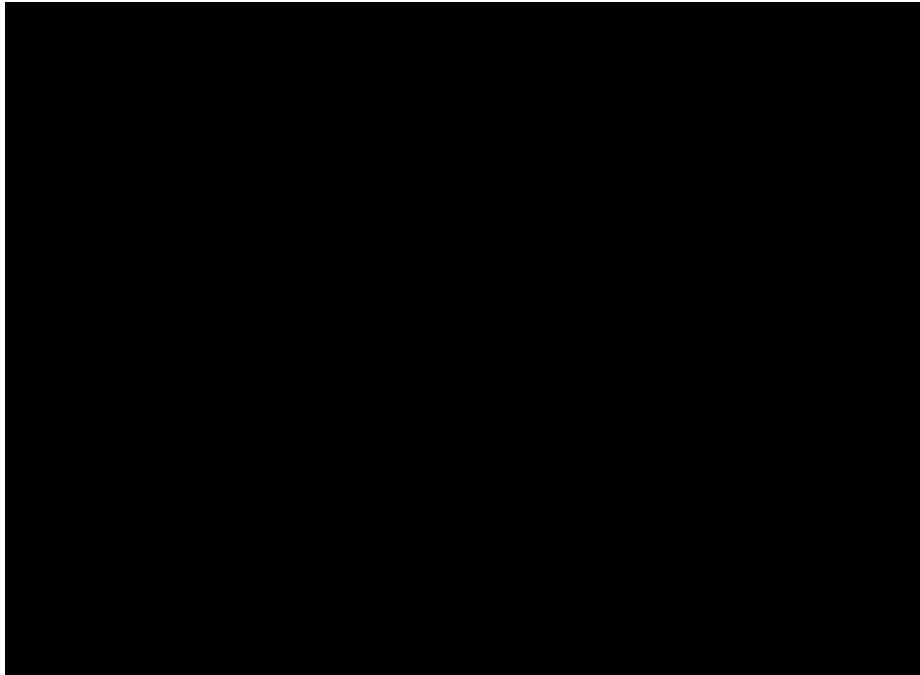
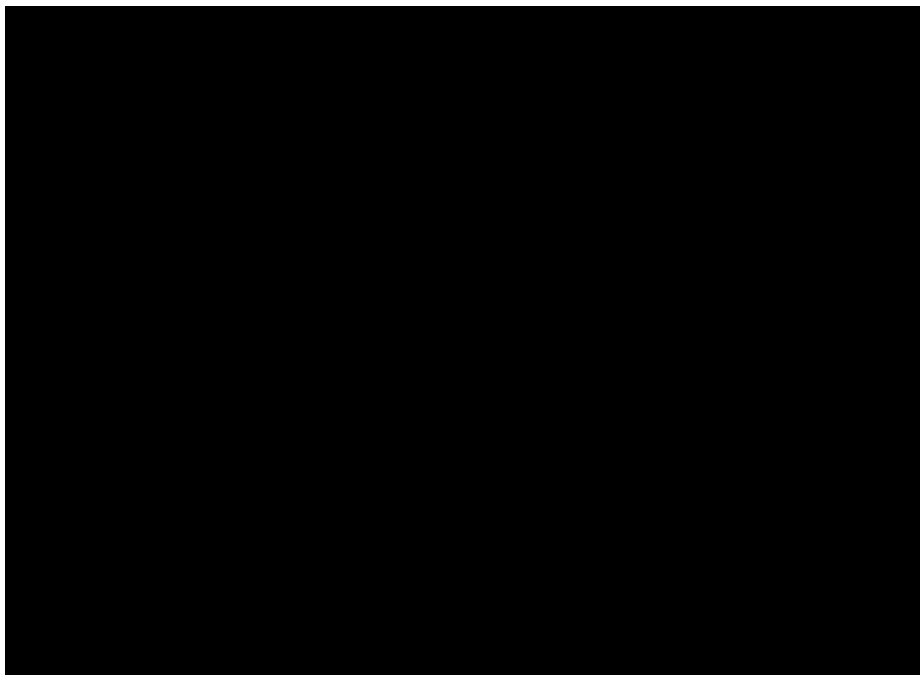


Figure 4-7 SCE Day-Of 1-6 Hour: Average Hourly Per-Customer Impact, Summer 2020



Load Impacts of TA/TI and AutoDR Participants

Similar to the AutoDR program, the Technical Assistance and Technology Incentives (TA/TI) program has two parts: technical assistance (TA) in the form of energy audits, and technology incentives (TI). The objective of the TA portion of the program was to subsidize customer energy

audits that had the objective of identifying ways in which customers could reduce load during DR events. The TI portion of the program provided incentive payments for the installation of equipment or control software supporting DR.

Table 4-29 and Table 4-30 presents the ex-post load impacts achieved in PY2020 by SCE CBP customers that enrolled in AutoDR or TA/TI at some point in the current or previous years for DA and DO, respectively.

Table 4-29 SCE Day Ahead 1-6 Hour: AutoDR and TA/TI Participant Impacts by Event

Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Aggregate Load Shed Test (MW)	Temp (F)
		Reference Load	Impact	Reference Load	Impact			
Avg. Non-Summer	2							78
Avg. Summer	43	171.1	35.9	7.4	1.6	21%	5.1	80
Nov 4, 2019	2							74
Nov 5, 2019	2							82
Nov 6, 2019	2							85
Nov 7, 2019	2							76
Nov 8, 2019	2							82
Dec 2, 2019	2							59
May 28, 2020	20							84
Jun 2, 2020	10							83
Jun 3, 2020	10							87
Jun 4, 2020	10							93
Jun 10, 2020	5							88
Jul 9, 2020	52	152.0	50.4	7.9	2.6	33%	5.1	75
Jul 10, 2020	52							79
Jul 13, 2020	52							84
Jul 27, 2020	52	132.1	50.4	6.9	2.6	38%	5.1	74
Aug 3, 2020	52							76
Aug 12, 2020	52	164.0	74.3	8.5	3.9	45%	5.1	76
Aug 13, 2020	52							81
Aug 14, 2020	52	247.5	22.1	12.9	1.1	9%	5.1	89
Aug 17, 2020	52							86
Sep 3, 2020	52	222.7	42.6	11.6	2.2	19%	5.1	77
Sep 4, 2020	52	221.1	26.1	11.5	1.4	12%	5.1	81
Sep 8, 2020	52							79
Sep 9, 2020	52	175.8	39.4	9.1	2.1	22%	5.1	76
Sep 10, 2020	52	245.9	79.6	12.8	4.1	32%	5.1	77
Oct 1, 2020	52							92

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Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Aggregate Load Shed Test (MW)	Temp (F)
		Reference Load	Impact	Reference Load	Impact			
Oct 2, 2020	52	■	■	■	■	■	■	89
Oct 5, 2020	52	■	■	■	■	■	■	83
Oct 6, 2020	52	■	■	■	■	■	■	81
Oct 7, 2020	52	190.1	45.9	9.9	2.4	24%	5.1	78

Table 4-30 SCE Day Of 1-6 Hour: AutoDR and TA/TI Participant Impacts by Event

Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Aggregate Load Shed Test (MW)	Temp (F)
		Reference Load	Impact	Reference Load	Impact			
Avg. Non-Summer	4	■	■	■	■	■	■	62
Avg. Summer	135	■	■	■	■	■	■	78
Nov 4, 2019	1	■	■	■	■	■	■	66
Nov 5, 2019	1	■	■	■	■	■	■	64
Nov 6, 2019	1	■	■	■	■	■	■	66
Nov 7, 2019	1	■	■	■	■	■	■	63
Nov 8, 2019	1	■	■	■	■	■	■	61
Dec 2, 2019	1	■	■	■	■	■	■	59
Dec 11, 2019	1	■	■	■	■	■	■	60
Feb 3, 2020	10	■	■	■	■	■	■	57
Feb 4, 2020	10	■	■	■	■	■	■	57
Feb 6, 2020	10	■	■	■	■	■	■	56
May 28, 2020	164	43.1	3.9	7.1	0.6	9%	7.0	77
Jun 2, 2020	172	52.0	24.1	8.9	4.2	46%	7.2	76
Jun 3, 2020	181	■	■	■	■	■	■	77
Jun 4, 2020	181	■	■	■	■	■	■	79
Jun 10, 2020	153	■	■	■	■	■	■	85
Jul 9, 2020	150	76.9	19.4	11.5	2.9	25%	6.7	78
Jul 10, 2020	134	■	■	■	■	■	■	80
Jul 13, 2020	159	■	■	■	■	■	■	87
Jul 27, 2020	150	75.5	19.4	11.3	2.9	26%	6.7	78
Jul 28, 2020	25	■	■	■	■	■	■	89
Jul 29, 2020	9	■	■	■	■	■	■	67
Jul 30, 2020	9	■	■	■	■	■	■	65
Jul 31, 2020	9	■	■	■	■	■	■	69
Aug 3, 2020	167	76.9	16.1	12.8	2.7	21%	7.2	78
Aug 12, 2020	155	81.7	16.3	12.7	2.5	20%	6.8	80

Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Aggregate Load Shed Test (MW)	Temp (F)
		Reference Load	Impact	Reference Load	Impact			
Aug 13, 2020	167	74.1	9.3	12.4	1.5	12%	7.2	84
Aug 14, 2020	167	81.1	9.2	13.5	1.5	11%	7.2	90
Aug 17, 2020	167	81.5	9.3	13.6	1.5	11%	7.2	88
Aug 18, 2020	12	■	■	■	■	■	■	80
Sep 3, 2020	165	■	■	■	■	■	■	79
Sep 4, 2020	165	■	■	■	■	■	■	83
Sep 8, 2020	165	■	■	■	■	■	■	81
Sep 9, 2020	165	■	■	■	■	■	■	77
Sep 10, 2020	165	■	■	■	■	■	■	79
Oct 1, 2020	153	■	■	■	■	■	■	93
Oct 2, 2020	153	■	■	■	■	■	■	90
Oct 5, 2020	153	■	■	■	■	■	■	85
Oct 6, 2020	153	■	■	■	■	■	■	83
Oct 7, 2020	153	■	■	■	■	■	■	79

SDG&E

Events for SDG&E

Table 4-32 presents a summary of the 2020 events for SDG&E's CBP program by product. Over the course of the program year, the DO product participants experienced 24 event days, while the DA product participants experienced 27 events. Events were called with various event windows. Similar to PG&E and SCE, the average event day is defined as the average of all events called in PY2020 regardless of the event window. We also present impacts for the average event day on the joint event hour, HE19, which is the hour when all event windows overlap. SDG&E did not call any geographically targeted events but did experience fluctuations in monthly nominations. Table 4-31 presents SDG&E's monthly nominations by product offering.

Table 4-31 SDG&E Monthly Enrollment and MW Nominations

Month	Day Ahead		Day Of	
	Enrolled Accounts	Nominated Capacity (MW)	Enrolled Accounts	Nominated Capacity (MW)
May	9	0.4	178	3.4
June	11	0.5	142	3.0
July	24	0.6	175	3.2
August	24	0.6	175	3.2
September	24	0.7	152	3.2
October	20	0.4	129	2.2
Average Summer	19	0.5	159	3.0

Table 4-32 SDG&E Event Summary

Date	Day of Week	Event Hours (HE)	# Accounts			
			DA 11AM to 7PM	DA 1PM to 9PM	DO 11AM to 7PM	DO 1PM to 9PM
Avg. Event	-	19	4	19	67	91
Jun 2, 2020	Tuesday	19-20	-	7	-	-
Jun 3, 2020	Wednesday	18-19, 19-20	4	7	-	101
Jul 10, 2020	Friday	19-20	-	20	-	110
Jul 13, 2020	Monday	19-20	-	20	-	110
Jul 29, 2020	Wednesday	18-19, 19-20	4	20	-	110
Jul 30, 2020	Thursday	18-19, 18-21, 19-20	4	20	65	110
Jul 31, 2020	Friday	18-19, 18-21, 19-20	4	20	65	110
Aug 3, 2020	Monday	19-20	-	20	-	-
Aug 14, 2020	Friday	16-19, 18-21	4	20	66	109
Aug 17, 2020	Monday	16-19, 17-20	4	20	66	109
Aug 18, 2020	Tuesday	16-19, 17-20	4	20	66	109
Aug 19, 2020	Wednesday	16-19, 18-21	4	20	66	109
Aug 21, 2020	Friday	18-19, 18-21, 19-20	4	20	66	109
Aug 27, 2020	Thursday	17-19, 18-19, 18-20	4	-	66	109
Sep 4, 2020	Friday	17-19, 17-20, 18-19, 18-20	4	20	66	86
Sep 8, 2020	Tuesday	17-19, 18-21	4	20	66	86
Sep 9, 2020	Wednesday	19-20	-	20	-	-
Sep 16, 2020	Wednesday	18-19, 19-20	4	20	-	-
Sep 17, 2020	Thursday	17-19	4	20	-	-
Sep 18, 2020	Friday	17-18	4	20	-	-
Sep 29, 2020	Tuesday	16-19, 18-20	-	-	66	86
Sep 30, 2020	Wednesday	16-19, 17-20	4	-	66	86
Oct 1, 2020	Thursday	16-19, 17-20	-	20	70	59

Similar to PG&E, SDG&E called multiple events using the same event window, depending on the product dispatch window. For the 11 AM to 7 PM dispatch window, SDG&E called most events between 5 PM to 7 PM (HE18-HE19). For the 1 PM to 9 PM dispatch window, most events were called between 6 PM to 8 PM (HE19-HE20). Accordingly, the ex-post regression models also favored using event window indicators over event hour indicators. Using event hour indicators could not fully capture the response on events called in windows that were not called as much as those indicated for each dispatch window.

Summary Load Impacts

Table 4-33 shows the average summer event day impacts for each product, each notification option, and overall CBP, both at the per-customer level and in aggregate. Table 4-34 shows the average monthly and overall program performance by program, including the percent of delivered nominations. On average, the DO and DA product offerings did not meet their nominated capacity, but they did have some success at the event level. We discuss this in more detail below.

Table 4-33 SDG&E Impacts Summary, Average Event Day PY2020

Product	Accounts	Nominated Capacity (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact
			Reference Load	Impact	Reference Load	Impact	
DA 11AM-7PM	4	0.2	61.1	4.3	0.2	0.0	7%
DA 1PM-9PM	19	0.4	134.0	20.8	2.5	0.4	16%
Total Day Ahead	23	0.6	121.3	18.0	2.8	0.4	15%
DO 11AM-7PM	67	0.9	95.5	2.3	6.4	0.2	2%
DO 1PM-9PM	91	2.0	130.1	22.3	11.8	2.0	17%
Total Day Of	158	2.9	115.4	13.8	18.3	2.2	12%
Total CBP	181	3.5	116.1	14.3	21.0	2.6	12%

The overall aggregate impact was 2.6 MW in PY2020, which fell short of its nominated capacity by 0.9 MW or 25%. This shortfall is similar across both products. Interestingly, while the products fell short of their nominations on a typical day, SDG&E showed relative success in some months (presented in subsequent tables). On average, both products were able to successfully meet nominations with delivery above 70% of nominated capacity.

Table 4-34 SDG&E Impacts Summary, Monthly Performance

Month	Day Ahead				Day Of			
	Nominated Accounts	Nom Capacity (MW)	Aggregate Impact (MW)	% Delivered	Nominated Accounts	Nom Capacity (MW)	Aggregate Impact (MW)	% Delivered
May	-	-	-	-	-	-	-	-
June	11	0.49	0.55	111%	101	2.4	2.7	115%
July	24	0.62	0.39	62%	175	3.2	2.8	87%
August	24	0.64	0.60	93%	175	3.2	2.3	71%
September	24	0.69	0.32	46%	152	3.2	2.2	69%
October	20	0.36	0.31	86%	129	2.2	1.5	65%
Overall	23	0.58	0.41	71%	158	2.9	2.2	74%

Comparison of Ex-Post Impacts

In Table 4-35 and Table 4-36 below, we present the comparison of current ex-post impacts to previous ex-post impacts, and current ex-post impacts to prior ex-ante impacts. These

comparisons give the reader a sense of how the program has performed over time, and how the program has performed relative to the most recent forecast.

Table 4-35 SDG&E: Current Ex-Post v. Previous Ex-Post, Average Event Day

Product	Year	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Day Ahead	2018	27	228.5	6.9	6.1	0.2	3%	75
	2019	15	408.7	26.3	6.1	0.4	6%	76
	2020	23	121.3	18.0	2.8	0.4	15%	78
Day Of	2018	186	134.8	18.6	25.1	3.5	14%	84
	2019	185	120.6	19.6	22.3	3.6	16%	77
	2020	158	115.4	13.8	18.3	2.2	12%	77

Table 4-35 above presents the ex-post impacts over time. SGD&E's non-residential program has remained somewhat stable in terms of participants but has seen variation in reference loads and per customer impacts over the past three years. For example, the Day Ahead program had a substantial increase in percentage this year while also seeing a decrease in reference load. The Day Of program, on the other hand, saw decreased reference load and percent impacts in 2020.

In Table 4-36 below, we present the PY2020 ex-post impacts compared to PY2019 ex-ante impacts. Day Ahead ex-post impacts were comparable to last year's ex-ante forecast, even exceeding the MW forecast due to additional enrollment. Day Of ex-post impacts, on the other hand, were lower than the ex-ante forecast by about 18 percent.

Table 4-36 SDG&E Current Ex-Post (Average Event Day) v. Prior Ex-Ante (SDG&E 1-in-2, Typical Event Day, 2020)

Product	Estimate	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Day Ahead	PY2019 Ex-Ante	11	371.7	18.7	4.2	0.2	5%	81
	Current Ex-Post	23	121.3	18.0	2.8	0.4	15%	78
Day Of	PY2019 Ex-Ante	190	117.7	17.0	22.3	3.2	14%	81
	Current Ex-Post	158	115.4	13.8	18.3	2.2	12%	77

Impacts by Event Day

Table 4-37 through Table 4-40 show the average event-hour impacts for the four CBP products. Impacts are included for each event, both at the average per-customer level and in aggregate. The tables include results for the average event day.

In PY2020, the DA product offering showed more success in the 1 PM to 9 PM dispatch window, meeting or exceeding capacity nominations on average and in most of August and October. The

DA product offering did not see much success in the 11 PM to 7 PM dispatch window. Participants were not able to meet capacity nominations on any of the events called in PY2020.

Table 4-37 SDG&E Day Ahead 11 AM to 7 PM Product: Impacts by Event

Event	# of Accts	Nominated Capacity (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Avg. Event	4	0.23	61.1	4.3	0.2	0.02	7%	87
Jun 3, 2020	4	0.21	50.1	49.6	0.2	0.20	99%	83
Jul 29, 2020	4	0.21	50.5	1.0	0.2	<0.01	2%	86
Jul 30, 2020	4	0.21	50.6	1.0	0.2	<0.01	2%	97
Jul 31, 2020	4	0.21	50.7	1.0	0.2	<0.01	2%	97
Aug 14, 2020	4	0.23	59.3	-1.6	0.2	-0.01	-3%	97
Aug 17, 2020	4	0.23	59.3	-1.6	0.2	-0.01	-3%	96
Aug 18, 2020	4	0.23	59.4	-1.6	0.2	-0.01	-3%	96
Aug 19, 2020	4	0.23	59.2	-1.6	0.2	-0.01	-3%	93
Aug 21, 2020	4	0.23	51.1	1.2	0.2	<0.01	2%	85
Aug 27, 2020	4	0.23	49.9	<0.1	0.2	<0.01	0%	92
Sep 4, 2020	4	0.23	56.5	<0.1	0.2	<0.01	0%	97
Sep 8, 2020	4	0.23	49.4	<0.1	0.2	<0.01	0%	75
Sep 16, 2020	4	0.23	100.6	<0.1	0.4	<0.01	0%	86
Sep 17, 2020	4	0.23	100.2	<0.1	0.4	<0.01	0%	92
Sep 18, 2020	4	0.23	100.6	<0.1	0.4	<0.01	0%	94
Sep 30, 2020	4	0.23	63.0	-20.2	0.3	-0.08	-32%	93

Table 4-38 SDG&E Day Ahead 1 PM to 9 PM Product: Impacts by Event

Event	# of Accts	Nominated Capacity (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Avg. Event	19	0.4	134.0	20.8	2.5	0.4	16%	76
Jun 2, 2020	7	0.3	213.7	35.5	1.5	0.2	17%	69
Jun 3, 2020	7	0.3	242.9	35.5	1.7	0.2	15%	69
Jul 10, 2020	20	0.4	133.2	11.2	2.7	0.2	8%	76
Jul 13, 2020	20	0.4	125.1	11.2	2.5	0.2	9%	72
Jul 29, 2020	20	0.4	109.3	25.6	2.2	0.5	23%	70
Jul 30, 2020	20	0.4	120.1	18.9	2.4	0.4	16%	74
Jul 31, 2020	20	0.4	123.2	18.9	2.5	0.4	15%	75
Aug 3, 2020	20	0.4	112.9	26.4	2.3	0.5	23%	71
Aug 14, 2020	20	0.4	143.1	29.1	2.9	0.6	20%	82
Aug 17, 2020	20	0.4	143.9	33.5	2.9	0.7	23%	80

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Event	# of Accts	Nominated Capacity (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Aug 18, 2020	20	0.4	145.4	33.5	2.9	0.7	23%	81
Aug 19, 2020	20	0.4	136.6	29.1	2.7	0.6	21%	78
Aug 21, 2020	20	0.4	141.0	18.8	2.8	0.4	13%	81
Sep 4, 2020	20	0.5	136.5	12.0	2.7	0.2	9%	80
Sep 8, 2020	20	0.5	119.2	19.5	2.4	0.4	16%	73
Sep 9, 2020	20	0.5	120.7	19.9	2.4	0.4	16%	73
Sep 16, 2020	20	0.5	127.6	19.9	2.6	0.4	16%	77
Sep 17, 2020	20	0.5	138.7	23.0	2.8	0.5	17%	84
Sep 18, 2020	20	0.5	142.2	18.8	2.8	0.4	13%	84
Oct 1, 2020	20	0.4	143.7	18.1	2.9	0.4	13%	84
Oct 2, 2020	20	0.4	150.0	21.0	3.0	0.4	14%	87
Oct 5, 2020	20	0.4	128.6	11.7	2.6	0.2	9%	79
Oct 6, 2020	20	0.4	123.5	11.7	2.5	0.2	9%	76
Oct 7, 2020	20	0.4	117.1	8.2	2.3	0.2	7%	72
Oct 13, 2020	20	0.4	132.5	21.0	2.7	0.4	16%	86

As mentioned above, the DO product offerings performed similarly to the DA offering in PY2020. The table below for the 11 AM to 7 PM shows the product did not have much success in that dispatch window. For the 1 PM to 9 PM, however, participants were able to meet or exceed their nomination capacity all through July and during five additional events.

Table 4-39 SDG&E Day Of 11 AM to 7 PM: Impacts by Event

Event	# of Accts	Nominated Capacity (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Avg. Event	67	0.9	95.5	2.3	6.4	0.2	2%	78
Jul 30, 2020	65	0.9	89.2	2.2	5.8	0.1	2%	77
Jul 31, 2020	65	0.9	96.9	2.2	6.3	0.1	2%	79
Aug 14, 2020	66	1.0	105.3	5.5	7.0	0.4	5%	88
Aug 17, 2020	66	1.0	107.7	5.5	7.1	0.4	5%	85
Aug 18, 2020	66	1.0	110.5	6.2	7.3	0.4	6%	84
Aug 19, 2020	66	1.0	107.6	5.5	7.1	0.4	5%	85
Aug 21, 2020	66	1.0	104.9	-0.5	6.9	0.0	0%	84
Aug 27, 2020	66	1.0	103.0	2.6	6.8	0.2	3%	80
Sep 4, 2020	66	1.0	104.9	1.4	6.9	0.1	1%	82
Sep 8, 2020	66	1.0	101.6	10.0	6.7	0.7	10%	75
Sep 29, 2020	66	1.0	108.2	5.0	7.1	0.3	5%	86

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Event	# of Accts	Nominated Capacity (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Sep 30, 2020	66	1.0	111.3	5.0	7.3	0.3	5%	92
Oct 1, 2020	70	0.8	103.8	6.8	7.3	0.5	7%	89
Oct 6, 2020	70	0.8	93.2	5.2	6.5	0.4	6%	77
Oct 12, 2020	70	0.8	91.3	5.2	6.4	0.4	6%	79
Oct 13, 2020	70	0.8	96.0	6.8	6.7	0.5	7%	86
Oct 14, 2020	70	0.8	96.3	6.8	6.7	0.5	7%	84
Oct 19, 2020	70	0.8	85.9	5.2	6.0	0.4	6%	68

Table 4-40 SDG&E Day Of 1 PM to 9 PM: Impacts by Event

Event	# of Accts	Nominated Capacity (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Avg. Event	91	2.0	130.1	22.3	11.8	2.0	17%	77
Jun 3, 2020	101	2.4	107.0	27.1	10.8	2.7	25%	70
Jul 10, 2020	110	2.3	111.8	21.5	12.3	2.4	19%	76
Jul 13, 2020	110	2.3	110.1	21.5	12.1	2.4	20%	72
Jul 29, 2020	110	2.3	107.5	21.5	11.8	2.4	20%	70
Jul 30, 2020	110	2.3	113.6	21.5	12.5	2.4	19%	73
Jul 31, 2020	110	2.3	117.0	21.5	12.9	2.4	18%	75
Aug 14, 2020	109	2.3	122.2	20.8	13.3	2.3	17%	82
Aug 17, 2020	109	2.3	121.7	19.4	13.3	2.1	16%	80
Aug 18, 2020	109	2.3	124.8	19.4	13.6	2.1	16%	80
Aug 19, 2020	109	2.3	125.2	20.8	13.7	2.3	17%	78
Aug 21, 2020	109	2.3	128.4	24.8	14.0	2.7	19%	80
Aug 27, 2020	109	2.3	119.5	19.3	13.0	2.1	16%	77
Sep 4, 2020	86	2.2	143.2	23.8	12.3	2.0	17%	78
Sep 8, 2020	86	2.2	130.3	27.1	11.2	2.3	21%	73
Sep 29, 2020	86	2.2	142.5	23.8	12.3	2.0	17%	78
Sep 30, 2020	86	2.2	146.6	25.0	12.6	2.2	17%	87
Oct 1, 2020	59	1.4	164.0	24.2	9.7	1.4	15%	84
Oct 6, 2020	59	1.4	155.6	27.2	9.2	1.6	17%	76
Oct 13, 2020	59	1.4	158.3	25.7	9.3	1.5	16%	84
Oct 14, 2020	59	1.4	148.0	22.6	8.7	1.3	15%	83
Oct 15, 2020	59	1.4	148.3	22.6	8.7	1.3	15%	79
Oct 20, 2020	59	1.4	150.4	27.2	8.9	1.6	18%	67

Table 4-41 presents the impacts for an average event day by industry group.^{48,49}

Table 4-41 SDG&E Impacts by Industry and Notice

Industry		# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Ref. Load	Impact	Ref. Load	Impact		
Day	Agriculture, Mining & Construction	4	61.1	4.3	0.2	0.0	7%	87
	Retail stores	19	134.0	20.8	2.5	0.4	16%	76
	Total Day Ahead	23	121.3	18.0	2.8	0.4	15%	78
Day Of	Manufacturing	1	592.5	-16.6	0.6	0.0	-3%	76
	Retail stores	132	123.0	16.9	16.3	2.2	14%	77
	Offices, Hotels, Finance, Services	11	74.4	-2.5	0.8	0.0	-3%	81
	Institutional/Government	26	40.5	-0.3	1.1	0.0	-1%	76
	Total Day Of	158	115.4	13.8	18.3	2.2	12%	77
Total CBP		200	181	116.1	14.3	21.0	2.6	12%

Hourly Load Impacts

Figure 4-8 and Figure 4-9 illustrate the per-customer hourly profiles of the estimated reference load, observed load, and estimated load impacts (in kW) for SDG&E's CBP DO and DA products, respectively, on an average event day. In both the DO and DA figures, results for the 11 AM to 7 PM and 1 PM to 9 PM products are combined. The hours highlighted in the blue-green show the hours wherein at least one product is called. The common event hour is highlighted by the vertical dotted line. The data underlying the figures are available in the MS Excel-based Protocol table generators that are included as appendices to this report.

⁴⁸ SDG&E's service territory is classified as a single LCA, so we have only included a subgroup comparison by industry type.

⁴⁹ The results in Table 4-41 are for an average event day. Note that the total for the program does not always exactly equal the total of the individual industry segments. This is because different groups of customers are called for each event, and in some cases, no customers in a segment are called. The average for that segment will reflect only those events where customers in that segment were called. The total program is the average across all events, regardless of which groups of customers are called for each event. Because the total program and the individual segments are averaged across different events, the total program may not exactly match the sum of the individual segments.

Figure 4-8 SDG&E All Day-Ahead: Average Hourly Per-Customer Impact, 2020

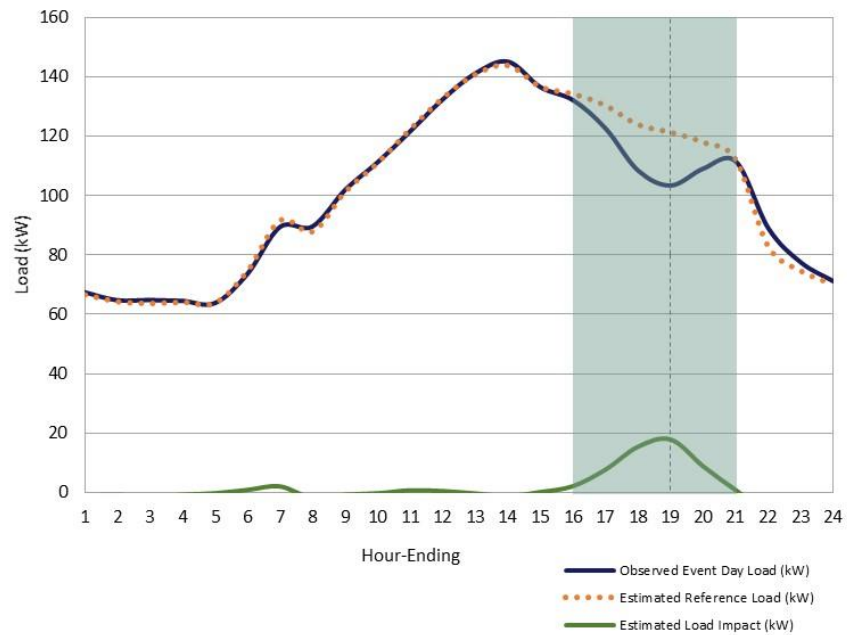
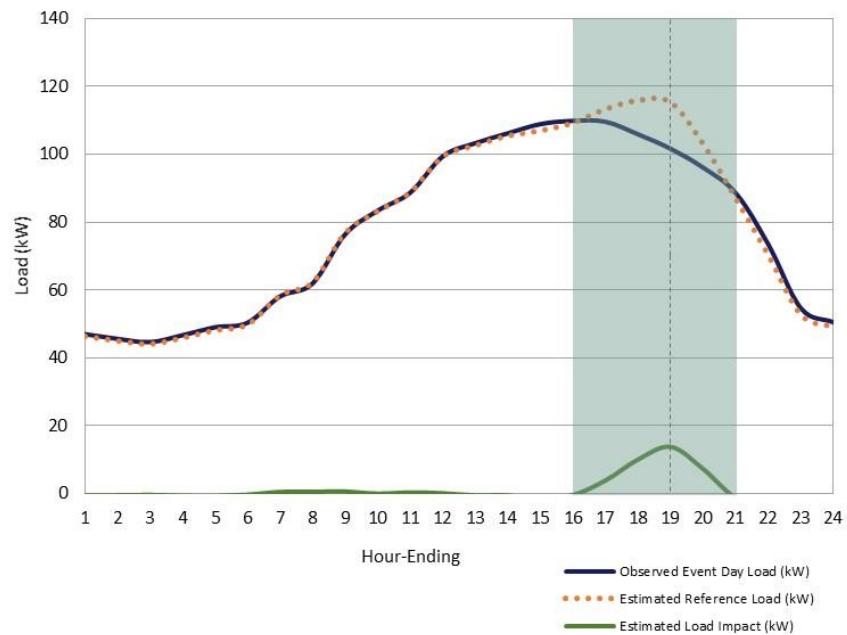


Figure 4-9 SDG&E All Day-Of: Average Hourly Per-Customer Impact, 2020



Load Impacts of TA/TI and AutoDR Participants

SDG&E did not have any TA/TI or AutoDR participants in PY2020.

5

EX-ANTE RESULTS

This section presents the ex-ante results, which include the load impact forecasts for the 1-in-2 and 1-in-10 weather conditions for each utility and product.

Overview of Results

Table 5-1 summarizes the 11-year enrollment and average Resource Adequacy (RA) window load impact forecast by utility, customer class, notification type, and year during the month of August. Table 5-2 summarizes the average RA window load impact forecasts for an August peak day in 2021 by utility, customer class, and notification type for each weather scenario.

Table 5-1 Statewide CBP, 2021-2031 Forecast for Month of August

Utility	Customer Class	Notice	Number of Service Accounts			Aggregate Impact (MW)		
			2021	2023	2025-2031 (Each Year)	2021	2023	2025-2031 (Each Year)
PGE	Residential	Day Ahead	8,247	16,494	16,494	2.4	4.9	4.9
	Non-Residential	Day Ahead	2,049	2,258	2,258	40.5	44.7	44.7
SCE	Non-Residential	Day Ahead	410	410	410	2.6	2.6	2.6
		Day Of	380	380	380			
SDG&E	Non-Residential	Day Ahead	18	19	20	0.2	0.2	0.2
		Day Of	164	170	177	1.5	1.5	1.6

Table 5-2 Statewide CBP, Summary of Average RA Window Ex-Ante Impacts, August Peak Day, 2021

Utility	Customer Class	Notice	# of Accts	Per Customer (kW)	Aggregate Impact (MW)	Percent Impact (%)			
						Utility Peak		CAISO Peak	
						1-in-2	1-in-10	1-in-2	1-in-10
PGE	Residential	Day Ahead	8,247	0.3	2.4	20.7%	19.7%	21.3%	21.0%
	Non-Residential	Day Ahead	2,049	19.8	40.5	15.3%	15.0%	15.5%	15.2%
SCE	Non-Residential	Day Ahead	410	6.2	2.6	7.0%	7.0%	7.0%	7.0%
		Day Of	380						
SDG&E	Non-Residential	Day Ahead	18	11.8	0.2	9.9%	9.6%	9.7%	9.8%
		Day Of	164	9.1	1.5	9.5%	9.3%	9.4%	9.4%

Note that since CBP impacts are inherently nomination-driven, not weather-driven, we assumed constant per-customer load impacts across the weather scenarios. The per-customer impacts are also estimated to remain constant across the months of May through October, i.e., constant nominations through the season. However, since participant usage can be weather-dependent,

the weather scenarios do affect the estimated reference load. This results in varying percent impacts across the months and weather scenarios.

PG&E

Enrollment and Load Impact Summary

PG&E forecasts lower overall MW nominations in CBP, decreasing from PY2019's ex-ante forecast. The PY2020 forecasted MW nominations for a 2021 August peak day decreased to a combined 42.9 MW compared to PY2019's 2021 August peak day forecast of 48 MW.

PG&E's non-residential forecast increased to 40.5 MW compared to PY2019's 38 MW for a 2021 August peak day. PG&E expects the future of the program to produce more reliable MW nominations as a result of key program changes, especially the increase of the max number of events per month, the shift of the bidding window closer to event days, and the reduction of the bid cap (pending CPUC approval). In addition, PY2020's nomination achievement/deliveries are being addressed at the aggregator level. PG&E has signed on seven new aggregators for the upcoming season. Also, continuing aggregators have already resolved energy management system bugs that severely impacted event day performances and are working to enroll more customers to their offerings. The gained experience and enrollment increases will work to minimize the performance variability and increase nomination achievement.

On the other hand, PG&E's residential forecast decreased to 2.4 MW compared to PY2019's 10 MW for a 2021 August peak day. PG&E did not have residential participation prior to PY2020, thus PG&E's PY2019 forecast was based on key assumptions. Additionally, PY2020's low performance is a result of inexperience in the analysis of the residential CBP product, unexpected shelter-in-place effects, and a low rate of automation. PG&E worked with PY2020's sole residential aggregator to incorporate performance feedback in its offerings. The reduced forecast is informed by the actual performance from PY2020, and the lower target is more realistic and achievable. PG&E also expects new aggregators to participate in residential CBP and anticipates increased automation for residential customers, which will further support the realization of the MW forecast.

PG&E forecasts growth through 2022 and maintains a constant forecast through the remainder of the forecast horizon. Figure 5-1 shows PG&E's CBP DA enrollment and load impact forecast for an August peak day under the PG&E 1-in-2 weather scenario.

Figure 5-1 PG&E CBP Enrollment and Load Impact Forecast (PG&E 1-in-2, August Peak Day)

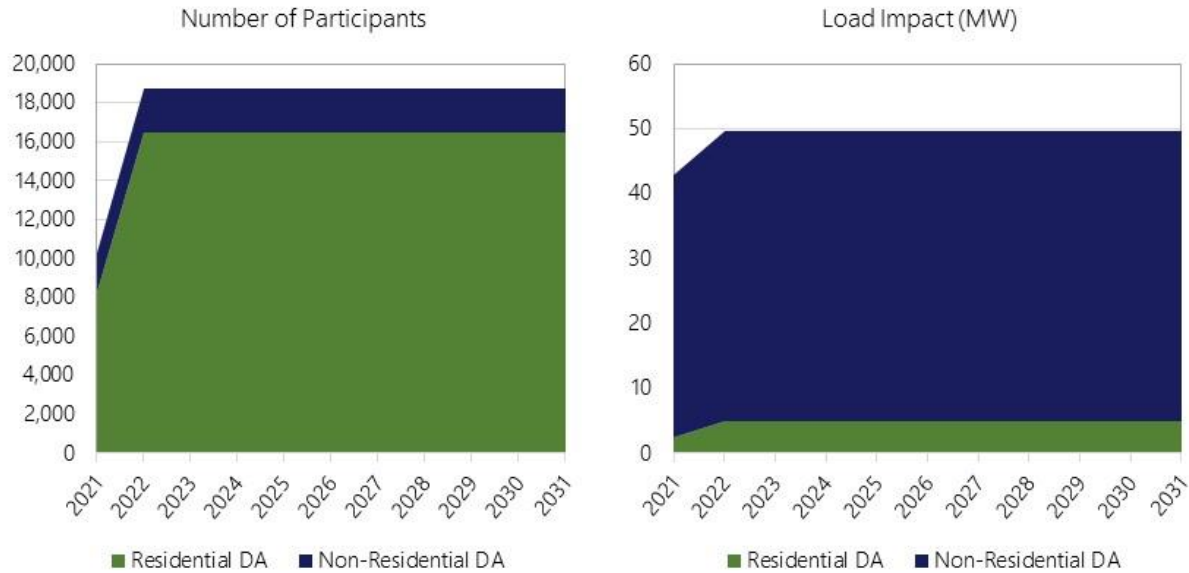


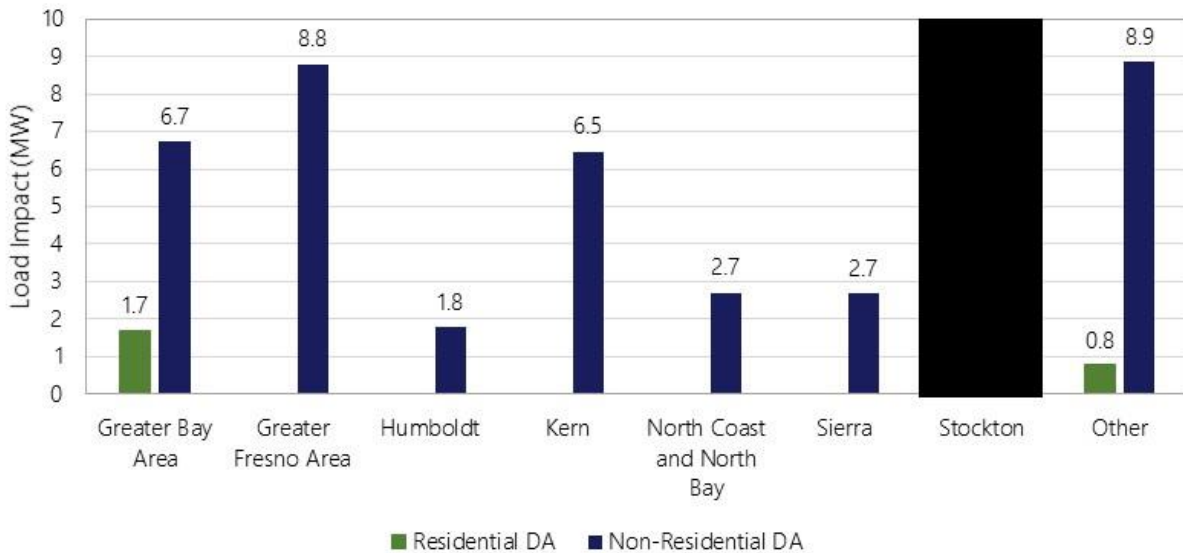
Table 5-3 summarizes the average RA window load impact forecasts for PG&E's CBP DA on an August peak day in 2021. The table includes the per-customer average impacts, aggregate impacts, and corresponding percent impacts under the 1-in-2 and 1-in-10 weather scenarios and for the utility peak and the CAISO peak.

Table 5-3 PG&E Non-Residential Day Ahead: Average RA Window Ex-Ante Impacts for an August Peak Day, 2020

Program	# of Accts	Per Customer Impact (kW)	Aggregate Impact (MW)	Percent Impact (%)			
				Utility Peak		CAISO Peak	
				1-in-2	1-in-10	1-in-2	1-in-10
Residential DA	8,247	0.3	2.4	20.7%	19.7%	21.3%	21.0%
Non-Residential DA	2,049	19.8	40.5	15.3%	15.0%	15.5%	15.2%

Figure 5-2 illustrates the average RA window load impacts distributed by LCA for residential and non-residential CBP DA on an August peak day in 2021. The results shown are for 1-in-2 weather conditions for the utility peak.

Figure 5-2 PG&E Day Ahead: Average RA Window Aggregate Load Impacts by LCA (PG&E 1-in-2, August Peak Day, 2021)



Hourly Load Impacts

As mentioned in Section 3, we estimated impacts across the 5-hour RA window using two components:

1. Load impact estimates for each customer using the hour called to most events in each PY2020 season. For PG&E, we used HE19 for both residential and non-residential programs. This estimate is assumed to be the maximum load impact on an event.
2. The shape of the impacts across the 5-hour event window based on historical events called for longer durations.

Using PY2020 events called, we developed a unique shape of impacts for both residential and non-residential event response. Residential historical load impacts show consistently flat responses even on longer event durations. Non-residential historical load impacts show the maximum load impact is achieved in the first hour and a slight decrease through the remainder of the event hours.

Table 5-4 shows the shape of the RA window impacts as a percent of the maximum impact for residential and non-residential.

Table 5-4 PG&E CBP: RA Window Shape of Impacts

Program	Percent of Maximum Impact				
	HE17	HE18	HE19	HE20	HE21
Residential DA	100%	100%	100%	100%	100%
Non-Residential DA	100%	90%	85%	51%	46%

Figure 5-3 and Figure 5-4 compare the per-customer estimated reference load, estimated event day load, and resulting load impact estimates for an August peak day in 2021 for PG&E's residential and non-residential CBP programs. The results are for the PG&E 1-in-2 weather condition. The hours highlighted in the blue-green show the Resource Adequacy (RA) window, 4 PM to 9 PM.

Figure 5-3 PG&E Non-Residential Day Ahead: Hourly Event Day Per-Customer Load (PG&E 1-in-2, August Peak Day, 2021)

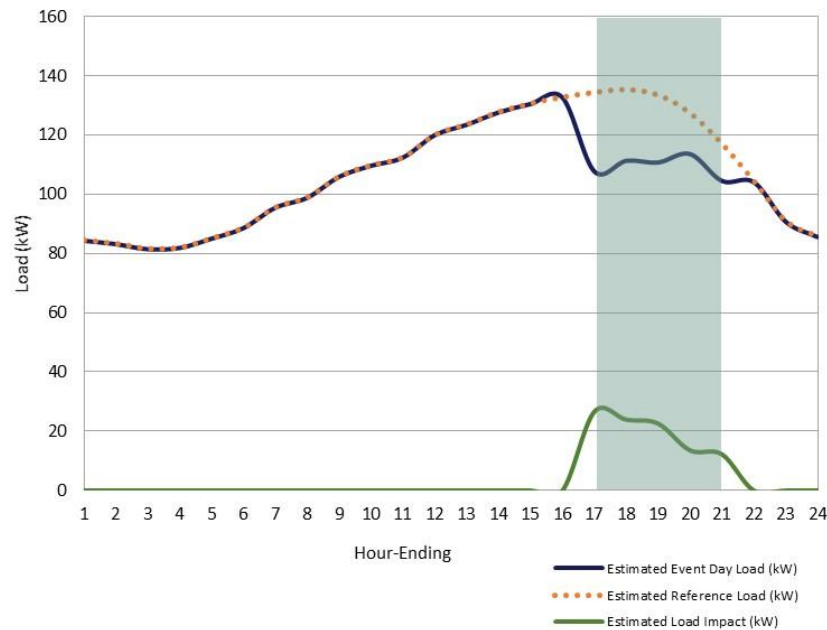
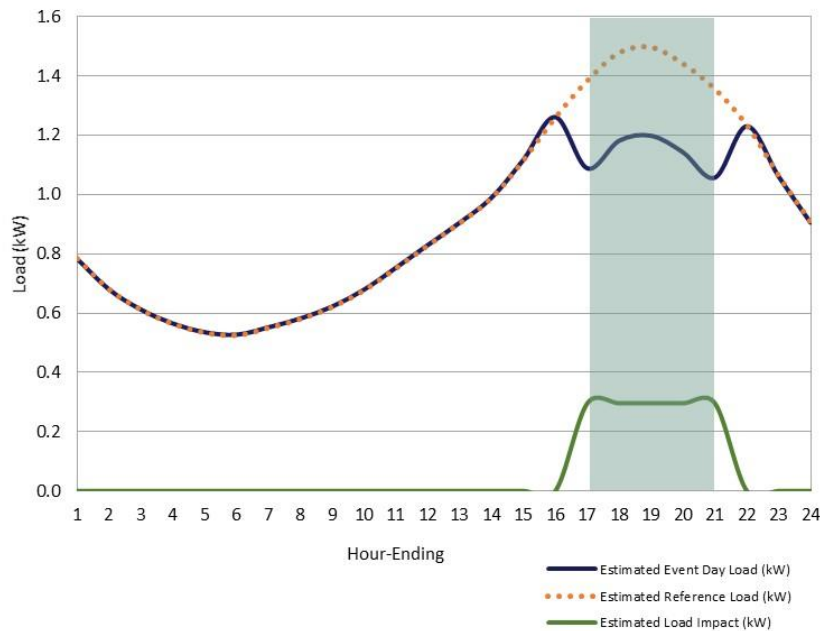


Figure 5-4 PG&E Residential Day Ahead: Hourly Event Day Per-Customer Load Impacts (PG&E 1-in-2, August Peak Day, 2021)



Comparison of Ex-Ante Impacts

In Table 5-5 and Table 5-6, we present the comparison of current ex-ante impacts to current ex-post impacts and current ex-ante impacts to prior ex-ante impacts, respectively.

Table 5-5 gives the reader a sense of how the program would have performed in a 1-in-2 weather year. In this comparison, we use HE19, and the same participant counts for both estimates, only changing weather inputs. The table below shows that the residential⁵⁰ events called in the PY2020 are comparable to PG&E 1-in-2 weather conditions. Non-residential events, on the other hand, are milder than PG&E 1-in-2 weather conditions. Participants in both programs show small positive weather responses, showing slightly higher reference loads under the 1-in-2 weather conditions.

Additionally, non-residential ex-ante impacts are calculated by size and LCA, regardless of product participation. Thus, we see an increase in per-customer and aggregate impacts relative to the ex-post average event day. This increase is not related to weather since we assume that CBP impacts are nomination-driven and non-weather responsive.

⁵⁰ For the purposes of this comparison, this table shows weather-adjusted residential impacts, which is different from PG&E's residential CBP 2021-2031 forecast.

Table 5-5 PG&E: Current Ex-Ante (PG&E 1-in-2, August Peak Day, 2020) v. Current Ex-Post (Average Event Day), HE19

Program	Estimate	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Residential DA	Current Ex-Ante	623	■	■	■	■	■	86
	Current Ex-Post	623	■	■	■	■	■	86
Non-Residential DA	Current Ex-Ante	531	129.59	25.49	68.87	13.55	20%	91
	Current Ex-Post	531	120.52	18.90	64.05	10.04	16%	85

Table 5-6 gives the reader a sense of how the program forecast changed since last year. These changes are the following:

- Enrollment forecast and average customer loads were updated based on PY2020 performance and program outlook.
- Assumptions on RA window impacts were updated based on events called for longer durations. This resulted in a lower average RA impact relative to PY2019 assumptions.

Table 5-6 PG&E: Current Ex-Ante v. Prior Ex-Ante (PG&E 1-in-2, August Peak Day, 2021), RA Window

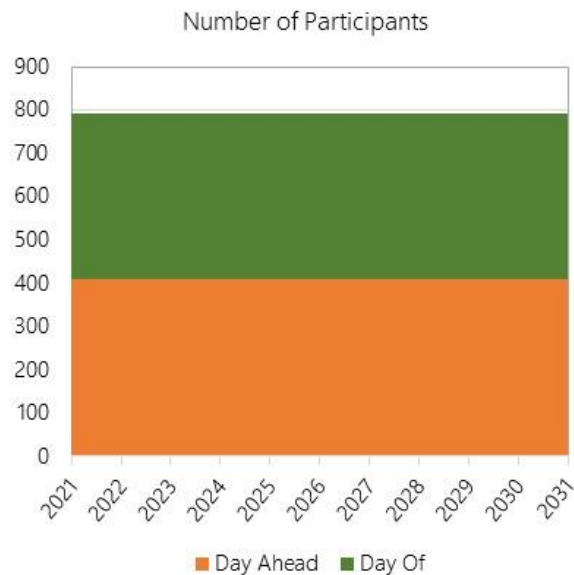
Program	Estimate	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Residential DA	PY2020 Forecast	8,247	1.4	0.3	11.8	2.4	21%	85
	PY2019 Forecast	25,000	-	0.4	-	10.0	-	-
Non-Residential DA	PY2020 Forecast	2,049	129.5	19.8	265.3	40.5	15%	90
	PY2019 Forecast	1,586	191.0	24.0	303.0	38.0	13%	89

SCE

Enrollment and Load Impact Summary

SCE's enrollment forecasts for both CBP DA and DO are derived from the average nominations during each season in PY2020, incorporating known and anticipated PY2021 participation. SCE also assumes a constant enrollment forecast for both non-residential CBP DA and DO throughout the 2021-2031 forecast horizon. Figure 5-5 shows SCE's non-residential CBP enrollment and load impact forecast for an August peak day (summer season) under the SCE 1-in-2 weather scenario.

Figure 5-5 SCE CBP Enrollment and Load Impact Forecast (SCE 1-in-2, August Peak Day)



For this filing, SCE assumes zero residential participation in CBP. Of the three counterparties that have expressed interest in PG&E's residential CBP since its inception, SCE has active bilateral DR contracts with two and is in active litigation with the third. Additionally, the CPUC has not ruled on SCE's Mid-Cycle advice filing, so the parameters of SCE's residential CBP cannot yet be determined.

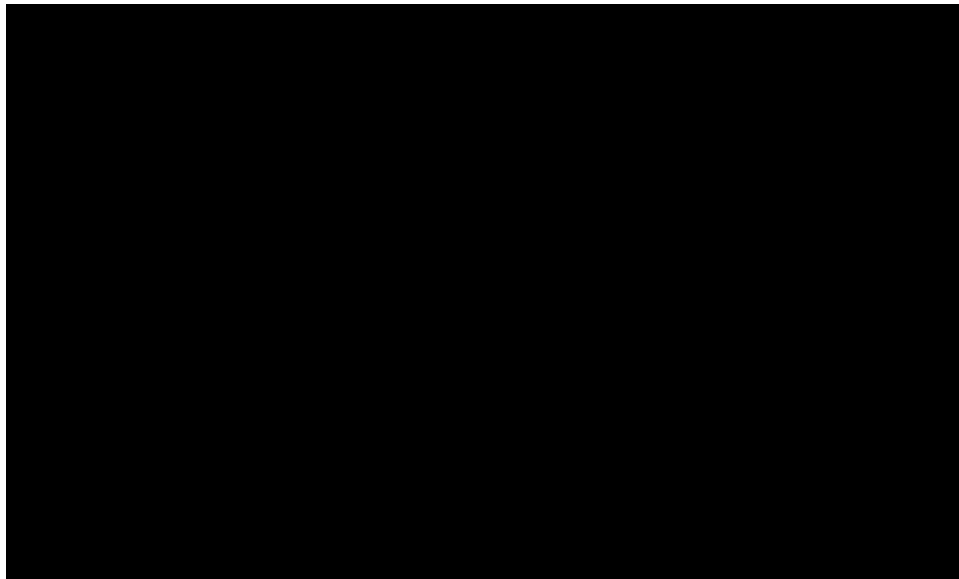
Table 5-7 summarizes the average RA window load impact forecasts for the DA and DO products on a January peak day (non-summer) and an August peak day (summer) in 2021. The table includes the per-customer average impacts, aggregate impacts, and corresponding percent impacts under the 1-in-2 and 1-in-10 weather scenarios and for the utility peak and the CAISO peak. Similar to PG&E, we assume constant per-customer average impacts across the weather scenarios. The varying percent impacts are due to the reference load's response to each weather scenario.

Table 5-7 SCE CBP: Average RA Window Ex-Ante Impacts, 2021

Season	Program	# of Accts	Per Customer Impact (kW)	Aggregate Impact (MW)	Percent Impact (%)			
					Utility Peak		CAISO Peak	
					1-in-2	1-in-10	1-in-2	1-in-10
Non-Summer	Day Ahead	4	■	■	■	■	■	■
	Day Of	11	■	■	■	■	■	■
Summer	Day Ahead	410	6.2	2.6	7.0%	7.0%	7.0%	7.0%
	Day Of	380	■	■	■	■	■	■

Figure 5-6 illustrates the average RA window load impacts distributed by LCA for non-residential CBP DA on an August peak day in 2021. The results shown are for 1-in-2 weather conditions for the utility peak.

Figure 5-6 SCE CBP: Ex-Ante Load Impacts by LCA (SCE 1-in-2, August Peak Day, 2021)



Hourly Load Impacts

As mentioned in Section 3, we estimated impacts across the 5-hour RA window using two components:

1. Load impact estimates for each customer using the hour called to most events in each PY2020 season. For SCE, we used HE18 and HE20 for non-summer and summer, respectively.
2. The shape of the impacts across the 5-hour event window based on historical events called for longer durations.

Historically, SCE CBP programs primarily achieve the maximum load impact in the first event hour, with the remainder of the event hours showing a slow decrease in delivered load impacts.

Non-summer DA, on the other hand, achieves maximum load impact on the second event hour. The load impact estimate on the selected hour (#1 above) is placed on the RA hour that achieves the maximum load impact for each program and season. Table 5-8 shows the estimated shape of the impacts as a percent of the maximum load impact for each program and season.

Table 5-8 SCE CBP: RA Window Shape of Impacts

Season	Program	Percent of Maximum Impact				
		HE17	HE18	HE19	HE20	HE21
Non-Summer	Day Ahead	86%	100%	72%	44%	16%
	Day Of	100%	90%	34%	75%	19%
Summer	Day Ahead	100%	79%	61%	58%	48%
	Day Of	100%	71%	57%	41%	50%

Figure 5-7 and Figure 5-8 compare the reference load, event day load, and resulting average customer load impacts for an August peak day in 2021 for the DA and DO products, respectively. The results are for the utility peak 1-in-2 weather conditions. The RA window is shown as a blue highlighted region.

Figure 5-7 SCE Day Ahead: Hourly Event Day Per-Customer Load Impacts (SCE 1-in-2, August Peak Day, 2021)

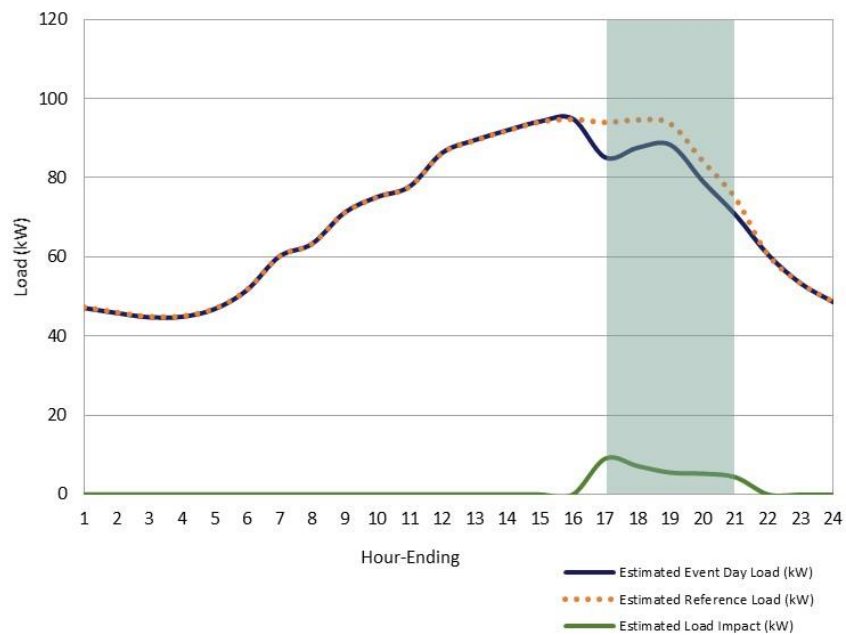


Figure 5-8 SCE Day Of: Hourly Event Day Per-Customer Load Impacts (SCE 1-in-2, August Peak Day, 2021)



Comparison of Ex-Ante Impacts

In Table 5-9 and Table 5-10 below, we present the comparison of current ex-ante impacts to current ex-post impacts and current ex-ante impacts to prior ex-ante impacts, respectively.

Table 5-9 gives the reader a sense of how the program would have performed in a 1-in-2 weather year. In this comparison, we use HE20, and the same participant counts for both estimates, only changing weather inputs. The table below shows that the events called in the PY2020 summer season are milder than SCE's 1-in-2 weather conditions. Participants in both programs also show a small negative weather response, showing slightly lower reference loads under the 1-in-2 weather conditions. As mentioned, we assume non-weather responsive impacts and see very little difference in the per-customer impacts.

Table 5-9 SCE: Current Ex-Ante (SCE 1-in-2, August Peak Day, 2020) v. Current Ex-Post (Average Summer Event), HE20

Product	Estimate	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Day Ahead	Current Ex-Ante	387	84.2	9.0	32.6	3.5	10%	88
	Current Ex-Post	387	90.7	10.1	35.1	3.9	11%	80
Day Of	Current Ex-Ante	312	■	■	■	■	■	88
	Current Ex-Post	312	■	■	■	■	■	78

Table 5-10 gives the reader a sense of how the program forecast changed since last year. These changes are the following:

- Enrollment forecast and average customer loads were updated based on PY2020 participation, which involved larger customers and a higher enrollment.
- Assumptions on RA window impacts were updated based on events called for longer durations. This resulted in a lower average RA impact relative to PY2019 assumptions, but impacts are still higher due to the change in program participation.

Table 5-10 SCE: Current Ex-Ante v. Prior Ex-Ante (SCE 1-in-2, August Peak Day, 2021), RA Window

Product	Estimate	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Day Ahead	PY2020 Forecast	410	88.3	6.2	36.2	2.6	7%	89
	PY2019 Forecast	384	■	■	■	■	■	90
Day Of	PY2020 Forecast	380	■	■	■	■	■	93
	PY2019 Forecast	233	■	■	■	■	■	90

SDG&E

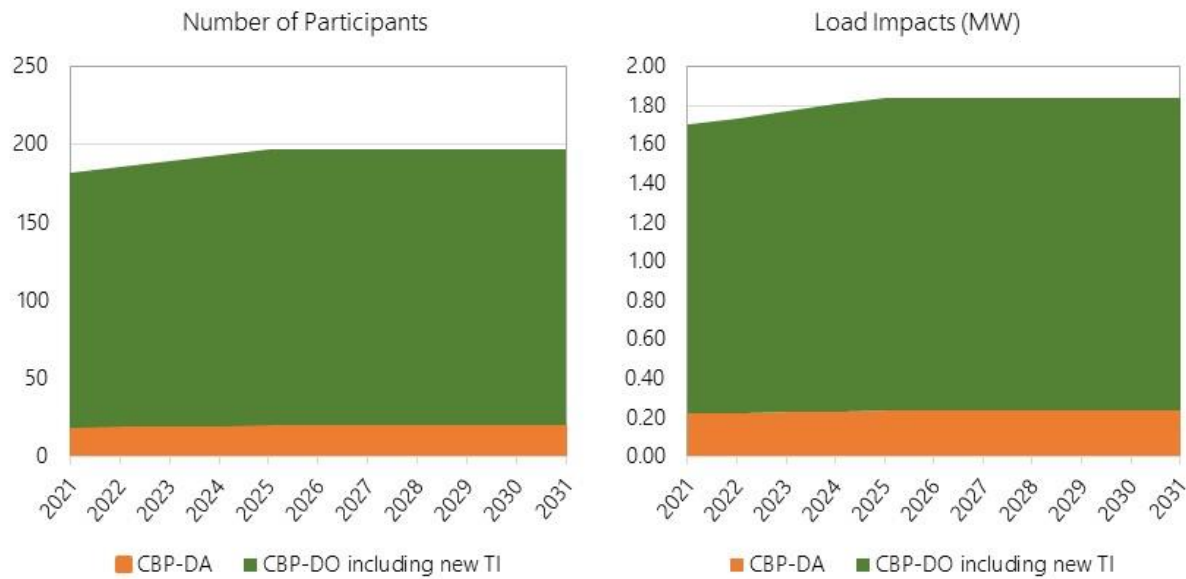
Enrollment and Load Impact Summary

SDG&E currently offers four CBP products. There are currently two DA 2-4 hour products, one with operating hours of 11 AM - 7 PM and the other with operating hours of 1 PM - 9 PM. Similarly, there are currently two DO 2-4 hour products, one with operating hours of 11 AM - 7 PM and the other with operating hours of 1 PM - 9 PM. SDG&E also simplified program triggers by basing it on price only, instead of on price and heat rate; this became effective July 1, 2018.

As in previous years, the enrollment forecast assumes the customer enrollment will increase by 2% per year starting in 2021 through 2025 due to the CBP program improvements proposed by SDG&E. In addition, SDG&E forecasts that the customer enrollment in the CBP DO program will increase by another 1% per year starting in 2021 through 2025 due to growth in the Technical Incentives (TI) program. Therefore, total DO enrollment is expected to increase by 3% per year starting in 2021 through 2025 due to program improvements and growth in TI. The enrollment forecasts for the DA and DO products after 2025 and through 2031 show a flat trend at the 2025 values.

Figure 5-9 shows SDG&E's non-residential CBP enrollment and load impact forecast for an August peak day under the SDG&E 1-in-2 weather scenario.

Figure 5-9 SDG&E CBP Enrollment and Load Impact Forecast (SDG&E 1-in-2, August Peak Day)



The ex-ante load impact forecast follows the 2021-2031 enrollment forecast trends for the DA and DO products. Similar to PG&E and SCE, we assume flat per-customer average impacts across the weather scenarios. The varying percent impacts are due to the reference load's response to each weather scenario. The impacts are also estimated to remain constant during the months of May through October.

Table 5-11 summarizes the average RA window load impact forecasts for the DA and DO products on an August peak day in 2020⁵¹. The table includes the per-customer average impacts, aggregate impacts, and corresponding percent impacts under the 1-in-2 and 1-in-10 weather scenarios and for the utility peak and the CAISO peak.

Table 5-11 SDG&E CBP: Average RA Window Ex-Ante Impacts for an August Peak Day, 2021

Notice	# of Accts	Per Customer Impact (kW)	Aggregate Impact (MW)	Percent Impact (%)			
				Utility Peak		CAISO Peak	
				1-in-2	1-in-10	1-in-2	1-in-10
Total Day Ahead	18	11.8	0.2	9.9%	9.6%	9.7%	9.8%
Total Day Of ⁵²	164	9.1	1.5	9.5%	9.3%	9.4%	9.4%

⁵¹ Though labeled as an August peak day in 2021, the results would be identical for each month, May through October, in the 2021 forecast.

⁵² SDG&E has two CBP DO forecasts. The forecast listed here includes new enrollments in the Technical Incentives (TI) program.

Hourly Load Impacts

As mentioned in Section 3, we estimated impacts across the 5-hour RA window using two components:

3. Load impact estimates for each customer using the hour called to most events in each PY2020 season. For SDG&E, we used HE19 for both programs. This estimate is assumed to be the maximum load impact on an event.
4. The shape of the impacts across the 5-hour event window based on historical events called for longer durations.

Historically, each SDG&E product showed a unique impact shape. Both DA and DO 1-9 Hour products achieve the maximum load impact in the first hour and show a slight decrease through the remainder of the event hours. The DA 11-7 Hour product shows consistently flat responses, while the DO 11-7 Hour product typically reaches maximum response on the second event hour.

Table 5-12 SDG&E CBP: RA Window Table 5-12 shows the RA window shape of the impacts as a percent of the maximum impact for each SDG&E CBP product. Note that both 11-7 Hour products show zero impacts on HE20-HE21 since these products are not available for these hours.

Table 5-12 SDG&E CBP: RA Window Shape of Impacts

Program	Product	Percent of Maximum Impact				
		HE17	HE18	HE19	HE20	HE21
Day Ahead	DA 11-7 Hour	100%	100%	100%	0%	0%
	DA 1-9 Hour	100%	69%	65%	56%	47%
Day Of	DO 11-7 Hour	61%	100%	72%	0%	0%
	DO 1-9 Hour	100%	84%	68%	58%	48%

Figure 5-10 and Figure 5-11 compare the reference load, event day load, and resulting aggregate load impacts for an August peak day in 2021 for the DA and DO products, respectively. The results are for 1-in-2 weather conditions and the utility peak.

Figure 5-10 SDG&E Day Ahead: Hourly Event Day Aggregate Load Impacts (SDG&E 1-in-2, August Peak Day, 2021)

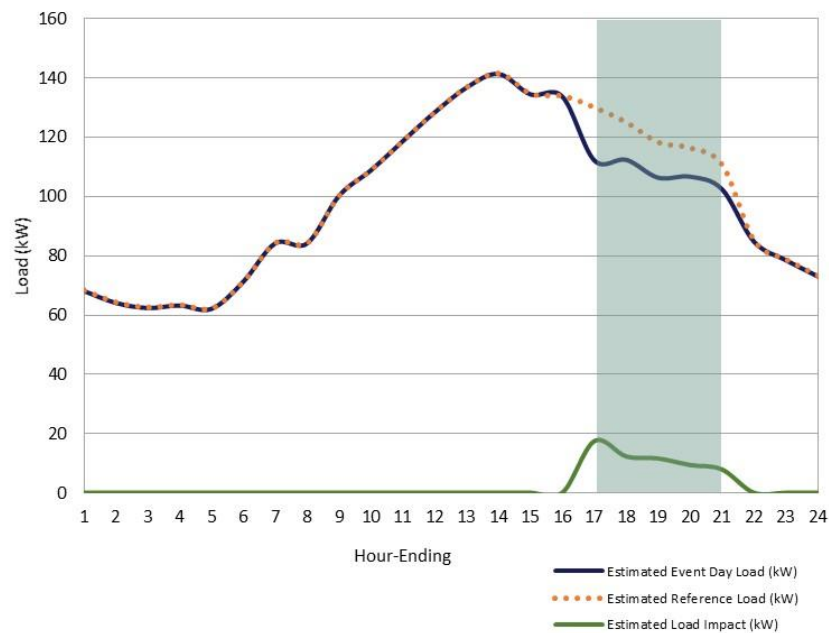
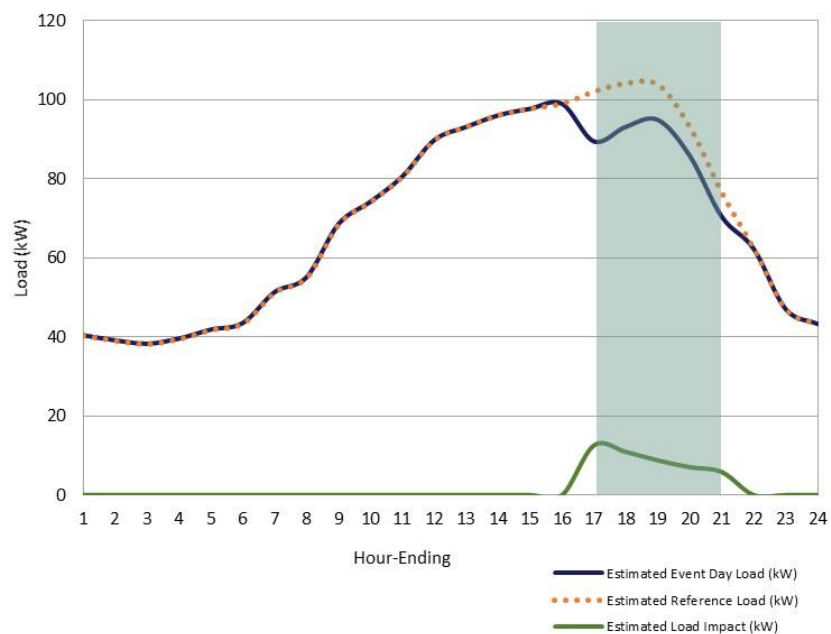


Figure 5-11 SDG&E Day Of: Hourly Event Day Aggregate Load Impacts (SDG&E 1-in-2, August Peak Day, 2021)



Comparison of Ex-Ante Impacts

In Table 5-13 and Table 5-14, we present the comparison of current ex-ante impacts to current ex-post impacts and current ex-ante impacts to prior ex-ante impacts, respectively.

Table 5-13 gives the reader a sense of how the program would have performed in a 1-in-2 weather year. In this comparison, we use HE19, and the same participant counts for both estimates, only changing weather inputs. The table below shows that the events called in the PY2020 are milder than SDG&E's 1-in-2 weather conditions. Participants in both programs also show a small negative weather response, showing slightly lower reference loads under the 1-in-2 weather conditions. As mentioned, we assume non-weather responsive impacts and see very little difference in the per-customer impacts.

Table 5-13 SDG&E: Current Ex-Ante (SDG&E 1-in-2, August Peak Day, 2020) v. Current Ex-Post (Average Event Day), HE19

Product	Estimate	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Day Ahead	Current Ex-Ante	23	118.2	17.6	2.7	0.4	15%	84
	Current Ex-Post	23	121.3	18.0	2.8	0.4	15%	78
Day Of	Current Ex-Ante	158	103.8	12.6	16.4	2.0	12%	83
	Current Ex-Post	158	115.4	13.8	18.3	2.2	12%	77

Table 5-14 gives the reader a sense of how the program forecast changed since last year. These changes are the following:

- Enrollment forecast and average customer loads were updated based on PY2020 participation, which involved smaller customers on average.
- Assumptions on RA window impacts were updated based on events called for longer durations. This resulted in a lower average RA impact relative to PY2019 assumptions.

Table 5-14 SDG&E: Current Ex-Ante v. Prior Ex-Ante (SDG&E 1-in-2, August Peak Day, 2021), RA Window

Product	Estimate	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Day Ahead	PY2020 Forecast	18	120.0	11.8	2.2	0.2	10%	84
	PY2019 Forecast	11	380.3	18.7	4.3	0.2	5%	84
Day Of	PY2020 Forecast	164	95.8	9.1	15.7	1.5	9%	83
	PY2019 Forecast	193	121.0	17.0	23.4	3.3	14%	83

6

KEY FINDINGS AND RECOMMENDATIONS

In this section, we present the key findings from the Statewide PY2020 CBP evaluation and recommendations for future program year evaluations.

Overview of Results

Table 6-1 presents the PY2020 average summer event day nominated capacity and impacts by program and IOU, in aggregate. On average, PG&E's DA program is the largest contributor with 10.1 MW on an average event day. None of the programs met/exceeded their nominated capacities. SDG&E's programs achieved the highest percent of delivered nominations with 71% and 74% for SDG&E DA and DO, respectively.

Table 6-1 Summary of PY2020 Ex-Post Impacts and Nominated Capacity: Average Summer Event Day

Utility	Day Ahead				Day Of			
	Nominated Accounts	Nominated Capacity (MW)	Aggregate Impact (MW)	% Delivered	Nominated Accounts	Nominated Capacity (MW)	Aggregate Impact (MW)	% Delivered
PG&E	1,155	█	█	64%	-	-	-	-
SCE	387	6.0	3.9	65%	312	█	█	67%
SDG&E	23	0.6	0.4	71%	158	2.9	2.2	74%

Table 6-2 compares the average RA window ex-ante impact estimates, in aggregate, for an August peak day in 2021 versus 2031. SCE assumes a flat 11-year enrollment forecast, PG&E assumes program growth through 2022, and SDG&E assumes program growth through 2025. The SDG&E DO forecast shown below includes new enrollments in the TI program.

Table 6-2 Summary of Average RA Window Ex-Ante Impacts, August Peak Day, 2021 v. 2031

Utility	Day Ahead				Day Of			
	PY 2021		PY 2031		PY 2021		PY 2031	
	# of Accts	Aggregate Impact (MW)	# of Accts	Aggregate Impact (MW)	# of Accts	Aggregate Impact (MW)	# of Accts	Aggregate Impact (MW)
PG&E	10,296	42.9	18,752	49.6	-	-	-	-
SCE	410	2.6	410	2.6	380	█	380	█
SDG&E	18	0.2	20	0.2	164	1.5	177	1.6

Key Findings by IOU

This section discusses each IOU's CBP PY2020 findings. Please note the following:

- The average day represents a wide range of events. All events called are included in calculating the average, regardless of participant count and event timing. Results for the most prevalent event hour⁵³ are presented.
- Meeting or exceeding capacity nominations is the true measure of the program's success. Customer recruitment is equally important, but since events are called based on different triggers, low participation counts and low aggregate impacts do not necessarily mean poor response. Meeting or exceeding capacity nominations means that aggregators and customers were able to curtail their load when asked to do so.

PG&E

In PY2020, PG&E implemented minor changes in the CBP implementation, which allowed eligible participation of nominated residential customers. PG&E's CBP continues to have only Day Ahead product offerings and remains a geographically targeted DR, calling 6 or less Sub-LAPs (out of 14 total) in 19 events (out of 28 total).

Table 6-3 Summary of PG&E PY2020 Ex-Post Impacts and Nominated Capacity: Average Event Day

Program	Day Ahead			
	Nominated Accounts	Nominated Capacity (MW)	Aggregate Impact (MW)	% Delivered
Residential DA	623	■	■	■
Non-Residential DA	531	15.59	10.04	64%
Total Program	1,155	■	■	64%

This year, we have the following key findings:

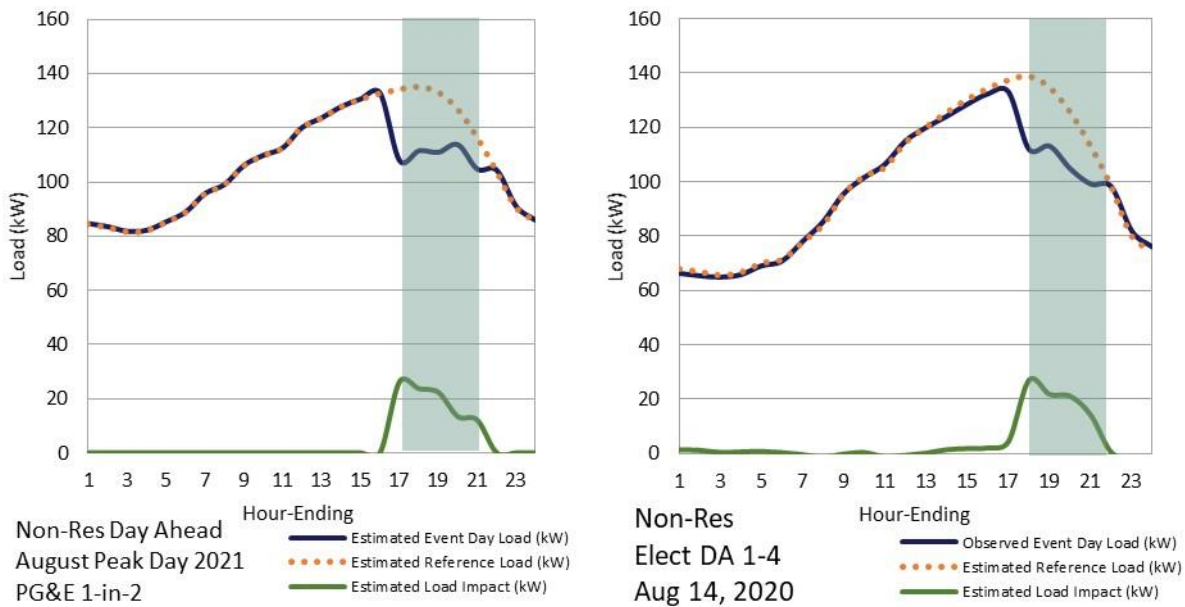
- PG&E's CBP program called the most diverse events among the 3 IOUs with 1 to 14 Sub-LAPs called, 1 to 1,647 participants nominated, and event windows between the hours of 2 PM and 9 PM. The average event day shows results for HE19 (6 PM – 7 PM) since it is the window that PG&E events have most in common. Table 4-3 summarizes the PY2020 events in more detail.
- The entire DA program, on average, did not meet/exceed their capacity nominations, only delivering 64% of nominated capacities. However, PG&E's DA program is also the largest contributor with 10.0 MW non-residential reductions, on average.
- Participation adjusts to fill aggregator nominations. Comparisons of PY2020 load impacts to previous program years show that the participant population consistently changes

⁵³ PG&E and SDG&E show HE19. SCE show HE18 and HE20 for non-summer and summer estimates, respectively.

from year-to-year. PY2020 electric usage saw shifts in all customer classes, but aggregator recruitment determines the appropriate customers capable of curtailing load when needed.

- Ex-ante impact assumptions were updated to better estimate a 5-hour event called during the RA window. Figure 6-1 shows a side-by-side comparison of the PG&E 1-in-2 Non-Residential Day Ahead 2021 August Peak Day and August 14th Elect DA 1-4 Hour event. The two figures show how the assumptions capture participants' responses to longer duration events. The differences in magnitude are driven by the participants included in both averages. The ex-ante estimates include all DA participants, while the ex-post estimates only include participants called to the August 14th event.

Figure 6-1 PG&E Non-Residential Day Ahead: Hourly Load Impact Comparison



SCE

Effective January 19, 2020, SCE's dispatch window shifted to 3 PM to 9 PM, previously being 1 PM to 7 PM. SCE continued to offer both DA and DO products with 1-6 hour durations. SCE's CBP is essentially a geographically targeted DR, calling individual Sub-LAPs as awarded by CAISO. However, similar to PY2019, SCE only called a handful of localized events in PY2020, calling mostly system-level events. The variability in event characteristics is due to the variability in monthly nominations both across the two seasons (summer v. non-summer).

Table 6-4 presents the average event day nominated capacity and impacts by program and season, in aggregate. It also shows the estimated delivered impacts as a percent of nominations.

Table 6-4 Summary of SCE PY2020 Ex-Post Impacts and Nominated Capacity: Average Event Day

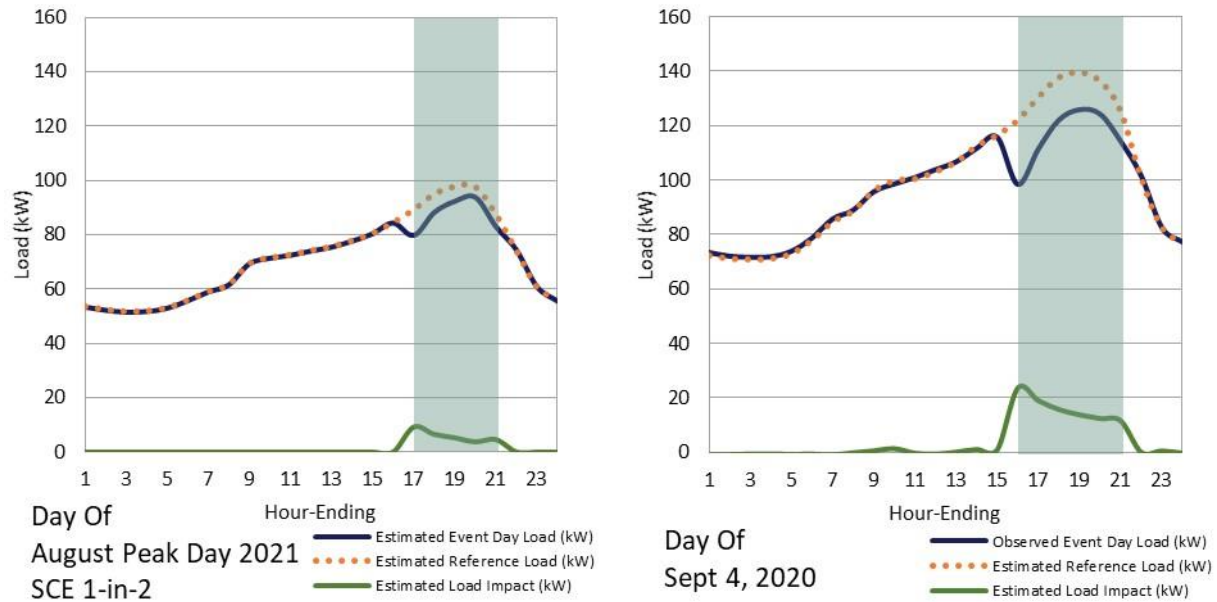
Season	Day Ahead				Day Of			
	Nominated Accounts	Nominated Capacity (MW)	Aggregate Impact (MW)	% Delivered	Nominated Accounts	Nominated Capacity (MW)	Aggregate Impact (MW)	% Delivered
Non-Summer	3	■	■	103%	5	■	■	11%
Summer	387	6.0	3.9	65%	312	■	■	67%

This year, we have the following key findings:

- Similar to PG&E, the average event day represents a wide range of events with 1 to 6 Sub-LAPs called, 1 to 831 participants nominated, and event widows between the hours of 2 PM⁵⁴ and 9 PM. Most non-summer events were called between 5 PM – 6 PM, and most summer events were called between 7 PM – 8 PM; thus, reporting shows HE18 and HE20 for average non-summer and average summer event days, respectively.
- The DA non-summer season was successful in exceeding their nominated capacity, on average, at 103% of nominations delivered. However, these three participants are no longer participating in future non-summer seasons but will continue to participate in future summer events.
- Both DO seasons and the DA summer season were unsuccessful in meeting or exceeding their nominated capacities, on average. SCE's summer season shows 65% and 67% of nominations delivered for DA and DO, respectively. Both programs showed success in the majority of June and September events. DO non-summer season, however, showed very poor delivery with only 11% of nominations delivered.
- Participation adjusts to fill aggregator nominations. Comparisons of PY2020 load impacts to previous program years show that the participant population consistently changes from year-to-year. PY2020 electric usage saw shifts in all customer classes, but aggregator recruitment determines the appropriate customers capable of curtailing load when needed.
- Ex-ante impact assumptions were updated to better estimate a 5-hour event called during the RA window. Figure 6-2 shows a side-by-side comparison of the SCE 1-in-2 Day Of 2021 August Peak Day and September 4th DO 1-6 Hour event. The two figures show how the assumptions capture participants' responses to longer duration events. The differences in magnitude are driven by the participants included in both averages. The ex-ante estimates include all DO summer participants, while the ex-post estimates only include participants called to the September 4th event.

⁵⁴ Events called from 2PM-3PM occurred before the effective change in SCE's dispatch window.

Figure 6-2 SCE Day Of: Hourly Load Impact Comparison



SDG&E

SDG&E currently offers four CBP products and continues to have both Day Ahead and Day Of programs with two sets of operating hours: 11 AM – 7 PM and 1 PM – 9 PM. Table 6-5 presents the average event day nominated capacity and impacts by program and product, in aggregate. It also shows the estimated delivered impacts as a percent of nominations.

Table 6-5 Summary of SDG&E PY2020 Ex-Post Impacts and Nominated Capacity: Average Event Day

Product	Day Ahead				Day Of			
	Nominated Accounts	Nominated Capacity (MW)	Aggregate Impact (MW)	% Delivered	Nominated Accounts	Nominated Capacity (MW)	Aggregate Impact (MW)	% Delivered
11 AM to 7 PM	4	0.2	<0.1	8%	67	0.9	0.2	17%
1 PM to 9 PM	19	0.4	0.4	110%	91	2.0	2.0	99%
Total Program	23	0.6	0.4	71%	158	2.9	2.2	74%

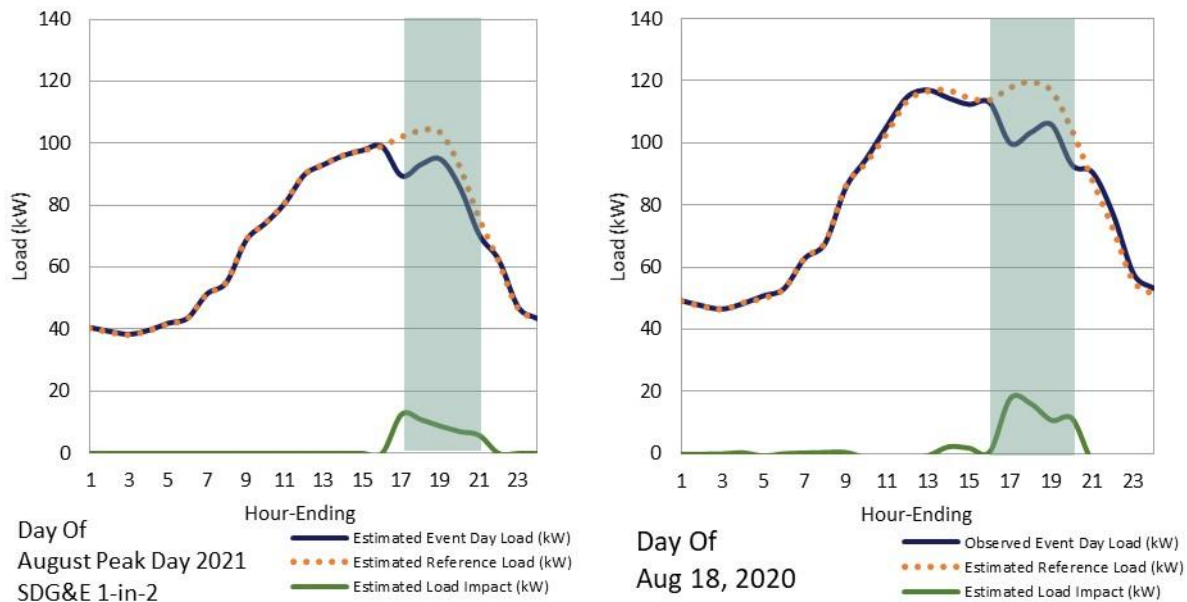
This year, we have the following key findings:

- SDG&E's CBP program continued to call events as needed by calling on different products on different event windows within the same day. For example, the DA 11 AM to 7 PM

nominations were called between 3 PM – 7 PM, while the DA 1 PM to 9 PM nominations were called between 6 PM – 8 PM.

- The products under the 1 PM to 9 PM dispatch window successfully met their capacity nominations in both programs, on average. Participants nominated for these two products achieved 110% (DA) and 99% (DO) of nominations delivered.
- SDG&E's DA and DO programs were not successful in meeting nominated capacities, on average. The products under the 11 AM to 7 PM dispatch window did not successfully meet nominated capacities, showing poor deliveries. This brought down the program averages to 71% and 74% for DA and DO, respectively.
- Consistent with the other IOUs, ex-ante impact assumptions were updated to better estimate a 5-hour event called during the RA window. Figure 6-3 shows a side-by-side comparison of the SDG&E 1-in-2 Day Of 2021 August Peak Day and August 18th DO event. The two figures illustrate how the assumptions capture participants' responses to longer duration events. The differences in magnitude are driven by the participants included in both averages. The ex-ante estimates include all DO participants, while the ex-post estimates only include participants called to the August 18th event.

Figure 6-3 SDG&E Day Of: Hourly Load Impact Comparison



Recommendations

AEG has the following recommendations for future research and evaluation related to the Capacity Bidding Programs.

- Reevaluate the definition of the average event day. The current definition, consistent across all IOUs, includes all events called calculating the average, regardless of participant

count and event timing. Results for the most prevalent event hour⁵⁵ are presented. In PY2020, a number of events were called in “outlier” hours, i.e., PG&E’s September 14th event on HE15. Although only a handful, these outlier events, by definition, are included in the average but are not represented in the reported event hour. As more outlier events are dispatched, it is likely that certain exclusions may be considered and applied as appropriate.

- **Clearly differentiate between nominated customers and dispatched customers.** In future evaluation reports PG&E suggests, and AEG agrees, that the terminology should be updated to more clearly differentiate between customers nominated on a monthly or seasonal basis and those actually called, or dispatched, for individual events. This includes the differentiation between nominated load and delivered load. In this report, we refer to the total enrolled customers and their associated impact as the nomination or nominated load. For a specific event, nomination refers to number of customers that were called, or dispatched, and the impact that was delivered on a given event.

⁵⁵ PG&E and SDG&E show HE19. SCE show HE18 and HE20 for non-summer and summer estimates, respectively.

A

APPENDICES

PG&E CBP Ex-Post Table Generator

PG&E CBP Ex-Ante Table Generator (Non-Residential)

SCE CBP Ex-Post Table Generator

SCE CBP Ex-Ante Table Generator (Non-Residential)

SDG&E CBP Ex-Post Table Generator

SDG&E CBP Ex-Ante Table Generator

B

MODEL VALIDITY

We selected and validated customer-specific regression models during our optimization process. The customer-specific models are designed to be able to:

- Accurately predict the actual participant load on event days, and
- Accurately predict the reference load, or what customers would have used on event days, in absence of an event.

To meet these two specific goals, our optimization process included an analysis of both the in-sample and out-of-sample mean absolute percent error (MAPE) and mean percent error (MPE) for each of the candidate regression models for each IOU and product. We used the out-of-sample tests to show how well each of the candidate models could predict a customer's load on non-event days that were as similar as possible to actual event days; this test gave us an estimate of how well each model could predict the reference load. We used the in-sample tests to show how well each model performed on the actual event days; therefore, it helped us understand how well the model was able to match the actual load.

As described in Section 3, our optimization procedure has four key steps: (1) assessing weather sensitivity; (2) in-sample and out-of-sample testing; (3) assessing model validity; and, (4) model fine-tuning. This section presents metrics related to steps 2 and 3, specifically:

- Selection of event-like days used in out-of-sample testing.
- Metrics from in-sample and out-of-sample tests from the final models of the ex-post analysis: MAPE, MPE, and comparison load graphs.

Selecting Event-Like Days

To select similar non-event days, we used a Euclidean Distance matching approach. Euclidean distance is a simple and highly effective way of creating matched pairs. To determine how close event day temperature is to a potential event-like day, we calculated a Euclidean distance metric defined as the square root of the sum of the squared differences between the matching variables. Any number of relevant variables could be included in the Euclidean distance; in this program year, we included three weather variables in the Euclidean distance metrics calculation to select similar non-event days: (1) daily maximum temperature; (2) daily minimum temperatures; and (3) average daily temperature. The Euclidean distance metric used can be calculated by Equation B1 below.

$$ED = \sqrt{(MaxTemp_{event} - MaxTemp_{non-event})^2 + (MinTemp_{event} - MinTemp_{non-event})^2 + (MeanTemp_{event} - MeanTemp_{non-event})^2} \quad (B1)$$

In Figure B-1 to Figure B-3, we show comparisons of the distributions of average daily temperature of event days and event-like days. We show a single utility level comparison because

these dates were chosen at the utility level, i.e. all subgroups have the same set of event and event-like dates.

Figure B-1 PG&E Average Daily Temperatures of Event Days v. Event-Like Days

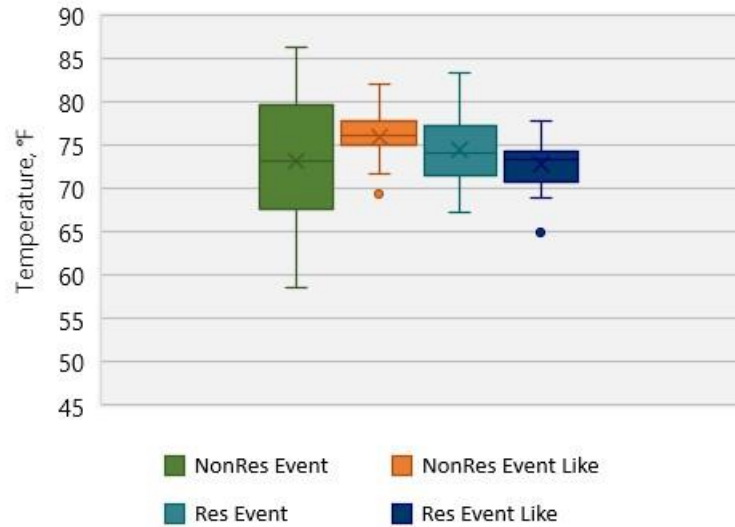


Figure B-2 SCE Average Daily Temperatures of Event Days v. Event-Like Days

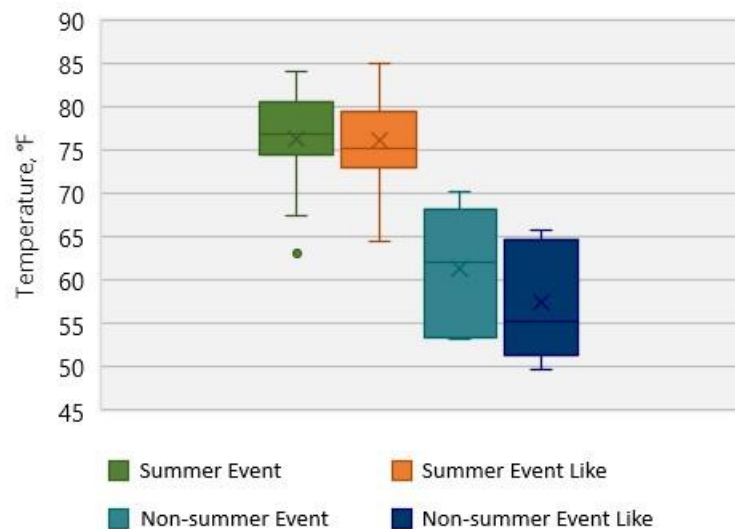
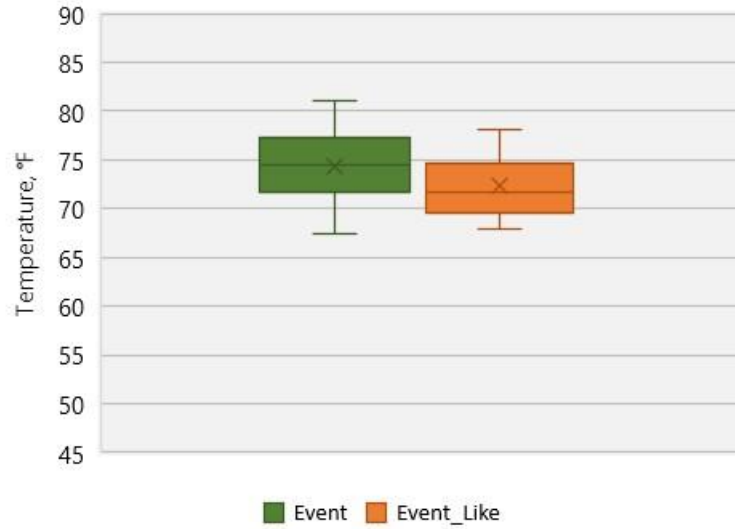


Figure B-3 SDG&E Average Daily Temperatures of Event Days v. Event-Like Days



Optimization Process and Results

Next, we estimated the MAPE and MPE, for the entire day, for each IOU and product, and for each candidate model, both for the in-sample and the out-of-sample scenarios:

- To perform the in-sample test, we fitted each candidate model to the entire data set. The results of these fitted models are used to predict the usage on event days. Then we assessed the accuracy and bias of the predictions by calculating the in-sample MAPE and in-sample MPE, respectively.
- To perform the out-of-sample test, we remove the out-of-sample event-like days from the analysis dataset and the candidate models are fitted to the remaining data. Then we assessed the accuracy and bias of the predictions by calculating the out-of-sample MAPE and out-of-sample MPE, respectively.

These two tests resulted in several in-sample and out-of-sample metrics. Recall that the goal of the tests is to find the best model for each participant in terms of its ability to predict the reference load and the actual load for each subgroup. Therefore, for each participant, we combined the two tests into a single metric, giving each candidate model a single metric. The metric is defined in as follows:

$$\mathbf{metric}_{ic} = (0.4 * MAPE_{in}) + (0.4 * MAPE_{out}) + (0.1 * abs(MPE_{in})) + (0.1 * abs(MPE_{out}))$$

Where,

$$MAPE = \frac{100\%}{n} \sum_{h=1}^n \left| \frac{Actual_h - Estimate_h}{Actual_h} \right|, \quad MPE = \frac{100\%}{n} \sum_{h=1}^n \frac{Actual_h - Estimate_h}{Actual_h}$$

Once we have a single metric for each participant and candidate model combination, we selected the best model for each participant by choosing the model specification with the smallest overall metric. The results of the optimization process are shown in the following tables and figures.

Table B-1 presents the weighted average MAPE and MPE for the final set of models for each IOU, by product. A three IOUs and products have MAPE and MPE estimates below 2.1%. PG&E's small group has approximately 4.3% MAPE and MPE, which are still relatively low. We see very small MPE values, which indicate relatively low level of bias. Most out-of-sample MPE values are negative and most in-sample MPE values are positive, which indicates that withholding event-like days cause predicted reference loads that are higher than actual values.

Table B-1 Weighted Average MAPE and MPE by Utility and Product

Utility	Product	Out-of-Sample		In-Sample	
		MAPE	MPE	MAPE	MPE
PG&E	Residential Elect DA	0.04%	-0.01%	0.02%	0.00%
	Non-Residential Elect DA	1.09%	0.46%	0.39%	-0.12%
	Non-Residential Prescribed DA	2.43%	0.17%	1.91%	-0.31%
SCE	Day Ahead	2.18%	0.09%	2.04%	-0.11%
	Day Of	1.63%	0.44%	1.50%	0.04%
SDG&E	Day Ahead	3.08%	-0.09%	2.04%	-0.05%
	Day Of	1.70%	0.40%	1.62%	-0.16%

Figure B-4 to Figure B-6 present the average event-like day predicted loads (dotted lines) and actual loads (solid lines) from the in-sample and out-of-sample tests by utility and size group. In each case, the predicted load is very close to the actual load. This tells us that on average, the customer-specific regression models do a very good job estimating what customer loads would be like on event-like days, and therefore are able to produce very accurate reference loads.

Figure B-4 PG&E Actual and Predicted Loads

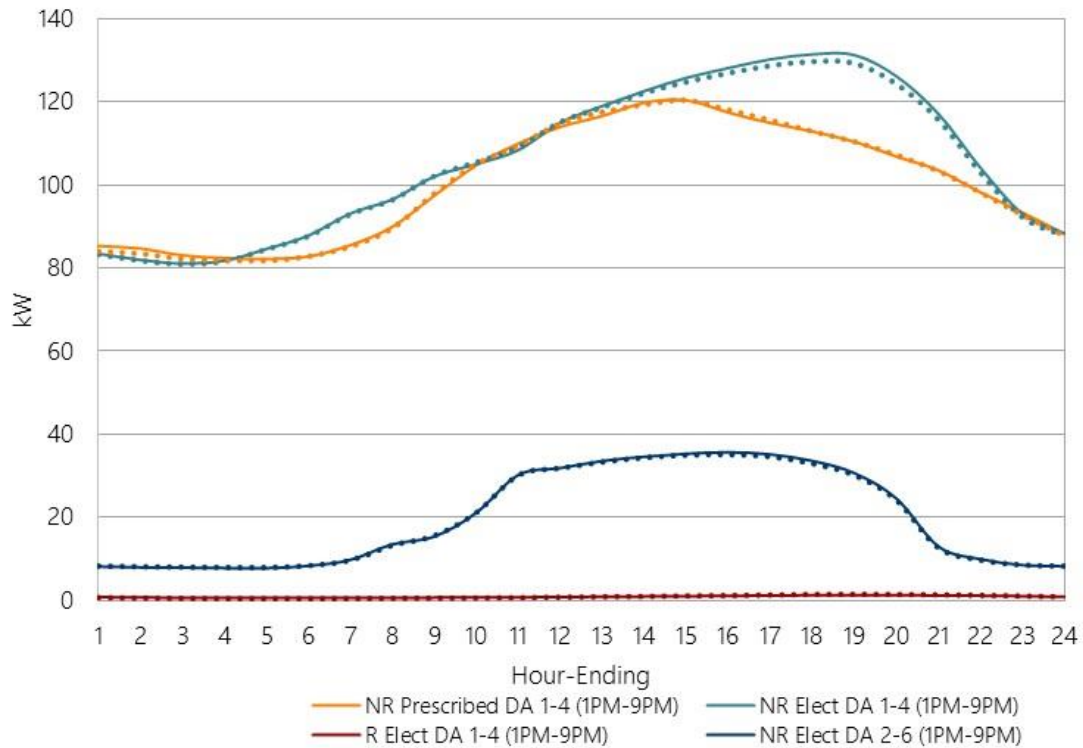


Figure B-5 SCE Actual and Predicted Loads

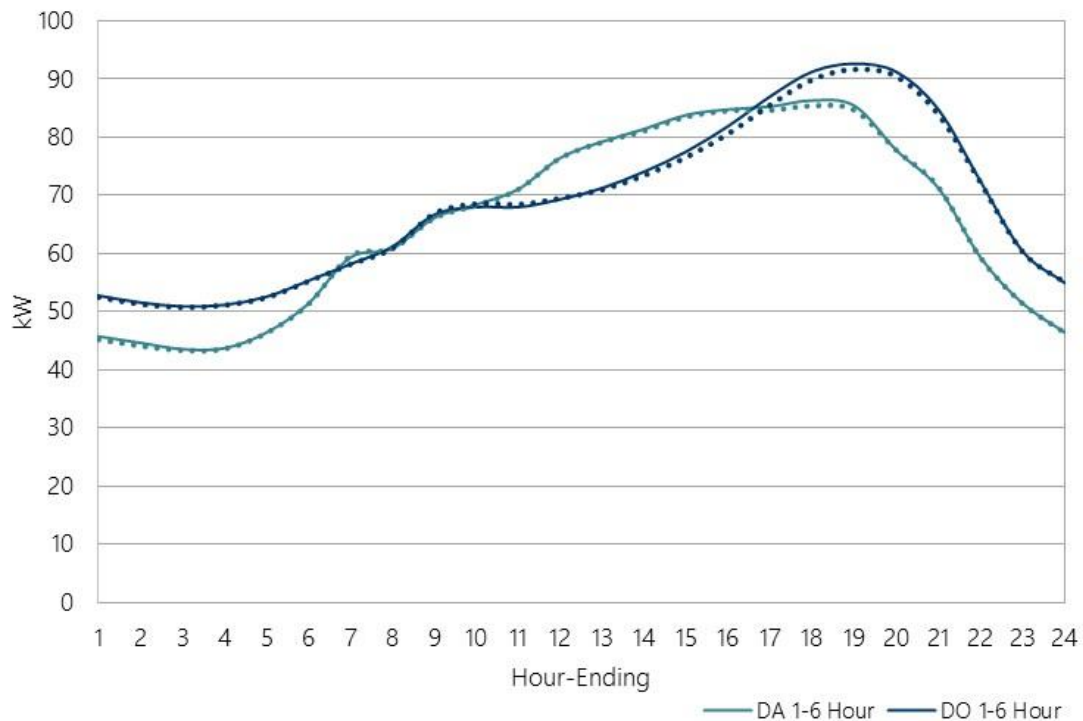
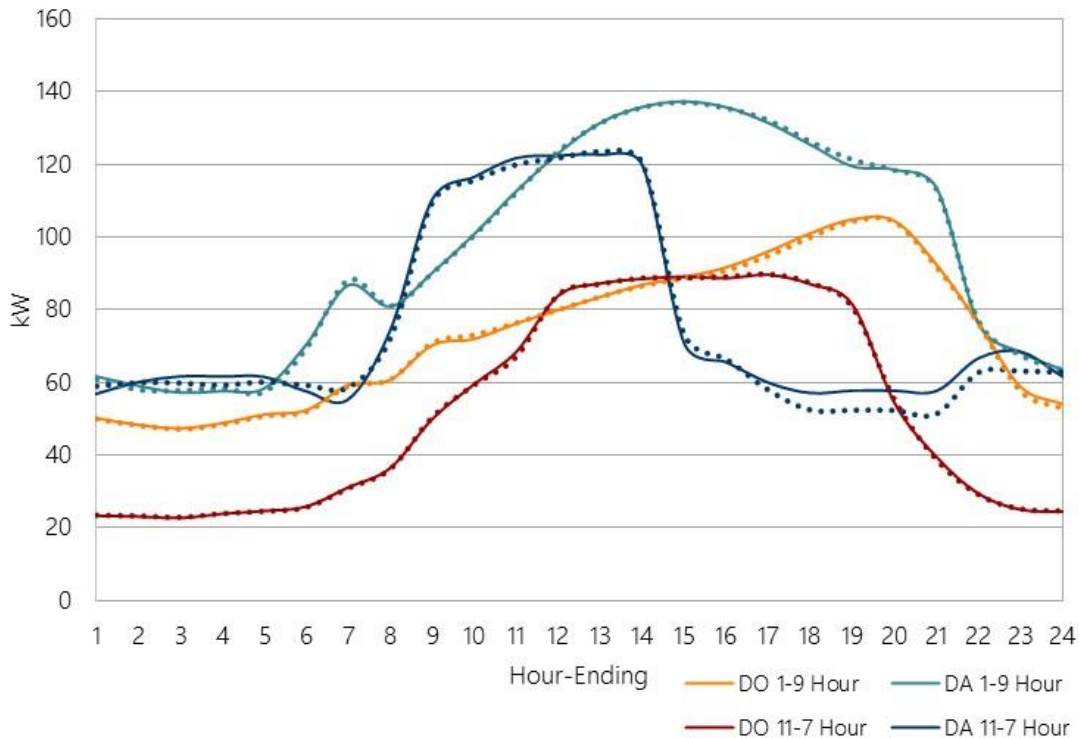


Figure B-6 SDG&E Actual and Predicted Loads



Additional Checks

Visual inspection can be a simple but highly effective tool. During the inspection, we looked for specific aspects of the predicted and reference load shapes to tell us how well the models performed. For example,

- We checked to make sure that the reference load is closely aligned with the actual and predicted loads during the early morning and late evening hours when there is likely to be little effect from the event. Large differences can indicate that there is a problem with the reference load either over- or under-estimating usage in absence of the event.
- We closely examined the reference load for odd increases or decreases in load that could indicate an effect that is not properly being captured in the models. If we found such an increase or decrease, we investigated the cause and attempted to control for the effect in the models.
- We also looked for bias, both visually and mathematically. Bias is the consistent over- or under-prediction of the actual load. We may see bias that is temperature-related, under-predicting on hot days, and over-predicting on cool days. We have also seen bias that is time-based, over-predicting in the beginning of the year, and under-predicting at the end of the year. Identification of bias and its source often allows us to adjust the models to capture and isolate the bias-inducing effects within the model specification.

C

ADDITIONAL SCE EX-POST SUMMARIES

Table C-1 through Table C-4 show the event day impacts for two additional geographical areas in SCE's service territory: South of Lugo and Southern Orange County.

South of Lugo

Table C-1 South of Lugo Event Day Impacts: Day Ahead 1-6 Hour

Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
		Reference Load	Impact	Reference Load	Impact		
Nov 4, 2019	3	■	■	■	■	■	74
Nov 5, 2019	3	■	■	■	■	■	82
Nov 6, 2019	3	■	■	■	■	■	85
Nov 7, 2019	3	■	■	■	■	■	76
Nov 8, 2019	3	■	■	■	■	■	82
Dec 2, 2019	3	■	■	■	■	■	59
May 28, 2020	33	■	■	■	■	■	69
Jun 2, 2020	105	■	■	■	■	■	79
Jun 3, 2020	105	114.4	20.2	12.0	2.1	18%	80
Jun 4, 2020	105	115.2	29.8	12.1	3.1	26%	83
Jun 10, 2020	105	■	■	■	■	■	87
Jul 9, 2020	119	129.2	29.5	15.4	3.5	23%	80
Jul 10, 2020	119	147.9	20.6	17.6	2.5	14%	85
Jul 13, 2020	119	132.3	20.6	15.7	2.5	16%	91
Jul 27, 2020	119	125.0	29.5	14.9	3.5	24%	81
Aug 3, 2020	115	139.5	35.0	16.0	4.0	25%	81
Aug 12, 2020	115	144.2	35.0	16.6	4.0	24%	83
Aug 13, 2020	115	139.8	12.8	16.1	1.5	9%	88
Aug 14, 2020	115	■	■	■	■	■	95
Aug 17, 2020	115	■	■	■	■	■	92
Sep 3, 2020	124	139.8	26.7	17.3	3.3	19%	79
Sep 4, 2020	124	■	■	■	■	■	89
Sep 8, 2020	124	135.2	17.0	16.8	2.1	13%	82
Sep 9, 2020	124	■	■	■	■	■	77
Sep 10, 2020	124	141.8	38.0	17.6	4.7	27%	84
Oct 1, 2020	124	140.0	11.4	17.4	1.4	8%	99
Oct 2, 2020	124	■	■	■	■	■	95
Oct 5, 2020	124	113.8	18.2	14.1	2.3	16%	89

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Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
		Reference Load	Impact	Reference Load	Impact		
Oct 6, 2020	124	■	■	■	■	■	87
Oct 7, 2020	124	135.5	20.6	16.8	2.6	15%	83

Table C-2 South of Lugo Event Day Impacts: Day Of 1-6 Hour

Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
		Reference Load	Impact	Reference Load	Impact		
Feb 3, 2020	4	■	■	■	■	■	58
Feb 4, 2020	4	■	■	■	■	■	58
Feb 6, 2020	4	■	■	■	■	■	57
May 28, 2020	101	46.9	6.4	4.7	0.7	14%	78
Jun 2, 2020	132	51.1	18.6	6.7	2.5	36%	78
Jun 3, 2020	132	60.7	19.1	8.0	2.5	31%	79
Jun 4, 2020	132	55.1	18.6	7.3	2.5	34%	81
Jun 10, 2020	132	72.8	18.6	9.6	2.5	26%	87
Jul 9, 2020	120	72.1	13.7	8.7	1.6	19%	79
Jul 10, 2020	120	78.0	14.3	9.4	1.7	18%	84
Jul 13, 2020	120	76.2	14.3	9.1	1.7	19%	90
Jul 27, 2020	120	71.6	13.7	8.6	1.6	19%	80
Aug 3, 2020	125	72.3	10.9	9.0	1.4	15%	80
Aug 12, 2020	125	74.9	10.9	9.4	1.4	15%	82
Aug 13, 2020	125	73.2	7.2	9.1	0.9	10%	87
Aug 14, 2020	125	80.5	6.7	10.1	0.8	8%	94
Aug 17, 2020	125	81.2	6.7	10.1	0.8	8%	90
Sep 3, 2020	83	90.7	13.7	7.5	1.1	15%	78
Sep 4, 2020	83	94.6	12.0	7.9	1.0	13%	88
Sep 8, 2020	83	81.7	12.0	6.8	1.0	15%	81
Sep 9, 2020	83	84.9	13.7	7.0	1.1	16%	77
Sep 10, 2020	83	88.2	24.7	7.3	2.0	28%	82
Oct 1, 2020	78	86.1	6.9	6.7	0.5	8%	98
Oct 2, 2020	78	83.3	4.0	6.5	0.3	5%	94
Oct 5, 2020	78	79.8	14.0	6.2	1.1	18%	88
Oct 6, 2020	78	77.9	14.0	6.1	1.1	18%	86
Oct 7, 2020	78	75.9	13.7	5.9	1.1	18%	82

South Orange County

Table C-3 South Orange County Event Day Impacts: Day Ahead 1-6 Hour

Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
		Reference Load	Impact	Reference Load	Impact		
May 28, 2020	36	████	████	████	████	████	68
Jun 2, 2020	15	63.8	6.4	1.0	0.1	10%	71
Jun 3, 2020	15	65.5	3.5	1.0	0.1	5%	70
Jun 4, 2020	15	56.4	6.4	0.8	0.1	11%	71
Jun 10, 2020	15	65.8	6.4	1.0	0.1	10%	87
Jul 9, 2020	21	63.2	9.9	1.3	0.2	16%	70
Jul 10, 2020	21	106.6	4.1	2.2	0.1	4%	74
Jul 13, 2020	21	87.0	4.1	1.8	0.1	5%	80
Jul 27, 2020	21	63.2	9.9	1.3	0.2	16%	70
Aug 3, 2020	19	81.6	20.0	1.6	0.4	25%	68
Aug 12, 2020	19	85.2	20.0	1.6	0.4	23%	71
Aug 13, 2020	19	90.5	6.3	1.7	0.1	7%	76
Aug 14, 2020	19	112.4	6.6	2.1	0.1	6%	84
Aug 17, 2020	19	104.2	6.6	2.0	0.1	6%	79
Sep 3, 2020	20	82.7	4.9	1.7	0.1	6%	71
Sep 4, 2020	20	103.4	5.5	2.1	0.1	5%	77
Sep 8, 2020	20	93.8	5.5	1.9	0.1	6%	75
Sep 9, 2020	20	86.6	4.9	1.7	0.1	6%	74
Sep 10, 2020	20	113.5	16.9	2.3	0.3	15%	77
Oct 1, 2020	20	104.9	5.6	2.1	0.1	5%	92
Oct 2, 2020	20	114.2	5.0	2.3	0.1	4%	85
Oct 5, 2020	20	113.9	13.3	2.3	0.3	12%	82
Oct 6, 2020	20	95.9	13.3	1.9	0.3	14%	78
Oct 7, 2020	20	85.5	13.3	1.7	0.3	16%	76

Table C-4 South Orange County Event Day Impacts: Day Of 1-6 Hour

Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
		Reference Load	Impact	Reference Load	Impact		
Feb 3, 2020	5	████	████	████	████	████	59
Feb 4, 2020	5	████	████	████	████	████	59
Feb 6, 2020	5	████	████	████	████	████	57
May 28, 2020	39	36.2	1.0	1.4	<0.1	3%	67
Jun 2, 2020	49	44.2	10.8	2.2	0.5	24%	71
Jun 3, 2020	49	47.4	8.1	2.3	0.4	17%	69

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Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
		Reference Load	Impact	Reference Load	Impact		
Jun 4, 2020	49	45.8	10.8	2.2	0.5	23%	71
Jun 10, 2020	49	60.8	10.8	3.0	0.5	18%	86
Jul 9, 2020	45	58.2	8.3	2.6	0.4	14%	70
Jul 10, 2020	45	63.9	8.3	2.9	0.4	13%	74
Jul 13, 2020	45	62.7	8.3	2.8	0.4	13%	79
Jul 27, 2020	45	57.3	8.3	2.6	0.4	15%	70
Aug 3, 2020	47	58.9	4.7	2.8	0.2	8%	68
Aug 12, 2020	47	60.1	4.7	2.8	0.2	8%	71
Aug 13, 2020	47	60.1	4.5	2.8	0.2	7%	75
Aug 14, 2020	47	68.9	3.7	3.2	0.2	5%	83
Aug 17, 2020	47	68.4	3.7	3.2	0.2	5%	78
Sep 3, 2020	40	82.3	9.1	3.3	0.4	11%	70
Sep 4, 2020	40	84.6	8.8	3.4	0.4	10%	77
Sep 8, 2020	40	81.2	8.8	3.2	0.4	11%	75
Sep 9, 2020	40	80.0	9.1	3.2	0.4	11%	74
Sep 10, 2020	40	83.4	14.7	3.3	0.6	18%	77
Oct 1, 2020	36	88.3	3.8	3.2	0.1	4%	92
Oct 2, 2020	36	89.2	2.7	3.2	0.1	3%	84
Oct 5, 2020	36	83.2	8.7	3.0	0.3	10%	81
Oct 6, 2020	36	■	■	■	■	■	78
Oct 7, 2020	36	80.9	8.7	2.9	0.3	11%	76

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