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2018 STATEWIDE LOAD IMPACT EVALUATION OF CALIFORNIA CAPACITY BIDDING PROGRAMS

Ex-Post and Ex-Ante Load Impacts

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Confidential information is redacted and denoted with black highlighting:

Report prepared for:

PACIFIC GAS & ELECTRIC COMPANY
SAN DIEGO GAS & ELECTRIC COMPANY
SOUTHERN CALIFORNIA EDISON

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ABSTRACT

This report documents the 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), for Program Year 2018 (PY2018). The scope of this evaluation covers the statewide Capacity Bidding Program (CBP), which is operated by all three IOUs. The primary goals of this evaluation study are to 1) estimate the ex-post load impacts for PY2018, and 2) estimate ex-ante load impacts for years 2019 through 2029.

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 IOUs in the DR programs. Depending on their contractual arrangement with the IOU, aggregators can enroll and nominate customer service accounts in a mix of day-ahead (DA) and day-of (DO) triggered DR product types. The terms and conditions of service can vary widely, depending on the individual contracts and tariffs negotiated between the aggregator and the IOU, and contracts between the aggregator and the customer.

Nominated customer service accounts in the DO products exceeded those in the DA products for SCE and SDG&E. Starting in PY2018, DO products are no longer offered by PG&E. The number of nominated customer service accounts[1] on a single event day ranged from less than 20 service accounts to over 500, depending on the product type. Some programs and notice types called events on as few as three days in 2018, while others called events on up to 46 days, including several events that were called for various combinations of distribution-based geographical locations or Sub-Load Aggregation Points (Sub-LAPs). These local, or Sub-LAP, events might be called when the utility does not need the entire nominated load reduction, in cases of localized distribution events, or based upon CAISO awards.

AEG estimated hourly ex-post load impacts for each program, notice type, product type, and event during 2018, using regression analysis of individual customer-level hourly load, weather, and event data. The estimated load impacts are reported by IOU, for each event, associated with each 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. In addition, AEG estimated ex-post impacts associated with Technical Assistance and Technology Incentives (TA/TI) and Automated Demand Response (AutoDR) participants.[2]

Estimated aggregate load impacts for an average CBP DA event were 8.8 MW for PG&E, 2.1 MW for SCE, and 0.2 MW for SDG&E. Aggregate load impacts for CBP with DO notice 4.9 MW for SCE and 3.5 MW for SDG&E, on average.

[1] PG&E refers to these as service agreements.

[2] TA/TI and AutoDR participants are customers that have received technology incentives for the purchase and installation of load control equipment and technology that enables a customer's ability to automatically curtail its load during a DR event.

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 2019.

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 then participate as a group to provide load reduction during DR events.

The evaluation covers one price-responsive DR program: the Capacity Bidding Program (CBP). As of program year 2018, the Aggregator Managed Portfolio (AMP) program is no longer offered by any of the three IOUs. The CBP programs offered by each IOU differ slightly in program features and operation. In all programs, however, the aggregators enroll customers under the terms of their own contracts for the DR or load reduction capacity; the utilities are not involved in the contracts between the aggregators and the participating customers.

The primary goals of the 2018 impact evaluation are as follows:

- Estimate hourly ex-post load impacts for each product and IOU for PY2018.
- Estimate average monthly ex-ante load impacts for each product and IOU for years 2019 through 2029.

In the following subsections, we present a description of each IOU's program, the evaluation methodology, PY2018's 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 residential[3] and non-residential utility customers to act on their behalf with respect to 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.[4] Customers enrolled in CBP

[3] In PY2018, the program was open to residential customer enrollment. PG&E currently has one active residential aggregator, but this aggregator did not have eligible nominations for PY2018. PG&E expects that residential participation will start in PY2019.

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

may participate in another DR program, so long as it is an energy-only program (e.g. cannot have a capacity payment component) and does not have the same notification type (DA or DO).

CBP provides monthly capacity payments ($/kW) to aggregators based on the nominated kW load, the specific operating month, the event duration, and the event notice option. Delivered capacity determines performance. If a CBP aggregator's delivered capacity is less than 50% for SCE and SDG&E or less than 60% for PG&E, the aggregator is assessed a penalty. If no events are called, CBP aggregators receive the full monthly capacity payment in accordance with their nominations, but no energy payments.[5] Additional energy payments ($/kWh) are made to the aggregator[6] based on the measured kWh reductions (relative to the program baseline) that are achieved when an event is called.[7]

For PG&E, CBP events are determined by California Independent System Operator (CAISO) market awards. Events can be called on non-holiday weekdays in the months of May through October, between the hours of 11 AM and 7 PM or 1 PM and 9 PM, with a maximum of 30 event hours per month (or more under the Elect and Elect+ options).

For SCE, CBP events can be triggered by any of the following conditions: high temperatures, resource limitations, a generating unit outage, transmission constraints, a system emergency, an alert called by the CAISO, or market prices go above a given price threshold. Events can be called on any non-holiday weekday year-round, between the hours of 1 PM and 7 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 the months of May through October, between the hours of 11 AM and 7 PM or 1 PM and 9 PM, with a maximum of 24 event hours per month.

Number of Accounts

Since localized events were highly utilized in PY2018, it is important to distinguish total nomination (i.e. total enrollment) versus event nomination (i.e. event participation). In Table E-1, we present the total number of nominated accounts for an average summer month[8] in PY2018 by program, notice 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	512	n/a
SCE	50	270
SDG&E	32	184

[5] 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.

[6] Customers participating directly receive any additional energy payments directly.

[7] 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.

[8] A summer month is defined as months between May through October.

Evaluation Methods

AEG used customer-specific 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. Because the CBP events are called only on isolated days over the course of the program year and participants face identical TOU 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 year, day of 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, which can be in an average load in the morning or evening.

After developing a set of customer-specific 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.

For SDG&E's CBP products, AEG also estimated the incremental impacts associated with AutoDR and Technical Assistance and Technology Incentives (TA/TI) program participants as compared with non-enabled participants. The first step was to use a Euclidean Distance matching approach to select a group of CBP participants that were similar to the AutoDR and TA/TI participants, but did not participate in AutoDR or TA/TI. Then, AEG estimated the incremental impacts using a statistical difference-in-differences (DID) approach.

Results

2018 Events

Table E-2 summarizes the number of event days by notification type, program, and utility for the PY2018 evaluation period.[9]

[9] The PY2018 evaluation period is May 1 through Oct. 31, 2018 for PG&E and SDG&E and is Nov. 1, 2017 – Oct. 31, 2018 for SCE.

Table E-2 Number of PY2018 Event Days by Notice Type

Utility	Nov 2017-Apr 2018		May 2018-Oct 2018	
	Day Ahead	Day Of	Day Ahead	Day Of
PG&E	n/a	n/a	46[10]	n/a
SCE	14	23	23	25
SDG&E	n/a	n/a	26[11]	3

2018 Ex-Post Impacts

Table E-3 summarizes the 2018 ex-post load impacts and nominated capacity by notification type, program, and utility. The data presented are for the average summer event day.[12] Table E-4 through Table E-6 present the 2018 ex-post load impacts and nominated capacity for each utility by event day and notification type.

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. This means that aggregators and customers were able to curtail their load when asked to do so.

Table E-3 Summary of PY2018 Ex-Post Impacts and Nominated Capacity: Average Summer Event Day

Utility	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)
PG&E	197	44.8	8.8	9.2	n/a			
SCE	43	47.9	2.1	3.0	214	22.8	4.9	4.5
SDG&E	27	6.9	0.2	0.3	186	18.6	3.5	3.9

[10] PG&E had 39 Elect DA event days and 22 Prescribed DA event days with 15 event days called by both product offerings.

[11] SDG&E had 25 DA 11 AM to 7 PM event days and 18 DA 1 PM to 9 PM event days with 17 event days called by both product offerings.

[12] 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 PY2018 PG&E Ex-Post Impacts and Nominated Capacity

Event	Day Ahead			
	# of Accts	Per Customer Impact (kW)	Aggregate Impact (MW)	Nominated Capacity (MW)
Jun 13, 2018	56	[redacted]	[redacted]	[redacted]
Jun 22, 2018	18	[redacted]	[redacted]	[redacted]
Jul 3, 2018	5	[redacted]	[redacted]	[redacted]
Jul 10, 2018	60	[redacted]	[redacted]	[redacted]
Jul 11, 2018	71	[redacted]	[redacted]	[redacted]
Jul 12, 2018	71	[redacted]	[redacted]	[redacted]
Jul 17, 2018	5	[redacted]	[redacted]	[redacted]
Jul 18, 2018	55	[redacted]	[redacted]	[redacted]
Jul 19, 2018	55	[redacted]	[redacted]	[redacted]
Jul 20, 2018	16	[redacted]	[redacted]	[redacted]
Jul 23, 2018	443	35.7	15.8	23.8
Jul 24, 2018	486	47.5	23.1	27.1
Jul 25, 2018	508	48.0	24.4	26.1
Jul 26, 2018	65	[redacted]	[redacted]	[redacted]
Jul 27, 2018	57	[redacted]	[redacted]	[redacted]
Jul 30, 2018	57	[redacted]	[redacted]	[redacted]
Jul 31, 2018	55	[redacted]	[redacted]	[redacted]
Aug 1, 2018	70	[redacted]	[redacted]	[redacted]
Aug 2, 2018	48	[redacted]	[redacted]	[redacted]
Aug 6, 2018	60	[redacted]	[redacted]	[redacted]
Aug 7, 2018	482	[redacted]	[redacted]	[redacted]
Aug 8, 2018	446	[redacted]	[redacted]	[redacted]
Aug 9, 2018	386	39.0	15.0	22.0
Aug 10, 2018	12	[redacted]	[redacted]	[redacted]
Aug 13, 2018	1	[redacted]	[redacted]	[redacted]
Sep 4, 2018	48	[redacted]	[redacted]	[redacted]
Sep 5, 2018	48	[redacted]	[redacted]	[redacted]
Sep 6, 2018	48	[redacted]	[redacted]	[redacted]
Sep 7, 2018	3	[redacted]	[redacted]	[redacted]
Sep 10, 2018	48	[redacted]	[redacted]	[redacted]
Sep 11, 2018	48	[redacted]	[redacted]	[redacted]
Oct 1, 2018	22	[redacted]	[redacted]	[redacted]
Oct 2, 2018	22	[redacted]	[redacted]	[redacted]
Oct 3, 2018	22	[redacted]	[redacted]	[redacted]
Oct 5, 2018	53	[redacted]	[redacted]	[redacted]
Oct 8, 2018	53	[redacted]	[redacted]	[redacted]

Event	Day Ahead			
	# of Accts	Per Customer Impact (kW)	Aggregate Impact (MW)	Nominated Capacity (MW)
Oct 9, 2018	31	[redacted]	[redacted]	[redacted]
Oct 10, 2018	31	[redacted]	[redacted]	[redacted]
Oct 12, 2018	31	[redacted]	[redacted]	[redacted]
Oct 15, 2018	2	[redacted]	[redacted]	[redacted]
Oct 17, 2018	14	[redacted]	[redacted]	[redacted]
Oct 18, 2018	14	[redacted]	[redacted]	[redacted]
Oct 19, 2018	14	[redacted]	[redacted]	[redacted]
Oct 22, 2018	379	[redacted]	[redacted]	[redacted]
Oct 23, 2018	12	[redacted]	[redacted]	[redacted]
Oct 24, 2018	6	[redacted]	[redacted]	[redacted]

Table E-5 Summary of PY2018 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 1, 2017	22	[redacted]	[redacted]	[redacted]	103	[redacted]	[redacted]	[redacted]
Nov 2, 2017	22	[redacted]	[redacted]	[redacted]	103	[redacted]	[redacted]	[redacted]
Nov 3, 2017	22	[redacted]	[redacted]	[redacted]	103	[redacted]	[redacted]	[redacted]
Nov 6, 2017	22	[redacted]	[redacted]	[redacted]	103	[redacted]	[redacted]	[redacted]
Nov 7, 2017	22	[redacted]	[redacted]	[redacted]	103	[redacted]	[redacted]	[redacted]
Nov 8, 2017	22	[redacted]	[redacted]	[redacted]	103	[redacted]	[redacted]	[redacted]
Nov 9, 2017	22	[redacted]	[redacted]	[redacted]	103	[redacted]	[redacted]	[redacted]
Nov 10, 2017	22	[redacted]	[redacted]	[redacted]	103	[redacted]	[redacted]	[redacted]
Nov 13, 2017	22	[redacted]	[redacted]	[redacted]	103	[redacted]	[redacted]	[redacted]
Nov 14, 2017	22	[redacted]	[redacted]	[redacted]	103	[redacted]	[redacted]	[redacted]
Nov 15, 2017	22	[redacted]	[redacted]	[redacted]	103	[redacted]	[redacted]	[redacted]
Nov 20, 2017	22	[redacted]	[redacted]	[redacted]	103	[redacted]	[redacted]	[redacted]
Nov 21, 2017	22	[redacted]	[redacted]	[redacted]	103	[redacted]	[redacted]	[redacted]
Nov 22, 2017	22	[redacted]	[redacted]	[redacted]	103	[redacted]	[redacted]	[redacted]
Dec 1, 2017	n/a				96	[redacted]	[redacted]	[redacted]
Dec 7, 2017	n/a				38	[redacted]	[redacted]	[redacted]
Dec 8, 2017	n/a				38	[redacted]	[redacted]	[redacted]
Dec 11, 2017	n/a				76	[redacted]	[redacted]	[redacted]
Dec 12, 2017	n/a				76	[redacted]	[redacted]	[redacted]

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)
Dec 13, 2017	n/a				101	[redacted]	[redacted]	[redacted]
Dec 26, 2017	n/a				38	[redacted]	[redacted]	[redacted]
Dec 28, 2017	n/a				76	[redacted]	[redacted]	[redacted]
Dec 29, 2017	n/a				76	[redacted]	[redacted]	[redacted]
May 29, 2018	44	[redacted]	[redacted]	[redacted]	n/a			
Jun 4, 2018	74	[redacted]	[redacted]	[redacted]	85	[redacted]	[redacted]	[redacted]
Jun 12, 2018	29	14.0	0.4	0.7	85	18.3	1.6	1.6
Jul 6, 2018	66	[redacted]	[redacted]	[redacted]	279	[redacted]	[redacted]	[redacted]
Jul 9, 2018	66	[redacted]	[redacted]	[redacted]	78	[redacted]	[redacted]	[redacted]
Jul 10, 2018	66	[redacted]	[redacted]	[redacted]	279	[redacted]	[redacted]	[redacted]
Jul 11, 2018	66	[redacted]	[redacted]	[redacted]	279	[redacted]	[redacted]	[redacted]
Jul 17, 2018	66	[redacted]	[redacted]	[redacted]	279	[redacted]	[redacted]	[redacted]
Jul 18, 2018	n/a				201	19.9	4.0	3.4
Aug 1, 2018	59	[redacted]	[redacted]	[redacted]	284	[redacted]	[redacted]	[redacted]
Aug 6, 2018	n/a				284	[redacted]	[redacted]	[redacted]
Aug 7, 2018	59	[redacted]	[redacted]	[redacted]	284	[redacted]	[redacted]	[redacted]
Aug 8, 2018	59	[redacted]	[redacted]	[redacted]	284	[redacted]	[redacted]	[redacted]
Aug 9, 2018	59	[redacted]	[redacted]	[redacted]	284	[redacted]	[redacted]	[redacted]
Sep 17, 2018	n/a				246	[redacted]	[redacted]	[redacted]
Sep 18, 2018	10	[redacted]	[redacted]	[redacted]	54	26.8	1.4	1.2
Sep 20, 2018	25	24.3	0.6	2.4	241	25.5	6.1	4.7
Sep 21, 2018	25	24.3	0.6	2.4	206	[redacted]	[redacted]	[redacted]
Sep 24, 2018	30	[redacted]	[redacted]	[redacted]	n/a			
Sep 26, 2018	30	[redacted]	[redacted]	[redacted]	246	[redacted]	[redacted]	[redacted]
Sep 27, 2018	15	27.8	0.4	1.8	152	25.5	3.9	2.7
Oct 1, 2018	n/a				208	[redacted]	[redacted]	[redacted]
Oct 15, 2018	n/a				242	[redacted]	[redacted]	[redacted]
Oct 16, 2018	29	26.6	0.8	2.1	242	[redacted]	[redacted]	[redacted]
Oct 17, 2018	29	26.6	0.8	2.1	242	[redacted]	[redacted]	[redacted]
Oct 18, 2018	29	26.6	0.8	2.1	242	[redacted]	[redacted]	[redacted]
Oct 19, 2018	29	26.6	0.8	2.1	34	11.3	0.4	0.9
Oct 22, 2018	29	26.6	0.8	2.1	n/a			

Table E-6 Summary of PY2018 SDG&E Ex-Post Impacts and Nominated Capacity[13]

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)
Jul 6, 2018	66	2.9	0.2	0.4	n/a			
Jul 10, 2018	65	1.8	0.1	0.4	n/a			
Jul 11, 2018	65	1.8	0.1	0.4	n/a			
Jul 12, 2018	66	1.9	0.1	0.4	n/a			
Jul 16, 2018	65	1.8	0.1	0.4	n/a			
Jul 18, 2018	66	3.7	0.2	0.4	n/a			
Jul 20, 2018	1	9.4	0.0	0.0	n/a			
Jul 23, 2018	65	1.8	0.1	0.4	n/a			
Jul 24, 2018	66	1.9	0.1	0.4	n/a			
Jul 25, 2018	66	1.9	0.1	0.4	n/a			
Aug 1, 2018	3	46.5	0.1	0.2	n/a			
Aug 6, 2018	3	85.4	0.3	0.2	186	18.6	3.5	3.9
Aug 7, 2018	3	85.4	0.3	0.2	186	18.6	3.5	3.9
Aug 8, 2018	3	85.4	0.3	0.2	n/a			
Aug 9, 2018	3	85.4	0.3	0.2	186	18.6	3.5	3.9
Oct 1, 2018	2	65.1	0.1	0.1	n/a			
Oct 18, 2018	2	65.1	0.1	0.1	n/a			
Oct 19, 2018	2	65.1	0.1	0.1	n/a			
Oct 22, 2018	2	65.1	0.1	0.1	n/a			
Oct 23, 2018	6	27.1	0.2	0.2	n/a			
Oct 24, 2018	6	27.1	0.2	0.2	n/a			
Oct 25, 2018	6	27.1	0.2	0.2	n/a			
Oct 26, 2018	6	46.6	0.3	0.2	n/a			
Oct 29, 2018	6	27.1	0.2	0.2	n/a			
Oct 30, 2018	6	27.1	0.2	0.2	n/a			
Oct 31, 2018	6	27.1	0.2	0.2	n/a			

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

Enrollment Forecast

Table E-7 summarizes the enrollment forecast by utility, program, notification type, and year, during the month of August.

- Beginning in 2018, PG&E only offered the DA product, and forecasts constant non-residential enrollment across the 2019-2029 horizon. Residential CBP is expected to have material enrollment starting 2019 and remain constant through the forecast horizon.
- SCE expects an influx of residential accounts to DA in 2023, following full opening of the program to residential customers. However, residential CBP enrollment may occur earlier than 2023, pending the 2020 mid-cycle filing required in D.17-12-003[14].
- SDG&E's enrollment forecast for the DA and DO products assumes the customer enrollment will increase by 3% per year starting in 2019 through 2022 due to the CBP program improvements proposed by SDG&E in the application for 2018-2022. In addition, SDG&E forecasts that the customer enrollment in the CBP DO program will increase by another 1% per year starting in 2019 through 2022 due to growth in the Technical Incentives (TI) program. Therefore, total DO enrollment is expected to increase by 4% per year starting in 2019 through 2022 due to program improvements and growth in TI. The enrollment forecasts for the DA and DO products after 2022 and through 2029 show a flat trend at the 2022 values.

Table E-7 2019-2029 Enrollment Forecast for Month of August

Utility	Notice	Number of Service Accounts				
		2019	2020	2021	2022	2023-2029 (Each Year)
PG&E (Non-residential)	Day Ahead	693	693	693	693	693
SCE	Day Ahead	90	90	90	90	3,321[15]
	Day Of	800	800	800	800	800
SDG&E	Day Ahead	65	67	69	71	71
	Day Of[16]	191	197	203	209	209

Ex-Ante Impacts

Table E-8 summarizes the aggregate load impact forecasts for an August peak day in 2019 by program and utility for each weather scenario.

[14] Decision Adopting Demand Response Activities and Budgets for 2018 through 2022. Decision 17-12-003. December 14, 2017. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M202/K275/202275258.PDF.

[15] SCE's DA enrollment forecast expects an influx of residential accounts in 2023 following full opening of program to residential customers. If CPUC abandons initiative to require the program to be open to residential customers, the enrollments should be 90, as for 2019-22. Accompanying appendix on SCE ex-ante impacts only includes non-residential impact estimates.

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

Table E-8 Summary of Average Event-Hour Ex-Ante Impacts, August Peak Day, 2019

Utility	Notice	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
PG&E (Non-residential)	Day Ahead	40.3	27.9	17.6%	17.0%	18.0%	17.5%
SCE	Day Ahead	[redacted]	[redacted]	[redacted]%	[redacted]%	[redacted]%	[redacted]%
	Day Of	[redacted]	[redacted]	[redacted]%	[redacted]%	[redacted]%	[redacted]%
SDG&E	Day Ahead	2.8	0.2	1.2%	1.2%	1.2%	1.2%
	Day Of	13.9	2.7	10.8%	10.5%	10.7%	10.7%

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.

As mentioned earlier, CBP is now open to residential customers. PG&E expects material MW from residential CBP in 2019 and makes a constant forecast of 4 MW per year through the forecast horizon starting 2019. SCE assumes a constant aggregate residential CBP forecast of 3 MW per year throughout the forecast horizon starting in 2023. SDG&E's enrollment forecast does not include residential customers.

Key Findings

In PY2018, we have the following key findings:

1. CBP is now a more time- and/or geographically-targeted DR program, utilizing more localized events.
   - PG&E's CBP program called the most diverse events among the 3 IOUs with 1 to 13 Sub-LAPs called, 1 to 508 participants nominated, and event windows between the hours of 2 PM and 9 PM.
   - Similarly, SCE called a wide range of events with 1 to 5 Sub-LAPs called, 29 to 345 participants nominated, and event widows between the hours of 1 PM and 7 PM.
   - SDG&E's CBP program called events as needed by calling on different products on different event windows within the same day.
2. Each IOU's product offerings earned mixed results in meeting/exceeding their capacity nominations.
   - PG&E's Elect DA product offering, on average, met/exceeded their capacity nominations, successfully doing so in 21 out of 39 events. Prescribed DA, on average, did not meet their capacity nominations on most days, but had success in 4 out of 22 events.

- SCE's summer DO program (DO 1-6 Hour) was the only program in PY2018 across all three IOUs that exceeded its nominated capacity, on average. The September 20th event curtailed 6.1 MW, well beyond their 4.7 MW nomination. The non-summer program (DA 1-4 Hour and DO 1-4 Hour) was not as successful. Neither products met the nominated capacity on any event called.
- SDG&E's DA and DO products operating between 1 PM – 9 PM met and exceeded their capacity nominations. The DO program achieved consistent responses through both products despite calling events on three consecutive days.

3. Customer retention from previous years is not as high as projected.
   - PG&E's, retention of previous DO program participants was not as high as projected but included larger customers. Last year's forecast projected 700 total customers in the DA program, but maximum nomination count was only 551 customers.
   - SCE's, retention of previous AMP program participants was not as high as projected in PY2017. Last year's forecast projected 1,250 total customers in the DO program, but maximum nomination count was only 291 customers.
   - SDG&E's DA 11 AM – 7 PM product may experience a similar customer retention issue with a mid-year drop in total nomination (65 participant nominations in July to 2 participant nominations in August).

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1

INTRODUCTION

This report documents the load impact evaluation of CBP, the aggregator-based DR program operated by PG&E, SCE, and SDG&E for PY2018.

Research Objectives

The key objectives of this study are to estimate both ex-post and ex-ante impacts for each IOU's CBP. 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 program. These results are presented at the program level and separately for each notification type and product. They are also provided for each customer class, each industry group, each LCA, each size group, each aggregator, for AutoDR, and for dually enrolled DR participants.[17]
- Ex ante impacts are estimated for each year over an 11-year[18] 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 and separately for each notification type. The impacts are provided for the average customer and all customers in aggregate for the resource adequacy (RA) window (4 PM to 9 PM). They are also provided for each customer class[19] (as applicable), each LCA (as applicable), each size group (as applicable), and each busbar (as applicable).

Key Issues for PY2018 Analysis

In PY2018, several program changes were implemented. PG&E and SDG&E now offer entirely different sets of products and have changed their manner of calling events. In previous years, both IOUs typically called events from 3 PM to 7 PM with very few events in different windows. Both IOUs now call events similar to SCE's, which include a variety of event windows within the program's operating hours. In addition to the CBP program changes, SDG&E also implemented changes in their TOU periods beginning December 1, 2017.

To accommodate these program changes, we limited our analysis to include only PY2018 data. In previous evaluations, we incorporated historical data, as far back as 2014, to strengthen our regression models and optimization process. Given all the implemented changes, incorporating historical data into the analysis would only add to the complexity of the models and likely add "noise" or increase the error in the estimates.

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

[18] SDG&E has requested ex-ante impacts for a 12-year time horizon: 2018-2029.

[19] Defined as residential v. non-residential. In PY2018, the customer class subgroup is only applicable in the ex-ante impact analysis. It will be part of the ex-post impact analysis starting in PY2019.

We also had to rethink how we define the average event day and how to present impact estimates. In previous evaluations, we defined the average event day as the average of all system-level events called during the typical event window. In PY2018, the typical event window is less apparent. We define the average event day as the average of all called events and present impacts on the common event hour (the hour when all event windows overlap). This common event hour is most often 6 PM to 7 PM (HE-19).

Report Organization

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

- Section 2 describes the CBP programs as they are implemented by each IOU. 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 2018 program year.
- Section 4 presents the ex-post impact results.
- Section 5 presents the ex-ante impact results.
- Section 6 discusses the relationship between ex-post and ex-ante results.
- Section 7 presents key findings and recommendations.

2

PROGRAM DESCRIPTIONS AND RESOURCES

This section describes the CBP programs as they are implemented by each IOU. We also present information regarding the total number of accounts nominated in each program, 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 may differ slightly in program features and operations.

In CBP, aggregators are entities that contract with eligible residential[20] and non-residential utility customers to act on their behalf with respect to 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.[21] Customers enrolled in CBP may participate in another DR program, so long as it is an energy-only program (e.g. cannot have a capacity payment component) and does not have the same notification type (DA or DO).

CBP provides monthly capacity payments ($/kW) to aggregators based on the nominated kW load, the specific operating month, the event duration, and the event notice option. Delivered capacity determines performance. If a CBP aggregator's delivered capacity is less than 50% for SCE and SDG&E or less than 60% for PG&E, the aggregator is assessed a penalty. If no events are called, CBP aggregators receive the full monthly capacity payment in accordance with their nominations, but no energy payments.[22] Additional energy payments ($/kWh) are made to the aggregator[23] based on the measured kWh reductions (relative to the program baseline) that are achieved when an event is called.[24]

[20] In PY2018, the program was open to residential customer enrollment. PG&E currently has one active residential aggregator, but this aggregator did not have eligible nominations for PY2018. PG&E expects that residential participation will start in PY2019.

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

[22] 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.

[23] Customers participating directly receive any additional energy payments directly.

[24] 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.

As mentioned earlier, each IOU's program may differ in program features and operations. The following describes each IOU's different product offerings in PY2018:

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 and 2-6 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). PG&E CBP events may be called Monday through Friday, excluding holidays, during May through October between 11 AM to 7 PM (Prescribed) or 1 PM to 9 PM (Elect and Elect+), with a maximum of 30 hours per month (or possibly more hours under Elect and Elect+ Options if the participants so choose). CBP events are determined by California Independent System Operator (CAISO) market awards.

SCE

Effective May 1, 2018, SCE's CBP offers both DA and DO notifications for 1-6 hour durations only. However, since the scope of the PY2018 evaluation is Nov 1, 2017 through October 31, 2018, SCE's DA and DO 1-4 Hour products will be included in this report. SCE CBP events may be called Monday through Friday, excluding holidays, year-round between 1 pm to 7 pm, with a maximum of 5 events and 30 hours per month. CBP events can be triggered by any of the following conditions: high temperatures, resource limitations, a generating unit outage, transmission constraints, a system emergency, an alert called by the CAISO, or market prices go above a given price threshold.

SDG&E

Effective December 1, 2017, SDG&E made changes to their TOU periods, redefining the on-peak period to be 4 PM to 9 PM for all days and seasons and moving the month of May into the winter season. As of PY2018, SDG&E reduced its number of CBP products from nine to four. There were 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 were 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, during May through October, with a maximum of 24 hours per month.

Effective July 1, 2018, SDG&E made the following changes on the program triggers:

- Day Ahead Product: SDG&E may call an event whenever the day-ahead market price is equal to or greater than $75/MWh or as utility system conditions warrant. 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).
- 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 PY2018 product types for SDG&E.

Table 2-1 CBP Nominated Service Accounts, by Utility and Industry Group, Average Summer Event Day (2018)

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

Table 2-2 presents the number of nominated service accounts that responded during an average summer CBP event in 2018, by industry segment. Since nominations vary by month, we use the number of nominated service accounts responding on an average summer event day to reflect the typical number of program participants. The table includes data for each utility, by notification type and industry group. The table also includes a sum of their maximum demand, which is a metric provided by each IOU. Note that the maximum demand of each customer may occur at different times of the day (non-coincident demand).

For reference, Table 2-3 presents the eight industry-type definitions and corresponding NAICS codes.

Table 2-2 CBP Nominated Service Accounts, by Utility and Industry Group, Average Summer Event Day (2018)

Utility	Industry Type	Day Ahead		Day Of	
		Accounts	Sum of Max Demand (MW)	Accounts	Sum of Max Demand (MW)
PG&E	1. Agriculture, Mining & Construction	55	11.1	-	-
	2. Manufacturing	5	[redacted]	-	-
	3. Wholesale, Transport, Other Utilities	4	[redacted]	-	-
	4. Retail Stores	213	[redacted]	-	-
	5. Offices, Hotels, Finance, Services	96	44.8	-	-
	6. Schools	2	[redacted]	-	-
	7. Institutional/Government	2	[redacted]	-	-
	8. Other/Unknown	7	[redacted]	-	-
	Total	**197**	**101.8**	**-**	**-**
SCE	1. Agriculture, Mining & Construction	-	-	15	[redacted]
	2. Manufacturing	1	[redacted]	2	[redacted]
	3. Wholesale, Transport, Other Utilities	7	[redacted]	1	[redacted]
	4. Retail Stores	36	12.6	181	32.2
	5. Offices, Hotels, Finance, Services	-	-	26	[redacted]
	6. Schools	-	-	1	[redacted]
	7. Institutional/Government	-	-	-	-
	8. Other/Unknown	-	-	-	-
	Total	**43**	**28.6**	**214**	**50.5**
SDG&E	1. Agriculture, Mining & Construction	2	0.4	1	0.2
	2. Manufacturing	-	-	1	2.0
	3. Wholesale, Transport, Other Utilities	-	-	-	-
	4. Retail Stores	3	0.3	168	30.2
	5. Offices, Hotels, Finance, Services	62	27.2	14	2.8
	6. Schools	-	-	-	-
	7. Institutional/Government	1	3.6	1	0.4
	8. Other/Unknown	-	-	1	0.1
	Total	**27**	**13.9**	**186**	**35.8**

Table 2-3 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

Program Changes

Several program changes have been proposed by the IOUs, some already adopted by the Commission. Some of the key changes expected to be implemented in future program years:

- PG&E currently has active residential aggregators and expects that residential participation will start in PY2019. Decision 17-12-003[25] requires SCE and SDG&E to pilot a residential aggregator option in their CBP programs and authorizes a budget to administer the pilot and award incentives. SCE's CBP-DA enrollment forecast accounts for residential participation beginning in 2023; SDG&E's enrollment forecast does not.
- SCE is proposing to change the dispatch window, currently at 1 PM to 7 PM, to align with the Resource Adequacy (RA) window (4 PM to 9 PM). This proposed change has not been filed, but SCE expects this change to be implemented in 2021.
- Effective December 15, 2018, SDG&E changed the DA product's day-ahead market price trigger from $75/MWh to $80/MWh.
- In PY2019, SDG&E will no longer allow dual DR enrollment in CBP. Customers who are dually enrolled prior to October 1, 2018 will be grandfathered in.

[25] Decision Adopting Demand Response Activities and Budgets for 2018 through 2022. Decision 17-12-003. December 14, 2017. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M202/K275/202275258.PDF.

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 PY2018 ex-post analysis was designed specifically to meet each of the following goals:

- To develop hourly and daily load impact estimates for each event in the 2018 program year.
- To provide these estimates by various segments: IOU, program, LCA, industry group, Automated Demand Response (AutoDR) and TA&TI participation, and notification type.
- To estimate the distribution of load impacts by customer segment for the average event.

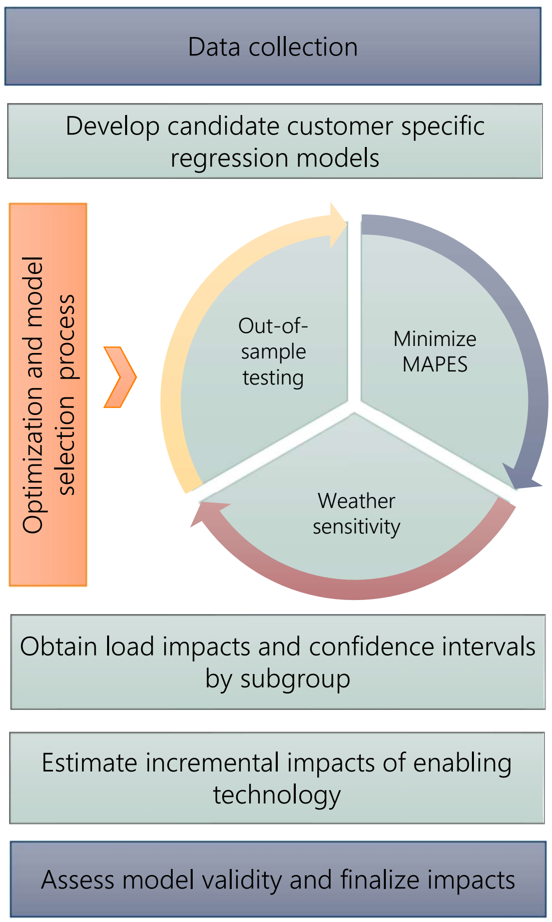
AEG used customer-specific regressions to estimate the load impact for each customer on each event day. Because CBP is implemented somewhat differently within each IOU's territory, the ex-post analysis was conducted independently for each IOU to account for those differences in the modeling and analysis. However, the same basic methodology was employed across all three IOUs to balance consistency of results with modifications to account for differences in implementation and rate design. 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 simply 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 week, month, hour, etc.).
- 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 are better able to model changes in energy usage than an aggregated model.
- Because the events are called only on isolated days over the course of the program year, and on all other days the participants face similar TOU rates, the data conforms nicely to what researchers often call a repeated-measures design. This simply means that all participants are subjected to the treatment at the same time, repeatedly over the course

of the study. In this case, the control can be 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. The subsections that follow describe the process in more detail.

Figure 3-1 Ex-Post Analysis Approach



Data Collection and Validation

AEG constructed a large 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 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 a set of rules to omit intervals from the analysis. Also, 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.

Develop Candidate Customer-Specific Regression Models

After collecting the data required for the evaluation, the next step was to develop a set of candidate models. 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.[26]

Table 3-1 presents the different explanatory variables used to create candidate models for the CBP and AMP participants.

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, multiple cooling degree hour (CDH) terms with base values of 75, 70, and 65 depending on service territory, 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
$EarlyMornLoad_{i,d}$	The average of each day's load in hours 12 AM through 4 AM
$MornLoad_{i,d}$	The average of each day's load in hours 4 AM through 10 AM
$EveLoad_{i,d}$	The average of each day's load in hours 9 PM through 12 AM
	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

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.

[26] Any unexplained variation will end up in the error term.

- Non-weather sensitive models include the load adjustment and calendar effects.

Optimization Process

After developing a set of candidate models, a single "best" model was selected for each customer. The final model was selected to minimize error and bias through a series of out-of-sample tests and MAPE (mean absolute percentage error) and MPE (mean percentage error) comparisons.[27]

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 the best model specification for each customer.
- We used the estimated coefficients and the baseline portion of the model to predict what this customer would have used on 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.

[27] For more information on the model out-of-sample tests and MAPE results see Appendix B, Model Validity.

- 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.

Obtain Load Impacts and Confidence Intervals by Subgroup

Aggregation of Impacts

Because we estimated an impact for each customer, the model results are easily aggregated to represent impacts for each of the required subpopulations of participants for each of 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 be different 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 for the event 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:
- o 24 nominated customers
- o 23 with sufficient valid data to estimate impacts
- o Aggregate impact for 23 customers = 2,300 kW
- o Average per-customer impact for the subgroup would be calculated with the aggregated data for the 23 customers: 2,300 kW / 23 customers = 100 kW per customer
- o Aggregate impact for all 24 nominated customers: 100 kW/customer x 24 customers = 2,400 kW
- Subgroup #2 in Product A:
- o 76 nominated customers, all with sufficient valid data to estimate impacts
- o Aggregate impact for 76 customers: 6,460 kW
- o Average per-customer impact: 6,460 kW / 76 customers = 85 kW per customer
- Total for Product A:
- o 100 nominated customers
- o 99 with sufficient valid data to estimate impacts
- o Aggregate impact for 99 customers = 2,300 kW + 6,460 kW = 8,760 kW
- o Average per-customer impact for the subgroup would be calculated with the aggregated data for the 99 customers: 8,760 kW / 99 customers = 88.48 kW per customer

    - Aggregate for all 100 nominated customers: 88.48 kW/customer x 100 customers = 8,848 kW

- Sum of Subgroup #1 plus Subgroup #2 = 2,400 kW + 6,460 kW= 8,860 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 who were called for the event. These aggregations are performed at either the program level, by industry group, or by 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 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 simpler approach compared to what we've done in past evaluations.[28] Although it is a more conservative estimate since it does not allow to take into account the covariances between the event hours, a comparison of the results from the two methodologies show that the differences are not substantial. We will be recommending the use of this simpler approach in future evaluations.

Calculating Impacts for an Average Event Day

Given the changes implemented in PY2018 on how events are called, we defined the average event day consistently across the three IOUs. *For each product and subgroup*, we defined the average event day 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. 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 can be nominated for each event; therefore, the average is necessarily made up of different groups of customers across different days. This 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 the aggregate impact of each subgroup.

[28] Per SDG&E's request, the previous evaluations' approach of estimating an additional regression model for the entire event window was employed in SDG&E's ex-post impact analysis.

Another way to do it would be to create the averages first at the lowest level of disaggregation, and then sum them to the total level of aggregation desired. 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

We estimated the incremental impacts associated with the AutoDR and TA/TI participants as compared with a group of similar non-enabled participants for SDG&E's CBP products. First, we selected a group of program participants that are similar to the AutoDR and TA/TI participants, but did not participate in AutoDR or TA/TI, using a Euclidean Distance matching approach. Next, we estimated the incremental impacts using a statistical difference-in-difference (DID). We describe DID methodology first, and then describe the matching approach.

The DID method involves taking the difference between the control group and treatment group energy use during both the treatment period and the non-treatment period, and then subtracting the pre-treatment difference from the treatment period difference. In this case, we wanted to estimate the incremental impact associated with the treatment group. Therefore, we defined the non-treatment period as the average reference load on event days and the treatment period as the average predicted load on event days. The differences are done at the group level, based on the average across all customers in each group. Where X is the control group and Y is the treatment group, as shown below in Equation 3.3.

$$Incremental\ Savings = (X_{PredActual} - Y_{PredActual}) - (X_{reference} - Y_{reference}) \tag{3.3}$$

Using algebra, this can be rewritten as the difference in impacts, show below in Equation 3.4.

$$Incremental\ Savings = (Y_{Refrence} - Y_{PredActual}) - (X_{reference} - X_{PredActual}) \tag{3.4}$$

We then calculated the standard errors of the incremental savings and used them to establish a confidence interval at the 95% level.

When it is not practical to use a randomized control trial (RCT), as in this case, a matched control group can be created. Our goal was to select control customers that are as similar as possible to each treatment customer during the non-treatment period (which in our case is the average event day reference load), based on known observable characteristics. We used a stratified Euclidean distance to choose the best match within the control group pool for each participant. First, we assigned each participant and potential control to a bucket based on their industry type, and product. Then, we minimized the Euclidean distance (the square root of the sum of squared deviations) between the participant and control customers across as many characteristics from the non-treatment period as possible. Any number of relevant variables could be included in the Euclidean distance; in this case we used average hourly on-peak values, and both morning and evening off-peak averages. The Euclidean distance for this set of variables can be calculated by Equation 3.5 below.

$$ED = \sqrt{(Off\_1 - Off\_1_C)^2 + (EOff\_2_T - EOff\_2_C)^2 + (kWh16_T - kWh16_C + \ldots + kWh21_T - kWh21_C\ )^2} \quad (3.5)$$

Ex-Ante Impact Analysis

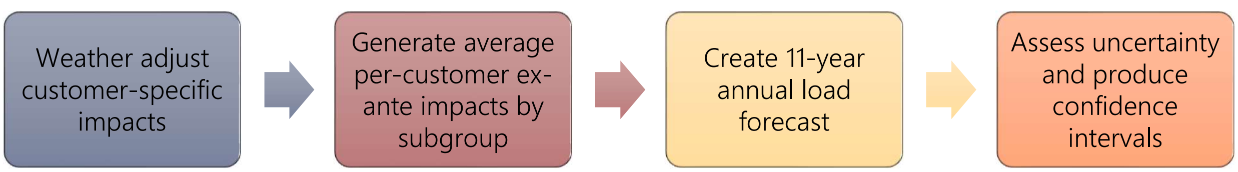
The main goal of the ex-ante analysis is to produce an annual 11-year[29] forecast of the load impacts expected from the CBP programs.

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.
- 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 3-2 provides an overview of the ex-ante analysis approach which includes four basic 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 3-2 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 for each of the appropriate subgroups. This 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. The customer-specific regression models estimated flat per-customer average impacts across the weather scenarios, but the percent impacts vary.

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

[29] SDG&E has requested ex-ante impacts for a 12-year time horizon: 2018-2029.

- For each customer, we began with the coefficients estimated in the customer-specific regression models developed for the ex-post analysis.
- 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 of these scenarios assuming no events are called. The result will be a weather-adjusted reference load for each customer for each weather scenario required.
- Next, we determined the most prevalent event hour called for each customer. This was most often HE19 for all three IOUs, with HE18 and HE20 for select customers. 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.
- We applied this load impact estimate to all hours of the Resource Adequacy window, which is HE17 through HE21 year-round as of PY2019.[30]
- We then calculated the predicted load for each scenario by adding the estimated load impact to the weather-adjusted reference load.

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, it becomes a relatively simple exercise to 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 enrollment forecasts and set of per-customer average ex-ante impacts to create the annual forecast of load impacts over the next 11 years.

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

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

error in the enrollment forecast, the confidence intervals do not include the enrollment forecast uncertainty.

4

EX-POST RESULTS

This section presents the PY2018 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 2018, all three IOUs offered CBP Day Ahead (DA) products. However, the CBP Day Of (DO) product was only offered by SCE and SDG&E. Table 4-1 presents the PY2018 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 PY2018

Utility	Product	Accounts	Nominated Capacity (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)	
				Reference Load	Impact	Reference Load	Impact
PG&E	Elect DA	187	4.9	221.4	32.0	41.3	6.0
	Prescribed DA	10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SCE	Day Ahead	43	3.0	432.1	47.9	18.7	2.1
	Day Of	214	4.5	175.8	22.8	37.6	4.9
SDG&E	Day Ahead	27	0.3	228.5	6.9	6.1	0.2
	Day Of	186	3.9	134.8	18.6	25.1	3.5

Note that the average event day is calculated using all events regardless of participant count and event timing. The results shown are for the common event hour HE19 or 6 PM – 7 PM, which is the hour wherein all events overlap. In previous years, we calculated the average event day using the most often-called event window (usually HE16 – HE19 or 3 PM – 7 PM), including only system-level events. In the next sections, we will 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 2018 events for PG&E's CBP program by product offering: Elect DA and Prescribed DA. The Elect DA participants experienced a total of 39 event days and were nominated to participate in three products: Elect DA 1-4 Hour (11 AM to 7 PM), Elect DA 1-4 Hour (1 PM to 9 PM), Elect DA 2-6 Hour (1 PM to 9 PM). The Prescribed DA participants experienced a total of 22 event days, participating only in one product: Prescribed DA 1-4 Hour (11 AM to 7 PM).

In PY2018, 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 nominated 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 PY2018 regardless of event window and number of Sub-LAPs called. We present impacts for the average event day on the common event hour, HE19, which is the hour when all event windows overlap.

Table 4-2 PG&E Day Ahead Monthly Enrollment

Month	# of Accounts
May	496
June	526
July	551
August	531
September	523
October	446
Average Month	**512**

Table 4-3 PG&E Event Summary

Date	Day of Week	# of Sub-LAPs	Event Hours (HE)	# Accounts	
				Elect DA	Prescribed DA
Avg. Event	**-**	**14**	**19**	**187**	**10**
Jun 13, 2018	Wednesday	1	20-20	56	-
Jun 22, 2018	Friday	1	18-18	18	-
Jul 3, 2018	Tuesday	1	15-17	-	5
Jul 10, 2018	Tuesday	2	16-18, 20-20	55	5
Jul 11, 2018	Wednesday	5	19-19, 19-20	55	16
Jul 12, 2018	Thursday	5	17-19, 19-19, 19-20	55	16
Jul 17, 2018	Tuesday	1	17-17	-	5
Jul 18, 2018	Wednesday	1	20-20	55	-
Jul 19, 2018	Thursday	1	20-20	55	-
Jul 20, 2018	Friday	1	16-16	16	-
Jul 23, 2018	Monday	13	16-19, 17-19, 19-19, 19-20	430	13
Jul 24, 2018	Tuesday	13	16-19, 17-19, 17-21, 18-19	473	13
Jul 25, 2018	Wednesday	13	16-19, 17-19, 17-21, 18-21	495	13
Jul 26, 2018	Thursday	2	18-21, 19-19	65	-
Jul 27, 2018	Friday	2	16-19, 18-21	55	2
Jul 30, 2018	Monday	2	17-19, 19-20	55	2
Jul 31, 2018	Tuesday	1	18-20	55	-
Aug 1, 2018	Wednesday	6	16-19, 19-19	48	22
Aug 2, 2018	Thursday	1	16-19	48	-

Date	Day of Week	# of Sub-LAPs	Event Hours (HE)	# Accounts	
				Elect DA	Prescribed DA
Aug 6, 2018	Monday	6	16-19, 19-19	49	11
Aug 7, 2018	Tuesday	13	16-19, 17-19, 18-19, 19-19, 19-20	471	11
Aug 8, 2018	Wednesday	12	16-19, 18-19, 19-19, 19-20	435	11
Aug 9, 2018	Thursday	12	19-19, 19-20	386	-
Aug 10, 2018	Friday	6	17-19, 18-19	1	11
Aug 13, 2018	Monday	1	19-19	1	-
Sep 4, 2018	Tuesday	1	18-19	48	-
Sep 5, 2018	Wednesday	1	18-19	48	-
Sep 6, 2018	Thursday	1	18-19	48	-
Sep 7, 2018	Friday	2	19-19	1	2
Sep 10, 2018	Monday	1	19-19	48	-
Sep 11, 2018	Tuesday	1	19-19	48	-
Oct 1, 2018	Monday	1	18-19	22	-
Oct 2, 2018	Tuesday	1	18-19	22	-
Oct 3, 2018	Wednesday	1	18-19	22	-
Oct 5, 2018	Friday	1	19-19	53	-
Oct 8, 2018	Monday	1	18-19	53	-
Oct 9, 2018	Tuesday	1	18-19	31	-
Oct 10, 2018	Wednesday	1	19-19	31	-
Oct 12, 2018	Friday	1	18-19	31	-
Oct 15, 2018	Monday	1	19-19	-	2
Oct 17, 2018	Wednesday	5	19-19	-	14
Oct 18, 2018	Thursday	5	19-19	-	14
Oct 19, 2018	Friday	5	19-19	-	14
Oct 22, 2018	Monday	13	19-19	365	14
Oct 23, 2018	Tuesday	4	19-19	-	12
Oct 24, 2018	Wednesday	2	18-19, 19-19	6	-

Summary Load Impacts

Table 4-4 and Table 4-5 present the average event hour impacts for the Elect DA and Prescribed DA participants, respectively, 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 4-4 PG&E 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	**187**	**4.9**	**221.4**	**32.0**	**41.3**	**6.0**	**14%**	**77**
Jun 13, 2018	56	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	74
Jun 22, 2018	18	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	96
Jul 10, 2018	55	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	79
Jul 11, 2018	55	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	76
Jul 12, 2018	55	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	74
Jul 18, 2018	55	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	76
Jul 19, 2018	55	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	76
Jul 20, 2018	16	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	85
Jul 23, 2018	430	22.4	178.5	34.7	76.8	14.9	19%	85
Jul 24, 2018	473	25.7	182.0	46.5	86.1	22.0	26%	90
Jul 25, 2018	495	24.7	200.2	47.0	99.1	23.3	23%	88
Jul 26, 2018	65	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	76
Jul 27, 2018	55	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	70
Jul 30, 2018	55	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	72
Jul 31, 2018	55	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	73
Aug 1, 2018	48	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	73
Aug 2, 2018	48	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	74
Aug 6, 2018	49	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	80
Aug 7, 2018	471	25.0	186.8	38.7	88.0	18.2	21%	79
Aug 8, 2018	435	23.8	203.3	39.6	88.4	17.2	19%	84
Aug 9, 2018	386	22.0	189.7	39.0	73.2	15.0	21%	90
Aug 10, 2018	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	74
Aug 13, 2018	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	69
Sep 4, 2018	48	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	76
Sep 5, 2018	48	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	70
Sep 6, 2018	48	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	73
Sep 7, 2018	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	66
Sep 10, 2018	48	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	77
Sep 11, 2018	48	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	75
Oct 1, 2018	22	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	75
Oct 2, 2018	22	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	78
Oct 3, 2018	22	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	73
Oct 5, 2018	53	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	73
Oct 8, 2018	53	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	83

Event	# of Accts	Nominated Capacity (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Oct 9, 2018	31	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	69
Oct 10, 2018	31	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	67
Oct 12, 2018	31	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	80
Oct 22, 2018	365	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	67
Oct 24, 2018	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	53

Table 4-5 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	**10**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]**%**	**82**
Jul 3, 2018	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	72
Jul 10, 2018	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	82
Jul 11, 2018	16	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	85
Jul 12, 2018	16	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	85
Jul 17, 2018	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	74
Jul 23, 2018	13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	94
Jul 24, 2018	13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	95
Jul 25, 2018	13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	97
Jul 27, 2018	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	103
Jul 30, 2018	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	100
Aug 1, 2018	22	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	85
Aug 6, 2018	11	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	83
Aug 7, 2018	11	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	77
Aug 8, 2018	11	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	80
Aug 10, 2018	11	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	85
Sep 7, 2018	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	100
Oct 15, 2018	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	79
Oct 17, 2018	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	73
Oct 18, 2018	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	73
Oct 19, 2018	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	77
Oct 22, 2018	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	71
Oct 23, 2018	12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	67

Table 4-6 and Table 4-7 present the impacts for an average event day by Industry and Local Capacity Area (LCA).[31][32]

Table 4-6 PG&E Impacts by Industry and Product Offering

	Industry	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Ref. Load	Impact	Ref. Load	Impact		
Elect DA	Agriculture, Mining & Construction	49	95.0	86.4	4.6	4.2	91%	99
	Manufacturing	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	92
	Wholesale, Transport, other utilities	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	95
	Retail stores	212	162.0	27.3	34.4	5.8	17%	82
	Offices, Hotels, Finance, Services	92	270.4	25.5	25.0	2.4	9%	76
	Schools	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	70
	Institutional/Government	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	77
	Other or unknown	7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	75
	Total Elect DA	**187**	**221.4**	**32.0**	**41.3**	**6.0**	**14%**	**77**
Prescribed DA	Agriculture, Mining & Construction	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	89
	Manufacturing	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	95
	Wholesale, Transport, other utilities	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	71
	Retail stores	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	75
	Offices, Hotels, Finance, Services	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	73
	Schools	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	68
	Institutional/Government	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	88
	Total Prescribed DA	**10**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]**%**	**82**
Total CBP DA		**197**	**350.7**	**44.8**	**69.1**	**8.8**	**13%**	**77**

[31] The results in Table 4-6 and Table 4-7 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.

[32] 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 4-7 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		
Elect DA	Greater Bay Area	113	221.8	23.7	25.0	2.7	11%	74
Elect DA	Greater Fresno Area	68	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	80
Elect DA	Humboldt	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	53
Elect DA	Kern	13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	97
Elect DA	Northern Coast	35	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	82
Elect DA	Other	17	256.4	38.2	4.3	0.6	15%	84
Elect DA	Sierra	23	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	92
Elect DA	Stockton	16	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	94
Elect DA	**Total Elect DA**	**187**	**221.4**	**32.0**	**41.3**	**6.0**	**14%**	**77**
Prescribed DA	Greater Bay Area	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	72
Prescribed DA	Greater Fresno Area	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	101
Prescribed DA	Northern Coast	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	88
Prescribed DA	Other	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	87
Prescribed DA	Stockton	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	88
Prescribed DA	**Total Prescribed DA**	**10**	[redacted]	[redacted]	[redacted]	[redacted]	**[redacted]%**	**82**
Total CBP DA		**197**	**350.7**	**44.8**	**69.1**	**8.8**	**13%**	**77**

Hourly Load Impacts

Figure 4-1 and Figure 4-2 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 blue-green show the hours where in at least one group is called. The common event hour, hour-ending 19, 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 4-1 PG&E Elect Day Ahead: Average Hourly Per-Customer Impact, 2018

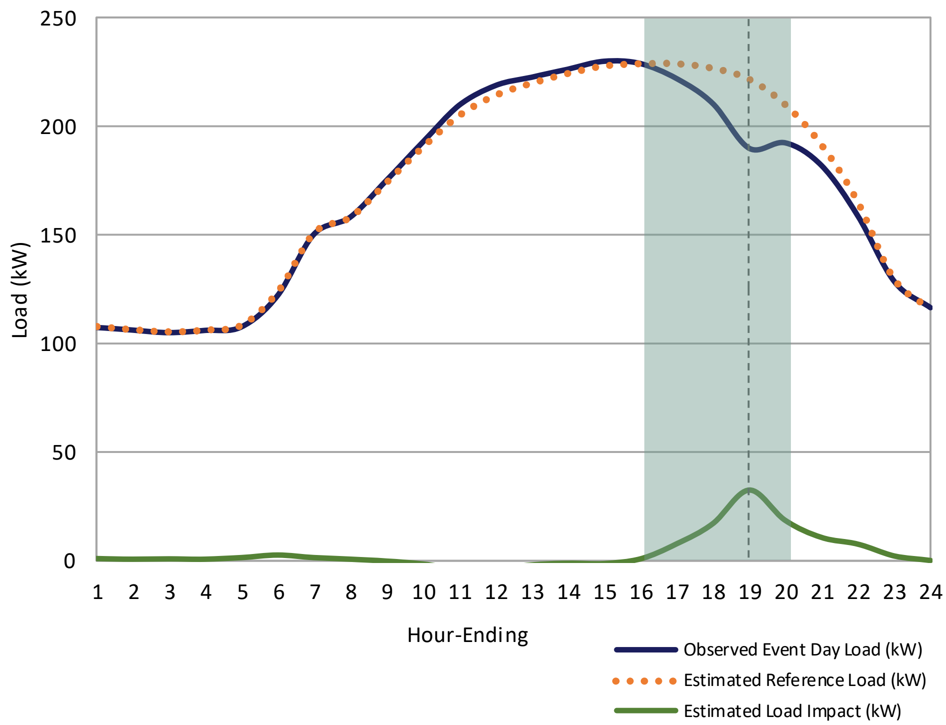


Figure 4-2 PG&E Prescribed Day Ahead: Average Hourly Per-Customer Impact, 2018

Figure redacted to protect customer or aggregator confidentiality.

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.

Table 4-8 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 4-8 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	**111**	**193.4**	**41.7**	**21.5**	**4.6**	**22%**	**5.4**	**84**
Jun 22, 2018	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	96
Jul 20, 2018	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	85
Jul 23, 2018	171	195.5	41.4	33.4	7.1	21%	8.1	86
Jul 24, 2018	209	177.5	42.9	37.1	9.0	24%	10.5	91
Jul 25, 2018	177	198.9	45.2	35.2	8.0	23%	8.4	90
Jul 26, 2018	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	98
Aug 7, 2018	170	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	79
Aug 8, 2018	156	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	83
Aug 9, 2018	156	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	88
Oct 22, 2018	154	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	68
Oct 24, 2018	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	53

Table 4-9 shows the per-customer and aggregate ex-post impacts by event day for the AutoDR participants for the Prescribed DA product offering.[33]

Table 4-9 PG&E Prescribed 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	**6**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]**%**	[redacted]	**80**
Jul 3, 2018	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	72
Jul 10, 2018	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	82
Jul 11, 2018	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	84
Jul 12, 2018	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	87
Jul 17, 2018	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	74
Jul 23, 2018	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	99
Jul 24, 2018	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	101
Jul 25, 2018	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	104
Aug 1, 2018	12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	84
Aug 6, 2018	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	81
Aug 7, 2018	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	70
Aug 8, 2018	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	72

[33] 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.

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 10, 2018	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	80
Oct 17, 2018	7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	76
Oct 18, 2018	7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	75
Oct 19, 2018	7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	79
Oct 22, 2018	7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	76
Oct 23, 2018	7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	68

SCE

Events for SCE

We present summaries of the PY2018[34] events for SCE's CBP program for DA and DO products. Because of the changes in SCE's product offerings that took effect on May 1, 2018, all events prior to May 1, 2018 were called under the 1-4 Hour option, for both DA and DO. All events after May 1, 2018 were called under the 1-6 Hour option. The DO participants experienced a total of 48 event days over the course of the program year, while DA participants experienced 37 event days. As in previous year, events were called with a wide variety of event hours. Table 4-11 below shows the number of Sub-LAPs, the event windows called, and the number of accounts nominated on each event day. For reference, Table 4-10 presents the total monthly enrollment for the DA and DO programs, which would be comparable to participation counts of a system-level event.

Similar to PG&E, the average event day is defined as the average of all events called in PY2018 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 common event hours HE19 and HE18 for summer and non-summer, respectively.

Table 4-10 SCE Monthly Enrollment

Month	# of Accounts	
	Day Ahead	Day Of
November	22	103
December	-	103
Avg. Non-Summer	**22**	**103**
May	44	276
June	74	291
July	66	279
August	59	284
September	30	246
October	29	242
Avg. Summer	**50**	**270**

[34] SCE's PY2018 evaluation period is from Nov. 1, 2017 through Oct. 31, 2018.

Table 4-11 SCE Event Summary

Date	Day of Week	# of Sub-LAPs	Event Hours (HE)	# Accounts	
				Day Ahead	Day Of
Avg. Non-Summer Event	**-**	**5**	**18**	**22**	**89**
Avg. Summer Event	**-**	**5**	**19**	**43**	**214**
Nov 1, 2017	Wednesday	5	19-19	22	103
Nov 2, 2017	Thursday	5	19-19	22	103
Nov 3, 2017	Friday	5	19-19	22	103
Nov 6, 2017	Monday	5	18-19, 19-19	22	103
Nov 7, 2017	Tuesday	5	18-19	22	103
Nov 8, 2017	Wednesday	5	17-19	22	103
Nov 9, 2017	Thursday	5	18-19	22	103
Nov 10, 2017	Friday	5	18-18, 18-19	22	103
Nov 13, 2017	Monday	5	17-19, 18-18, 18-19	22	103
Nov 14, 2017	Tuesday	5	18-18, 18-19	22	103
Nov 15, 2017	Wednesday	5	18-18	22	103
Nov 20, 2017	Monday	5	18-18, 18-19	22	103
Nov 21, 2017	Tuesday	5	17-19, 18-18	22	103
Nov 22, 2017	Wednesday	5	17-18, 17-19, 18-18	22	103
Dec 1, 2017	Friday	3	18-18	-	96
Dec 7, 2017	Thursday	1	18-19	-	38
Dec 8, 2017	Friday	1	18-18	-	38
Dec 11, 2017	Monday	2	18-18	-	76
Dec 12, 2017	Tuesday	2	18-18	-	76
Dec 13, 2017	Wednesday	4	18-18	-	101
Dec 26, 2017	Tuesday	1	18-19	-	38
Dec 28, 2017	Thursday	2	18-19	-	76
Dec 29, 2017	Friday	2	18-19	-	76
May 29, 2018	Tuesday	4	19-19	44	-
Jun 4, 2018	Monday	4	15-17, 18-19	74	85
Jun 12, 2018	Tuesday	1	17-19	29	85
Jul 6, 2018	Friday	5	14-19, 15-19, 17-19	66	279
Jul 9, 2018	Monday	4	15-19, 18-19, 19-19	66	78
Jul 10, 2018	Tuesday	5	14-19, 15-19, 17-19	66	279
Jul 11, 2018	Wednesday	5	15-19, 19-19	66	279
Jul 17, 2018	Tuesday	5	19-19	66	279

Date	Day of Week	# of Sub-LAPs	Event Hours (HE)	# Accounts	
				Day Ahead	Day Of
Jul 18, 2018	Wednesday	3	18-19	-	201
Aug 1, 2018	Wednesday	5	15-19, 17-19	59	284
Aug 6, 2018	Monday	5	18-19, 19-19	-	284
Aug 7, 2018	Tuesday	5	17-19	59	284
Aug 8, 2018	Wednesday	5	19-19	59	284
Aug 9, 2018	Thursday	5	19-19	59	284
Sep 17, 2018	Monday	5	19-19	-	246
Sep 18, 2018	Tuesday	1	19-19	10	54
Sep 20, 2018	Thursday	4	19-19	25	241
Sep 21, 2018	Friday	3	19-19	25	206
Sep 24, 2018	Monday	4	19-19	30	-
Sep 26, 2018	Wednesday	5	19-19	30	246
Sep 27, 2018	Thursday	2	19-19	15	152
Oct 1, 2018	Monday	4	15-19, 19-19	-	208
Oct 15, 2018	Monday	5	19-19	-	242
Oct 16, 2018	Tuesday	5	19-19	29	242
Oct 17, 2018	Wednesday	5	19-19	29	242
Oct 18, 2018	Thursday	5	19-19	29	242
Oct 19, 2018	Friday	3	19-19	29	34
Oct 22, 2018	Monday	3	19-19	29	-

Summary Load Impacts

Table 4-12 to Table 4-15 below show the average event-hour impacts for the four CBP products, respectively: DA 1-4 Hour, DO 1-4 Hour, DA 1-6 Hour, and DO 1-6 Hour. 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.

Table 4-12 SCE Day Ahead 1-4 Hour: Impacts by Event[35]

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	**22**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]**%**	**73**
Nov 1, 2017	22	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	65
Nov 2, 2017	22	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	64
Nov 3, 2017	22	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	66
Nov 6, 2017	22	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	68
Nov 7, 2017	22	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	72
Nov 8, 2017	22	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	72
Nov 9, 2017	22	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	68
Nov 10, 2017	22	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	68
Nov 13, 2017	22	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	70
Nov 14, 2017	22	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	74
Nov 15, 2017	22	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	76
Nov 20, 2017	22	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	73
Nov 21, 2017	22	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	83
Nov 22, 2017	22	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	87

Table 4-13 SCE Day Ahead 1-6 Hour: 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	**43**	**3.0**	**432.1**	**47.9**	**18.7**	**2.1**	**11%**	**81**
May 29, 2018	44	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	70
Jun 4, 2018	74	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	76
Jun 12, 2018	29	0.7	125.4	14.0	3.6	0.4	11%	73
Jul 6, 2018	66	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	107
Jul 9, 2018	66	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	86
Jul 10, 2018	66	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	85
Jul 11, 2018	66	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	82
Jul 17, 2018	66	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	80
Aug 1, 2018	59	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	90
Aug 7, 2018	59	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	95
Aug 8, 2018	59	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	90

[35] 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	Nominated Capacity (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Aug 9, 2018	59	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	87
Sep 18, 2018	10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	74
Sep 20, 2018	25	2.4	249.9	24.3	6.2	0.6	10%	76
Sep 21, 2018	25	2.4	284.6	24.3	7.1	0.6	9%	82
Sep 24, 2018	30	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	73
Sep 26, 2018	30	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	80
Sep 27, 2018	15	1.8	261.0	27.8	3.9	0.4	11%	90
Oct 16, 2018	29	2.1	238.6	26.6	6.9	0.8	11%	74
Oct 17, 2018	29	2.1	230.3	26.6	6.7	0.8	12%	75
Oct 18, 2018	29	2.1	252.1	26.6	7.3	0.8	11%	79
Oct 19, 2018	29	2.1	244.1	26.6	7.1	0.8	11%	80
Oct 22, 2018	29	2.1	268.5	26.6	7.8	0.8	10%	71

Table 4-14 SCE Day Of 1-4 Hour: Impacts by Event[36]

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	**89**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]**%**	**71**
Nov 1, 2017	103	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	64
Nov 2, 2017	103	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	63
Nov 3, 2017	103	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	65
Nov 6, 2017	103	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	66
Nov 7, 2017	103	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	69
Nov 8, 2017	103	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	70
Nov 9, 2017	103	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	67
Nov 10, 2017	103	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	66
Nov 13, 2017	103	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	69
Nov 14, 2017	103	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	71
Nov 15, 2017	103	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	73
Nov 20, 2017	103	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	69
Nov 21, 2017	103	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	78
Nov 22, 2017	103	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	83
Dec 1, 2017	96	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	68

[36] 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	Nominated Capacity (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Dec 7, 2017	38	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	73
Dec 8, 2017	38	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	70
Dec 11, 2017	76	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	74
Dec 12, 2017	76	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	75
Dec 13, 2017	101	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	70
Dec 26, 2017	38	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	62
Dec 28, 2017	76	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	71
Dec 29, 2017	76	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	73

Table 4-15 SCE Day Of 1-6 Hour: 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	**214**	**4.5**	**175.8**	**22.8**	**37.6**	**4.9**	**13%**	**83**
Jun 4, 2018	85	1.6	73.4	14.2	6.2	1.2	19%	69
Jun 12, 2018	85	1.6	84.6	18.3	7.2	1.6	22%	73
Jul 6, 2018	279	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	108
Jul 9, 2018	78	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	79
Jul 10, 2018	279	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	88
Jul 11, 2018	279	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	85
Jul 17, 2018	279	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	85
Jul 18, 2018	201	3.4	147.8	19.9	29.7	4.0	13%	91
Aug 1, 2018	284	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	93
Aug 6, 2018	284	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	95
Aug 7, 2018	284	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	97
Aug 8, 2018	284	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	91
Aug 9, 2018	284	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	90
Sep 17, 2018	246	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	83
Sep 18, 2018	54	1.2	101.2	26.8	5.5	1.4	26%	73
Sep 20, 2018	241	4.7	135.8	25.5	32.7	6.1	19%	78
Sep 21, 2018	206	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	83
Sep 26, 2018	246	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	82
Sep 27, 2018	152	2.7	164.4	25.5	25.0	3.9	16%	88
Oct 1, 2018	208	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	83
Oct 15, 2018	242	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	71
Oct 16, 2018	242	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	72

Event	# of Accts	Nominated Capacity (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Oct 17, 2018	242	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	74
Oct 18, 2018	242	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	77
Oct 19, 2018	34	0.9	95.7	11.3	3.3	0.4	12%	78

Table 4-16 and Table 4-17 present the impacts by Industry for an average non-summer event day and average summer event day, respectively. Table 4-18 and Table 4-19 present the impacts by LCA for an average non-summer event day and average summer event day, respectively.[37] [38]

Table 4-16 SCE CBP Impacts by Industry and Notice, Non-Summer

	Industry	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Ref. Load	Impact	Ref. Load	Impact		
DA	Wholesale, Transport, other utilities	18	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	73
DA	Retail stores	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	72
DA	**Total Day Ahead**	**22**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]**%**	**73**
DO	Wholesale, Transport, other utilities	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	73
DO	Retail stores	83	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	71
DO	Offices, Hotels, Finance, Services	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	70
DO	**Total Day Of**	**89**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]**%**	**71**
Total Non-Summer CBP		**111**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]**%**	**71**

[37] The results in Table 4-16 through Table 4-19 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.

[38] 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 4-17 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		
DA	Manufacturing	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	78
DA	Wholesale, Transport, other utilities	7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	85
DA	Retail stores	36	220.9	28.6	8.0	1.0	13%	81
DA	**Total Day Ahead**	**43**	**432.1**	**47.9**	**18.7**	**2.1**	**11%**	**81**
DO	Agriculture, Mining & Construction	15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	81
DO	Manufacturing	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	88
DO	Wholesale, Transport, other utilities	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	85
DO	Retail stores	181	129.1	23.6	23.4	4.3	18%	83
DO	Offices, Hotels, Finance, Services	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	83
DO	Schools	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	72
DO	**Total Day Of**	**214**	**175.8**	**22.8**	**37.6**	**4.9**	**13%**	**83**
Total Summer CBP		**257**	**218.9**	**27.0**	**56.2**	**6.9**	**12%**	**83**

Table 4-18 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		
DA	LA Basin	22	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	73
DA	**Total Day Ahead**	**22**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]**%**	**73**
DO	LA Basin	71	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	71
DO	Outside LA Basin	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	66
DO	Ventura / Big Creek	25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	67
DO	**Total Day Of**	**89**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]**%**	**71**
Total Non-Summer CBP		**111**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]**%**	**71**

Table 4-19 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	37	196.4	30.8	7.2	1.1	16%	81
DA	Outside LA Basin	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	86
DA	Ventura / Big Creek	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	81
DA	**Total Day Ahead**	**43**	**432.1**	**47.9**	**18.7**	**2.1**	**11%**	**81**
DO	LA Basin	185	140.3	22.0	25.9	4.1	16%	83
DO	Outside LA Basin	17	157.8	26.7	2.6	0.4	17%	85
DO	Ventura / Big Creek	25	488.9	27.3	12.4	0.7	6%	86
DO	**Total Day Of**	**214**	**175.8**	**22.8**	**37.6**	**4.9**	**13%**	**83**
Total Summer CBP		**257**	**218.9**	**27.0**	**56.2**	**6.9**	**12%**	**83**

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 4-3 through Figure 4-6 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 blue-green show the hours where in at least one group is called. The common 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 4-3 SCE Day-Ahead 1-4 Hour: Average Hourly Per-Customer Impact, 2018

Figure redacted to protect customer or aggregator confidentiality.

Figure 4-4 SCE Day-Ahead 1-6 Hour: Average Hourly Per-Customer Impact, 2018

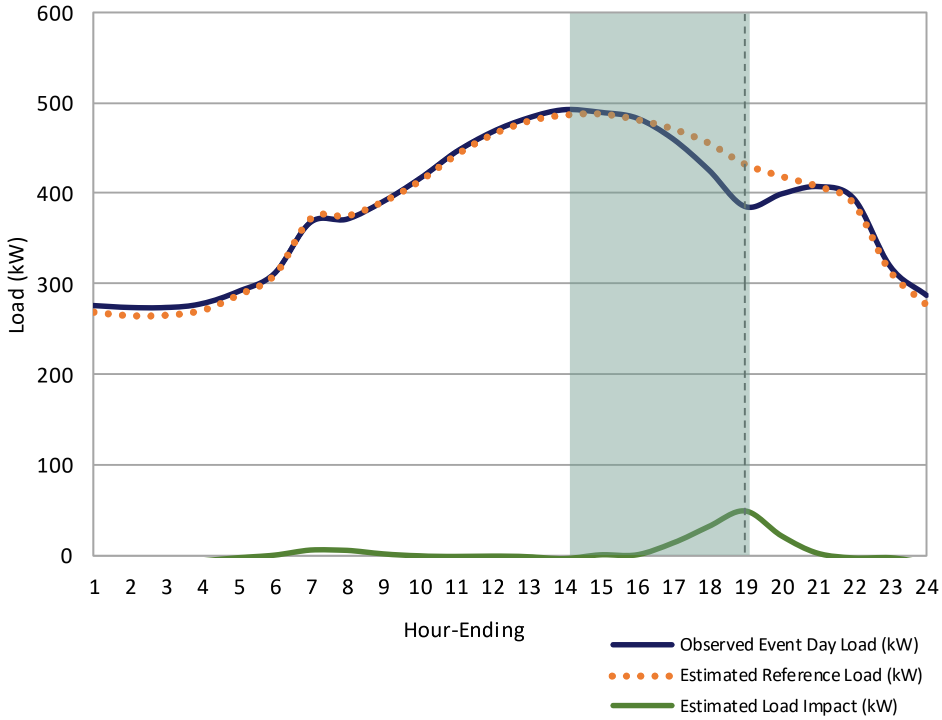
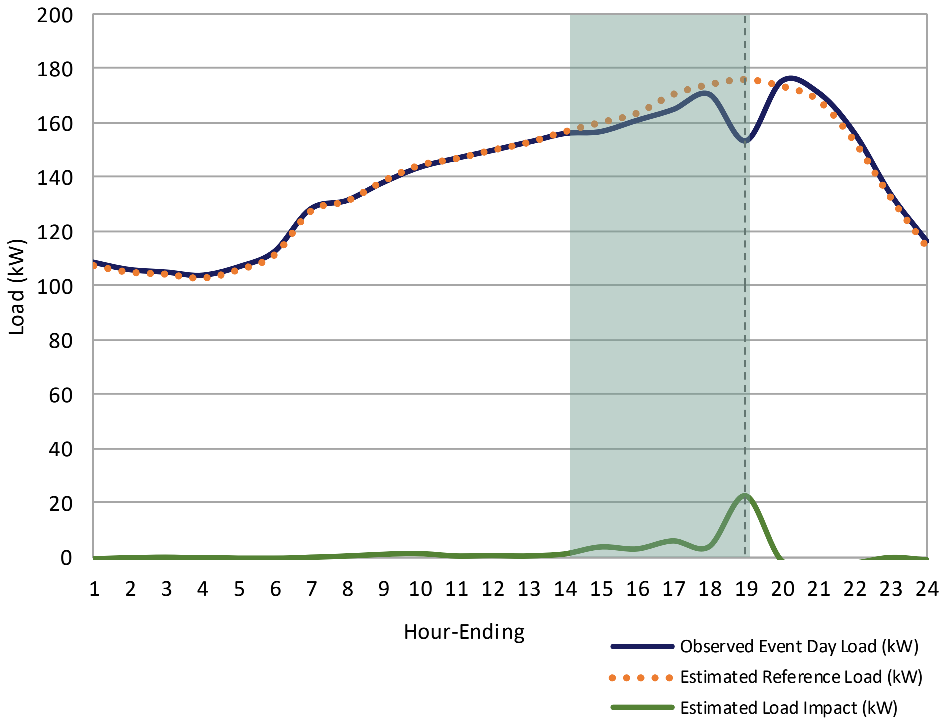


Figure 4-5 SCE Day-Of 1-4 Hour: Average Hourly Per-Customer Impact, 2018

Figure redacted to protect customer or aggregator confidentiality.

Figure 4-6 SCE Day-Of 1-6 Hour: Average Hourly Per-Customer Impact, 2018



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 4-20 and Table 4-21 presents the ex-post load impacts achieved in PY2018 by SCE CBP customers that enrolled in AutoDR or TA/TI at some point in the current or previous years. Only the DO products had AutoDR or TA/TI participants in PY2018.[39]

[39] 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 4-20 SCE Day Of 1-4 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	**26**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]**%**	[redacted]	**71**
Nov 1, 2017	29	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	63
Nov 2, 2017	29	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	62
Nov 3, 2017	29	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	64
Nov 6, 2017	29	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	66
Nov 7, 2017	29	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	69
Nov 8, 2017	29	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	70
Nov 9, 2017	29	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	66
Nov 10, 2017	29	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	65
Nov 13, 2017	29	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	69
Nov 14, 2017	29	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	72
Nov 15, 2017	29	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	73
Nov 20, 2017	29	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	70
Nov 21, 2017	29	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	80
Nov 22, 2017	29	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	84
Dec 1, 2017	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	69
Dec 7, 2017	12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	72
Dec 8, 2017	12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	69
Dec 11, 2017	23	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	73
Dec 12, 2017	23	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	75
Dec 13, 2017	28	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	72
Dec 26, 2017	12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	62
Dec 28, 2017	23	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	72
Dec 29, 2017	23	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	73

Table 4-21 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. Summer	**151**	**192.0**	**26.6**	**28.9**	**4.0**	**14%**	**8.1**	**82**
Jun 4, 2018	54	92.0	18.7	5.0	1.0	20%	2.9	70
Jun 12, 2018	54	108.9	24.7	5.9	1.3	23%	2.9	73
Jul 6, 2018	178	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	109
Jul 9, 2018	47	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	79

Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Aggregate Load Shed Test (MW)	Temp (F)
		Reference Load	Impact	Reference Load	Impact			
Jul 10, 2018	178	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	88
Jul 11, 2018	178	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	84
Jul 17, 2018	178	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	85
Jul 18, 2018	131	163.5	26.3	21.4	3.5	16%	6.3	91
Aug 1, 2018	182	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	93
Aug 6, 2018	182	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	95
Aug 7, 2018	182	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	97
Aug 8, 2018	182	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	90
Aug 9, 2018	182	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	89
Sep 17, 2018	193	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	82
Sep 18, 2018	47	104.2	29.0	4.9	1.4	28%	2.6	73
Sep 20, 2018	188	128.1	27.4	24.1	5.2	21%	9.4	77
Sep 21, 2018	164	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	82
Sep 26, 2018	193	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	81
Sep 27, 2018	117	156.4	28.9	18.3	3.4	18%	5.5	88
Oct 1, 2018	167	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	83
Oct 15, 2018	191	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	71
Oct 16, 2018	191	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	72
Oct 17, 2018	191	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	73
Oct 18, 2018	191	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	77
Oct 19, 2018	24	56.4	12.2	1.4	0.3	22%	1.3	78

SDG&E

Events for SDG&E

Table 4-22 presents a summary of the 2018 events for SDG&E's CBP program by product. Over the course of the program year, the DO product participants experienced only three event days, while the DA product participants experienced a total of 26 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 PY2018 regardless of event window. We also present impacts for the average event day on the common 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 4-23 presents SDG&E's monthly nominations by product offering.

Table 4-22 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**	**25**	**2**	**97**	**89**
Jul 6, 2018	Friday	16-19	65	1	-	-
Jul 10, 2018	Tuesday	16-19	65	-	-	-
Jul 11, 2018	Wednesday	18-19	65	-	-	-
Jul 12, 2018	Thursday	18-19, 19-20	65	1	-	-
Jul 16, 2018	Monday	17-19	65	-	-	-
Jul 18, 2018	Wednesday	18-19, 18-21	65	1	-	-
Jul 20, 2018	Friday	19-20	-	1	-	-
Jul 23, 2018	Monday	17-19	65	-	-	-
Jul 24, 2018	Tuesday	18-19, 19-20	65	1	-	-
Jul 25, 2018	Wednesday	18-19, 19-20	65	1	-	-
Aug 1, 2018	Wednesday	18-19, 19-20	2	1	-	-
Aug 6, 2018	Monday	18-19, 18-20, 18-21	2	1	97	89
Aug 7, 2018	Tuesday	16-19, 18-21	2	1	97	89
Aug 8, 2018	Wednesday	16-19, 18-21	2	1	-	-
Aug 9, 2018	Thursday	18-19, 18-21	2	1	97	89
Oct 1, 2018	Monday	16-19	2	-	-	-
Oct 18, 2018	Thursday	18-19	2	-	-	-
Oct 19, 2018	Friday	18-19	2	-	-	-
Oct 22, 2018	Monday	18-19	2	-	-	-
Oct 23, 2018	Tuesday	18-19, 19-20	2	4	-	-
Oct 24, 2018	Wednesday	18-19, 19-20	2	4	-	-
Oct 25, 2018	Thursday	18-19, 19-20	2	4	-	-
Oct 26, 2018	Friday	18-19, 18-20	2	4	-	-
Oct 29, 2018	Monday	18-19, 19-20	2	4	-	-
Oct 30, 2018	Tuesday	18-19, 19-20	2	4	-	-
Oct 31, 2018	Wednesday	18-19, 19-20	2	4	-	-

Table 4-23 SDG&E Monthly Enrollment

Month	# Accounts			
	DA 11AM to 7PM	DA 1PM to 9PM	DO 11AM to 7PM	DO 1PM to 9PM
May	56	1	166	5
June	56	1	77	85
July	65	1	97	102
August	65	1	97	89
September	2	1	96	97
October	2	4	96	98
Average Month	**31**	**2**	**105**	**79**

Summary Load Impacts

Table 4-24 through Table 4-27 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.

Table 4-24 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	**25**	**0.2**	**159.6**	**5.1**	**3.9**	**0.1**	**3%**	**75**
Jul 6, 2018	65	0.4	245.0	16.8	15.9	1.1	7%	95
Jul 10, 2018	65	0.4	255.5	16.8	16.6	1.1	7%	82
Jul 11, 2018	65	0.4	217.5	5.5	14.1	0.4	3%	79
Jul 12, 2018	65	0.4	216.1	5.5	14.0	0.4	3%	77
Jul 16, 2018	65	0.4	231.4	7.9	15.0	0.5	3%	77
Jul 18, 2018	65	0.4	197.5	5.5	12.8	0.4	3%	75
Jul 23, 2018	65	0.4	261.3	7.9	17.0	0.5	3%	85
Jul 24, 2018	65	0.4	229.1	5.5	14.9	0.4	2%	82
Jul 25, 2018	65	0.4	219.3	5.5	14.3	0.4	2%	80
Aug 1, 2018	2	0.2	63.2	62.4	0.1	0.1	99%	86
Aug 6, 2018	2	0.2	63.3	62.4	0.1	0.1	99%	96
Aug 7, 2018	2	0.2	75.4	74.5	0.2	0.1	99%	96
Aug 8, 2018	2	0.2	75.5	74.5	0.2	0.1	99%	88
Aug 9, 2018	2	0.2	63.3	62.4	0.1	0.1	99%	81
Oct 1, 2018	2	0.1	75.0	74.5	0.1	0.1	99%	72
Oct 18, 2018	2	0.1	62.9	62.4	0.1	0.1	99%	68
Oct 19, 2018	2	0.1	62.9	62.4	0.1	0.1	99%	69

Event	# of Accts	Nominated Capacity (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Oct 22, 2018	2	0.1	62.9	62.4	0.1	0.1	99%	64
Oct 23, 2018	2	0.1	62.9	62.4	0.1	0.1	99%	70
Oct 24, 2018	2	0.1	63.0	62.4	0.1	0.1	99%	72
Oct 25, 2018	2	0.1	63.0	62.4	0.1	0.1	99%	74
Oct 26, 2018	2	0.1	62.9	62.4	0.1	0.1	99%	76
Oct 29, 2018	2	0.1	62.9	62.4	0.1	0.1	99%	69
Oct 30, 2018	2	0.1	62.9	62.4	0.1	0.1	99%	63
Oct 31, 2018	2	0.1	62.8	62.4	0.1	0.1	99%	63

Table 4-25 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	**2**	**<0.1**	**1,013.3**	**28.1**	**2.2**	**0.1**	**3%**	**74**
Jul 6, 2018	1	<0.1	2,683.9	137.9	2.7	0.1	5%	95
Jul 12, 2018	1	<0.1	2,087.6	17.6	2.1	<0.1	1%	73
Jul 18, 2018	1	<0.1	1,932.5	146.5	1.9	0.1	8%	70
Jul 20, 2018	1	<0.1	1,809.6	17.6	1.8	<0.1	1%	73
Jul 24, 2018	1	<0.1	2,093.6	17.6	2.1	<0.1	1%	76
Jul 25, 2018	1	<0.1	1,929.6	17.6	1.9	<0.1	1%	73
Aug 1, 2018	1	<0.1	2,227.6	17.6	2.2	<0.1	1%	80
Aug 6, 2018	1	<0.1	2,309.8	97.8	2.3	0.1	4%	83
Aug 7, 2018	1	<0.1	2,352.5	146.5	2.4	0.1	6%	81
Aug 8, 2018	1	<0.1	2,227.5	146.5	2.2	0.1	7%	85
Aug 9, 2018	1	<0.1	2,516.5	146.5	2.5	0.1	6%	85
Oct 23, 2018	4	0.1	503.7	12.0	2.0	<0.1	2%	66
Oct 24, 2018	4	0.1	504.2	12.0	2.0	<0.1	2%	66
Oct 25, 2018	4	0.1	515.7	12.0	2.1	<0.1	2%	67
Oct 26, 2018	4	0.1	554.7	32.1	2.2	0.1	6%	70
Oct 29, 2018	4	0.1	502.6	12.0	2.0	<0.1	2%	64
Oct 30, 2018	4	0.1	480.5	12.0	1.9	<0.1	2%	65
Oct 31, 2018	4	0.1	465.5	12.0	1.9	<0.1	3%	67

Table 4-26 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	**97**	**1.4**	**112.2**	**7.6**	**10.9**	**0.7**	**7%**	**85**
Aug 6, 2018	97	1.4	111.3	6.8	10.8	0.7	6%	85
Aug 7, 2018	97	1.4	113.7	8.6	11.0	0.8	8%	89
Aug 9, 2018	97	1.4	114.1	6.8	11.1	0.7	6%	87

Table 4-27 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	**89**	**2.6**	**159.4**	**30.6**	**14.2**	**2.7**	**19%**	**83**
Aug 6, 2018	89	2.6	156.2	27.4	13.9	2.4	18%	81
Aug 7, 2018	89	2.6	155.6	27.4	13.8	2.4	18%	82
Aug 9, 2018	89	2.6	160.3	27.4	14.3	2.4	17%	84

Table 4-28 presents the impacts for an average event day by industry group.[40,41 42]

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

[41] The results in 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 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.

[42] 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 4-28 SDG&E Impacts by Industry and Notice

	Industry	# of Accts	Per Customer Impact (kW) Ref. Load	Per Customer Impact (kW) Impact	Aggregate Impact (MW) Ref. Load	Aggregate Impact (MW) Impact	% Impact	Temp (F)
Day Ahead	Agriculture, Mining & Construction	2	56.2	55.6	0.1	0.1	99%	78
Day Ahead	Retail stores	3	52.0	7.8	0.2	<0.1	15%	67
Day Ahead	Offices, Hotels, Finance, Services	62	170.5	-0.2	10.6	<0.1	0%	79
Day Ahead	Institutional/Government	1	2,134.9	51.7	2.1	0.1	2%	74
Day Ahead	**Total Day Ahead**	**27**	**228.5**	**6.9**	**6.1**	**0.2**	**3%**	**75**
Day Of	Agriculture, Mining & Construction	1	4.5	4.2	0.0	<0.1	94%	88
Day Of	Manufacturing	1	1,103.4	70.1	1.1	0.1	6%	87
Day Of	Retail stores	168	129.8	19.3	21.8	3.2	15%	84
Day Of	Offices, Hotels, Finance, Services	14	123.3	7.9	1.7	0.1	6%	88
Day Of	Institutional/Government	1	366.5	25.7	0.4	<0.1	7%	84
Day Of	Other or unknown	1	58.8	2.0	0.1	<0.1	3%	82
Day Of	**Total Day Of**	**186**	**134.8**	**18.6**	**25.1**	**3.5**	**14%**	**84**
Total CBP		**213**	**146.6**	**17.1**	**31.2**	**3.6**	**12%**	**83**

Hourly Load Impacts

Figure 4-7 and Figure 4-8 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 blue-green show the hours where in 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 Excel-based Protocol table generators that are included as appendices to this report.

Figure 4-7 SDG&E All Day-Ahead: Average Hourly Per-Customer Impact, 2018

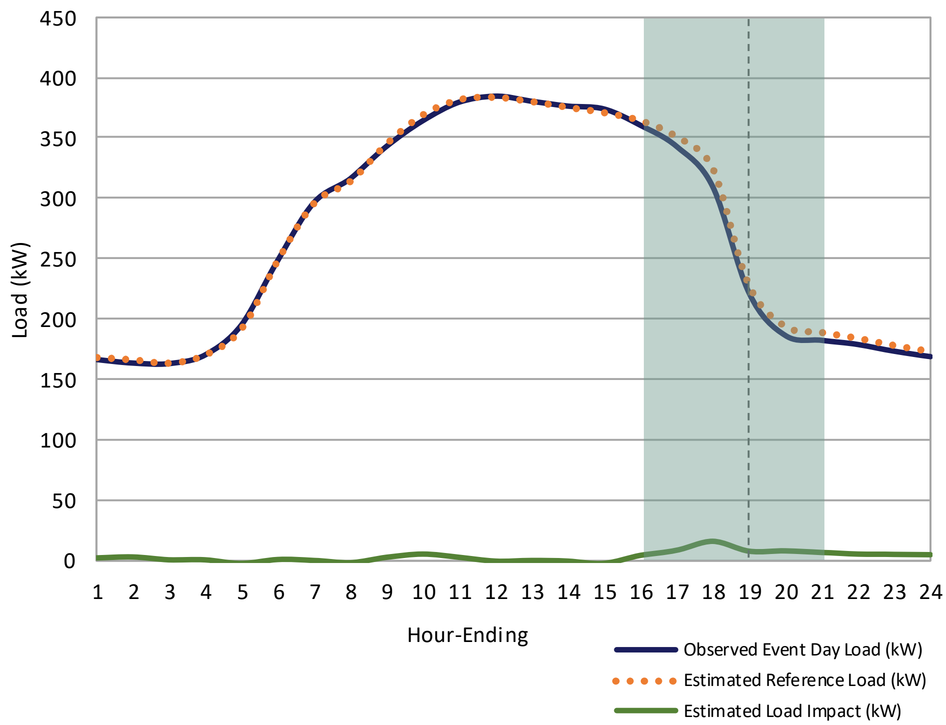
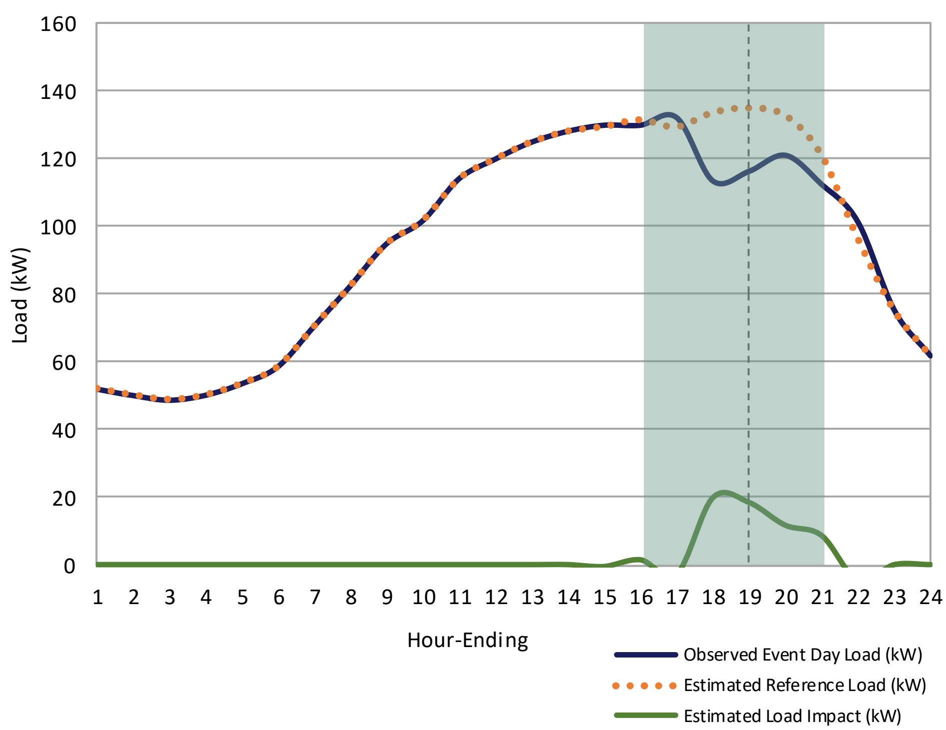


Figure 4-8 SDG&E All Day-Of: Average Hourly Per-Customer Impact, 2018



Load Impacts of TA/TI and AutoDR Participants

This section presents the ex-post load impacts achieved in PY2018 by SDG&E CBP customers that enrolled in AutoDR or TA/TI at some point in the current or previous years. In this section, as in the previous section, we present two sets of impacts: 1) the ex-post impacts for this subgroup, and 2) the incremental impacts achieved by the subgroup over similar program participants.

Table 4-29 through Table 4-32 present the average event-hour impacts and aggregate load shed test results for each product by event.

Table 4-29 SDG&E Day Ahead 11 AM to 7 PM: 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. Event	**17**	**389.9**	**0.7**	**6.6**	**<0.1**	**0%**	**3.0**	**78**
Jul 6, 2018	17	585.9	36.7	10.0	0.6	6%	3.0	91
Jul 10, 2018	17	610.7	36.7	10.4	0.6	6%	3.0	80
Jul 11, 2018	17	521.7	11.7	8.9	0.2	2%	3.0	77
Jul 12, 2018	17	522.2	11.7	8.9	0.2	2%	3.0	77
Jul 16, 2018	17	559.1	17.2	9.5	0.3	3%	3.0	76
Jul 18, 2018	17	472.4	11.7	8.0	0.2	2%	3.0	73
Jul 23, 2018	17	628.0	17.2	10.7	0.3	3%	3.0	83
Jul 24, 2018	17	544.5	11.7	9.3	0.2	2%	3.0	80
Jul 25, 2018	17	523.4	11.7	8.9	0.2	2%	3.0	77

Table 4-30 SDG&E Day-Ahead 1 PM to 9 PM: 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. Event	**3**	**52.0**	**7.8**	**0.2**	**<0.1**	**15%**	0.12	**67**
Oct 23, 2018	3	54.4	10.1	0.2	<0.1	19%	0.12	66
Oct 24, 2018	3	54.4	10.1	0.2	<0.1	19%	0.12	67
Oct 25, 2018	3	55.8	10.1	0.2	<0.1	18%	0.12	67
Oct 26, 2018	3	55.0	10.1	0.2	<0.1	18%	0.12	70
Oct 29, 2018	3	54.3	10.1	0.2	<0.1	19%	0.12	64
Oct 30, 2018	3	52.8	10.1	0.2	<0.1	19%	0.12	65
Oct 31, 2018	3	43.5	10.1	0.1	<0.1	23%	0.12	67

Table 4-31 SDG&E Day Of 11 AM to 7 PM: 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. Event	**16**	**80.6**	**12.7**	**1.3**	**0.2**	**16%**	**0.3**	**85**
Aug 6, 2018	16	81.2	13.8	1.3	0.2	17%	0.3	85
Aug 7, 2018	16	84.0	11.7	1.3	0.2	14%	0.3	89
Aug 9, 2018	16	82.2	13.8	1.3	0.2	17%	0.3	87

Table 4-32 SDG&E Day Of 1 PM to 9 PM: 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. Event	**31**	**116.2**	**32.0**	**3.6**	**1.0**	**28%**	**2.7**	**83**
Aug 6, 2018	31	115.1	29.8	3.6	0.9	26%	2.7	81
Aug 7, 2018	31	113.5	29.8	3.5	0.9	26%	2.7	82
Aug 9, 2018	31	116.6	29.8	3.6	0.9	26%	2.7	84

Incremental Load Impacts of TA/TI and AutoDR Participants

In addition to presenting the ex-post impacts for the subgroup, we also estimated the incremental impacts associated with the TA/TI and AutoDR participants as compared with a group of similar non-enabled participants. First, we selected a group of CBP participants that are similar to the AutoDR and TA/TI participants, but did not participate in AutoDR or TA/TI, using a Euclidean Distance matching approach. Next, we estimated the incremental impacts using a statistical difference-in-difference (DID) approach. We did the matching and DID analysis at the notification level and at the program level. We did not see any statistically significant incremental impacts in PY2018.

Figure 4-9 and Figure 4-10 show the treatment and control-group match for Day Ahead and Day Of products on an average event day, respectively. The graphs compare the average per-customer load profile of each group. There were 67 control-group matches for the incremental analysis, 20 participants in DA and 47 participants in DO.

Figure 4-9 SDG&E Day Ahead: AutoDR and TA/TI Event Day Match, kW

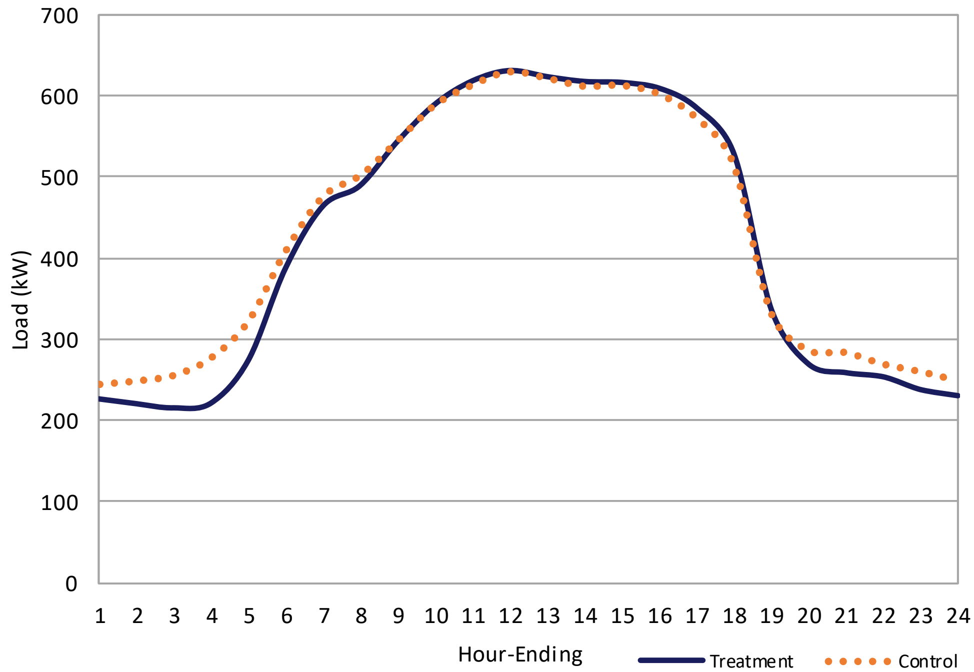


Figure 4-10 SDG&E Day Of: AutoDR and TA/TI Event Day Match, kW

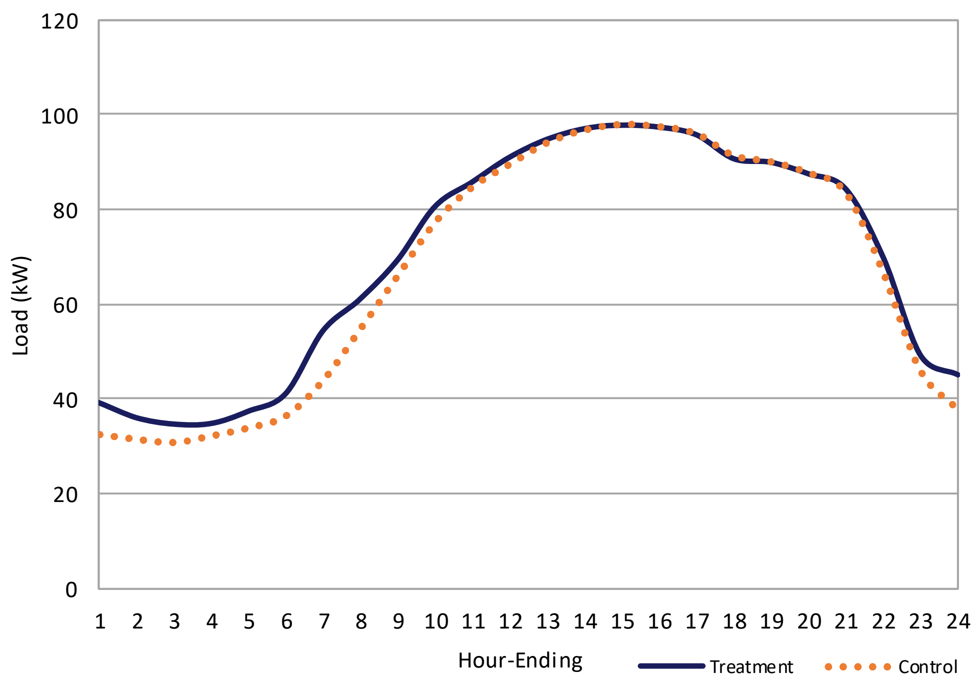


Figure 4-11 and Figure 4-12 illustrate the incremental impacts for Day Ahead and Day Of products, respectively. The figure shows the average per-customer incremental impact for each hour of an average event day. It also includes the upper and lower confidence intervals at the 95th percentile.

For DA participants, we see statistically significant incremental increase in usage during throughout the average event day. This means that the DA AutoDR and TA/TI participants have lower per-participant impacts than DA non-AutoDR and non-TA/TI participants. For DO participants, we do not see any statistically significant incremental impacts at any time during the average event day.

Figure 4-11 SDG&E Day Ahead: AutoDR and TA/TI Average Event Day Incremental Impacts, kW

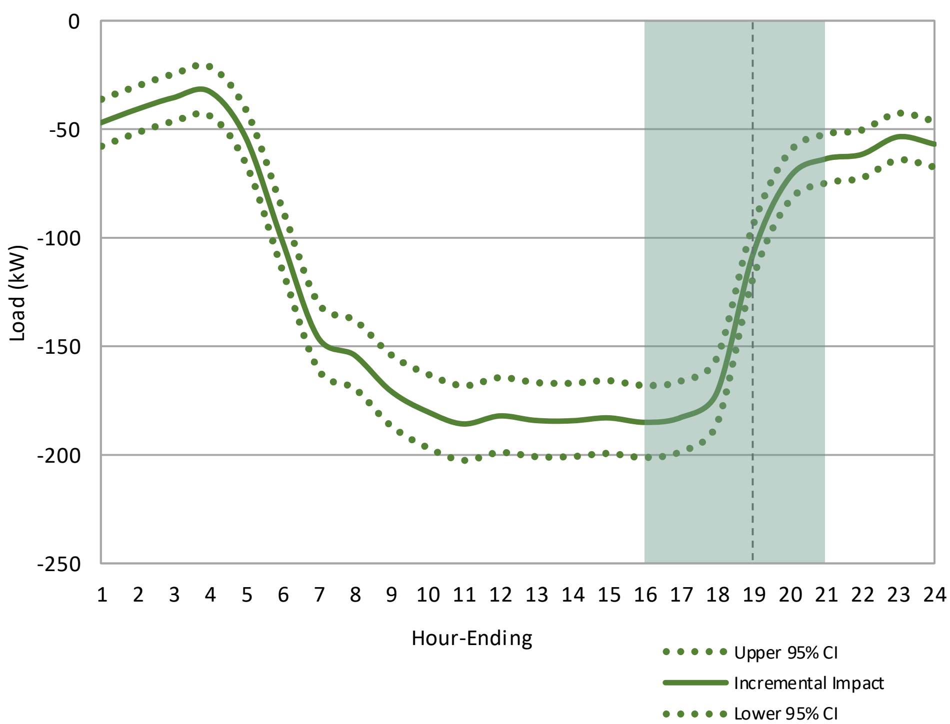
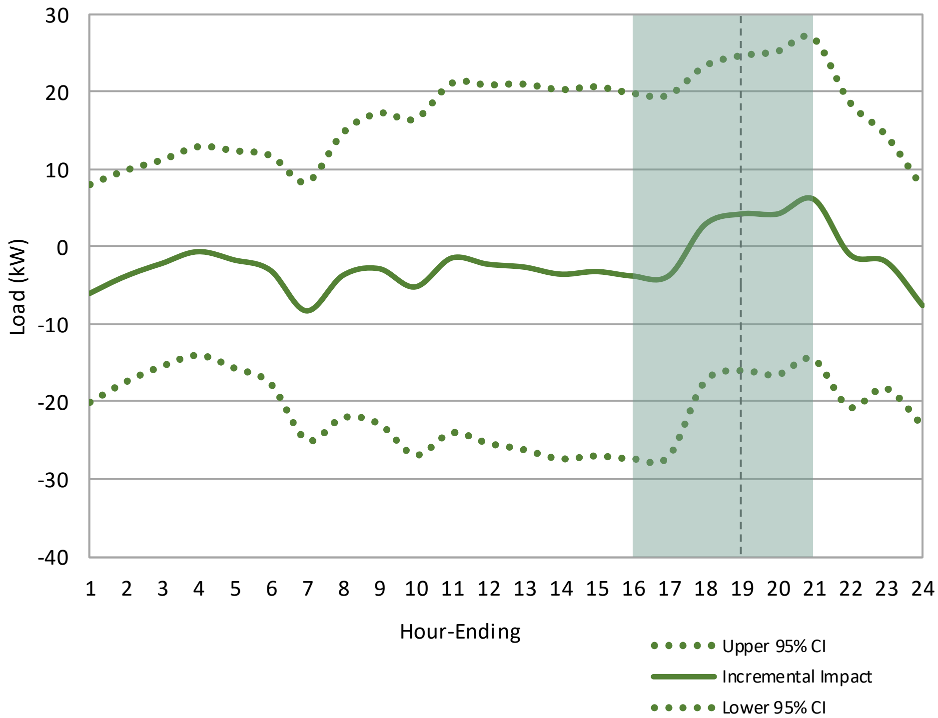


Figure 4-12 SDG&E Day Of: AutoDR and TA/TI Average Event Day Incremental Impacts, kW



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 aggregate load impact forecasts for an August peak day in 2019 by program and utility for each weather scenario.

Table 5-1 Summary of Average Event-Hour Ex-Ante Impacts, August Peak Day, 2019

Utility	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
PG&E (Non-residential)	Day Ahead	693	40.3	27.9	17.6%	17.0%	18.0%	17.5%
SCE (Non-residential)	Day Ahead	90	[redacted]	[redacted]	[redacted]%	[redacted]%	[redacted]%	[redacted]%
	Day Of	800	[redacted]	[redacted]	[redacted]%	[redacted]%	[redacted]%	[redacted]%
SDG&E	Day Ahead	65	2.8	0.2	1.2%	1.2%	1.2%	1.2%
	Day Of	191	13.9	2.7	10.8%	10.5%	10.7%	10.7%

PG&E

Enrollment and Load Impact Summary

PG&E estimates that non-residential CBP nominations will remain constant throughout the forecast horizon (2019-2029), with approximately 700 customers for the DA product. The ex-ante impact results forecast annual CBP load impacts for the non-residential DA product that are commensurate with the PY2018 per-customer impacts and with the 2019-2029 enrollment forecast.

As mentioned in Section 3, since CBP impacts are inherently nomination-driven, not weather-driven, we estimated flat per-customer average impacts across the weather scenarios. The impacts are also estimated to remain constant across the months of May through October. However, since some CBP participants' usage are weather-dependent, the weather scenarios do affect the estimated reference load. This results in varying percent impacts across the weather scenarios.

Table 5-2 summarizes the average event-hour load impact forecasts for non-residential CBP DA on an August peak day in 2019.[43] The table includes the per-customer average impacts, aggregate

[43] Though labeled as an August peak day in 2019, the results in Table 5-2 would be identical for each month, May through October, and each year, 2019 through 2029, in the forecast.

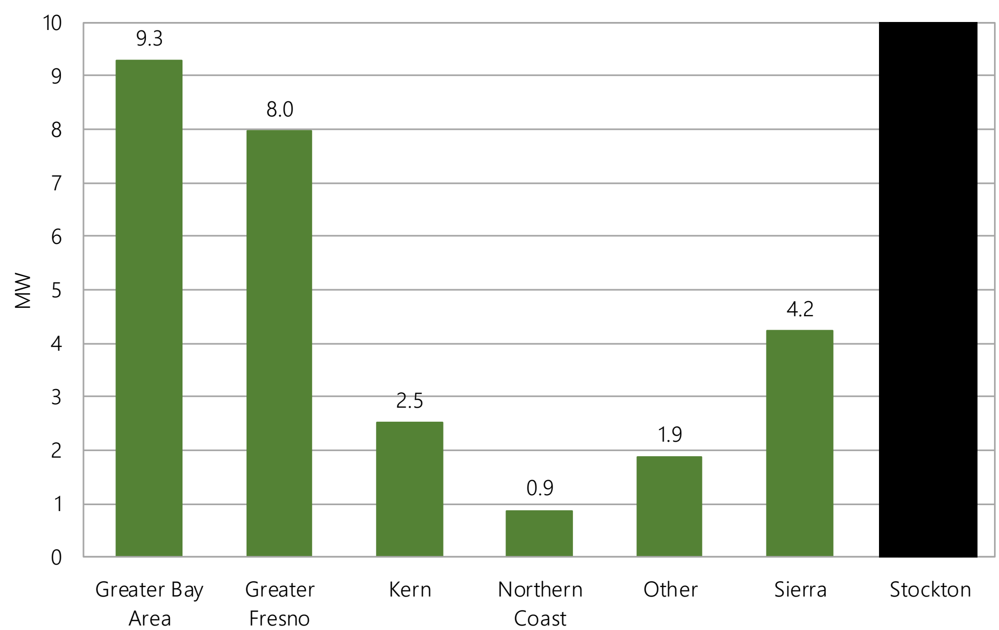
impacts, and corresponding percent impacts under the 1-in-2 and 1-in-10 weather scenarios and for the utility peak and the CAISO peak. PG&E expects material MW from residential CBP starting in 2019 and makes a constant forecast of 4 MW per year through the forecast horizon.

Table 5-2 PG&E Non-Residential Day Ahead: Average Event-Hour Ex-Ante Impacts for an August Peak Day, 2019

Size	# 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
Below 20 kW	4	[redacted]	[redacted]	[redacted]%	[redacted]%	[redacted]%	[redacted]%
20 kW to 199.99 kW	356	12.7	4.5	21.2%	20.3%	21.9%	21.1%
Above 200 kW	333	70.3	23.4	17.0%	16.5%	17.4%	16.9%
Total Day Ahead	**693**	**40.3**	**27.9**	**17.6%**	**17.0%**	**18.0%**	**17.5%**

Figure 5-1 illustrates the average event-hour load impacts distributed by LCA for non-residential CBP DA on an August peak day in 2019. The results shown are for 1-in-2 weather conditions for the utility peak. Results for Stockton are redacted to protect customer or aggregator confidentiality.

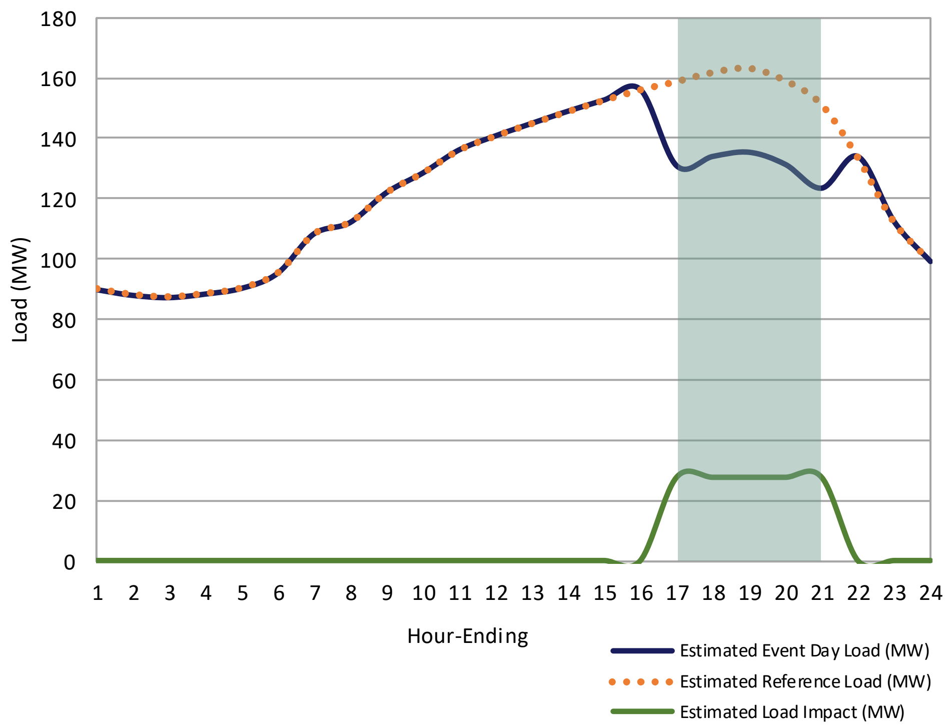
Figure 5-1 PG&E Non-Residential Day Ahead: Average Event-Hour Aggregate Load Impacts by LCA for an August Peak Day, 2019, 1-in-2 Utility Peak Weather Conditions



Hourly Reference Loads and Load Impacts

Figure 5-2 compares the estimated reference load, estimated event-day load, and resulting aggregate load impact estimates for an August peak day in 2019 for PG&E's non-residential CBP DA product. The results are for 1-in-2 weather conditions and the utility peak. The hours highlighted in blue-green show the Resource Adequacy (RA) window, 4 PM to 9 PM.

Figure 5-2 PG&E Non-Residential Day Ahead: Hourly Event-Day Aggregate Load Impacts for an August Peak Day, 2019, 1-in-2 Utility Peak Weather Conditions



SCE

Enrollment and Load Impact Summary

Consistent with last year, SCE forecasts CBP DA enrollment to stay at 90 customers until 2022. In 2023, SCE expects CBP DA enrollment to increase to 3,321 customers due to an influx of residential customers following full opening of the program to the residential class.[44] Subsequently, enrollment is projected to hold steadily at 3,321 participants for the remainder of the forecast horizon (2023-2029).

For CBP DO, SCE forecasts the enrollment to increase to 800 customers in 2019 and to stay constant at that value throughout the forecast horizon (2019-2029).

SCE implemented several changes in PY2018 and have proposed changes pending on filing and adoption by the Commission. The changes are anticipated to increase CBP enrollment over time.

[44] However, residential CBP enrollment may occur earlier than 2023, pending the 2020 mid-cycle filing required in D.17-12-003.

In PY2018, CBP offerings changed from six products to two products and established a monthly five-event maximum. SCE is also proposing to change the dispatch window from 1 PM – 7 PM to 4 PM – 9 PM.[45]

The ex-ante impact results forecast annual non-residential CBP load impacts for the DA and DO products that are commensurate with the PY2018 per-customer impacts and the non-residential 2019-2029 enrollment forecast. In addition, SCE assumes a constant aggregate residential CBP forecast of 3 MW throughout the forecast horizon starting in 2023 due to the expected influx of residential customers.

Similar to PG&E, we assume flat per-customer average impacts but with varying percent impacts across the weather scenarios. The impacts are also estimated to remain constant across the seasons (summer and non-summer).

Table 5-3 summarizes the average event-hour load impact forecasts for the DA and DO products on an August peak day in 2019.[46] 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 SCE CBP: Average Event-Hour Ex-Ante Impacts for an August Peak Day, 2019

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	90	[redacted]	[redacted]	[redacted]%	[redacted]%	[redacted]%	[redacted]%
Total Day Of	800	[redacted]	[redacted]	[redacted]%	[redacted]%	[redacted]%	[redacted]%

Hourly Reference Loads and Load Impacts

Figure 5-3 and Figure 5-4 compare the reference load, event-day load, and resulting aggregate load impacts for an August peak day in 2019 for the DA and DO products, respectively. The results are for 1-in-2 weather conditions and the utility peak.

As mentioned earlier, SCE's current dispatch window is from 1 PM to 7 PM, which does not align with the Resource Adequacy (RA) window from 4 PM to 9 PM. Consequently, the estimated ex-ante impacts do not fall within the RA window, which is highlighted in blue.

Figure 5-3 SCE Day Ahead: Hourly Event-Day Aggregate Load Impacts for an August Peak Day, 2019, 1-in-2 Utility Peak Weather Conditions

Figure redacted to protect customer or aggregator confidentiality.

[45] This proposed change has not been filed but is expected to be implemented in 2021.

[46] Though labeled as an August peak day in 2019, the results in Table 5-3 would be identical for each month, May through October, and each year, 2019 through 2029, in the forecast.

Figure 5-4 SCE Day Of: Hourly Event-Day Aggregate Load Impacts for an August Peak Day, 2019, 1-in-2 Utility Peak Weather Conditions

Figure redacted to protect customer or aggregator confidentiality.

SDG&E

Enrollment and Load Impact Summary

As of PY2018, SDG&E reduced its number of CBP products from nine to four. 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.

For the CBP DA and DO products, the enrollment forecast assumes the customer enrollment will increase by 3% per year starting in 2019 through 2022 due to the CBP program improvements proposed by SDG&E in the application for 2018-2022. In addition, SDG&E forecasts that the customer enrollment in the CBP DO program will increase by another 1% per year starting in 2019 through 2022 due to growth in the Technical Incentives (TI) program. Therefore, total DO enrollment is expected to increase by 4% per year starting in 2019 through 2022 due to program improvements and growth in TI. The enrollment forecasts for the DA and DO products after 2022 and through 2029 show a flat trend at the 2022 values.

The ex-ante load impact forecast follows the 2019-2029 enrollment forecast trends for the DA and DO products. Similar to PG&E and SCE, we assume flat per-customer average impacts but with varying percent impacts across the weather scenarios. The impacts are also estimated to remain constant during the months of May through October.

Table 5-4 summarizes the average event-hour load impact forecasts for the DA and DO products on an August peak day in 2019.[47] 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 5-4 SDG&E CBP: Average Event-Hour Ex-Ante Impacts for an August Peak Day, 2019

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	65	2.8	0.2	1.2%	1.2%	1.2%	1.2%
Total Day Of[48]	191	13.9	2.7	10.8%	10.5%	10.7%	10.7%

[47] Though labeled as an August peak day in 2019, the results in Table 5-4 would be identical for each month, May through October, in the 2019 forecast.

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

Hourly Reference Loads and Load Impacts

Figure 5-5 and Figure 5-6 compare the reference load, event-day load, and resulting aggregate load impacts for an August peak day in 2019 for the DA and DO products, respectively. The results are for 1-in-2 weather conditions and the utility peak.

Figure 5-5 SDG&E Day Ahead: Hourly Event-Day Aggregate Load Impacts for an August Peak Day, 2019, 1-in-2 Utility Peak Weather Conditions

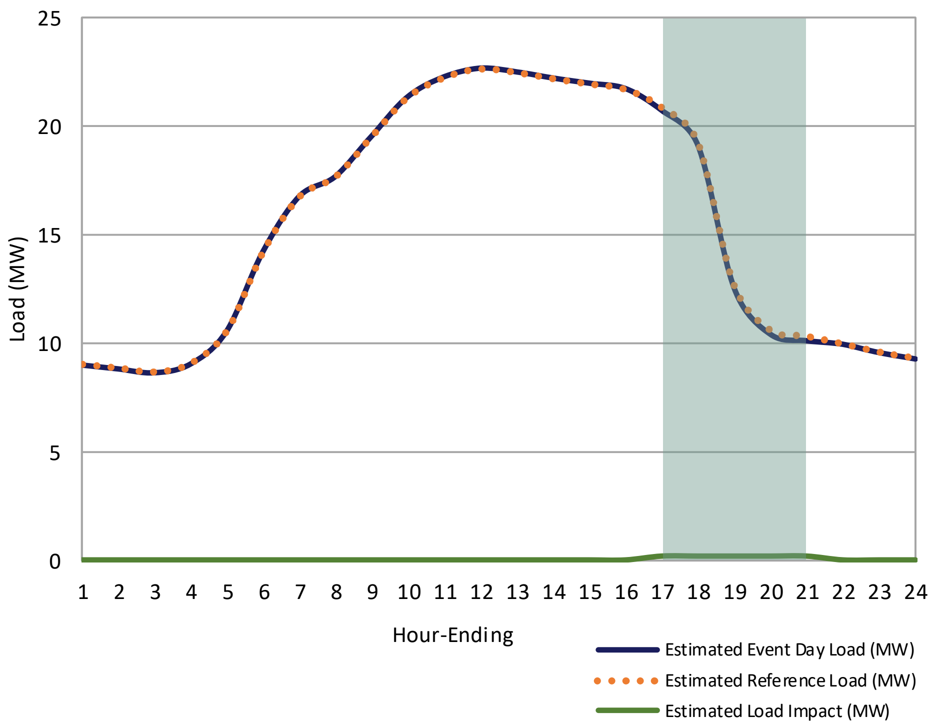
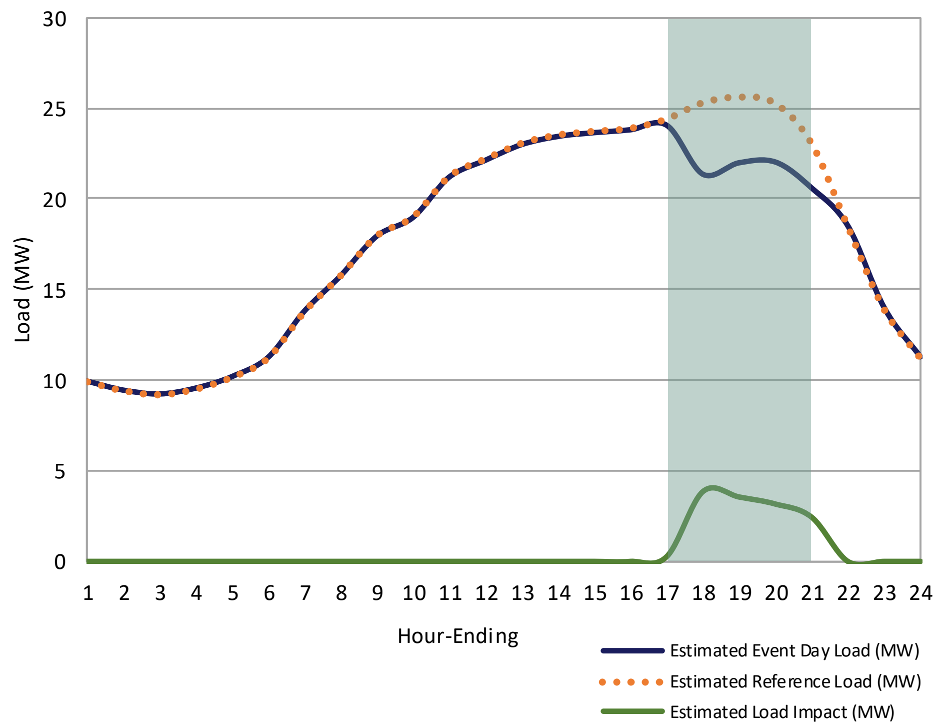


Figure 5-6 SDG&E Day Of: Hourly Event-Day Aggregate Load Impacts for an August Peak Day, 2019, 1-in-2 Utility Peak Weather Conditions



6

RECONCILIATIONS OF EX-POST AND EX-ANTE RESULTS

To make the relationship between ex-post and ex-ante estimates more easily understood and transparent, in this section we discuss the following:

- How current ex-post results differ from last year's ex-post results.
- How current ex-post results differ from last year's forecast.
- How current ex-ante results differ from the current ex-post results.
- How current ex-ante results differ from last year's forecast.

PG&E

Table 6-1 summarizes the non-residential CBP DA average event-hour ex-post load impact results for the past two years on an average event day. The table includes the number of participating accounts, the average event-hour reference loads, and average event temperature. Both per-customer and aggregate results are presented.

Note that the average event day is calculated using different approaches between PY2017 and PY2018. In PY2018, the average event day is calculated using all events regardless of participant count and event timing. The results shown are for the common event hour HE19 or 6 PM – 7 PM, which is the hour wherein all events overlap. In previous years (including PY2017), we calculated the average event day using the most often-called event window (usually HE16 – HE19 or 3 PM – 7 PM), including only system-level events. We discuss the comparison in more detail below.

Table 6-1 PG&E Non-Residential Day Ahead: Previous and Current Ex-Post, Average Event Day

Notice	Ex-Post Year	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (°F)
			Reference Load	Impact	Reference Load	Impact		
Day Of	2017	811	138.1	26.8	112.0	21.8	19%	91
Day Ahead	2017	19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	91
	2018	197	350.7	44.8	69.1	8.8	13%	77

Table 6-2 compares the current year's analysis with the previous year's analysis of non-residential CBP DA ex-post and ex-ante average event-hour impacts. To make the comparison as consistent as possible, the ex-post and ex-ante results represent events on monthly system peak days in

August, unless otherwise noted.[49] In addition, the ex-ante results reflect the utility peak 1-in-2 weather scenario.

Table 6-2 PG&E Non-Residential Day Ahead: Previous and Current Ex-Ante and Ex-Post, August Peak Day

Year	Model	Day	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
				Reference Load	Impact	Reference Load	Impact		
2018	Previous Ex-Ante	Aug Peak	700	165.4	30.0	115.8	21.0	18%	92
2018	Current Ex-Post	Aug 7th[50]	482	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	80
2019	Previous Ex-Ante	Aug Peak	700	165.4	30.0	115.8	21.0	18%	92
2019	Current Ex-Ante	Aug Peak	693	229.5	40.3	159.0	27.9	18%	89

For PG&E's non-residential CBP Day Ahead program, we see the following trends:

Current Ex-Post v. Previous Ex-Post: In 2018, we see a significant increase in enrollment, likely caused by the enrollment shift of previous DO program participants, which PG&E has discontinued. Note that Table 6-1 shows the participant count of an average event day. PY2018 DA event participation reached a maximum of 508 (on July 25th event, shown in Table 4-3) compared to 23 participants in PY2017 DA. However, PY2018 DA's count is relatively low compared to PY2017's DO participation at 811 on an average and 912 at maximum. This shows that PG&E was able to retain approximately 46% of PY2017's DO participants. As a result, PY2018 DA's average customer is significantly smaller, as seen in the per-customer impact and reference loads. The percent impact of PY2018 DA at 13% is noticeably lower than PY2017 at [redacted]% and 19% for DA and DO, respectively. This is likely a result of the PY2018 changes in PG&E's product offerings.

Current Ex-Post v. Previous Ex-Ante: The previous ex-ante estimates were developed with anticipated program changes taken into account, which includes expected migration of PY2017 DO participants into the DA program. Comparing the previous ex-ante estimates to the August 7th event, the aggregate ex-post impacts were higher in PY2018 ([redacted] MW) than projected (21.0 MW) despite lower actual enrollment compared to the forecasted enrollment. This is because of the higher per-customer impact on August 7th ([redacted] kW) than projected (30.0 kW). Note that despite the difference in aggregate and per-customer impacts, the estimates have comparable percent impacts at 19% and 18% for realized and projected, respectively.

Current Ex-Ante v. Current Ex-Post: The current ex-ante estimates for PY2019 (27.9 MW) and the current ex-post estimates for PY2018 ([redacted] MW) differ at the per-customer level due to the customers included in the two estimates. The current ex-post shows only a snapshot of the entire year, showing only the August 7th event day. The current ex-ante estimates incorporate all PY2018

[49] Though the ex-ante impacts are labeled as an August peak day, the ex-ante results are identical for each monthly system peak day, May through October.

[50] PG&E CBP Day Ahead August 7, 2018 event received the highest participation in the month of August.

participants and their varying responses throughout the year. However, looking at the percent impacts at [redacted]% and 18%, the two estimates are comparable.

Current Ex-Ante v. Previous Ex-Ante: The current ex-ante estimates have been updated according to what was achieved in PY2018, with some modest growth. At a glance, the enrollment forecasts and percent impacts are very similar. However, larger customers were recruited in PY2018, giving higher projected per-customer (40.3 kW) and aggregate impacts (27.9 MW) in PY2019 compared to previous ex-ante estimates.

SCE

Table 6-3 summarizes the CBP DA and DO average event-hour ex-post load impact results for the past two years on an average summer event day. The table includes the number of participating accounts, the average event-hour reference loads, and average event temperature. Both per-customer and aggregate results are presented.

Note that the average event day is calculated using different approaches between PY2017 and PY2018. In PY2018, the average event day is calculated using all events regardless of participant count and event timing. The results shown are for the common event hour HE19 or 6 PM – 7 PM, which is the hour wherein all events overlap. In previous years (including PY2017), we calculated the average event day using the most often-called event window (usually HE16 – HE19 or 3 PM – 7 PM), including only system-level events. We discuss the comparison in more detail below.

Table 6-3 SCE CBP: Previous and Current Ex-Post, Average Summer Event Day

Notice	Ex-Post Year	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Day Ahead	2017	48	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	88
	2018	43	432.1	47.9	18.7	2.1	11%	81
Day Of	2017	348	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	90
	2018	214	175.8	22.8	37.6	4.9	13%	83

Table 6-4 compares the current year's analysis with the previous year's analysis of CBP ex-post and ex-ante average event-hour impacts. The ex-ante impacts in the table reflect the utility peak 1-in-2 weather scenario on an August system peak day. The ex-post impacts reflect the average summer event day results.

Table 6-4 SCE CBP: Previous and Current Ex-Ante and Ex-Post, August Peak Day

	Yr	Model	Day	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
					Ref. Load	Impact	Ref. Load	Impact		
Day Ahead	2018	Previous Ex-Ante	Aug Peak	90	798.6	68.5	71.9	6.2	9%	96
		Current Ex-Post	Avg Event	43	432.1	47.9	18.7	2.1	11%	81
	2019	Previous Ex-Ante	Aug Peak	90	798.6	68.5	71.9	6.2	9%	96
		Current Ex-Ante	Aug Peak	90	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	90
Day Of	2018	Previous Ex-Ante	Aug Peak	1,250	203.2	18.5	254.0	23.1	9%	94
		Current Ex-Post	Avg Event	214	175.8	22.8	37.6	4.9	13%	83
	2019	Previous Ex-Ante	Aug Peak	1,250	203.2	18.5	254.0	23.1	9%	94
		Current Ex-Ante	Aug Peak	800	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	92

For SCE's CBP Day Ahead and Day Of programs, we see the following trends:

Current Ex-Post v. Previous Ex-Post: For DA, we see similar participation and percent impacts in PY2018 compared to PY2017. However, there was a change in customer makeup with less wholesale/transport/utility customers and more retail stores in PY2018. This resulted in lower per-customer impacts (47.9 kW) and, accordingly, lower aggregate impacts (2.1 MW) compared to PY2017. For DO, we see similar per-customer and percent impacts in PY2018 compared to PY2017. However, lower participation (214 in PY2018 v. 348 in PY2017) resulted in lower aggregate impacts in PY2018.

Current Ex-Post v. Previous Ex-Ante: For both programs, the current ex-post results show lower aggregate impacts (2.1 MW and 4.9 MW for DA and DO, respectively) than the previous ex-ante projections for PY2018 (6.2 MW and 23.1 for DA and DO, respectively) due to lower enrollment than expected. This is despite the higher percent impacts achieved by both programs, on average.

Current Ex-Ante v. Current Ex-Post: For both programs, the current ex-ante estimates for PY2018 have lower per-customer estimates than the current ex-post estimates because SCE's dispatch window (1 PM – 7 PM) currently does not align with the RA window (4 PM – 9 PM). The current ex-ante estimates assume zero impacts between 7 PM – 9 PM, resulting in lower average event-hour estimates. Higher forecasted enrollment, however, give comparable aggregate estimates for DA and higher aggregate estimates for DO ([redacted] MW v. 2.1 MW and [redacted] MW v. 4.9 MW, respectively).

Current Ex-Ante v. Previous Ex-Ante: As mentioned above, current ex-ante per-customer impacts are lower due to SCE's dispatch window not aligning with the RA window. Accordingly, the current ex-ante analysis for DA ([redacted] MW) projects lower impacts than did the previous ex-ante analysis (6.2 MW). For DO, updated assumptions forecast lower enrollment in 2019, giving much lower current ex-ante estimates ([redacted] MW) compared to previous estimates (23.1 MW).

SDG&E

Table 6-5 summarizes the CBP DA and DO average event-hour ex-post load impact results for the past two years for an average event day. The table includes the number of participating accounts, the average event-hour reference loads, and average event temperature. Both per-customer and aggregate results are presented.

Note that the average event day is calculated using different approaches between PY2017 and PY2018. In PY2018, the average event day is calculated using all events regardless of participant count and event timing. The results shown are for the common event hour HE19 or 6 PM – 7 PM, which is the hour wherein all events overlap. In previous years (including PY2017), we calculated the average event day using the most often-called event window (usually HE16 – HE19 or 3 PM – 7 PM), including only system-level events. We discuss the comparison in more detail below.

Table 6-5 SDG&E CBP: Previous and Current Ex-Post, Average Event Day

Notice	Ex-Post Year	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Day Ahead	2017	68	241.1	9.9	16.4	0.7	4%	77
	2018	27	228.5	6.9	6.1	0.2	3%	75
Day Of	2017	174	144.3	18.4	25.1	3.2	13%	85
	2018	186	134.8	18.6	25.1	3.5	14%	84

Table 6-6 compares the current year's analysis with the previous year's analysis of CBP ex-post and ex-ante average event-hour impacts. To make the comparison as consistent as possible, the ex-post and ex-ante results represent events on monthly system peak days in August, unless otherwise noted.[51] For DA current ex-post, we selected a July event day because July participation is the most representative of the DA PY2018 participant population. In addition, the ex-ante results reflect the utility peak 1-in-2 weather scenario.[52]

[51] Though the ex-ante impacts are labeled as an August peak day, the ex-ante results are identical for each monthly system peak day, May through October.

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

Table 6-6 SDG&E CBP: Previous and Current Ex-Ante and Ex-Post, August Peak Day

	Yr	Model	Day	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
					Ref. Load	Impact	Ref. Load	Impact		
Day Ahead	2018	Previous Ex-Ante	Aug Peak	69	248.9	9.8	17.2	0.7	4%	80
		Current Ex-Post	Jul 18th[53]	66	185.9	3.7	12.3	0.2	2%	75
	2019	Previous Ex-Ante	Aug Peak	71	248.9	9.8	17.7	0.7	4%	80
		Current Ex-Ante	Aug Peak	65	227.2	2.8	14.7	0.2	1%	84
Day Of	2018	Previous Ex-Ante	Aug Peak	171	141.3	18.5	24.2	3.2	13%	84
		Current Ex-Post	Avg Event	186	134.8	18.6	25.1	3.5	14%	84
	2019	Previous Ex-Ante	Aug Peak	183	141.3	18.5	25.9	3.4	13%	84
		Current Ex-Ante	Aug Peak	191	129.0	13.9	24.7	2.7	11%	83

For SDG&E's CBP Day Ahead and Day Of programs, we see the following trends:

Current Ex-Post v. Previous Ex-Post: For DA, we see a decrease in enrollment in PY2018. Note that Table 6-6 shows the participant count of an average event day. This decrease in participation, on average, is due to very low nominations in the months of August and October (3 and 4 participants, respectively) compared to 66 participants nominated in July. As a result, we see lower aggregate impacts in PY2018 (0.2 MW) compared to PY2017 (0.7 MW). For DO, we see very similar per-customer impacts between PY2017 and PY2018 and a small increase in enrollment, resulting in higher aggregate impacts in PY2018 (3.5 MW) compared to PY2017 (3.2 MW).

Current Ex-Post v. Previous Ex-Ante: The previous ex-ante estimates were developed based on PY2017 ex-post estimates. Again, for DO, we see actual PY2018 per-customer impacts to be very close to previously projected estimates. In PY2018, SDG&E's DO program enrolled more customers (186 participants) than projected (171 participants), resulting in higher aggregate impacts in PY2018. For DA, comparing the previous ex-ante estimates to the July 18th event, the aggregate and per-customer impacts are considerably lower in PY2018 despite having comparable enrollment. This is likely due to more events being called later in the day (between 5 PM – 7 PM). With the majority of PY2018 DA participants being offices/hotels/financial services, which likely do not have load to curtail during these hours, we are seeing much lower impacts for the DA program.

Current Ex-Ante v. Current Ex-Post: For DA, the current ex-ante estimates for PY2019 show comparable aggregate impacts (0.2 MW) to the current ex-post estimates for PY2018 (0.2 MW).

[53] PG&E CBP Day Of received the highest participation in the month of July. The July 18, 2018 event had the most comparable aggregate impacts to an average event day.

For DO, the current ex-ante estimates for PY2019 (2.7 MW) show lower aggregate impacts to the current ex-post estimates for PY2018 (3.5 MW) due to lower expected per-customer impacts.

Current Ex-Ante v. Previous Ex-Ante: The current ex-ante estimates for have been updated according to what was achieved in PY2018. DA enrollment projections decreased while DO enrollment projections increased. Since we saw a significant drop in PY2018 ex-post per-customer impacts, the current PY2019 aggregate ex-ante impacts for DA (0.2 MW) are lower to previous ex-ante impacts for PY2019 (0.7 MW). For DO, the current PY2019 ex-ante estimates were updated to reflect how events were called and how participants responded in PY2018. The RA window is between 4 PM – 9 PM, while DO events were called between 5 PM – 7 PM and 5 PM – 9 PM. In the current PY2018 estimates, we assume a very low pre-cooling effect from 4 PM – 5 PM, resulting in lower average event-hour impacts. This gives us lower projected impacts in 2018 (2.7 MW) than did the previous ex-ante analysis (3.4 MW).

7

KEY FINDINGS

In this section, we present the key findings from the Statewide PY2018 CBP evaluation and recommendations for future program year evaluations.

Overview of Results

In PY2018, PG&E and SDG&E reworked their CBP offerings to be a more time- and/or geographically-targeted DR, similar to what SCE has done in the past. As a result, statewide comparisons, such as comparing average event days[54], are more valid and straightforward than in previous years.

Table 7-1 presents the PY2018 average summer event day nominated capacity and impacts by program and IOU, in aggregate. On average, PG&E's DA program and SCE's DO program are the largest contributors with an 8.8 MW and 4.9 MW reductions on an event day, respectively. SCE's DO program is also the only program to meet/exceed its nominated capacity of 4.5 MW.

Table 7-1 Summary of PY2018 Ex-Post Impacts and Nominated Capacity: Average Summer Event Day

Utility	Day Ahead			Day Of		
	# of Accts	Nominated Capacity (MW)	Aggregate Impact (MW)	# of Accts	Nominated Capacity (MW)	Aggregate Impact (MW)
PG&E	197	9.2	8.8	-	-	-
SCE	43	3.0	2.1	214	4.5	4.9
SDG&E	27	0.3	0.2	186	3.9	3.5

Table 7-2 compares the average event-hour ex ante impact estimates, in aggregate, for an August peak day in 2019 versus 2029. Note that these estimates only include non-residential participants. PG&E and SCE assume a flat 11-year enrollment forecast, while SDG&E assumes a 3% enrollment growth through 2022 with an additional 1% growth in DO due to the Technical Incentives (TI) program. The SDG&E DO forecast shown below includes new enrollments in the TI program.

[54] The approach used in calculating the average event day is discussed in detail in Section 3, Study Methods.

Table 7-2 Summary of Non-Residential Average Event-Hour Ex-Ante Impacts, August Peak Day, 2019 v. 2029

Utility	Day Ahead				Day Of			
	PY 2019		PY 2029		PY 2019		PY 2029	
	# of Accts	Aggregate Impact (MW)	# of Accts	Aggregate Impact (MW)	# of Accts	Aggregate Impact (MW)	# of Accts	Aggregate Impact (MW)
PG&E	693	27.9	693	27.9	-	-	-	-
SCE	90	[redacted]	90	[redacted]	800	[redacted]	800	[redacted]
SDG&E	65	0.2	71	0.2	191	2.7	209	2.9

Key Findings by IOU

As mentioned in previous sections, changes in the Capacity Bidding Program have prompted adjustments in how results were presented in PY2018. We will discuss the changes in each IOU and how it relates to their findings, but it is important to note the following:

- The average day represents a wide range of events. In previous years, we calculated the average event day using the most often-called event window (usually HE16 – HE19 or 3 PM – 7 PM), including only system-level events. In PY2018, we include all events regardless of participant count and event timing and present the impacts for the window that most events have in common.
- 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 mean that aggregators and customers were able to curtail their load when asked to do so.

PG&E

In PY2018, PG&E completely revamped their Capacity Bidding Program, discontinuing the Day Of program and replacing their Day Ahead program with new product offerings. PG&E's CBP also shifted towards more geographically-targeted DR, calling only 1 or 2 Sub-LAPs (out of 14 total) in most of PY2018 events. They also did not call any system-level events, only calling 13 Sub-LAPs at the very most.[55]

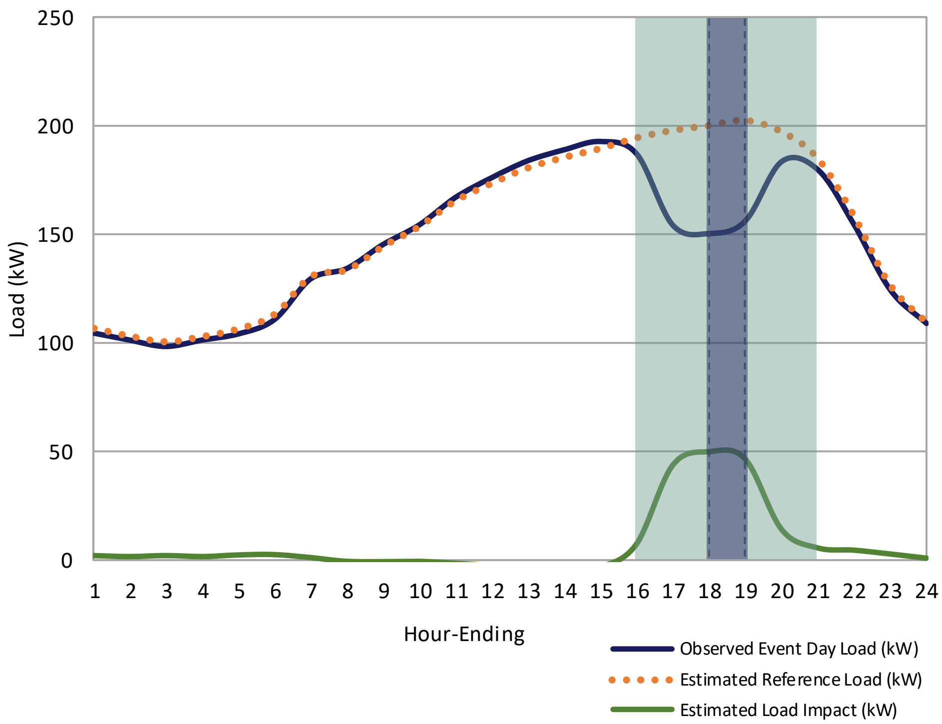
This year, we have the following key findings:

1. PG&E's CBP program called the most diverse events among the 3 IOUs with 1 to 13 Sub-LAPs called, 1 to 508 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, with only 3 events called on HE20 (7 PM – 8 PM). Table 4-3 summarizes the PY2018 events in more detail. Figure 7-1 shows an

[55] Other Sub-LAPs did not receive CAISO market awards.

example of an event day that calls 4 products, 13 Sub-LAPs, 4 event windows, and 508 participants. The hours highlighted in blue-green show the hours where in at least one group is called. The hours highlighted in dark blue show the hours where in all groups were called.

Figure 7-1 PG&E All Day-Ahead: Aggregate Hourly Impact, July 25, 2018



2. Elect DA, on average, met/exceeded their capacity nominations , successfully doing so in 21 out of 39 events. Prescribed DA, on average, did not meet their capacity nominations, but had success in 4 out of 22 events.
3. Retention of previous DO program participants was not as high as projected but included larger customers. Last year's forecast projected 700 total customers in the DA program, but maximum nomination count was only 551 customers (July enrollment, shown on Table 4-2). The PY2019 enrollment project has been adjusted to reflect this at 693 customers. Interestingly, the PY2018 DA program participants are larger customers, having very little participation amongst small customers (below 20 kW maximum demand).
4. Residential participation is expected to begin in PY2019. While ex-post impacts for residential impact projection did not materialize in 2018, PG&E makes a constant forecast of 4 MW per year through the forecast horizon.

SCE

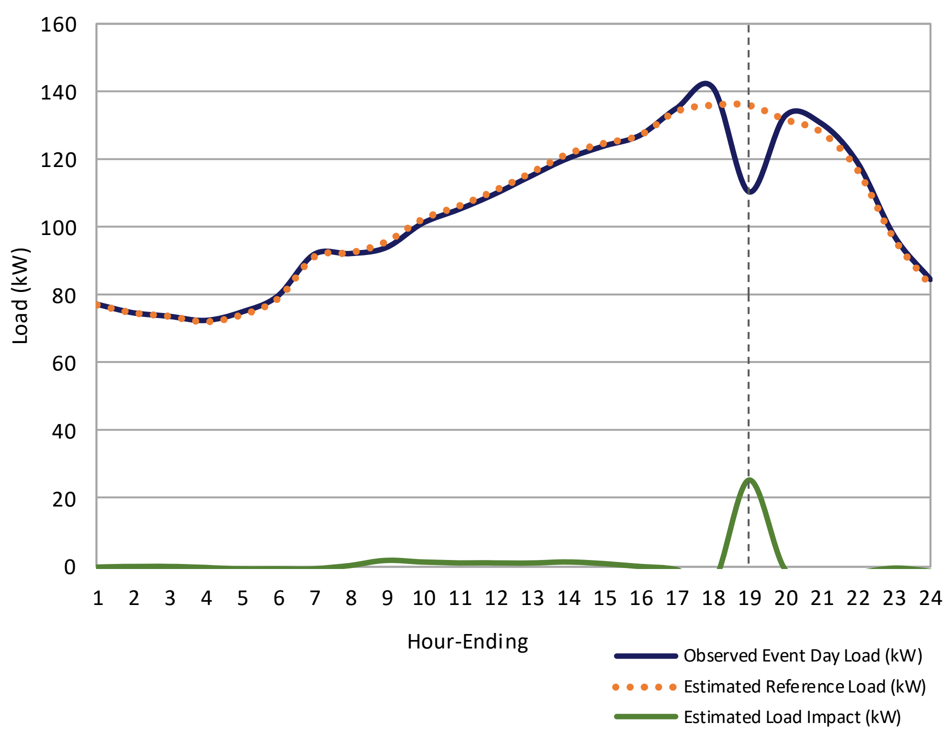
SCE had minimal changes in PY2018, changing both DA and DO programs to have 1-6 hour durations only starting May 1, 2018. Given the timing of this change, all non-summer events were called under the products with 1-4 hour durations and all summer events were called under the products with 1-6 hour durations.

SCE's CBP continues to be a geographically-targeted DR, calling individual Sub-LAPs as needed. Some events only called on one Sub-LAP. Some events called all 5 SCE Sub-LAPs in varying times of the dispatch window. Interestingly, SCE had 17 system-level events in PY2018 (out of 51 total events). System-level events are when all 5 Sub-LAPs are called on the same window.

This year, we have the following key findings:

1. Similar to PG&E, the average event day represents a wide range of events with 1 to 5 Sub-LAPs called, 29 to 345 participants nominated, and event widows between the hours of 1 PM and 7 PM. The average summer event day shows results for HE19 (6 PM – 7 PM), while the average non-summer event day shows results for HE18 (5 PM – 6 PM).
2. The summer DO program (DO 1-6 Hour) was the only program in PY2018 across all three IOUs that exceeded its nominated capacity, on average. The summer DA program on average did not meet capacity nominations but did exceed them in 5 out of 23 events. Figure 7-2 shows an example of an event that exceeded the nominated capacity. The September 20th event curtailed 6.1 MW, well beyond their 4.7 MW nomination.

Figure 7-2 SCE CBP Day Of: Aggregate Hourly Impact, September 20, 2018



3. The non-summer program (DA 1-4 Hour and DO 1-4 Hour) was not as successful. Neither products met the nominated capacity on any event called.
4. Retention of previous AMP program participants was not as high as projected. Last year's forecast projected 1,250 total customers in the DO program, but maximum nomination count was only 291 customers (June enrollment, shown in Table 4-10). The PY2019 enrollment projection has been adjusted to reflect this at 800 customers.
5. Ex-ante impacts are being under-represented due to SCE's dispatch window (1 PM – 7 PM) not aligning to the Resource Adequacy (RA) window (4 PM – 9 PM). SCE is proposing to change the dispatch window to align with the RA window but does not expect this change to be implemented until 2021.
6. Residential participation is expected to begin in PY2023. Ex-post impacts for residential impact projection is still unavailable. SCE makes a constant forecast of 3 MW per year through the forecast horizon.

SDG&E

In PY2018, SDG&E also revamped their CBP offering, reducing its number of CBP products from nine to four. SDG&E continues to have both Day Ahead and Day Of programs but now with two sets of operating hours: 11 AM – 7 PM and 1 PM – 9 PM. They also made several changes to their program triggers (discussed in more detail in Section 2).

This year, we have the following key findings:

1. SDG&E's CBP program called on events as needed by calling on different products on different event windows within the same day. For example, the DA 11 AM – 7 PM nominations were called between 5 PM – 7 PM, while the DA 1 PM – 9 PM nominations were called between 6 PM – 8 PM. The DA average event days represent a wider variety of events due to changes in participant counts from month to month.
2. Both DA and DO products operating between 1 PM – 9 PM met and exceeded their capacity nominations. This is not apparent in program level findings since results for both operating hours are combined and 11 AM – 7 PM products did not meet their capacity nominations. Table 7-3 presents the nominated capacity and ex-post aggregate impacts on an average event day, by product.

Table 7-3 Summary of SDG&E PY2018 Ex-Post Impacts and Nominated Capacity: Average Event Day

Operating Hours	Day Ahead			Day Of		
	# of Accts	Nominated Capacity (MW)	Aggregate Impact (MW)	# of Accts	Nominated Capacity (MW)	Aggregate Impact (MW)
11 AM to 7 PM	25	0.23	0.13	97	1.4	0.7
1 PM to 9 PM	2	0.05	0.06	89	2.6	2.7

3. The DO program achieved consistent responses in both products despite calling events on three consecutive days. These three days were the only events called in the DO program in PY2018.

4. The DA 11 AM – 7 PM product may be calling events too late in the day for its nominated participants. In previous years, CBP events were most often called between 3 PM – 7 PM. In PY2018, the DA 11 AM – 7 PM product called most of its events between 5 PM – 7 PM. With the majority of participants being offices/hotels/financial services, which likely do not have load to curtail during these hours, we are seeing much lower impacts for the DA 11 AM – 7 PM product. The change in the typically-called window may have prompted a drop in enrollment with 65 participant nominations in July to 2 participant nominations in August. Figure 7-3 and Figure 7-4 show examples of two events called between 3 PM – 7 PM and 5 PM – 7 PM, respectively.

Figure 7-3 SDG&E Day Ahead 11 AM to 7 PM Product: Aggregate Hourly Impact, July 10, 2018

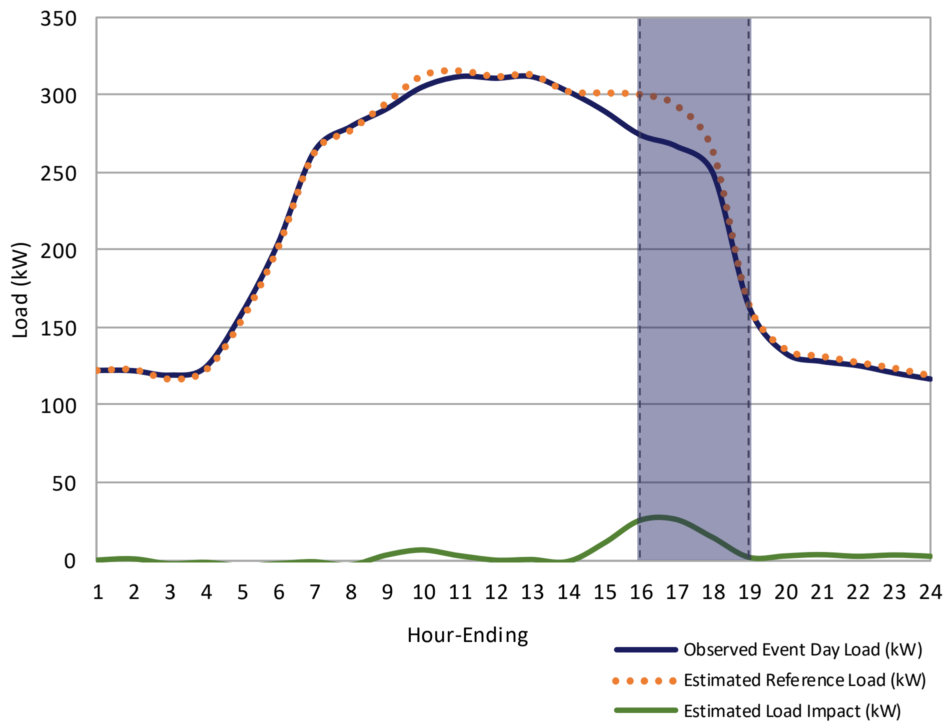
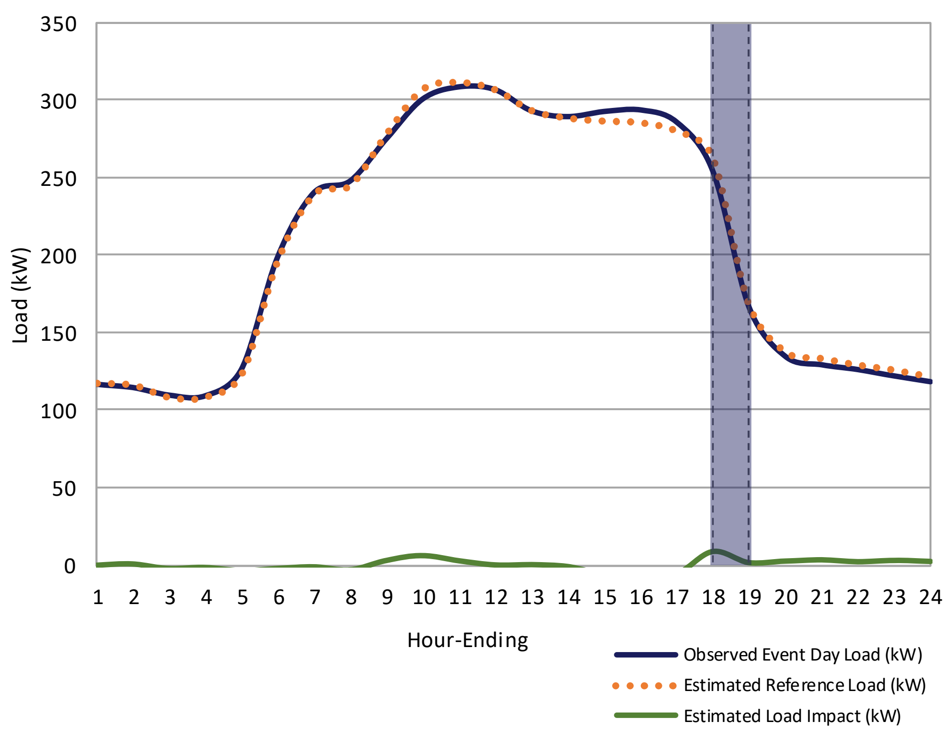


Figure 7-4 SDG&E Day Ahead 11 AM to 7 PM Product: Aggregate Hourly Impact, July 12, 2018



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

As mentioned in Section 3, Study Methods, we selected and validated the 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 MAPE (mean absolute percentage error) and MPE (mean percentage error) for each of the candidate regression models for each customer. 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. Our optimization procedure had several steps, which are described below:

- First, we identified the out-of-sample event-like days as several non-event days that are similar to event days based on temperature, month, and day of the week. Because of the program changes implemented in PY2018, we limited selection of event-like days to only PY2018. This eliminates the need to account for program changes (i.e., TOU period definitions, product definitions, etc.) in the regression models.
- After identifying the event-like days, those days were removed from the analysis dataset and the candidate models were fit to the remaining data. The results of the candidate models were used to predict the usage on the out-of-sample days. Then we assessed the error and bias in the reference load by calculating the MAPE and MPE between the actual usage and the predicted usage on the out-of-sample days.
- To perform the in-sample test, the event-like days are placed back in the analysis dataset and the candidate models were fit to the complete data. The results of the candidate models were used to predict the usage on the event days from PY2018. We also calculated the MAPE and MPE on these days to assess the error and bias in the predicted load.

The final step of the process was to select the candidate model with the minimum weighted MAPE and MPE for each individual customer. This model then became the final model specification. We describe the steps in more detail in the subsections that follow.

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 used three different Euclidean distance metrics to select similar non-event days: (1) daily maximum temperature; (2) average daily and daily maximum temperatures; (3) average daily temperature. The Euclidean distance metrics used can be calculated by Equations B.1 through B.3 below.

$$ED_1 = \sqrt{(MaxTemp_{event} - MaxTemp_{non-event})^2} \quad \text{(B.1)}$$

$$ED_2 = \sqrt{(MeanTemp_{event} - MeanTemp_{non-event})^2 + (MaxTemp_{event} - MaxTemp_{non-event})^2} \quad \text{(B.2)}$$

$$ED_3 = \sqrt{(MeanTemp_{event} - MeanTemp_{non-event})^2} \quad \text{(B.3)}$$

Since all three IOUs called several different event windows, we placed the focus on the entire day instead of a specific event window. Because we were limited to PY2018 non-event days, we selected less non-event days for this program year analysis to accommodate both the non-event day pool and the available customer data. To ensure that we selected an adequate group of event-like days, we do a final check and compare the distributions of weather and day types. For example, if there are more event days in August and more event days on a Tuesday, we try to account for that in the selected event-like days.

In Figure B-1 to Figure B-3 below we show comparisons of the distributions of average daily temperature of event days and event-like days. We show one comparison for each utility, because we do this selection at the utility level instead of the program or product level. We use this approach to accommodate customer moves between products or programs and the automation process of running individual customer regression models.

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

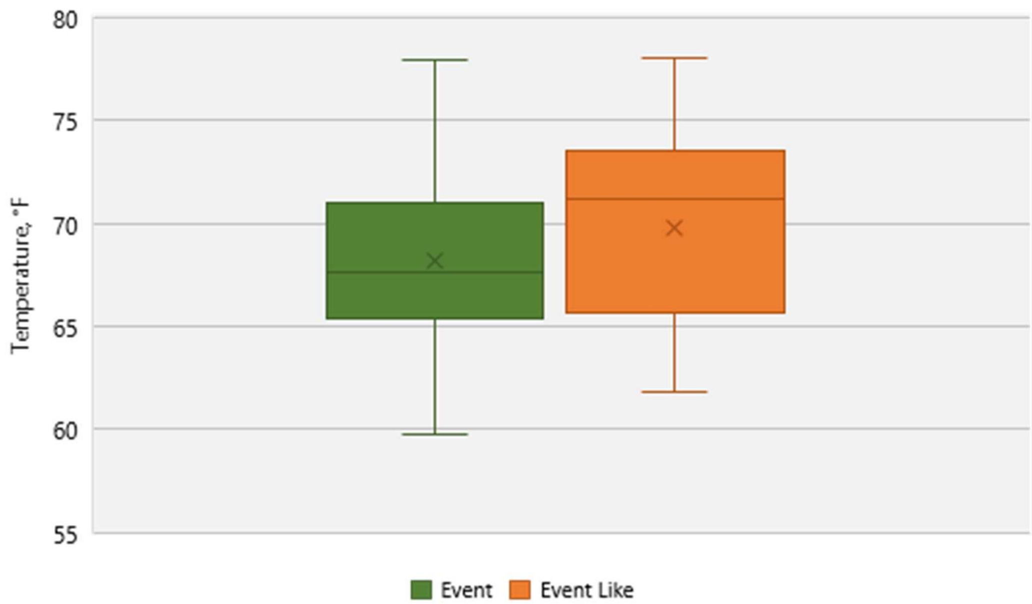


Figure B-2 SCE Average Daily Temperatures of Event Days v. Event-Like Days

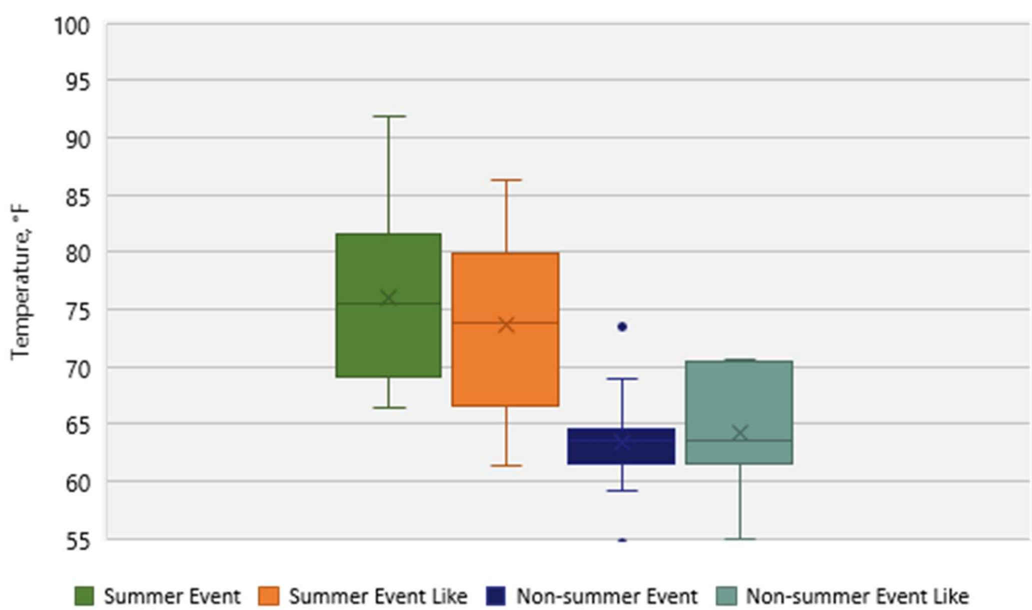
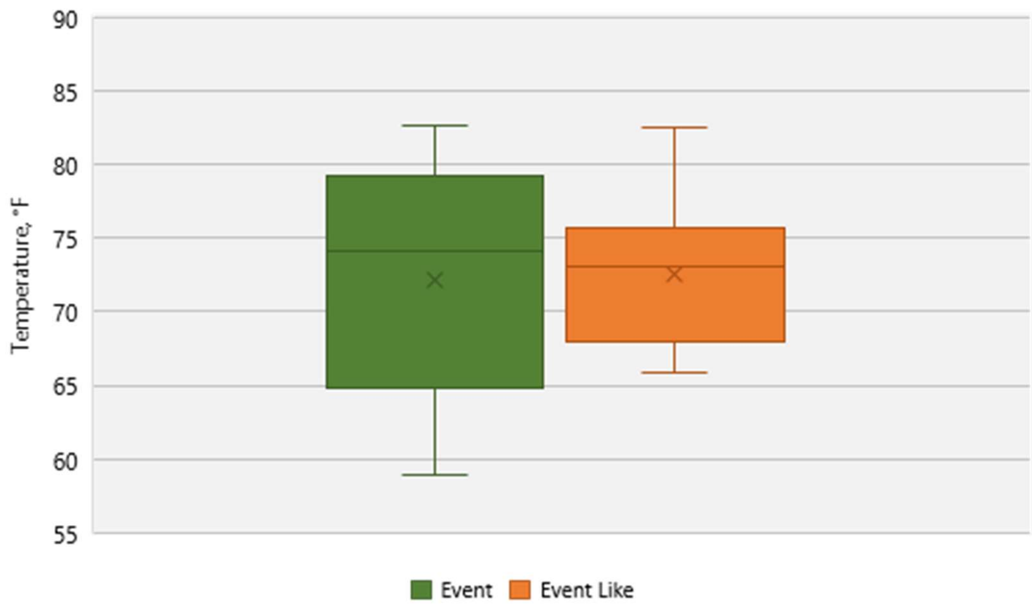


Figure B-3 SDG&E Average Daily Temperatures of Event Days v. Event-Like Days



Optimization Process and Results

Next, we estimated the MAPE and MPE, for the entire day, for each customer, and for each candidate model, both for the in-sample period and for the out-of-sample period. Again, because of the several different event windows, we decided to focus the test on the entire day. This resulted in thousands of in-sample and out-of-sample tests. Recall that the goal of the tests is to find the best model for each customer in terms of its ability to predict the reference load, and its ability to predict the actual load. Therefore, we collapsed the tests into a single metric, which could be calculated for each customer and each candidate model.

The metric is defined in Equation B.4:

$$\boldsymbol{metric_{ic}} = (0.5 * DailyEvntMAPE) + (0.5 * DailyEvntlikeMAPE) \quad \text{(B.4)}$$

Once we computed a single metric for each customer and candidate model combination, we then selected the best model for each customer 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 per-customer models for each utility, by product offering.[56] We present a weighted average where the MAPE and MPE

[56] We also excluded any very extreme cases since individual customer MAPES can be misleading, especially for customers with very large impacts, but very low actual event day loads, e.g. agricultural customers that drop load to near zero can have very large impacts and any deviation from a very small number can yield an extreme error. No more than 2% of the population was excluded in any given group.

are calculated at the aggregate level. These weighted averages are comparable to the MAPE and MPE that might come from an aggregate regression.

Across all three IOUs, programs, and products, most MAPE are below 5%. The MPE values are a mix of positive and negative values, indicating that the models do not have directional bias overall. In addition, the MPE values are relatively small, mostly within -0.5% and 0.1%, indicating a relatively low level of bias at the product level.

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	Elect DA	2.4%	-0.5%	2.0%	-0.1%
	Prescribed DA	4.3%	0.0%	6.2%	-0.4%
SCE	CBP DA	2.8%	-0.2%	2.6%	-0.1%
	CBP DO	2.2%	0.3%	2.1%	-0.1%
SDG&E	CBP DO	2.2%	0.1%	3.3%	0.0%
	CBP DA	2.3%	0.0%	2.0%	1.2%

Figure B-4 to Figure B-6 present the average event-like day predicted and actual loads from the out-of-sample tests, by product and utility. 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.

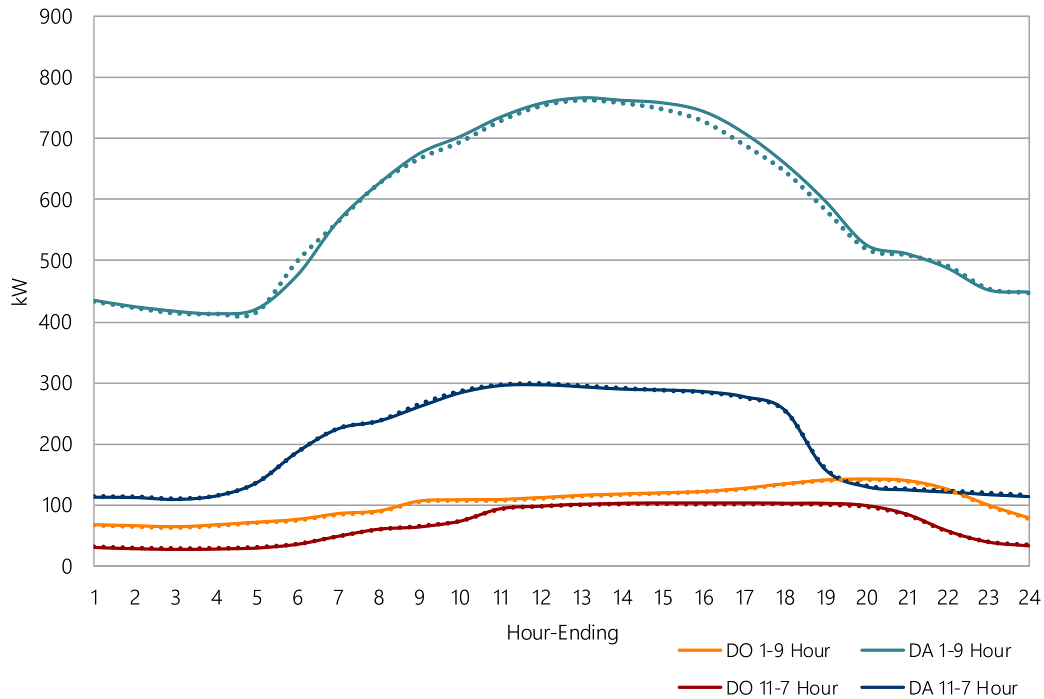
Figure B-4 PG&E Actual and Predicted Loads on Event-Like Days

Figure redacted to protect customer or aggregator confidentiality.

Figure B-5 SCE Actual and Predicted Loads on Event-Like Days

Figure redacted to protect customer or aggregator confidentiality.

Figure B-6 SDG&E Actual and Predicted Loads on Event-Like Days



Additional Checks

Visual inspection can be a simple but highly effective tool. During the inspection, we looked for specific aspects of the subgroup level 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-7 show the event day impacts for two additional geographical areas in SCE's service territory: South of Lugo and Southern Orange County. (Note that there were no South Orange County participants for the CBP DA 1-4 Hour events.)

South of Lugo

Table C-1 South of Lugo Event Day Impacts: Day Ahead 1-4 Hour

Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
		Reference Load	Impact	Reference Load	Impact		
Nov 1, 2017	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	65
Nov 2, 2017	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	64
Nov 3, 2017	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	66
Nov 6, 2017	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	69
Nov 7, 2017	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	74
Nov 8, 2017	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	73
Nov 9, 2017	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	69
Nov 10, 2017	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	69
Nov 13, 2017	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	72
Nov 14, 2017	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	76
Nov 15, 2017	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	78
Nov 20, 2017	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	75
Nov 21, 2017	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	87
Nov 22, 2017	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	89

Table C-2 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		
May 29, 2018	20	174.2	25.7	3.5	0.5	15%	72
Jun 4, 2018	30	147.7	37.0	4.4	1.1	25%	83
Jun 12, 2018	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	78
Jul 6, 2018	22	219.4	56.7	4.8	1.2	26%	114
Jul 9, 2018	22	180.0	49.0	4.0	1.1	27%	92
Jul 10, 2018	22	192.1	56.7	4.2	1.2	30%	92
Jul 11, 2018	22	181.2	42.2	4.0	0.9	23%	85
Jul 17, 2018	22	173.1	45.2	3.8	1.0	26%	87
Aug 1, 2018	22	177.9	32.4	3.9	0.7	18%	95

Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
		Reference Load	Impact	Reference Load	Impact		
Aug 7, 2018	22	184.9	32.6	4.1	0.7	18%	100
Aug 8, 2018	22	179.7	27.4	4.0	0.6	15%	92
Aug 9, 2018	22	171.9	27.4	3.8	0.6	16%	91
Sep 18, 2018	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	75
Sep 20, 2018	12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	80
Sep 21, 2018	12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	85
Sep 24, 2018	12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	75
Sep 26, 2018	12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	85
Sep 27, 2018	10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	91
Oct 16, 2018	12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	74
Oct 17, 2018	12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	76
Oct 18, 2018	12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	80
Oct 19, 2018	12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	81
Oct 22, 2018	12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	73

Table C-3 South of Lugo Event Day Impacts: Day Of 1-4 Hour

Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
		Reference Load	Impact	Reference Load	Impact		
Nov 1, 2017	24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	64
Nov 2, 2017	24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	63
Nov 3, 2017	24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	65
Nov 6, 2017	24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	69
Nov 7, 2017	24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	72
Nov 8, 2017	24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	72
Nov 9, 2017	24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	68
Nov 10, 2017	24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	67
Nov 13, 2017	24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	72
Nov 14, 2017	24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	74
Nov 15, 2017	24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	77
Nov 20, 2017	24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	71
Nov 21, 2017	24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	85
Nov 22, 2017	24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	87
Dec 1, 2017	24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	73
Dec 7, 2017	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	73
Dec 8, 2017	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	71
Dec 11, 2017	24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	75
Dec 12, 2017	24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	76

Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
		Reference Load	Impact	Reference Load	Impact		
Dec 13, 2017	24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	76
Dec 26, 2017	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	63
Dec 28, 2017	24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	75
Dec 29, 2017	24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	76

Table C-4 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		
Jun 4, 2018	21	85.2	12.4	1.8	0.3	15%	71
Jun 12, 2018	21	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	75
Jul 6, 2018	116	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	113
Jul 9, 2018	16	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	83
Jul 10, 2018	116	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	92
Jul 11, 2018	116	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	85
Jul 17, 2018	116	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	88
Jul 18, 2018	100	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	92
Aug 1, 2018	117	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	96
Aug 6, 2018	117	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	98
Aug 7, 2018	117	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	101
Aug 8, 2018	117	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	92
Aug 9, 2018	117	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	92
Sep 17, 2018	103	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	84
Sep 18, 2018	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	75
Sep 20, 2018	103	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	78
Sep 21, 2018	103	153.5	23.9	15.8	2.5	16%	85
Sep 26, 2018	103	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	83
Sep 27, 2018	89	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	89
Oct 1, 2018	102	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	86
Oct 15, 2018	102	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	70
Oct 16, 2018	102	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	73
Oct 17, 2018	102	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	75
Oct 18, 2018	102	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	79

South Orange County

Table C-5 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 29, 2018	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	63
Jun 4, 2018	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	65
Jun 12, 2018	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	72
Jul 6, 2018	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	106
Jul 9, 2018	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	78
Jul 10, 2018	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	79
Jul 11, 2018	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	79
Jul 17, 2018	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	73
Aug 1, 2018	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	84
Aug 7, 2018	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	84
Aug 8, 2018	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	84
Aug 9, 2018	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	79
Sep 18, 2018	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	74
Sep 20, 2018	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	69
Sep 21, 2018	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	73
Sep 24, 2018	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	67
Sep 26, 2018	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	71
Oct 16, 2018	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	73
Oct 17, 2018	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	73
Oct 18, 2018	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	79
Oct 19, 2018	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	81
Oct 22, 2018	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	67

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

Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
		Reference Load	Impact	Reference Load	Impact		
Nov 1, 2017	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	65
Nov 2, 2017	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	64
Nov 3, 2017	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	65
Nov 6, 2017	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	65
Nov 7, 2017	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	68
Nov 8, 2017	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	68
Nov 9, 2017	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	65
Nov 10, 2017	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	63

Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (℉)
		Reference Load	Impact	Reference Load	Impact		
Nov 13, 2017	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	66
Nov 14, 2017	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	69
Nov 15, 2017	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	70
Nov 20, 2017	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	66
Nov 21, 2017	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	76
Nov 22, 2017	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	81
Dec 1, 2017	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	66
Dec 7, 2017	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	74
Dec 8, 2017	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	70
Dec 11, 2017	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	74
Dec 12, 2017	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	75
Dec 13, 2017	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	69
Dec 26, 2017	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	61
Dec 28, 2017	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	66
Dec 29, 2017	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	69

Table C-7 South Orange County Event Day Impacts: Day Of 1-6 Hour

Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (℉)
		Reference Load	Impact	Reference Load	Impact		
Jun 4, 2018	21	99.7	20.5	2.1	0.4	21%	68
Jun 12, 2018	21	108.8	20.7	2.3	0.4	19%	72
Jul 6, 2018	19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	106
Jul 9, 2018	19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	81
Jul 10, 2018	19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	80
Jul 11, 2018	19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	80
Jul 17, 2018	19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	73
Aug 1, 2018	19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	85
Aug 6, 2018	19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	86
Aug 7, 2018	19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	85
Aug 8, 2018	19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	84
Aug 9, 2018	19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	79
Sep 17, 2018	17	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	75
Sep 18, 2018	17	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	73
Sep 20, 2018	17	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	69
Sep 21, 2018	17	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	72
Sep 26, 2018	17	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	70
Oct 1, 2018	17	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	85

Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
		Reference Load	Impact	Reference Load	Impact		
Oct 15, 2018	17	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	76
Oct 16, 2018	17	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	72
Oct 17, 2018	17	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	73
Oct 18, 2018	17	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	78

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