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Applied Energy Group

2019 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

SOUTHERN CALIFORNIA EDISON

SAN DIEGO GAS & ELECTRIC COMPANY

Energy Solutions. Delivered.

This work was performed by

Applied Energy Group, Inc.
500 Ygnacio Valley Blvd., Suite 250
Walnut Creek, CA 94596

Project Director: K. Marrin
Project Manager: A. Nguyen
Project Team: X. Zhang

in consultation with Pacific Gas & Electric Company, Southern California Edison, San Diego Gas & Electric Company, and the Demand Response Measurement & Evaluation Committee.

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 2019 (PY2019). 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 PY2019, and 2) estimate ex-ante load impacts for years 2020 through 2030.

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[1] (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.

The number of nominated customer service accounts[2] on a single event day ranged from less than 5 service accounts to over 800, depending on the product type. Some programs and notice types called events on as few as six days in 2019, while others called events on up to 29 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 2019, 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.[3]

Estimated aggregate load impacts for an average CBP DA event were 9.8 MW for PG&E, 2.7 MW for SCE, and 0.4 MW for SDG&E. Aggregate load impacts for CBP with DO notice [redacted] MW for SCE and 3.6 MW for SDG&E, on average.

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

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

[3] 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 2020.

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 2019 impact evaluation are as follows:

- Estimate hourly ex-post load impacts for each product and IOU for PY2019.
- Estimate average monthly ex-ante load impacts for each product and IOU for years 2020 through 2030.

In the following subsections, we present a description of each IOU's program, the evaluation methodology, PY2019'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[4] 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.[5] Customers enrolled in CBP

[4] Since PY2018, the program was open to residential customer enrollment. PG&E currently has two active residential aggregators, but an aggregator has yet to meet the CAISO 100 kW per resource requirement. Residential aggregators have not yet been nominated.

[5] 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 ($/kW) to aggregators based on the nominated kW load, the specific operating month, the event duration, and the event notice option. Delivered capacity determines performance. If a CBP aggregator's delivered capacity is less than 50% for SCE and SDG&E or less than 60% for PG&E, the aggregator is assessed a penalty. If no events are called, CBP aggregators receive the full monthly capacity payment in accordance with their nominations, but no energy payments.[6] Additional energy payments ($/kWh) are made to the aggregator[7] based on the measured kWh reductions (relative to the program baseline) that are achieved when an event is called.[8]

For PG&E, CBP events are determined by California Independent System Operator (CAISO) market awards. Events may also be called when the DA market price is greater than $95/MWh, when PG&E forecasts that capacity may not be adequate, or when forecasted temperatures exceed the threshold for a Sub-LAP. Events can be called on non-holiday weekdays in 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 are also determined by CAISO market awards. 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. Effective May 1, 2019, the maximum number of events called per month is limited to six event days with a maximum number of three consecutive days.

Number of Accounts

Since localized events continued to be highly utilized in PY2019, 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[9] in PY2019 by notification type and utility. These counts would be comparable to participation counts during system-level events.

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

Utility	Nominated Accounts	
	Day Ahead	Day Of
PG&E	690	-
SCE	245	191
SDG&E	11	184

[6] 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.

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

[8] 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.

[9] 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

2019 Events

Table E-2 summarizes the number of event days by notification type and utility for the PY2019 evaluation period.[10]

[10] The PY2019 evaluation period is May 1 through Oct. 31, 2019 for PG&E and SDG&E and is Nov. 1, 2018 – Oct. 31, 2019 for SCE.

Table E-2 Number of PY2019 Event Days by Notice Type

Utility	Nov 2018-Apr 2019		May 2019-Oct 2019	
	Day Ahead	Day Of	Day Ahead	Day Of
PG&E	n/a	n/a	14[11]	n/a
SCE	6	29	21	24
SDG&E	n/a	n/a	22[12]	16[13]

2019 Ex-Post Impacts

Table E-3 summarizes the 2019 ex-post load impacts and nominated capacity by notification type and utility. The data presented are for the average summer event day. [14] Table E-4 through Table E-6 present the 2019 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. On average, PG&E's DA and SDG&E's DO programs were successful in meeting or exceeding capacity nominations in PY2019.

Table E-3 Summary of PY2019 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	241	40.8	9.8	9.2	n/a			
SCE	262	10.3	2.7	3.8	151	[redacted]	[redacted]	[redacted]
SDG&E	15	26.3	0.4	0.7	185	19.6	3.6	3.6

[11] PG&E had 13 Elect DA event days and 13 Prescribed DA event days with 12 event days called by both product offerings.

[12] SDG&E had 18 DA 11 AM to 7 PM event days and 6 DA 1 PM to 9 PM event days with only 2 event days called by both product offerings.

[13] SDG&E had 11 DO 11 AM to 7 PM event days and 13 DO 1 PM to 9 PM event days with 8 event days called by both product offerings.

[14] 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 PY2019 PG&E Ex-Post Impacts and Nominated Capacity

Event	Day Ahead			
	# of Accts	Per Customer Impact (kW)	Aggregate Impact (MW)	Nominated Capacity (MW)
Jul 24, 2019	588	36.6	21.5	22.3
Jul 25, 2019	3	[redacted]	[redacted]	[redacted]
Aug 14, 2019	61	33.6	2.1	1.0
Aug 15, 2019	84	25.4	2.1	6.6
Aug 27, 2019	196	70.2	13.8	12.4
Sep 5, 2019	62	164.7	10.2	6.0
Sep 13, 2019	62	32.3	2.0	6.0
Sep 24, 2019	621	23.4	14.5	22.1
Sep 25, 2019	63	-6.8	-0.4	6.8
Oct 7, 2019	32	23.6	0.8	0.5
Oct 9, 2019	1	[redacted]	[redacted]	[redacted]
Oct 15, 2019	84	133.5	11.2	6.2
Oct 21, 2019	84	153.2	12.9	6.2
Oct 22, 2019	830	26.1	21.7	27.5

Table E-5 Summary of PY2019 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, 2018	11	[redacted]	[redacted]	[redacted]	58	[redacted]	[redacted]	[redacted]
Nov 2, 2018	11	[redacted]	[redacted]	[redacted]	58	[redacted]	[redacted]	[redacted]
Nov 5, 2018	11	[redacted]	[redacted]	[redacted]	58	[redacted]	[redacted]	[redacted]
Nov 6, 2018	11	[redacted]	[redacted]	[redacted]	58	[redacted]	[redacted]	[redacted]
Nov 14, 2018	7	[redacted]	[redacted]	[redacted]	15	[redacted]	[redacted]	[redacted]
Nov 16, 2018	4	[redacted]	[redacted]	[redacted]	43	[redacted]	[redacted]	[redacted]
Dec 3, 2018	n/a				53	[redacted]	[redacted]	[redacted]
Dec 4, 2018	n/a				53	[redacted]	[redacted]	[redacted]
Dec 5, 2018	n/a				53	[redacted]	[redacted]	[redacted]
Dec 6, 2018	n/a				53	[redacted]	[redacted]	[redacted]
Dec 7, 2018	n/a				53	[redacted]	[redacted]	[redacted]
Jan 2, 2019	n/a				62	[redacted]	[redacted]	[redacted]
Jan 3, 2019	n/a				62	[redacted]	[redacted]	[redacted]
Jan 4, 2019	n/a				62	[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)
Jan 7, 2019	n/a				62	[redacted]	[redacted]	[redacted]
Jan 8, 2019	n/a				51	[redacted]	[redacted]	[redacted]
Jan 16, 2019	n/a				11	[redacted]	[redacted]	[redacted]
Feb 4, 2019	n/a				37	[redacted]	[redacted]	[redacted]
Feb 5, 2019	n/a				43	[redacted]	[redacted]	[redacted]
Feb 6, 2019	n/a				43	[redacted]	[redacted]	[redacted]
Feb 7, 2019	n/a				43	[redacted]	[redacted]	[redacted]
Feb 8, 2019	n/a				43	[redacted]	[redacted]	[redacted]
Feb 11, 2019	n/a				6	[redacted]	[redacted]	[redacted]
Mar 1, 2019	n/a				36	[redacted]	[redacted]	[redacted]
Mar 4, 2019	n/a				42	[redacted]	[redacted]	[redacted]
Mar 5, 2019	n/a				42	[redacted]	[redacted]	[redacted]
Mar 6, 2019	n/a				42	[redacted]	[redacted]	[redacted]
Mar 7, 2019	n/a				42	[redacted]	[redacted]	[redacted]
Mar 8, 2019	n/a				6	[redacted]	[redacted]	[redacted]
Jun 11, 2019	134	[redacted]	[redacted]	[redacted]	141	[redacted]	[redacted]	[redacted]
Jun 12, 2019	134	[redacted]	[redacted]	[redacted]	141	[redacted]	[redacted]	[redacted]
Jul 23, 2019	111	11.2	1.2	1.7	156	20.5	3.2	4.7
Jul 24, 2019	111	12.8	1.4	1.7	156	22.6	3.5	4.7
Jul 25, 2019	79	10.0	0.8	1.2	156	20.5	3.2	4.7
Aug 5, 2019	n/a				159	21.0	3.3	5.2
Aug 6, 2019	287	[redacted]	[redacted]	[redacted]	159	21.0	3.3	5.2
Aug 14, 2019	333	[redacted]	[redacted]	[redacted]	159	21.0	3.3	5.2
Aug 15, 2019	333	11.5	3.8	4.8	159	21.0	3.3	5.2
Aug 26, 2019	n/a				169	[redacted]	[redacted]	[redacted]
Aug 27, 2019	333	11.5	3.8	4.8	44	[redacted]	[redacted]	[redacted]
Aug 28, 2019	333	11.5	3.8	4.8	44	[redacted]	[redacted]	[redacted]
Sep 3, 2019	n/a				204	[redacted]	[redacted]	[redacted]
Sep 4, 2019	336	11.0	3.7	4.4	204	[redacted]	[redacted]	[redacted]
Sep 5, 2019	336	12.5	4.2	4.4	204	[redacted]	[redacted]	[redacted]
Sep 6, 2019	336	11.9	4.0	4.4	204	[redacted]	[redacted]	[redacted]
Sep 9, 2019	336	10.7	3.6	4.4	n/a			
Sep 12, 2019	336	[redacted]	[redacted]	[redacted]	204	[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)
Oct 7, 2019	n/a				193	4.3	0.8	5.3
Oct 8, 2019	128	3.6	0.5	1.1	73	2.2	0.2	1.8
Oct 14, 2019	n/a				168	4.8	0.8	4.7
Oct 15, 2019	328	[redacted]	[redacted]	[redacted]	193	4.3	0.8	5.3
Oct 16, 2019	328	[redacted]	[redacted]	[redacted]	193	4.3	0.8	5.3
Oct 21, 2019	328	[redacted]	[redacted]	[redacted]	115	3.8	0.4	3.4
Oct 22, 2019	316	5.3	1.7	4.3	30	7.8	0.2	0.6
Oct 23, 2019	212	[redacted]	[redacted]	[redacted]	n/a			

Table E-6 Summary of PY2019 SDG&E Ex-Post Impacts and Nominated Capacity[15]

Event	Day Ahead				Day Of			
	# of Accts	Per Customer Impact (kW)	Aggregate Impact (MW)	Nominated Capacity (MW)	# of Accts	Per Customer Impact (kW)	Aggregate Impact (MW)	Nominated Capacity (MW)
Jun 10, 2019	8	20.4	0.2	0.4	90	28.5	2.6	2.3
Jun 11, 2019	8	20.4	0.2	0.4	90	28.5	2.6	2.3
Jun 12, 2019	8	20.4	0.2	0.4	n/a			
Jul 23, 2019	12	49.9	0.6	0.5	90	28.4	2.6	2.5
Jul 24, 2019	12	49.9	0.6	0.5	184	19.9	3.7	3.4
Jul 25, 2019	2	9.6	0.0	0.1	90	28.4	2.6	2.5
Aug 5, 2019	10	50.1	0.5	0.5	n/a			
Aug 14, 2019	10	50.1	0.5	0.5	n/a			
Aug 15, 2019	10	50.1	0.5	0.5	90	28.8	2.6	2.5
Aug 27, 2019	10	50.1	0.5	0.5	n/a			
Sep 4, 2019	10	37.0	0.4	0.5	184	20.1	3.7	3.6
Sep 5, 2019	10	14.3	0.1	0.5	184	17.4	3.2	3.6
Sep 6, 2019	10	37.0	0.4	0.5	97	12.4	1.2	1.2
Sep 12, 2019	10	37.0	0.4	0.5	n/a			
Sep 13, 2019	10	37.0	0.4	0.5	97	12.4	1.2	1.2
Sep 24, 2019	10	37.0	0.4	0.5	184	20.2	3.7	3.6
Sep 25, 2019	n/a				184	17.5	3.2	3.6
Oct 7, 2019	10	5.2	0.1	0.5	n/a			

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

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)
Oct 15, 2019	10	5.2	0.1	0.5	n/a			
Oct 16, 2019	10	5.2	0.1	0.5	97	12.4	1.2	1.2
Oct 21, 2019	10	5.2	0.1	0.5	182	20.3	3.7	3.5
Oct 22, 2019	10	5.2	0.1	0.5	182	17.6	3.2	3.5
Oct 23, 2019	10	5.2	0.1	0.5	182	20.3	3.7	3.5

2020-2030 Forecast

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

Table E-7 2020-2030 Forecast for Month of August

Utility	Customer Class	Notice	Number of Service Accounts			Aggregate Impact (MW)		
			2020	2021	2022-2030 (Each Year)	2020	2021	2022-2030 (Each Year)
PGE	Residential	Day Ahead	5,000	25,000	55,000	2.0	10.0	22.0
	Non-Residential	Day Ahead	1,503	1,586	1,670	36.0	38.0	40.0
SCE	Non-Residential	Day Ahead	384	384	384	[redacted]	[redacted]	[redacted]
		Day Of	233	233	233	[redacted]	[redacted]	[redacted]
SDG&E	Non-Residential	Day Ahead	11	11	12	0.2	0.2	0.2
		Day Of	188	191	195	3.2	3.3	3.4

Each IOU's 2020-2030 forecast is described as follows:

- PG&E forecasts growth in both residential and non-residential enrollment through 2022 and holds the forecast constant across the remainder of the forecast horizon (2023-2030). PG&E's residential forecast assumes a per-customer impact of 0.4 kW. The non-residential forecast will be discussed further below.
- SCE assumes a 15% increase in participation over August 2019 levels as a result of reduction in Demand Response Auction Mechanism (DRAM) funding and mandated participation by Self-Generation Incentive Program (SGIP) recipients in DR. SCE also assumes a constant enrollment forecast for both Non-residential DA and DO throughout the 2020-2030 forecast horizon. SCE will be filing for a residential CBP as a pilot-only program or open CBP to residential.
- SDG&E's enrollment forecast for the DA and DO products assumes the customer enrollment will increase by 3% per year starting in 2020 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 2020 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 2020 through 2022 due to program improvements and growth in TI. The enrollment forecasts for the DA and DO products after 2022 and through 2030 show a flat trend at the 2022 values. The forecast listed in Table E-7 for DO includes new enrollments in the Technical Incentives (TI) program. SDG&E's forecast does not include a residential forecast.

2019 Ex-Ante Impacts

Table E-8 summarizes the non-residential aggregate load impact forecasts for an August peak day in 2020 by notification type and utility for each weather scenario.

Table E-8 Summary of Non-Residential Resource Adequacy Window Ex-Ante Impacts, August Peak Day, 2020

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	Day Ahead	24.0	36.0	12.5%	12.2%	12.9%	12.5%
SCE	Day Ahead	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Day Of	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SDG&E	Day Ahead	18.7	0.2	4.9%	4.8%	4.9%	4.9%
	Day Of	17.0	3.2	14.1%	13.5%	13.8%	14.0%

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

Key Findings

In PY2019, we have the following key findings:

1. CBP remains a more time and/or geographically targeted DR program, utilizing localized events. However, all three IOUs, due to market conditions, called more consistent events through the PY2019 season.
   - PG&E's CBP program, like in PY2018, utilized many localized events with 1 to 14 Sub-LAPs called and 1 to 806 participants nominated. PG&E called only one system-level event: October 22nd. Also, PG&E called most events between 6 PM to 7 PM (HE19).
   - SCE only called a handful of localized events in PY2019, calling mostly system-level events. The variability in event characteristics (Sub-LAP and participant count) is due to the variability in monthly nominations both across the two seasons (summer v. non-summer) and the one-time spike in August enrollments (due to the CPP rate defaulting).

- Similar to SCE, SDG&E called mostly system-level events. SDG&E, however, did not experience much fluctuation in monthly nominations. SDG&E also called most events between 5 PM to 7 PM (HE18-HE19) and 6 PM to 8 PM (HE19-HE20) for the 11 AM to 7 PM and 1 PM to 9 PM dispatch windows, respectively.

2. Each IOU's product offerings earned mixed results in meeting/exceeding their capacity nominations.
   - PG&E's DA program is the largest contributor with 9.8 MW reductions, on average. This program also successfully exceeded its average nominated capacity of 9.2 MW.
   - SCE's DA and DO programs both did not succeed in meeting its nominated capacity, on average. Program management attributes this to several aggregators having struggles in deliveries through the course of the program year.
   - SDG&E's DO program successfully met its capacity nominations of 3.6 MW, on average. The DA program was able to deliver relatively consistent results through PY2019 (with the exception of DA 11 AM to 7 PM October events), but did not successfully meet capacity nominations, on average.
3. Participant retention and enrollment has improved since the program revamping, suggesting that aggregators and participants adjusted to most of the program changes at the end of PY2018.
   - PG&E's monthly nominations picked up through the PY2019 season, starting at 427 nominations in May and ending at 843 nominations in October. Growths in the ex-ante forecast can be credited to the program's success in retention and enrollment in PY2019.
   - SCE's drop in summer and non-summer enrollments were mainly due to the CPP rate defaulting in PY2019 and the CPP opt-out process required to re-enroll into the CBP program. By August, both DA and DO programs are back to anticipated program nominations.
   - Similar to PG&E, SDG&E exhibited good participant retention in PY2019 with some small growth in the DA program with 6 participants as of October 2018 and ranging from 10-12 participants in PY2019.

Recommendations

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

- Incorporate monthly average event days in reporting. A monthly average event day is not required under the DR Load Impact Protocols. However, given that CBP participation is driven by monthly MW nominations, we believe that monthly average events can facilitate better conclusions. Examples of reporting items that can be done at the monthly level are identifying system-level events v. localized events and meeting or exceeding capacity nominations. Although these reporting items are still required for the entire program year (via the average event day), having these monthly comparisons are also quite telling of the program's success.

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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 PY2019.

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.[16]
- Ex-ante impacts are estimated for each year over a 11-year[17] 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[18] (as applicable), each LCA (as applicable), each size group (as applicable), and each busbar (as applicable).

Key Issues for PY2019 Analysis

In PY2019, PG&E and SDG&E implemented minor program changes that did not require major changes in the overall analysis methodology. All three IOUs are anticipating some changes in PY2020, which will be discussed in Section 2. These changes impact the ex-ante analysis assumptions but also do not impact the overall methodology. We continued with the following approaches:

- We limited our analysis to include only PY2019 data. We had success with this approach in PY2018 and determined that PY2019 data is sufficient for producing robust estimates. Working with less data also increased efficiency by lowering data processing times.
- We kept the definition of the average event day consistent with PY2018, which is the average of all called events and present impacts on the common event hour, which was HE19. Since the IOUs only implemented minor changes in PY2019, we determined that

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

[17] PG&E and SDG&E has requested a PY2019 back cast as part of the ex-ante impact analysis.

[18] Defined as residential v. non-residential. In PY2019, the customer class subgroup is still only applicable in the ex-ante impact analysis. It will be part of the ex-post impact analysis starting in PY2020 if residential nominations meet eligibility requirements.

the average event day definition remains appropriate and will enable appropriate comparisons to the PY2018 evaluation.

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 2019 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[19] 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.[20] 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 ($/kW) to aggregators based on the nominated kW load, the specific operating month, the event duration, and the event notice option. Delivered capacity determines performance. If a CBP aggregator's delivered capacity is less than 50% for SCE and SDG&E or less than 60% for PG&E, the aggregator is assessed a penalty. If no events are called, CBP aggregators receive the full monthly capacity payment in accordance with their nominations, but no energy payments.[21] Additional energy payments ($/kWh) are made to the

[19] Since PY2018, the program was open to residential customer enrollment. PG&E currently has one active residential aggregator, but this aggregator has yet to meet the CAISO 100 kW per resource requirement. This residential aggregator has not yet been nominated.

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

[21] 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.

aggregator[22] based on the measured kWh reductions (relative to the program baseline) that are achieved when an event is called.[23]

The following describes each IOU's different product offerings in PY2019:

PG&E

As of PY2018, PG&E's CBP only offers day-ahead notification. It has three options: Prescribed, Elect, and Elect+. For all three options, aggregators nominate a monthly capacity amount. Under the Prescribed option, PG&E sets the CAISO market bid price and dispatch strategy within specified operating hours (1-4 hours and 2-6 hours). Under the Elect option, aggregators set their own CAISO market bid price within specified operating hours (1-4 hours, 2-6 hours, and 1-8 hours). The Elect+ option is similar to Elect, but an aggregator can participate in additional hours outside the minimum specified operating hours (1-4 hours, 2-6 hours, and 1-24 hours). 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).

SCE

Effective May 1, 2018, SCE's CBP offers both DA and DO notifications for 1-6 hour durations only. 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. Like PG&E, SCE CBP events are determined by CAISO market awards.

SDG&E

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

SDG&E made the following changes on the program triggers:

- Effective December 15, 2018, Day Ahead Product: SDG&E may call an event whenever the day-ahead market price is equal to or greater than $80/MWh or as utility system conditions warrant. Day-ahead market price is defined as California Independent System

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

[23] 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.

Operator (CAISO) DLAP or applicable pnode SDGE-APND day-ahead market locational marginal price (DAM LMP).

- Effective July 1, 2018, Day Of Product: SDG&E may call an event whenever the forecasted real time price is equal to or greater than $95/MWh for Day Of 11 AM to 7 PM; $110/MWh for Day Of 1 PM to 9 PM or as utility system conditions warrant. Real time price is defined as the CAISO DLAP or applicable pnode_SDGE-APND average hourly real time market locational marginal price (LMP).

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

Table 2-1 SDG&E Product Types

Product	Hours	Minimum Duration per Event	Maximum Duration per Event	Maximum Cumulative Event Duration per Operational Month	Maximum Events per Day
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

To characterize the distribution of PY2019 CBP participation, Table 2-2 presents the number of nominated service accounts for each IOU, size group, and industry segment. Since nominations vary by month, we use the number of service accounts nominated at any point in PY2019, i.e., the maximum nomination count. For reference, Table 2-3 presents the eight industry-type definitions and corresponding NAICS codes.

Table 2-2 CBP Nominated Service Accounts, by Utility, Size, and Industry Group, PY2019

Utility	Industry Type	Size			Total
		Below 20 kW	20 kW to 199.99 kW	Above 200 kW	
PG&E	1. Agriculture, Mining & Construction	2	23	16	**41**
	2. Manufacturing	-	1	1	**2**
	3. Wholesale, Transport, Other Utilities	-	16	4	**20**
	4. Retail Stores	12	460	209	**681**
	5. Offices, Hotels, Finance, Services	1	33	58	**92**
	6. Schools	-	16	2	**18**
	7. Institutional/Government	-	-	-	**-**
	8. Other/Unknown	1	31	10	**42**
	Total	**16**	**580**	**300**	**896**
SCE	1. Agriculture, Mining & Construction	-	14	1	**15**
	2. Manufacturing	-	1	1	**2**
	3. Wholesale, Transport, Other Utilities	1	6	16	**23**
	4. Retail Stores	34	409	80	**523**
	5. Offices, Hotels, Finance, Services	1	21	7	**29**
	6. Schools	-	-	1	**1**
	7. Institutional/Government	-	2	1	**3**
	8. Other/Unknown	-	2	-	**2**
	Total	**36**	**455**	**107**	**598**
SDG&E	1. Agriculture, Mining & Construction	-	2	1	**3**
	2. Manufacturing	-	-	1	**1**
	3. Wholesale, Transport, Other Utilities	-	-	-	**-**
	4. Retail Stores	7	109	59	**175**
	5. Offices, Hotels, Finance, Services	-	7	7	**14**
	6. Schools	-	2	2	**4**
	7. Institutional/Government	-	3	3	**6**
	8. Other/Unknown	-	1	-	**1**
	Total	**7**	**124**	**73**	**204**

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:

Residential CBP

- PG&E currently has two active Residential CBP aggregators with customers in the portfolio, but an aggregator has yet to meet the CAISO 100 kW per resource requirement. Residential aggregators have not yet been nominated. PG&E submitted advice letters (AL 5752-E and AL 5752-E-A) requesting changes to the tariff and aggregator agreement to add language specific to Residential participants for PY2020 on prohibited resources and a pilot electronic enrollment process.
- SCE will either be filing for (1) Residential CBP as a pilot-only program or (2) open CBP to Residential. One concern is the possibility that Residential CBP will cannibalize participants from other current residential DR programs.
- SDG&E plans on filing an advice letter to add on Residential CBP as a pilot on the DR Mid-cycle 2020 in compliance with Decision 16-09-056 OP22 and OP18.

Non-Residential CBP

- PG&E submitted advice letters (AL 5752-E and AL 5752-E-A) requesting changes to the tariff and aggregator agreement for: (1) the removal of the Load Serving Entity (LSE) requirement to qualify as a 100 kW recourse; and, (2) the removal of program hours 11 AM to 7 PM and only offer program hours 1 PM to 9 PM to better align with the Resource Adequacy (RA) window (4 PM to 9 PM).
- SCE's advice letter (AL 4131-E) requesting to change the dispatch window to 3 PM to 9PM, currently at 1 PM to 7 PM, was approved to be effective retroactive to January 19th, 2020. This change better aligns the dispatch window with the RA window (4 PM to 9 PM).
- Pursuant to D.16-09-056 OP 9, SDG&E will propose to update its price triggers and notification time for CBP during the DR mid-cycle 2020.

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 PY2019 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 2019 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.

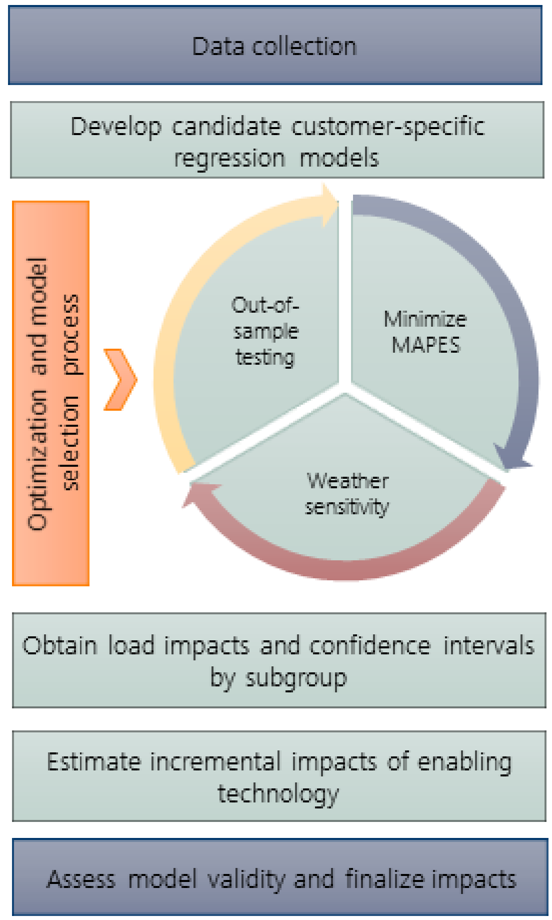
AEG used customer-specific regressions to estimate the load impact for each customer on each event day. Because CBP is implemented somewhat differently within each IOU's territory, the ex-post analysis was conducted independently for each IOU to account for those differences in the modeling and analysis. 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 to what researchers often call a repeated-measures design. This 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.[24]

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

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, cooling degree hour (CDH) terms with base value of 70, heating degree hour (HDH) with base value of 60, and lagged versions of various weather-related variables
$Month_{i,d}$	A series of indicator variables for each month
$DayOfWeek_{i,d}$	A series of indicator variables for each day of the week
$OtherEvt_{i,d}$	Equals one on event days of other demand response programs in which the customer is enrolled
$MornLoad_{i,d}$	The average of each day's load in hours 4 AM through 10 AM
$MidLoad_{i,d}$	The average of each day's load in hours 10 AM through 2 PM
$EveLoad_{i,d}$	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
$P*EventWindow_{i,d}$	An indicator variable for aggregator program event days interacted with an indicator for the window the event is called

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

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

Optimization 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.[25]

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.

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

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.
- 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:
  - 24 nominated customers
  - 23 with sufficient valid data to estimate impacts
  - Aggregate impact for 23 customers = 2,300 kW
  - Average per-customer impact for the subgroup would be calculated with the aggregated data for the 23 customers: 2,300 kW / 23 customers = 100 kW per customer
  - Aggregate impact for all 24 nominated customers: 100 kW/customer x 24 customers = 2,400 kW
- Subgroup #2 in Product A:
  - 76 nominated customers, all with sufficient valid data to estimate impacts
  - Aggregate impact for 76 customers: 6,460 kW
  - Average per-customer impact: 6,460 kW / 76 customers = 85 kW per customer
- Total for Product A:
  - 100 nominated customers
  - 99 with sufficient valid data to estimate impacts
  - Aggregate impact for 99 customers = 2,300 kW + 6,460 kW = 8,760 kW
  - 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. Although it is a more conservative estimate since it does not allow us 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 employed this approach in PY2018 and recommend the use of this simpler approach in future evaluations.

Calculating Impacts for an Average Event Day

Given 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. 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 the 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.

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

This can be rewritten as the difference in impacts, as in Equation 3.4.

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

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.

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

Ex-Ante Impact Analysis

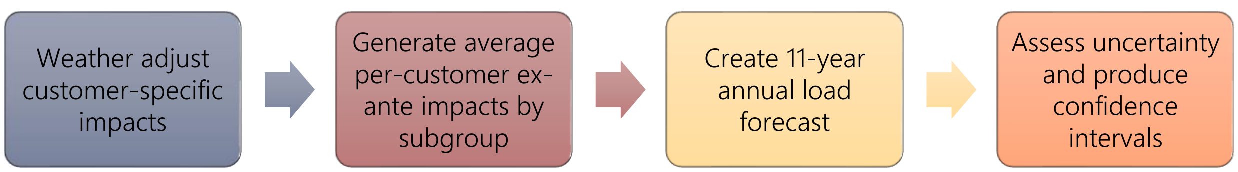
The main goal of the ex-ante analysis is to produce an annual 11-year[26] forecast (2020 through 2030) of the load impacts expected from the CBP programs.

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:

- For each customer, we began with the coefficients estimated in the customer-specific regression models developed for the ex-post analysis.

[26] PG&E and SDG&E has requested a PY2019 back cast as part of the ex-ante impact 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. In PY2019, this was HE19 for all three IOUs. Using the regression model of the selected hour, we estimated the non-weather dependent load impact using a linear combination of the coefficients of the impact variables.
- We applied this load impact estimate to all hours of the Resource Adequacy window, which is HE17 through HE21 year-round as of PY2019.[27]
- 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, we average the individual impacts and generate per-customer average impacts by subgroup. For example, the average impact for a particular LCA is the average of the impacts predicted for each customer in that LCA. At this stage, we also worked with the IOUs to determine the best way to account for participation between notification types to ensure that they are not double-counted in the per-customer averages.

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

Creation of 11-Year Annual Load Impact Forecasts

AEG provided the IOUs with the per-customer average ex-ante impacts by year and subgroup. The IOUs used the per-customer impacts—along with contractual MW adjusted by historical performance relative to the aggregator's MW nomination and/or anticipated program changes—to determine the enrollment forecasts. AEG used the current PY2019 enrollment to create weather-adjusted impacts for PY2019[28] and the PY2020-PY2030 enrollment forecasts 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 error in the enrollment forecast, the confidence intervals do not include the enrollment forecast uncertainty.

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

[28] The PY2019 back cast requested by PG&E and SDG&E.

4

EX-POST RESULTS

This section presents the PY2019 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 2019, 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 PY2019 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 PY2019

Utility	Product	Accounts	Nominated Capacity (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)	
				Reference Load	Impact	Reference Load	Impact
PG&E	Day Ahead	241	9.2	312.6	40.8	75.3	9.8
SCE	Day Ahead	262	3.8	86.7	10.3	22.7	2.7
	Day Of	151	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SDG&E	Day Ahead	15	0.7	408.7	26.3	6.1	0.4
	Day Of	185	3.6	120.6	19.6	22.3	3.6

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 years prior to the PY2018 program changes, 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 2019 events for PG&E's CBP program by product offering: Elect DA[29] and Prescribed DA. The Elect DA participants experienced a total of 13 event days and were nominated to participate in two products: Elect DA 1-4 Hour (11 AM to 7 PM) and Elect DA 2-6 Hour (1 PM to 9 PM). The Prescribed DA participants experienced a total of 13 event days, participating only in one product: Prescribed DA 1-4 Hour (11 AM to 7 PM).

[29] Note that no aggregators chose to participate in the Elect+ product offering in PY2019.

In PY2019, 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 PY2019 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 and MW Nominations

Month	Enrolled Accounts	Nominated Capacity (MW)
May	427	18.6
June	563	19.4
July	726	27.0
August	797	30.2
September	783	26.6
October	843	27.5
Average Month	**690**	**24.9**

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**	**234**	**7**
Jul 24, 2019	Wednesday	12	19-19, 19-20	587	1
Jul 25, 2019	Thursday	1	20-20	3	-
Aug 14, 2019	Wednesday	1	19-19	60	1
Aug 15, 2019	Thursday	3	17-19, 18-18, 19-19	82	2
Aug 27, 2019	Tuesday	5	19-19	194	2
Sep 5, 2019	Thursday	2	19-19	60	2
Sep 13, 2019	Friday	2	19-19	60	2
Sep 24, 2019	Tuesday	12	19-19, 19-20	619	2
Sep 25, 2019	Wednesday	3	18-19	61	2
Oct 7, 2019	Monday	1	19-19	31	1
Oct 9, 2019	Wednesday	1	18-19	-	1
Oct 15, 2019	Tuesday	3	19-19	60	24
Oct 21, 2019	Monday	3	19-19	60	24
Oct 22, 2019	Tuesday	14	18-19, 19-19, 19-20	806	24

PG&E also primarily called one-hour events during HE19, calling 21 out of 33 unique product-level events in HE19. Because of this, the ex-post regression models favored using event window indicators over event hour indicators. Using event hour indicators could not fully capture the response on events called in windows different from HE19.

Summary Load Impacts

Table 4-4 shows the average summer event day impacts for Elect DA, Prescribed DA, and overall CBP, both at the per-customer level and in aggregate. On average, the Prescribed DA product offering performed very well, with participants exceeding their nominated capacity. The Elect DA product offering also performed well, at the event level, despite participants not meeting their nominated capacity on average. We discuss this in more detail below.

Table 4-4 PG&E CBP Impacts Summary, Average Summer Event Day PY2019

Product	Accounts	Nominated Capacity (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact
			Reference Load	Impact	Reference Load	Impact	
Total Day Ahead	241	9.2	312.6	40.8	75.3	9.8	13%

Table 4-5 and Table 4-6 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 4-5 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	**234**	**5.5**	**166.6**	**21.1**	**39.0**	**5.0**	**13%**	**85**
Jul 24, 2019	587	17.3	155.5	22.7	91.3	13.3	15%	91
Jul 25, 2019	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	99
Aug 14, 2019	60	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	94
Aug 15, 2019	82	1.5	338.6	23.6	27.8	1.9	7%	88
Aug 27, 2019	194	7.3	204.7	27.6	39.7	5.3	13%	81
Sep 5, 2019	60	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	73
Sep 13, 2019	60	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	95
Sep 24, 2019	619	17.0	154.5	23.2	95.6	14.4	15%	89
Sep 25, 2019	61	1.7	367.7	29.3	22.4	1.8	8%	97
Oct 7, 2019	31	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	83
Oct 15, 2019	60	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	70
Oct 21, 2019	60	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	82
Oct 22, 2019	806	22.2	124.4	15.3	100.2	12.3	12%	80

In PY2019, the Elect DA product offering called several localized events, calling only one system-level event (October 22nd). Although Elect DA did not meet or exceed the nominated capacity on average, participants called to respond to events were able to do so in 8 out of 13 events. This success is largely attributed to a single aggregator; thus, those impact results are indicated as confidential in the table above.

Table 4-6 PG&E Prescribed Day Ahead: Impacts by Event[30]

Event	# of Accts	Nominated Capacity (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Avg. Event	**7**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	**84**
Jul 24, 2019	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	88
Aug 14, 2019	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	94
Aug 15, 2019	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	94
Aug 27, 2019	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	82
Sep 5, 2019	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	72
Sep 13, 2019	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	94
Sep 24, 2019	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	89
Sep 25, 2019	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	95
Oct 7, 2019	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	83
Oct 9, 2019	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	71
Oct 15, 2019	24	5.3	1,785.4	390.3	42.9	9.4	22%	70
Oct 21, 2019	24	5.3	1,850.0	459.0	44.4	11.0	25%	81
Oct 22, 2019	24	5.3	1,804.4	387.8	43.3	9.3	21%	84

In PY2019, the Prescribed DA product offering impacts were largely driven by one very large customer; thus, the majority of the results are indicated as confidential in the table above.

Table 4-7 and Table 4-8 present the impacts for an average event day by Industry and Local Capacity Area (LCA).[31]

[30] 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.

[31] The results in Table 4-7 and Table 4-8 are for an average event day. Note that the total for the program does not always exactly equal the total of the individual segments (industry or LCAs). This is because different groups of customers are called for each event, and in some cases, no customers in a segment are called. The average for that segment will reflect only those events where customers in that segment were called. The total program is the average across all events, regardless of which groups of customers are called for each event. Because the total program and the individual segments are averaged across different events, the total program may not exactly match the sum of the individual segments.

Table 4-7 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	17	127.1	66.9	2.1	1.1	53%	90
Elect DA	Manufacturing	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	86
Elect DA	Wholesale, Transport, other utilities	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	85
Elect DA	Retail stores	337	130.2	17.6	43.8	5.9	14%	82
Elect DA	Offices, Hotels, Finance, Services	58	300.5	32.2	17.6	1.9	11%	85
Elect DA	Institutional/Government	12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	85
Elect DA	Other or unknown	13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	87
Elect DA	**Total Elect DA**	**234**	**166.6**	**21.1**	**39.0**	**5.0**	**13%**	**85**
Prescribed DA	Agriculture, Mining & Construction	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	85
Prescribed DA	Wholesale, Transport, other utilities	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	82
Prescribed DA	Retail stores	22	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	78
Prescribed DA	**Total Prescribed DA**	**7**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	**84**
Total CBP DA		**197**	241	312.6	40.8	75.3	9.8	13%

Table 4-8 PG&E Impacts by LCA and Product Offering[32]

	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	122	180.1	21.7	21.9	2.6	12%	84
Elect DA	Greater Fresno Area	55	183.4	22.7	10.1	1.2	12%	86
Elect DA	Kern	35	133.4	23.8	4.7	0.8	18%	90
Elect DA	Northern Coast	45	133.3	15.9	6.0	0.7	12%	88
Elect DA	Other	40	114.0	13.0	4.5	0.5	11%	86
Elect DA	Sierra	37	120.4	18.7	4.4	0.7	16%	83
Elect DA	Stockton	37	121.2	27.6	4.5	1.0	23%	91
Elect DA	**Total Elect DA**	**234**	**166.6**	**21.1**	**39.0**	**5.0**	**13%**	**85**
Prescribe	Greater Bay Area	7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	84
Prescribe	Sierra	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	82
Prescribe	**Total Prescribed DA**	**7**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	**84**
Total CBP DA		**197**	241	312.6	40.8	75.3	9.8	13%

[32] 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.

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, HE19, 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, 2019

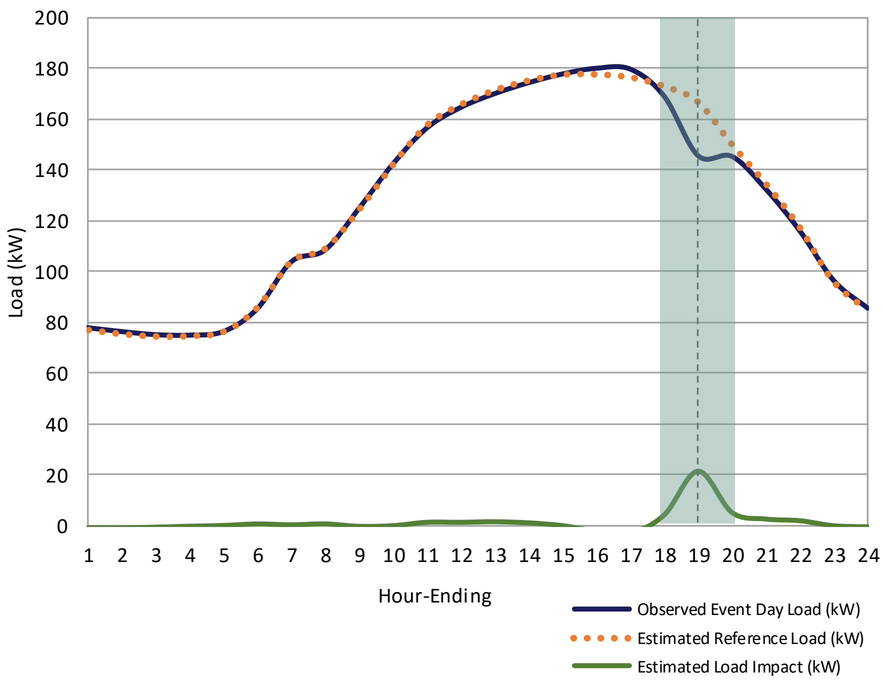


Figure 4-2 PG&E Prescribed Day Ahead: Average Hourly Per-Customer Impact, 2019

[redacted]

Load Impacts of AutoDR Participants

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

In PY2019, only the Elect DA product offering recruited AutoDR participants. Table 4-9 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 4-9 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	**89**	**205.6**	**42.1**	**18.3**	**3.7**	**20%**	**4.1**	**81**
Jul 24, 2019	123	217.5	48.8	26.8	6.0	22%	5.5	92
Aug 15, 2019	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	65
Aug 27, 2019	35	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	82
Sep 24, 2019	118	220.4	49.9	26.0	5.9	23%	5.4	89
Oct 22, 2019	163	174.9	31.9	28.5	5.2	18%	8.0	79

SCE

Events for SCE

We present summaries of the PY2019[33] events for SCE's CBP program for DA and DO products. The DO participants experienced a total of 53 event days over the course of the program year, while DA participants experienced 27 event days. As in previous years, events were called using a wide variety of event hours with events starting as early as 1 PM (HE14) and as late as 6 PM (HE19) and most events ending at 7 PM (HE19). Table 4-11 below shows the number of Sub-LAPs, the event windows called, and the number of accounts nominated on each event day.

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. In PY2019, we see a one-time spike in enrollment in August. This is attributed to the Critical Peak Pricing (CPP) rate, which defaulted SCE's C&I customers in PY2019. Dual enrollment is no longer allowed between these two programs, and CPP opt-out procedures prohibited these customers from participating in the earlier months of the summer. Note that SCE mostly called system-level events, calling all participants nominated within a single month. The variability in event participation is due to the dual enrollment rules that played into the PY2019 defaulting into the CPP rate.

Similar to PG&E, the average event day is defined as the average of all events called in PY2019 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 for both summer and non-summer.

[33] SCE's PY2019 evaluation period is from Nov. 1, 2018 through Oct. 31, 2019.

Table 4-10 SCE Monthly Enrollment and MW Nominations

Month	Day Ahead		Day Of	
	Enrolled Accounts	Nominated Capacity (MW)	Enrolled Accounts	Nominated Capacity (MW)
November	11	[redacted]	58	[redacted]
December	-	-	53	[redacted]
January	-	-	62	[redacted]
February	-	-	43	[redacted]
March	-	-	42	[redacted]
April	3	[redacted]	1	[redacted]
Avg. Non-Summer	**7**	[redacted]	**43**	[redacted]
May	143	4.6	175	4.3
June	166	4.4	173	4.8
July	163	3.1	199	6.6
August	334	4.9	203	7.1
September	336	4.4	204	6.4
October	328	4.4	194	5.3
Avg. Summer	**245**	**4.3**	**191**	**5.8**

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	-	**4**	**19**	**9**	**44**
Avg. Summer Event	-	**6**	**19**	**262**	**151**
Nov 1, 2018	Thursday	4	18-19	11	58
Nov 2, 2018	Friday	4	18-19	11	58
Nov 5, 2018	Monday	4	18-19	11	58
Nov 6, 2018	Tuesday	4	18-19	11	58
Nov 14, 2018	Wednesday	1	17-19, 18-18	7	15
Nov 16, 2018	Friday	3	18-18	4	43
Dec 3, 2018	Monday	4	17-19, 18-19	-	53
Dec 4, 2018	Tuesday	4	17-19, 18-19	-	53
Dec 5, 2018	Wednesday	4	17-19, 18-18	-	53
Dec 6, 2018	Thursday	4	16-19	-	53
Dec 7, 2018	Friday	4	16-19	-	53
Jan 2, 2019	Wednesday	4	18-19, 19-19	-	62
Jan 3, 2019	Thursday	4	18-19	-	62
Jan 4, 2019	Friday	4	18-19	-	62

Date	Day of Week	# of Sub-LAPs	Event Hours (HE)	# Accounts	
				Day Ahead	Day Of
Jan 7, 2019	Monday	4	18-18, 18-19	-	62
Jan 8, 2019	Tuesday	3	18-18, 18-19	-	51
Jan 16, 2019	Wednesday	1	18-19	-	11
Feb 4, 2019	Monday	3	19-19	-	37
Feb 5, 2019	Tuesday	4	18-19, 19-19	-	43
Feb 6, 2019	Wednesday	4	17-19	-	43
Feb 7, 2019	Thursday	4	16-19	-	43
Feb 8, 2019	Friday	4	16-19	-	43
Feb 11, 2019	Monday	1	14-19	-	6
Mar 1, 2019	Friday	3	18-19	-	36
Mar 4, 2019	Monday	4	18-19	-	42
Mar 5, 2019	Tuesday	4	17-19, 18-19	-	42
Mar 6, 2019	Wednesday	4	18-19, 19-19	-	42
Mar 7, 2019	Thursday	4	19-19	-	42
Mar 8, 2019	Friday	1	19-19	-	6
Jun 11, 2019	Tuesday	4	19-19	134	141
Jun 12, 2019	Wednesday	4	19-19	134	141
Jul 23, 2019	Tuesday	5	18-19, 19-19	111	156
Jul 24, 2019	Wednesday	5	19-19	111	156
Jul 25, 2019	Thursday	4	18-19, 19-19	79	156
Aug 5, 2019	Monday	3	19-19	-	159
Aug 6, 2019	Tuesday	4	19-19	287	159
Aug 14, 2019	Wednesday	5	19-19	333	159
Aug 15, 2019	Thursday	5	19-19	333	159
Aug 26, 2019	Monday	4	19-19	-	169
Aug 27, 2019	Tuesday	5	19-19	333	44
Aug 28, 2019	Wednesday	5	19-19	333	44
Sep 3, 2019	Tuesday	5	19-19	-	204
Sep 4, 2019	Wednesday	6	17-19, 18-19	336	204
Sep 5, 2019	Thursday	6	15-19, 16-19, 17-19	336	204
Sep 6, 2019	Friday	6	18-19, 19-19	336	204
Sep 9, 2019	Monday	6	18-19	336	-
Sep 12, 2019	Thursday	6	19-19	336	204
Oct 7, 2019	Monday	5	19-19	-	193
Oct 8, 2019	Tuesday	2	19-19	128	73

Date	Day of Week	# of Sub-LAPs	Event Hours (HE)	# Accounts	
				Day Ahead	Day Of
Oct 14, 2019	Monday	4	19-19	-	168
Oct 15, 2019	Tuesday	6	19-19	328	193
Oct 16, 2019	Wednesday	6	19-19	328	193
Oct 21, 2019	Monday	6	18-19, 19-19	328	115
Oct 22, 2019	Tuesday	5	18-19	316	30
Oct 23, 2019	Wednesday	5	19-19	212	-

Summary Load Impacts

Table 4-12 shows the average summer event day impacts for DA and DO product offerings and overall CBP for both non-summer and summer seasons, both at the per-customer level and in aggregate. On average, SCE's CBP participants did not meet their nominated capacity in PY2019. SCE program management attributes this to several aggregators having struggles in deliveries through the course of the program year. We discuss this in more detail below.

Table 4-12 SCE CBP Impacts Summary, Average Event Day PY2019

Product & Season	Accounts	Nominated Capacity (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact
			Reference Load	Impact	Reference Load	Impact	
Non-Summer DA	9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%
Non-Summer DO	44	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%
Total Non-Summer	**54**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%
Summer DA	262	3.8	86.7	10.3	22.7	2.7	12%
Summer DO	151	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%
Total Summer	**413**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%

Table 4-13 to Table 4-16 below show the average event-hour impacts for the two CBP products, summer and non-summer. Impacts are included for each event, both at the average per-customer level, and in aggregate. For event days with multiple event windows, the values shown in this table represent the average event hour using only the hours that the multiple event windows have in common. The tables include results for the average summer event and average non-summer event.

In PY2019 non-summer months, only one aggregator participated in the DA product offering; thus, all results are indicated as confidential in the table below. The DA product offering, overall, was not able to meet capacity nominations, only doing so in 1 out of 27 events. As mentioned above, several aggregators struggled to deliver capacity reductions in PY2019. Most notably in October, where we see a drop from around consistent 14% summer reductions to 8% reductions in October. SCE program management notes that energy storage customers are able to deliver consistent responses and may be worth looking into in future analyses.

Table 4-13 SCE Day Ahead 1-6 Hour: Non-Summer Impacts by Event[34]

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	9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	73
Nov 1, 2018	11	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	78
Nov 2, 2018	11	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	84
Nov 5, 2018	11	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	69
Nov 6, 2018	11	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	69
Nov 14, 2018	7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	76
Nov 16, 2018	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	74

Table 4-14 SCE Day Ahead 1-6 Hour: Summer Impacts by Event

Event	# of Accts	Nominated Capacity (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Avg. Summer	**262**	**3.8**	**86.7**	**10.3**	**22.7**	**2.7**	**12%**	**86**
Jun 11, 2019	134	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	88
Jun 12, 2019	134	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	81
Jul 23, 2019	111	1.7	97.2	11.2	10.8	1.2	12%	89
Jul 24, 2019	111	1.7	99.7	12.8	11.1	1.4	13%	90
Jul 25, 2019	79	1.2	86.6	10.0	6.8	0.8	12%	86
Aug 6, 2019	287	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	87
Aug 14, 2019	333	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	91
Aug 15, 2019	333	4.8	86.4	11.5	28.8	3.8	13%	89
Aug 27, 2019	333	4.8	84.6	11.5	28.2	3.8	14%	88
Aug 28, 2019	333	4.8	79.8	11.5	26.6	3.8	14%	85
Sep 4, 2019	336	4.4	87.0	11.0	29.2	3.7	13%	91
Sep 5, 2019	336	4.4	89.1	12.5	29.9	4.2	14%	92
Sep 6, 2019	336	4.4	84.0	11.9	28.2	4.0	14%	89
Sep 9, 2019	336	4.4	78.2	10.7	26.3	3.6	14%	80
Sep 12, 2019	336	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	87
Oct 8, 2019	128	1.1	45.1	3.6	5.8	0.5	8%	73
Oct 15, 2019	328	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	81
Oct 16, 2019	328	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	80
Oct 21, 2019	328	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	84

[34] 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		
Oct 22, 2019	316	4.3	91.5	5.3	28.9	1.7	6%	88
Oct 23, 2019	212	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	86

In PY2019 non-summer months, the DO product offering is also indicated as being entirely confidential, although due to a mix of reasons (both the 15/15 rule and aggregator confidentiality). Similar to DA, the DO product offering, overall, was not able to meet capacity nominations, unable to do so in all 53 events. In February and March, we see a decrease in customer response attributed to having less cooling load to available to drop. The DO product offering also experienced aggregator struggles in October with reductions dropping down to 3-4% (from 10-23% earlier in the summer).

Table 4-15 SCE Day Of 1-6 Hour: Non-Summer 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	**44**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	**60**
Nov 1, 2018	58	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	78
Nov 2, 2018	58	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	83
Nov 5, 2018	58	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	71
Nov 6, 2018	58	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	70
Nov 14, 2018	15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	74
Nov 16, 2018	43	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	70
Dec 3, 2018	53	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	60
Dec 4, 2018	53	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	61
Dec 5, 2018	53	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	53
Dec 6, 2018	53	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	52
Dec 7, 2018	53	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	62
Jan 2, 2019	62	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	55
Jan 3, 2019	62	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	59
Jan 4, 2019	62	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	61
Jan 7, 2019	62	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	61
Jan 8, 2019	51	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	67
Jan 16, 2019	11	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	60
Feb 4, 2019	37	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	53

[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		
Feb 5, 2019	43	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	50
Feb 6, 2019	43	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	53
Feb 7, 2019	43	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	58
Feb 8, 2019	43	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	59
Feb 11, 2019	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	51
Mar 1, 2019	36	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	64
Mar 4, 2019	42	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	61
Mar 5, 2019	42	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	62
Mar 6, 2019	42	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	59
Mar 7, 2019	42	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	57
Mar 8, 2019	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	54

Table 4-16 SCE Day Of 1-6 Hour: Summer Impacts by Event

Event	# of Accts	Nominated Capacity (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Avg. Summer	**151**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	**87**
Jun 11, 2019	141	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	89
Jun 12, 2019	141	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	82
Jul 23, 2019	156	4.7	99.2	20.5	15.5	3.2	21%	93
Jul 24, 2019	156	4.7	100.0	22.6	15.6	3.5	23%	91
Jul 25, 2019	156	4.7	99.4	20.5	15.5	3.2	21%	92
Aug 5, 2019	159	5.2	97.1	21.0	15.4	3.3	22%	90
Aug 6, 2019	159	5.2	95.9	21.0	15.2	3.3	22%	88
Aug 14, 2019	159	5.2	96.7	21.0	15.4	3.3	22%	91
Aug 15, 2019	159	5.2	95.3	21.0	15.2	3.3	22%	89
Aug 26, 2019	169	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	88
Aug 27, 2019	44	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	91
Aug 28, 2019	44	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	88
Sep 3, 2019	204	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	92
Sep 4, 2019	204	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	92
Sep 5, 2019	204	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	92
Sep 6, 2019	204	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	90
Sep 12, 2019	204	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	87
Oct 7, 2019	193	5.3	85.6	4.3	16.5	0.8	5%	83
Oct 8, 2019	73	1.8	79.1	2.2	5.8	0.2	3%	72

Event	# of Accts	Nominated Capacity (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Oct 14, 2019	168	4.7	85.8	4.8	14.4	0.8	6%	72
Oct 15, 2019	193	5.3	105.9	4.3	20.4	0.8	4%	82
Oct 16, 2019	193	5.3	109.4	4.3	21.1	0.8	4%	80
Oct 21, 2019	115	3.4	127.2	3.8	14.6	0.4	3%	88
Oct 22, 2019	30	0.6	195.7	7.8	5.9	0.2	4%	84

Table 4-17 and Table 4-18 present the impacts by Industry for an average non-summer event day and average summer event day, respectively. Table 4-19 and Table 4-20 present the impacts by LCA for an average non-summer event day and average summer event day, respectively.[36] [37]

Table 4-17 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	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	73
DA	Retail stores	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	71
DA	**Total Day Ahead**	**9**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	**73**
DO	Manufacturing	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	62
DO	Wholesale, Transport, other utilities	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	58
DO	Retail stores	19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	60
DO	Offices, Hotels, Finance, Services	22	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	61
DO	Schools	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	58
DO	Institutional/Government	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	59
DO	Other or unknown	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	58
DO	**Total Day Of**	**44**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	**60**
Total Non-Summer CBP		**54**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	**62**

[36] The results in Table 4-17 through Table 4-20 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.

[37] 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 4-18 SCE CBP Impacts by Industry and Notice, Summer

	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)
DA	Wholesale, Transport, other utilities	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	95
DA	Retail stores	260	72.1	6.6	18.7	1.7	9%	86
DA	**Total Day Ahead**	**262**	**86.7**	**10.3**	**22.7**	**2.7**	**12%**	**86**
DO	Agriculture, Mining & Construction	10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	91
DO	Manufacturing	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	96
DO	Wholesale, Transport, other utilities	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	90
DO	Retail stores	111	92.4	13.6	10.2	1.5	15%	86
DO	Offices, Hotels, Finance, Services	26	94.2	8.5	2.5	0.2	9%	88
DO	Schools	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	73
DO	Institutional/Government	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	81
DO	Other or unknown	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	81
DO	**Total Day Of**	**151**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	**87**
Total Summer CBP		**413**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	**86**

Table 4-19 SCE CBP Impacts by LCA and Notice, Non-Summer

	Local Capacity Area	# 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)
DA	LA Basin	9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	73
DA	**Total Day Ahead**	9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	73
DO	LA Basin	40	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	61
DO	Ventura / Big Creek	9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	57
DO	**Total Day Of**	**44**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	**60**
Total Non-Summer CBP		**54**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	**62**

Table 4-20 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	199	89.2	11.2	17.8	2.2	13%	85
DA	Outside LA Basin	21	81.3	8.2	1.7	0.2	10%	91
DA	Ventura / Big Creek	43	77.9	7.3	3.4	0.3	9%	84
DA	**Total Day Ahead**	**262**	**86.7**	**10.3**	**22.7**	**2.7**	**12%**	**86**
DO	LA Basin	143	95.7	14.8	13.7	2.1	15%	87
DO	Outside LA Basin	7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	90
DO	Ventura / Big Creek	27	407.4	23.3	11.1	0.6	6%	82
DO	**Total Day Of**	**151**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	**87**
Total Summer CBP		**413**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	**86**

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 exhibits the issues encountered in the ex-post impact analysis, wherein the regression models are not predicting as well as is satisfactory. This is due to having very few participants (11 customers or less during each event) with very erratic loads. This is not the case for DA summer, and both DO summer and non-summer, where we see the reference load lining up well with the observed load during non-event hours.

Figure 4-3 SCE Day-Ahead 1-6 Hour: Average Hourly Per-Customer Impact, Non-Summer 2019

[redacted]

Figure 4-4 SCE Day-Ahead 1-6 Hour: Average Hourly Per-Customer Impact, Summer 2019

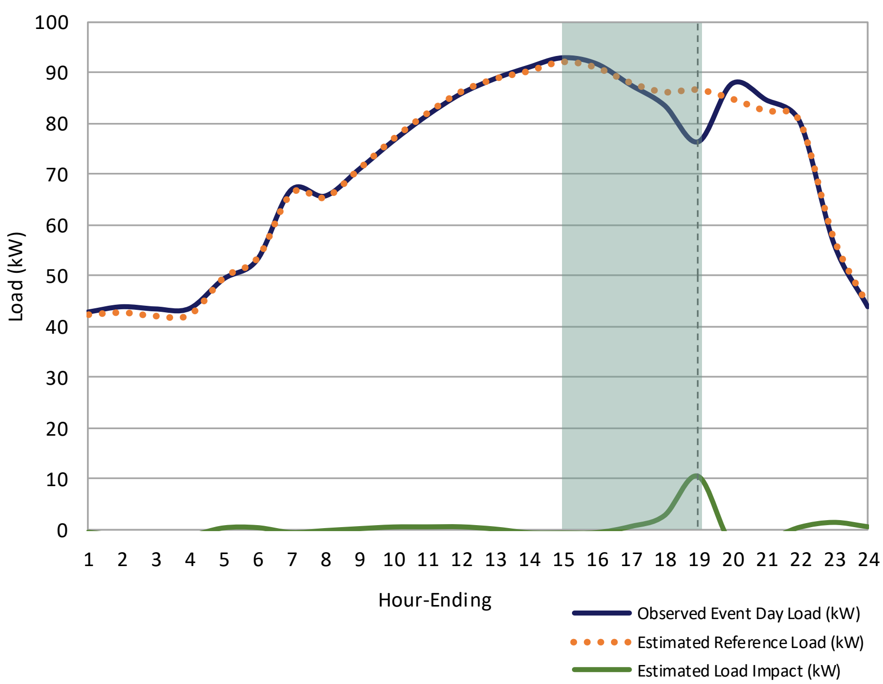


Figure 4-5 SCE Day-Of 1-6 Hour: Average Hourly Per-Customer Impact, Non-Summer 2019

[redacted]

Figure 4-6 SCE Day-Of 1-6 Hour: Average Hourly Per-Customer Impact, Summer 2019

[redacted]

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 4-21 and Table 4-22 presents the ex-post load impacts achieved in PY2019 by SCE CBP customers that enrolled in AutoDR or TA/TI at some point in the current or previous years for DA and DO, respectively.[38]

Table 4-21 SCE Day Ahead 1-6 Hour: AutoDR and TA/TI Participant Impacts by Event

Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Aggregate Load Shed Test (MW)	Temp (F)
		Reference Load	Impact	Reference Load	Impact			
Avg. Non-Summer	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	76
Avg. Summer	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	95
Nov 1, 2018	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	81
Nov 2, 2018	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	88
Nov 5, 2018	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	75
Nov 6, 2018	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	73
Nov 16, 2018	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	74
Jun 11, 2019	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	101
Jun 12, 2019	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	93
Aug 6, 2019	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	101
Aug 14, 2019	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	101
Aug 15, 2019	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	101
Aug 27, 2019	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	97
Aug 28, 2019	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	93
Sep 4, 2019	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	102
Sep 5, 2019	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	100
Sep 6, 2019	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	96
Sep 9, 2019	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	87
Sep 12, 2019	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	96
Oct 15, 2019	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	91

[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.

Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Aggregate Load Shed Test (MW)	Temp (F)
		Reference Load	Impact	Reference Load	Impact			
Oct 16, 2019	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	86
Oct 21, 2019	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	89
Oct 22, 2019	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	95
Oct 23, 2019	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	91

Table 4-22 SCE Day Of 1-6 Hour: AutoDR and TA/TI Participant Impacts by Event

Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Aggregate Load Shed Test (MW)	Temp (F)
		Reference Load	Impact	Reference Load	Impact			
Avg. Non-Summer	27	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	60
Avg. Summer	111	146.1	19.3	16.3	2.2	13%	5.7	87
Nov 1, 2018	31	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	78
Nov 2, 2018	31	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	83
Nov 5, 2018	31	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	72
Nov 6, 2018	31	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	70
Nov 14, 2018	7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	74
Nov 16, 2018	24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	71
Dec 3, 2018	31	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	60
Dec 4, 2018	31	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	61
Dec 5, 2018	31	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	53
Dec 6, 2018	31	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	52
Dec 7, 2018	31	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	62
Jan 2, 2019	32	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	55
Jan 3, 2019	32	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	59
Jan 4, 2019	32	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	61
Jan 7, 2019	32	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	61
Jan 8, 2019	27	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	67
Jan 16, 2019	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	61
Feb 4, 2019	27	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	53
Feb 5, 2019	32	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	50
Feb 6, 2019	32	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	53
Feb 7, 2019	32	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	58
Feb 8, 2019	32	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	59
Feb 11, 2019	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	51
Mar 1, 2019	27	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	64
Mar 4, 2019	32	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	61

Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Aggregate Load Shed Test (MW)	Temp (F)
		Reference Load	Impact	Reference Load	Impact			
Mar 5, 2019	32	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	63
Mar 6, 2019	32	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	60
Mar 7, 2019	32	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	57
Mar 8, 2019	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	54
Jun 11, 2019	118	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	90
Jun 12, 2019	118	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	83
Jul 23, 2019	121	105.9	24.1	12.8	2.9	23%	5.4	94
Jul 24, 2019	121	106.6	26.5	12.9	3.2	25%	5.4	91
Jul 25, 2019	121	106.2	24.1	12.8	2.9	23%	5.4	92
Aug 5, 2019	121	103.6	25.8	12.5	3.1	25%	5.4	90
Aug 6, 2019	121	102.3	25.8	12.4	3.1	25%	5.4	88
Aug 14, 2019	121	103.2	25.8	12.5	3.1	25%	5.4	91
Aug 15, 2019	121	101.8	25.8	12.3	3.1	25%	5.4	90
Aug 26, 2019	124	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	88
Aug 27, 2019	30	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	94
Aug 28, 2019	30	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	92
Sep 3, 2019	147	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	92
Sep 4, 2019	147	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	92
Sep 5, 2019	147	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	93
Sep 6, 2019	147	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	90
Sep 12, 2019	147	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	88
Oct 7, 2019	134	82.4	5.0	11.0	0.7	6%	7.2	84
Oct 8, 2019	48	87.6	2.2	4.2	0.1	2%	3.4	72
Oct 14, 2019	119	96.2	5.4	11.5	0.6	6%	6.5	72
Oct 15, 2019	134	101.3	5.0	13.6	0.7	5%	7.2	82
Oct 16, 2019	134	101.3	5.0	13.6	0.7	5%	7.2	81
Oct 21, 2019	85	103.5	1.6	8.8	0.1	2%	3.7	88
Oct 22, 2019	16	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	[redacted]	84

SDG&E

Events for SDG&E

Table 4-24 presents a summary of the 2019 events for SDG&E's CBP program by product. Over the course of the program year, the DO product participants experienced 23 event days, while the DA product participants experienced 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 PY2019 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 slight fluctuations in monthly nominations. Table 4-23 presents SDG&E's monthly nominations by product offering.

Table 4-23 SDG&E Monthly Enrollment and MW Nominations

Month	Day Ahead		Day Of	
	Enrolled Accounts	Nominated Capacity (MW)	Enrolled Accounts	Nominated Capacity (MW)
May	11	0.5	185	3.7
June	11	0.5	184	3.2
July	12	0.5	184	3.4
August	11	0.6	182	3.5
September	10	0.5	184	3.6
October	10	0.5	182	3.5
Average Month	**11**	**0.5**	**184**	**3.5**

Table 4-24 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**	**10**	**5**	**97**	**88**
Jun 10, 2019	Monday	19-20, 20-21	-	8	-	90
Jun 11, 2019	Tuesday	19-20	-	8	-	90
Jun 12, 2019	Wednesday	19-21	-	8	-	-
Jul 23, 2019	Tuesday	18-19, 19-20	10	2	-	90
Jul 24, 2019	Wednesday	18-19, 19-20	10	2	94	90
Jul 25, 2019	Thursday	19-20	-	2	-	90
Aug 5, 2019	Monday	18-19	10	-	-	-
Aug 14, 2019	Wednesday	18-19	10	-	-	-
Aug 15, 2019	Thursday	18-19, 19-20	10	-	-	90
Aug 27, 2019	Tuesday	18-19	10	-	-	-
Sep 4, 2019	Wednesday	18-19, 19-20	10	-	97	87
Sep 5, 2019	Thursday	16-19, 18-19, 18-20	10	-	97	87
Sep 6, 2019	Friday	18-19	10	-	97	-
Sep 12, 2019	Thursday	18-19	10	-	-	-
Sep 13, 2019	Friday	18-19	10	-	97	-
Sep 24, 2019	Tuesday	18-19, 19-20	10	-	97	87
Sep 25, 2019	Wednesday	18-19, 18-20	-	-	97	87
Oct 7, 2019	Monday	18-19	10	-	-	-

Date	Day of Week	Event Hours (HE)	# Accounts			
			DA 11AM to 7PM	DA 1PM to 9PM	DO 11AM to 7PM	DO 1PM to 9PM
Oct 15, 2019	Tuesday	18-19	10	-	-	-
Oct 16, 2019	Wednesday	18-19	10	-	97	-
Oct 21, 2019	Monday	18-19, 19-20	10	-	97	85
Oct 22, 2019	Tuesday	18-19, 18-20	10	-	97	85
Oct 23, 2019	Wednesday	18-19, 19-20	10	-	97	85

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

Summary Load Impacts

Table 4-25 shows the average summer event day impacts for each product, each notification option, and overall CBP, both at the per-customer level and in aggregate. On average, the DO product offerings performed very well, with participants meeting their nominated capacity. The DA product offering did not perform as well but did see some success at the event level. We discuss this in more detail below.

Table 4-25 SDG&E CBP Impacts Summary, Average Event Day PY2019

Product	Accounts	Nominated Capacity (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact
			Reference Load	Impact	Reference Load	Impact	
DA 11AM-7PM	10	0.5	330.4	30.4	3.3	0.3	9%
DA 1PM-9PM	5	0.2	565.2	18.3	2.8	0.1	3%
Total Day Ahead	**15**	**0.7**	**408.7**	**26.3**	**6.1**	**0.4**	**6%**
DO 11AM-7PM	97	1.2	100.0	12.4	9.7	1.2	12%
DO 1PM-9PM	88	2.4	143.3	27.5	12.6	2.4	19%
Total Day Of	**185**	**3.6**	**120.6**	**19.6**	**22.3**	**3.6**	**16%**
Total CBP	**200**	**4.3**	**142.2**	**20.1**	**28.4**	**4.0**	**14%**

Table 4-26 through Table 4-29 show the average event-hour impacts for the four CBP products. Impacts are included for each event, both at the average per-customer level and in aggregate. The tables include results for the average event day.

In PY2019, the DA product offering showed more success in the 11 AM to 7 PM dispatch window, meeting or exceeding capacity nominations through most of the summer. Responses fell in

October, dropping down to 4% after consistent 10-30% impacts earlier in the summer. The DA product offering did not see much success in the 1 PM to 9 PM dispatch window. Participants were not able to meet capacity nominations on any of the events called in PY2019, delivering only 1-5% reductions.

Table 4-26 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	**10**	**0.5**	**330.4**	**30.4**	**3.3**	**0.3**	**9%**	**76**
Jul 23, 2019	10	0.4	225.2	74.3	2.3	0.7	33%	82
Jul 24, 2019	10	0.4	216.5	74.3	2.2	0.7	34%	79
Aug 5, 2019	10	0.5	194.9	59.1	1.9	0.6	30%	79
Aug 14, 2019	10	0.5	197.9	59.1	2.0	0.6	30%	79
Aug 15, 2019	10	0.5	196.2	59.1	2.0	0.6	30%	78
Aug 27, 2019	10	0.5	204.8	59.1	2.0	0.6	29%	77
Sep 4, 2019	10	0.5	473.3	47.6	4.7	0.5	10%	83
Sep 5, 2019	10	0.5	519.4	46.3	5.2	0.5	9%	84
Sep 6, 2019	10	0.5	409.5	47.6	4.1	0.5	12%	82
Sep 12, 2019	10	0.5	399.7	47.6	4.0	0.5	12%	75
Sep 13, 2019	10	0.5	461.3	47.6	4.6	0.5	10%	81
Sep 24, 2019	10	0.5	407.5	47.6	4.1	0.5	12%	76
Oct 7, 2019	10	0.5	373.9	15.2	3.7	0.2	4%	74
Oct 15, 2019	10	0.5	368.0	15.2	3.7	0.2	4%	71
Oct 16, 2019	10	0.5	377.8	15.2	3.8	0.2	4%	72
Oct 21, 2019	10	0.5	385.0	15.2	3.9	0.2	4%	78
Oct 22, 2019	10	0.5	426.9	15.2	4.3	0.2	4%	80
Oct 23, 2019	10	0.5	410.0	15.2	4.1	0.2	4%	74

Table 4-27 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	**5**	**0.2**	**565.2**	**18.3**	**2.8**	**0.1**	**3%**	**75**
Jun 10, 2019	8	0.4	405.2	5.7	3.2	<0.1	1%	66
Jun 11, 2019	8	0.4	430.1	21.3	3.4	0.2	5%	70
Jun 12, 2019	8	0.4	407.2	10.6	3.3	0.1	3%	66
Jul 23, 2019	2	0.1	1,030.9	7.0	2.1	<0.1	1%	80
Jul 24, 2019	2	0.1	1,025.8	7.0	2.1	<0.1	1%	78
Jul 25, 2019	2	0.1	1,011.0	7.0	2.0	<0.1	1%	77

As mentioned above, the DO product offerings performed well in PY2019. The table below for the 11 AM to 7 PM dispatch window may seem slightly misleading with most events delivering 1.0 MW reductions and an average event delivering 1.2 MW reduction. Note that the event-level results show the average event window, which is mostly HE18-HE19, while the average event results show the common event hour, which is HE19. In this case, DO 11 AM to 7 PM participants were able to deliver higher energy reductions during HE19 (6 PM to 7 PM). Although not as apparent in the table below, the same observation can be said for DO 1 PM to 9 PM, wherein participants were able to deliver their highest energy reductions during HE19. However, 5 out of 13 events were able to meet or exceed their capacity nominations through the entire event window.

Table 4-28 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**	**1.2**	**100.0**	**12.4**	**9.7**	**1.2**	**12%**	**77**
Jul 24, 2019	94	0.9	96.5	9.7	9.1	0.9	10%	80
Sep 4, 2019	97	1.2	106.4	10.5	10.3	1.0	10%	83
Sep 5, 2019	97	1.2	109.0	10.5	10.6	1.0	10%	83
Sep 6, 2019	97	1.2	107.4	10.5	10.4	1.0	10%	82
Sep 13, 2019	97	1.2	105.9	10.5	10.3	1.0	10%	81
Sep 24, 2019	97	1.2	99.5	10.5	9.7	1.0	11%	77
Sep 25, 2019	97	1.2	96.7	10.5	9.4	1.0	11%	73
Oct 16, 2019	97	1.2	92.9	10.5	9.0	1.0	11%	72
Oct 21, 2019	97	1.2	95.7	10.5	9.3	1.0	11%	80
Oct 22, 2019	97	1.2	96.4	10.5	9.4	1.0	11%	81
Oct 23, 2019	97	1.2	97.3	10.5	9.4	1.0	11%	75

Table 4-29 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	**88**	**2.4**	**143.3**	**27.5**	**12.6**	**2.4**	**19%**	**76**
Jun 10, 2019	90	2.3	134.4	26.9	12.1	2.4	20%	71
Jun 11, 2019	90	2.3	133.0	26.9	12.0	2.4	20%	71
Jul 23, 2019	90	2.5	143.5	26.9	12.9	2.4	19%	79
Jul 24, 2019	90	2.5	142.5	26.9	12.8	2.4	19%	77
Jul 25, 2019	90	2.5	143.5	26.9	12.9	2.4	19%	77
Aug 15, 2019	90	2.5	141.0	27.3	12.7	2.5	19%	71

Event	# of Accts	Nominated Capacity (MW)	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Sep 4, 2019	87	2.4	155.4	27.1	13.5	2.4	17%	81
Sep 5, 2019	87	2.4	152.5	22.6	13.3	2.0	15%	80
Sep 24, 2019	87	2.4	146.6	27.4	12.8	2.4	19%	73
Sep 25, 2019	87	2.4	139.2	22.9	12.1	2.0	16%	72
Oct 21, 2019	85	2.3	143.3	27.8	12.2	2.4	19%	77
Oct 22, 2019	85	2.3	143.5	23.1	12.2	2.0	16%	78
Oct 23, 2019	85	2.3	142.2	27.8	12.1	2.4	20%	71

Table 4-30 presents the impacts for an average event day by industry group.[39,40]

Table 4-30 SDG&E Impacts by Industry and Notice

	Industry	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Ref. Load	Impact	Ref. Load	Impact		
Day Ahead	Agriculture, Mining & Construction	2	74.4	69.4	0.2	0.2	93%	79
Day Ahead	Retail stores	11	248.8	18.7	2.7	0.2	8%	75
Day Ahead	Institutional/Government	2	1,935.9	13.1	3.9	<0.1	1%	74
Day Ahead	**Total Day Ahead**	**15**	**408.7**	**26.3**	**6.1**	**0.4**	**6%**	**76**
Day Of	Manufacturing	1	1,036.4	82.4	1.0	0.1	8%	77
Day Of	Retail stores	162	115.5	19.8	18.7	3.2	17%	77
Day Of	Offices, Hotels, Finance, Services	14	103.7	11.5	1.5	0.2	11%	79
Day Of	Schools	3	87.6	34.2	0.2	0.1	39%	79
Day Of	Institutional/Government	4	220.2	18.8	0.9	0.1	9%	78
Day Of	Other or unknown	1	53.0	8.0	0.1	<0.1	15%	75
Day Of	**Total Day Of**	**185**	**120.6**	**19.6**	**22.3**	**3.6**	**16%**	**77**
Total CBP		**200**	**142.2**	**20.1**	**28.4**	**4.0**	**14%**	**77**

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

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

[40] The results in Table 4-30 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.

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, 2019

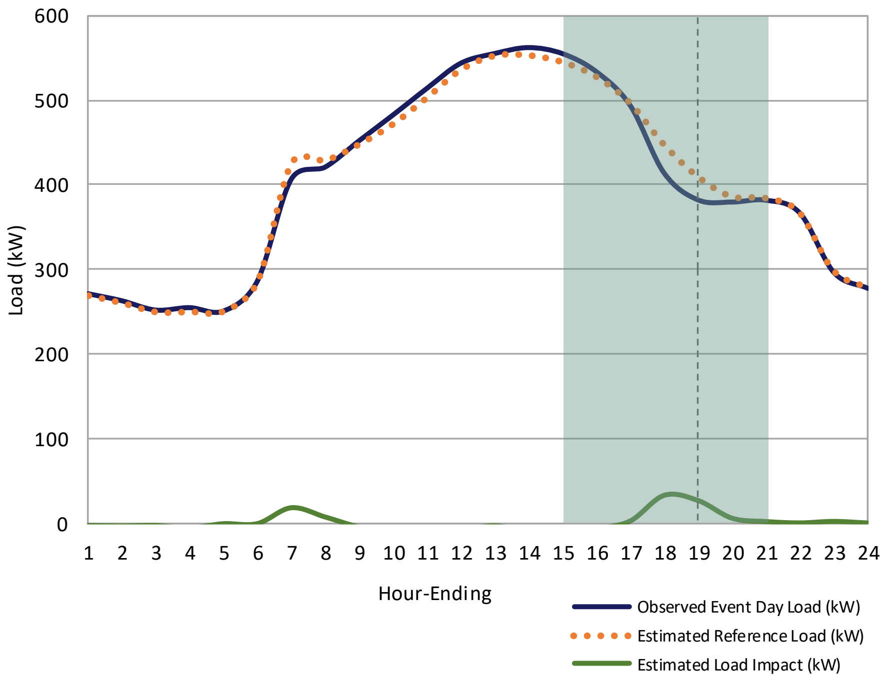
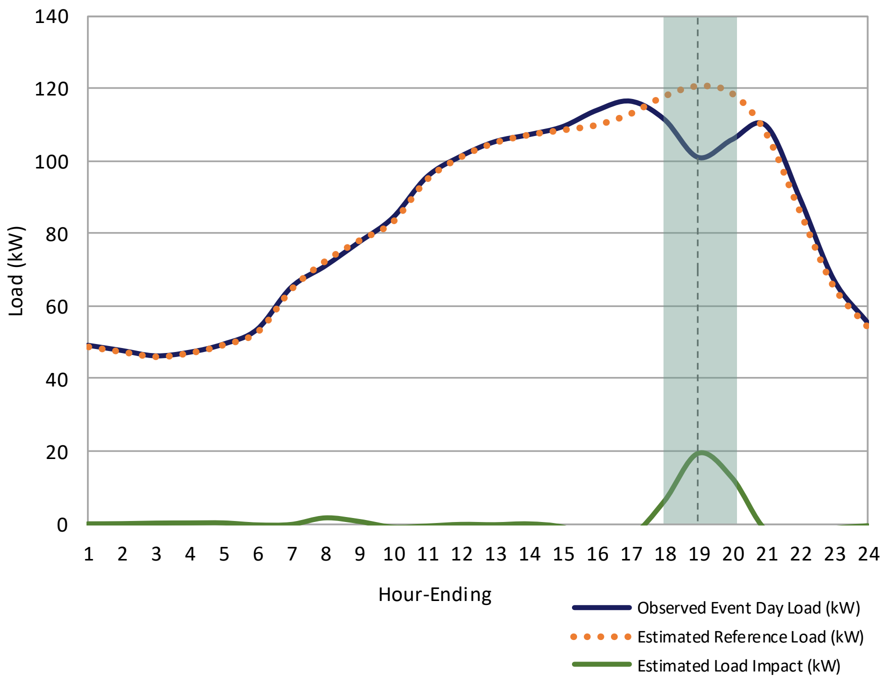


Figure 4-8 SDG&E All Day-Of: Average Hourly Per-Customer Impact, 2019



Load Impacts of TA/TI and AutoDR Participants

This section presents the ex-post load impacts achieved in PY2019 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 4-31 and Table 4-32 present the average event-hour impacts and aggregate load shed test results for each product by event. In PY2019, only DO participants were dually enrolled in AutoDR or TA/TI.

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	**12**	**58.3**	**8.2**	**0.7**	**0.1**	**14%**	**0.20**	**76**
Jul 24, 2019	12	62.8	9.2	0.8	0.1	15%	0.20	79
Sep 4, 2019	12	63.3	9.2	0.8	0.1	14%	0.20	83
Sep 5, 2019	12	64.5	9.2	0.8	0.1	14%	0.20	82
Sep 6, 2019	12	67.5	9.2	0.8	0.1	14%	0.20	82
Sep 13, 2019	12	65.2	9.2	0.8	0.1	14%	0.20	81
Sep 24, 2019	12	57.0	9.2	0.7	0.1	16%	0.20	76

Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Aggregate Load Shed Test (MW)	Temp (F)
		Reference Load	Impact	Reference Load	Impact			
Sep 25, 2019	12	58.8	9.2	0.7	0.1	16%	0.20	73
Oct 16, 2019	12	54.4	9.2	0.7	0.1	17%	0.20	72
Oct 21, 2019	12	52.8	9.2	0.6	0.1	17%	0.20	79
Oct 22, 2019	12	57.1	9.2	0.7	0.1	16%	0.20	80
Oct 23, 2019	12	57.0	9.2	0.7	0.1	16%	0.20	74

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	**28**	**95.7**	**30.7**	**2.6**	**0.8**	**32%**	**2.54**	**76**
Jun 10, 2019	28	88.3	28.5	2.5	0.8	32%	2.66	70
Jun 11, 2019	28	85.0	28.5	2.4	0.8	34%	2.66	70
Jul 23, 2019	28	93.7	28.5	2.6	0.8	30%	2.66	78
Jul 24, 2019	28	89.7	28.5	2.5	0.8	32%	2.66	77
Jul 25, 2019	28	94.1	28.5	2.6	0.8	30%	2.66	77
Aug 15, 2019	29	88.7	28.9	2.6	0.8	33%	2.75	71
Sep 4, 2019	27	107.0	29.1	2.9	0.8	27%	2.43	80
Sep 5, 2019	27	108.2	29.6	2.9	0.8	27%	2.43	80
Sep 24, 2019	27	93.7	29.1	2.5	0.8	31%	2.43	73
Sep 25, 2019	27	91.9	29.6	2.5	0.8	32%	2.43	72
Oct 21, 2019	27	94.1	29.1	2.5	0.8	31%	2.43	77
Oct 22, 2019	27	99.5	29.6	2.7	0.8	30%	2.43	79
Oct 23, 2019	27	92.0	29.1	2.5	0.8	32%	2.43	71

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 product level. Consistent with last year's findings in the DO program, we did not see any statistically significant incremental impacts in PY2019.

Figure 4-9 and Figure 4-10 show the treatment and control-group match for DO 11 AM to 7 PM and DO 1 PM to 9 PM products on an average event day, respectively. The graphs compare the average per-customer load profile of each group. There were 24 control-group matches for the incremental analysis, 13 participants in DO 11 AM to 7 PM and 11 participants in DO 1 PM to 9 PM.

Figure 4-9 SDG&E Day Of 11 AM to 7 PM: AutoDR and TA/TI Event Day Match, kW

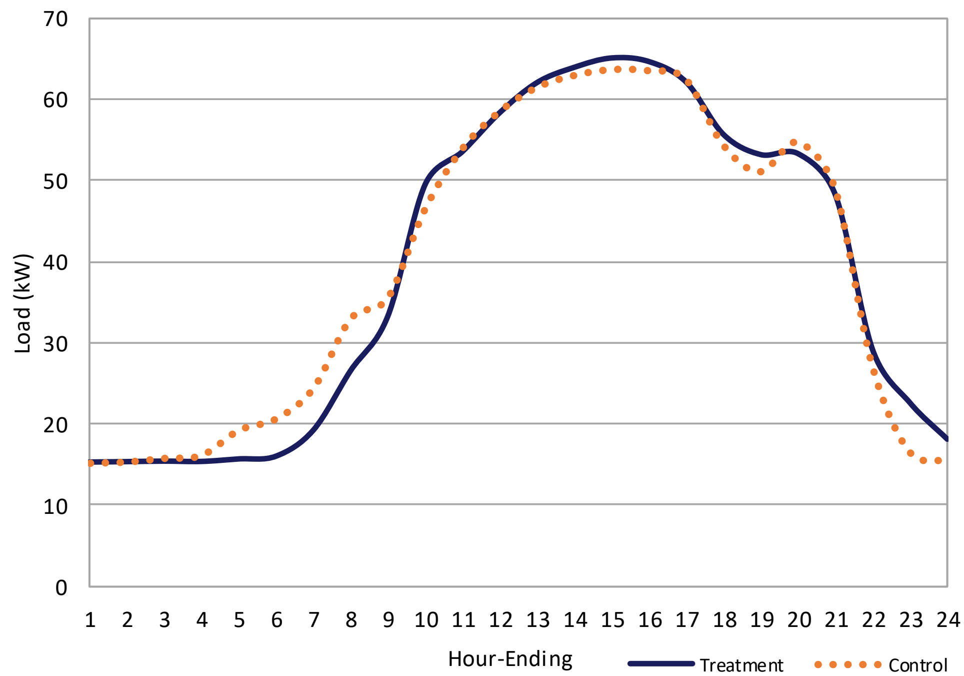


Figure 4-10 SDG&E Day Of 1 PM to 9 PM: AutoDR and TA/TI Event Day Match, kW

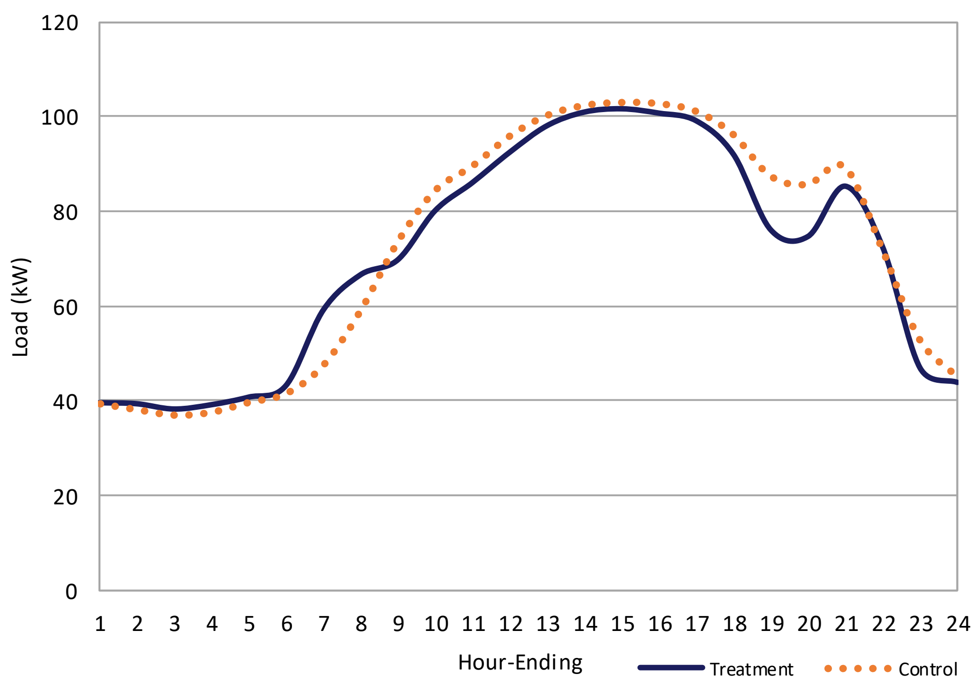


Figure 4-11 and Figure 4-12 illustrate the incremental impacts for DO 11 AM to 7 PM and DO 1 PM to 9 PM products, respectively. The figure shows the average per-customer incremental impact for each hour of an average event day. It also includes the upper and lower confidence intervals at the 95th percentile.

For 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 Of 11 AM to 7 PM: AutoDR and TA/TI Average Event Day Incremental Impacts, kW

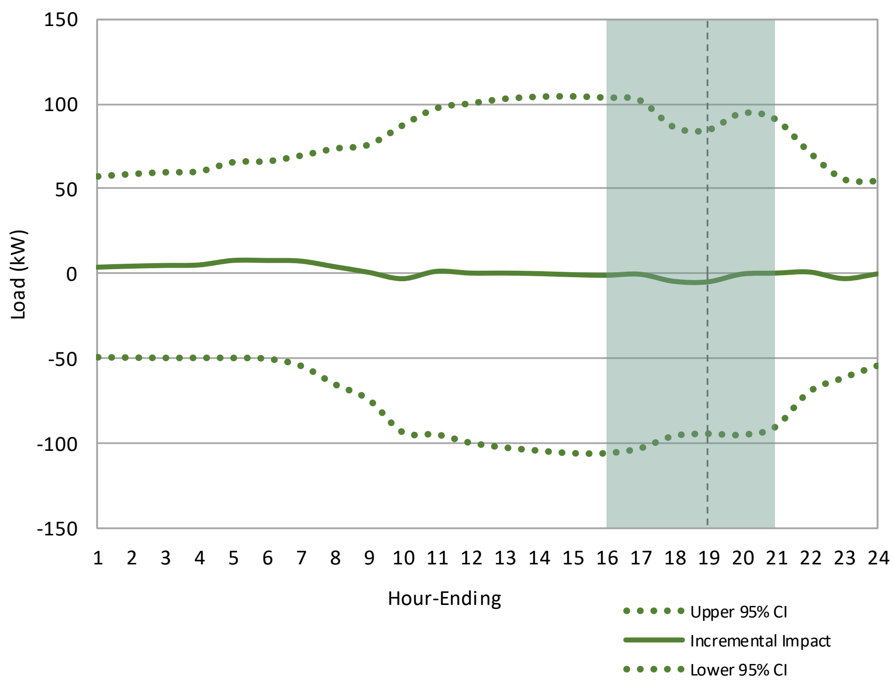
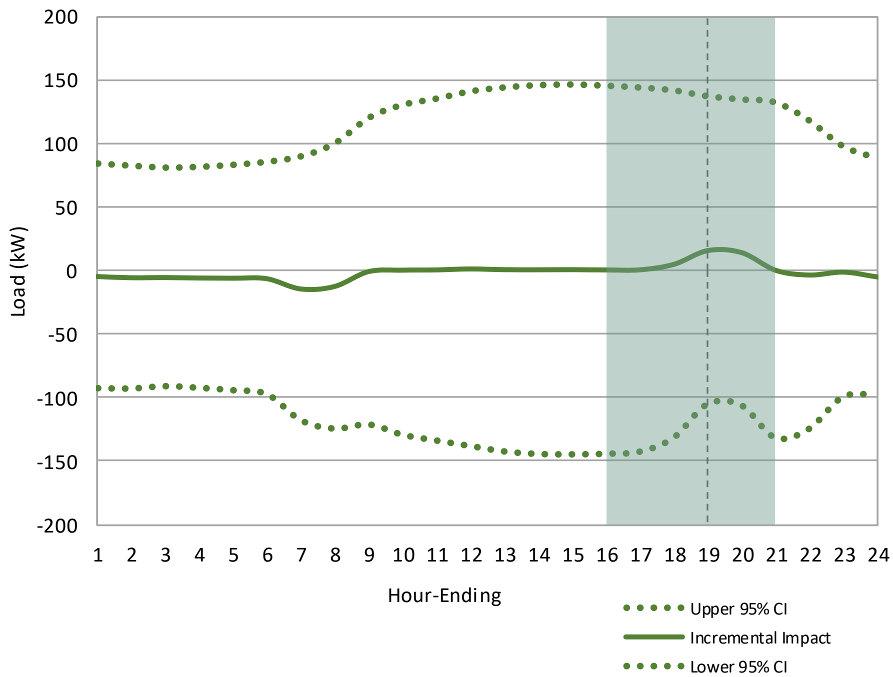


Figure 4-12 SDG&E Day Of 1 PM to 9 PM: AutoDR and TA/TI Average Event Day Incremental Impacts, kW



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 11-year enrollment and load forecast by utility, customer class, notification type, and year, during the month of August. Table 5-2 summarizes the non-residential aggregate load impact forecasts for an August peak day in 2020 by notification type and utility for each weather scenario.

Table 5-1 2020-2030 Forecast for Month of August

Utility	Customer Class	Notice	Number of Service Accounts			Aggregate Impact (MW)		
			2020	2021	2022-2030 (Each Year)	2020	2021	2022-2030 (Each Year)
PGE	Residential	Day Ahead	5,000	25,000	55,000	2.0	10.0	22.0
	Non-Residential	Day Ahead	1,503	1,586	1,670	36.0	38.0	40.0
SCE	Non-Residential	Day Ahead	384	384	384	[redacted]	[redacted]	[redacted]
		Day Of	233	233	233	[redacted]	[redacted]	[redacted]
SDG&E	Non-Residential	Day Ahead	11	11	12	0.2	0.2	0.2
		Day Of	188	191	195	3.2	3.3	3.4

Table 5-2 Non-Residential CBP, Summary of Average RA Window Ex-Ante Impacts, August Peak Day, 2020

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	Day Ahead	1,503	24.0	36.0	12.5%	12.2%	12.9%	12.5%
SCE	Day Ahead	384	[redacted]	[redacted]	[redacted]%	[redacted]%	[redacted]%	[redacted]%
	Day Of	233	[redacted]	[redacted]	[redacted]%	[redacted]%	[redacted]%	[redacted]%
SDG&E	Day Ahead	11	18.7	0.2	4.9%	4.8%	4.9%	4.9%
	Day Of	188	17.0	3.2	14.1%	13.5%	13.8%	14.0%

PG&E

Enrollment and Load Impact Summary

PG&E estimates that both residential and non-residential CBP nominations will grow through 2022 and remain constant throughout the remainder of the forecast horizon (2023-2030), with approximately 38.0 MW in 2020 and 62.0 in 2022 in capacity nominations. Table 5-5 shows PG&E's 11-year forecast by customer class. PG&E's residential forecast assumes a per-customer impact of 0.4 kW, which translates to 5,000 customer nominations in 2020 and 55,000 customer nominations in 2022. Table 5-4 shows the non-residential enrollment forecast by size group. The ex-ante impact results forecast annual CBP load impacts for the non-residential DA product that are commensurate with the PY2019 per-customer impacts and with the 2020-2030 enrollment forecast.

Table 5-3 PG&E 2020-2030 MW Forecast, August Peak Day

Customer Class	Aggregate Impact (MW)		
	2020	2021	2022-2030 (Each Year)
Residential	2.0	10.0	22.0
Non-Residential	36.0	38.0	40.0
Total Day Ahead	**38.0**	**48.0**	**62.0**

Table 5-4 PG&E 2020-2030 Non-Residential Enrollment Forecast, During Month of August

Size	Number of Service Accounts		
	2020	2021	2022-2030 (Each Year)
Below 20 kW	23	24	25
20 kW to 199.99 kW	969	1,023	1,077
Above 200 kW	511	540	568
Total Day Ahead	**1,503**	**1,586**	**1,670**

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 per-customer 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 5-5 summarizes the average Resource Adequacy (RA) window load impact forecasts for non-residential CBP DA on an August peak day in 2020. 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. In PY2019, the Small and Large subgroupings, and overall DA forecasts were largely driven by one very large customer; thus, these results are indicated as confidential.[41]

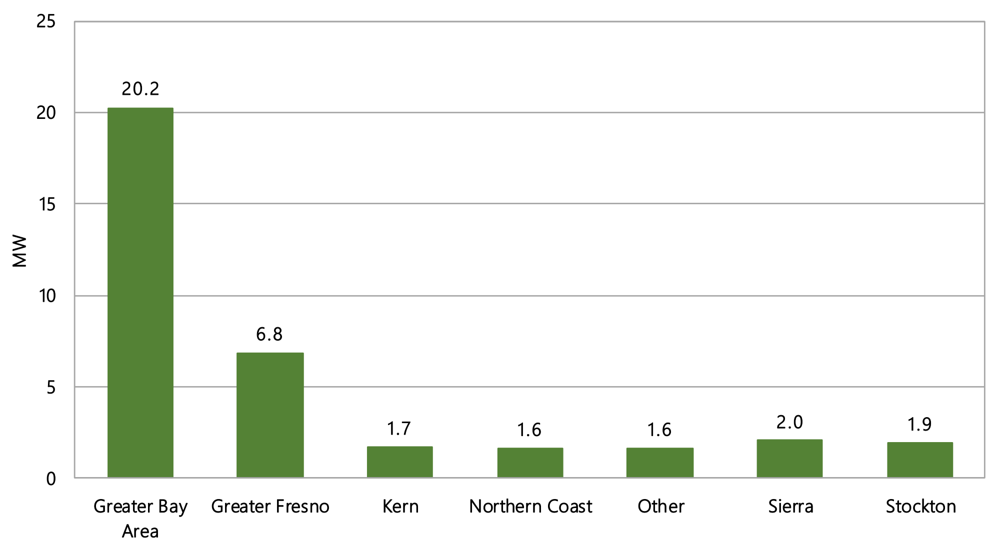
[41] In PY2019, PG&E updated their interpretation of confidential impacts. Since ex-ante impact estimates are based on simulated data and not actual customer load data, these estimates are not necessarily bound by the 15-customer rule. However, when a subgrouping contains one large customer where the total load (or load impacts) is virtually dominated by the single large customer and this large customer can be potentially identified by a knowledgeable outside party, then the data should still be treated as confidential.

Table 5-5 PG&E Non-Residential Day Ahead: Average RA Window 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	23	1.6	<0.1	16.2%	15.0%	18.3%	15.6%
20 kW to 199.99 kW	969	9.6	9.3	17.7%	17.0%	18.4%	17.5%
Above 200 kW	511	52.1	26.6	11.4%	11.1%	11.7%	11.3%
Total Day Ahead	**1,503**	**24.0**	**36.0**	**12.5%**	**12.2%**	**12.9%**	**12.5%**

Figure 5-1 illustrates the average RA window load impacts distributed by LCA for non-residential CBP DA on an August peak day in 2020. The results shown are for 1-in-2 weather conditions for the utility peak. Results for Greater Bay Area and Stockton are redacted to protect customer or aggregator confidentiality.

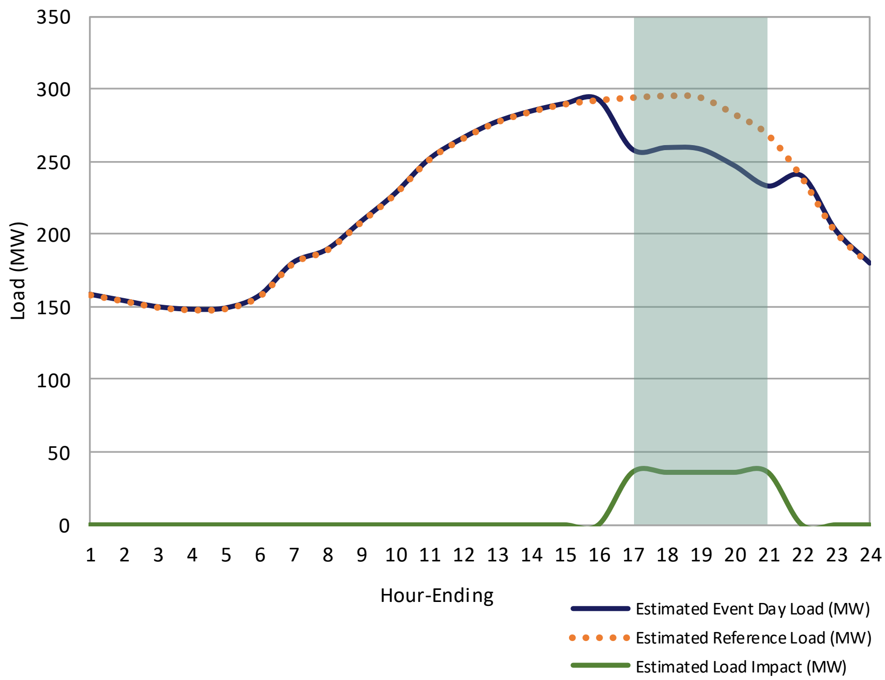
Figure 5-1 PG&E Non-Residential Day Ahead: Average RA Window Aggregate Load Impacts by LCA for an August Peak Day, 2020, 1-in-2 Utility Peak Weather Conditions



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 2020 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, 2020, 1-in-2 Utility Peak Weather Conditions



SCE

Enrollment and Load Impact Summary

SCE assumes a 15% increase in participation over August 2019 levels as a result of reduction in Demand Response Auction Mechanism (DRAM) funding and mandated participation by Self-Generation Incentive Program (SGIP) recipients in DR. SCE also assumes a constant enrollment forecast for both Non-residential CBP DA and DO throughout the 2020-2030 forecast horizon with 384 and 233 customers, respectively. SCE will be filing for a residential CBP as a pilot-only program or open CBP to residential.

The ex-ante impact results forecast annual non-residential CBP load impacts for the DA and DO products that are commensurate with the PY2019 per-customer impacts and the non-residential 2020-2030 enrollment forecast. 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).

SCE's advice letter (AL 4131-E) requesting to change the dispatch window to 3 PM to 9PM, currently at 1 PM to 7 PM, was approved to be effective retroactive to January 19th, 2020. This change better aligns the dispatch window with the RA window (4 PM to 9 PM).

Table 5-6 summarizes the average RA window load impact forecasts for the DA and DO products on an August peak day in 2019.[42] 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 5-6 SCE CBP: Average RA Window 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	384	[redacted]	[redacted]	[redacted]%	[redacted]%	[redacted]%	[redacted]%
Total Day Of	233	[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 2020 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 proposal to change the dispatch window to 3 PM to 9 PM was approved, which will better align with the RA window from 4 PM to 9 PM. This change shows the estimated ex-ante impacts falling within the RA window, which is highlighted in blue.

[42] Though labeled as an August peak day in 2020, the results in Table 5-7Table 5-6 would be identical for each month, May through October, and each year, 2020 through 2030, in the forecast.

Figure 5-3 SCE Day Ahead: Hourly Event Day Aggregate Load Impacts for an August Peak Day, 2020, 1-in-2 Utility Peak Weather Conditions

[redacted]

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

[redacted]

SDG&E

Enrollment and Load Impact Summary

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

As in previous years, the enrollment forecast assumes the customer enrollment will increase by 2% per year starting in 2020 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 2020 through 2022 due to growth in the Technical Incentives (TI) program. Therefore, total DO enrollment is expected to increase by 3% per year starting in 2020 through 2022 due to program improvements and growth in TI. The enrollment forecasts for the DA and DO products after 2022 and through 2030 show a flat trend at the 2022 values.

The ex-ante load impact forecast follows the 2020-2030 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 5-7 summarizes the average RA window load impact forecasts for the DA and DO products on an August peak day in 2020.[43] 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 5-7 SDG&E CBP: Average RA Window Ex-Ante Impacts for an August Peak Day, 2020

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	11	18.7	0.2	4.9%	4.8%	4.9%	4.9%
Total Day Of[44]	190	17.0	3.2	14.1%	13.5%	13.8%	14.0%

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 2020 for the DA and DO products, respectively. The results are for 1-in-2 weather conditions and the utility peak.

[43] Though labeled as an August peak day in 2020, the results in Table 5-7Table 5-7 would be identical for each month, May through October, in the 2020 forecast.

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

Figure 5-5 SDG&E Day Ahead: Hourly Event Day Aggregate Load Impacts for an August Peak Day, 2020, 1-in-2 Utility Peak Weather Conditions

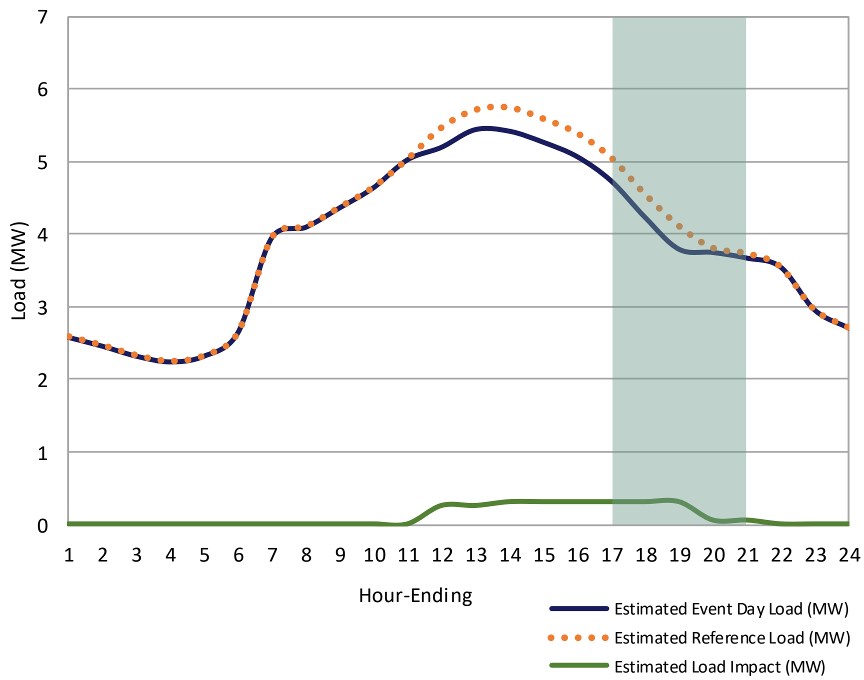
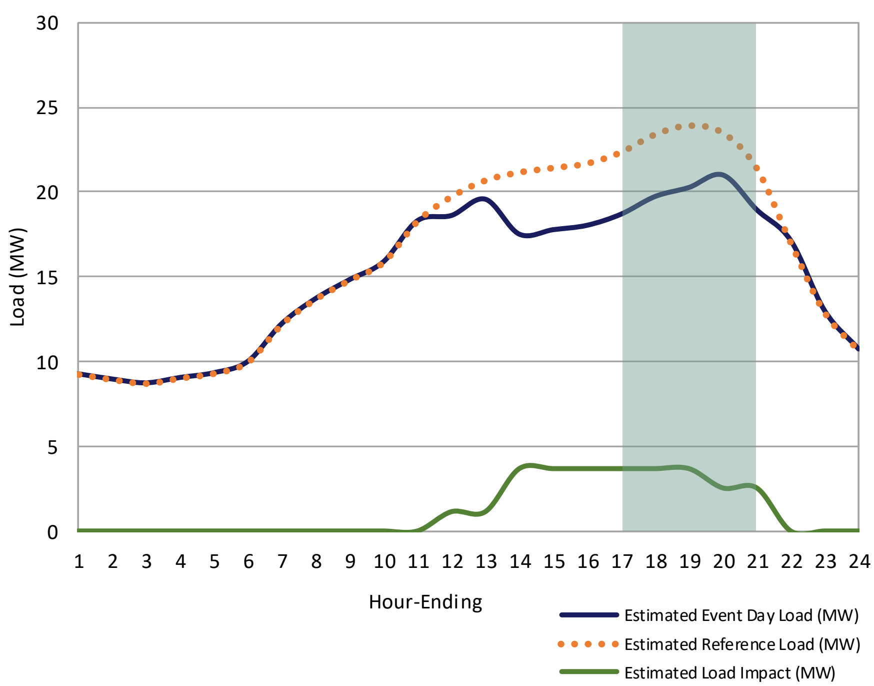


Figure 5-6 SDG&E Day Of: Hourly Event Day Aggregate Load Impacts for an August Peak Day, 2020, 1-in-2 Utility Peak Weather Conditions



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 ex-post and ex-ante load impact results for the past two years. The ex-post impacts shown below are the results for an average event day, while the ex-ante impacts shown are the results for an August[45] system peak day under the PG&E 1-in-2 weather scenario. 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. We discuss the comparison in more detail below.

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

Model	Impact Type	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
			Reference Load	Impact	Reference Load	Impact		
Previous	Ex-Post 2018	197	350.7	44.8	69.1	8.8	13%	77
	Ex-Ante 2019	693	229.5	40.3	159.0	27.9	18%	89
Current	Ex-Post 2019	241	312.6	40.8	75.3	9.8	13%	85
	Ex-Ante 2020	1,503	191.0	24.0	287.1	36.0	13%	89

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

Ex-Post 2018 v. Ex-Post 2019: In 2019, we see a slight increase in enrollment, likely due to participation picking up being in the second year of the changes implemented in PG&E's CBP. Note that Table 6-1 shows the participant count of an average event day. PY2019 event participation reached a maximum of 830 (on October 22nd event, shown in Table E-4) compared to 508 participants (July 25th) in PY2018. PY2019's DA participation count is now more comparable to PY2017 DO (prior to the program changes), which was 912 at maximum. Another notable

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

observation is the PY2019 average customer is relatively comparable, only slightly smaller than PY2018, as seen in the per-customer impact and reference loads. The percent impacts are also very comparable with both years showing 13% impacts. This shows that the participant population grew but kept relatively the same sized customers.

Ex-Post 2019 v. Ex-Ante 2019: The previous ex-ante estimates were developed based on PY2018 participation and performance, assuming 28 MW impacts in PY2019. PY2019 did surpass this estimate in participant enrollment (693 forecasted v. 797 actual August enrollment) but was not able to reach 28 MW in aggregate impacts. On October 22nd (event with maximum participation), program participants responded by shedding 21.7 MW (see Table E-4). Note that October 22nd was a generally cooler day (80°F at time of event) compared to an August event which could potentially be warmer (89°F in a 1-in-2 weather scenario).

Ex-Post 2019 v. Ex-Ante 2020: The current ex-ante estimates for PY2020 projects 36 MW impacts using the current ex-post estimates (PY2019), assuming system-level participation. Therefore, the ex-ante estimates for PY2020 are more comparable at the per-customer level with October 22nd, which had the maximum participation.

Ex-Ante 2019 v. Ex-Ante 2020: The current ex-ante estimates are derived from what was achieved in PY2019. Since the overall per-customer impacts are significantly lower in PY2019, and therefore influence lower impacts for ex-ante 2020 (24.0 kW v. 40.3 kW in PY2018), PG&E will need to significantly recruit participants (1,503 total participants in PY2020) to reach their impact goals of 36 MW. Alternatively, recruiting larger customers with larger potential impacts will allow PG&E to reach these goals with less participant recruitment.

SCE

Table 6-2 summarizes the non-residential CBP DA and DO ex-post and ex-ante load impact results for the past two summer seasons. The ex-post impacts shown below are the results for an average summer event day, while the ex-ante impacts shown are the results for an August[46] system peak day under the SCE 1-in-2 weather scenario. 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. We discuss the comparison in more detail in the following text.

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

Table 6-2 SCE Non-Residential Day Ahead: Previous and Current Ex-Post and Ex-Ante

	Model	Impact Type	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
				Ref. Load	Impact	Ref. Load	Impact		
Day Ahead	Previous	Ex Post 2018	43	432.1	47.9	18.7	2.1	11%	81
		Ex Ante 2019	90	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	90
	Current	Ex Post 2019	262	86.7	10.3	22.7	2.7	12%	86
		Ex Ante 2020	384	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	90
Day Of	Previous	Ex Post 2018	214	175.8	22.8	37.6	4.9	13%	83
		Ex Ante 2019	800	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	92
	Current	Ex Post 2019	151	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	87
		Ex Ante 2020	233	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	90

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

Ex-Post 2018 v. Ex-Post 2019: For both programs, we see similar responses (via percent impacts) in PY2019 compared to PY2018. However, there was a change in customer makeup with the DA program showing higher enrollment and is primarily made up of smaller retail stores in PY2019. This resulted in lower per-customer impacts (10.3 kW), but higher aggregate impacts (2.7 MW) compared to PY2018. The DO program did not experience such a significant change in the program population, but does show lower impacts, on average, due to the October response delivery issues mentioned in Section 4. This resulted in lower per-customer impacts ([redacted] kW) and, accordingly, lower aggregate impacts ([redacted] MW) compared to PY2018.

Ex-Post 2019 v. Ex-Ante 2019: In PY2018, ex-ante impact estimates assumed that SCE's dispatch window will remain between 1 PM – 7 PM through PY2020. This assumes zero impacts between 7 PM – 9 PM, resulting in lower average RA window estimates. The DA program shows even lower per-customer impacts in PY2019 ex-post, verifying that the DA enrollment consisted primarily of smaller C&I (retail) participants. Despite this, the increase in enrollment shows higher aggregate impacts (2.7 MW v. [redacted] MW) for the DA program's current ex-post results. As mentioned above, the DO program did not experience the same change in participant population, thus the higher per-customer impacts in PY2019. Given the much lower PY2019 enrollment than the previously projected 800 participants, the DO program shows lower aggregate impacts [redacted] MW v. [redacted] MW) in the current ex-post results.

Ex-Post 2019 v. Ex-Ante 2020: For both programs, the current ex-ante estimates for PY2020 uses the current ex-post estimates (PY2019), assuming system-level participation. Therefore, these two estimates are very comparable at the per-customer level and even more so to September events, which is when PY2019 hits maximum participation for both programs.

Ex-Ante 2019 v. Ex-Ante 2020: As mentioned above, the previous ex-ante impact estimates for PY2019 assumes that the SCE dispatch window will remain the same through PY2020. SCE's dispatch window has been approved to change to 3 PM – 9 PM, effective retroactive to January

19th, 2020. Consequently, the per-customer impacts in the current ex-ante estimates are closer to current ex-post estimates, slightly higher due to assuming maximum participation. Compared to the previous ex-ante estimates, current ex-ante impacts show an increase in the DA program and a decrease in the DO program due to difference in customer enrollment forecasts.

SDG&E

Table 6-3 summarizes the CBP DA and DO[47] ex-post and ex-ante load impact results for the past two years. The ex-post impacts shown below are the results for an average event day, while the ex-ante impacts shown are the results for an August[48] system peak day under the SDG&E 1-in-2 weather scenario. 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. We discuss the comparison in more detail below.

Table 6-3 SDG&E CBP: Previous and Current Ex-Post, Average Event Day

	Model	Impact Type	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
				Ref. Load	Impact	Ref. Load	Impact		
Day Ahead	Previous	Ex Post 2018	27	228.5	6.9	6.1	0.2	3%	75
		Ex Ante 2019	65	227.2	2.8	14.7	0.2	1%	80
	Current	Ex Post 2019	15	408.7	26.3	6.1	0.4	6%	76
		Ex Ante 2020	11	380.3	18.7	4.3	0.2	5%	84
Day Of	Previous	Ex Post 2018	186	134.8	18.6	25.1	3.5	14%	84
		Ex Ante 2019	191	129.0	13.9	24.7	2.7	11%	84
	Current	Ex Post 2019	185	120.6	19.6	22.3	3.6	16%	77
		Ex Ante 2020	190	121.0	17.0	22.9	3.2	14%	83

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

Ex-Post 2018 v. Ex-Post 2019: For DA, we see a decrease in enrollment in PY2019. Note that Table 6-3 shows the participant count of an average event day. This decrease in participation, on average, is due to the extreme drop in customer nominations in the later months of PY2018. In PY2019, the DA program exhibited growth in customer recruitment (6 participants in October 2018 v. 11 participants in May 2019), although small, and retained customer participation through the course of the summer. The DA program also recruited larger sized participants, comprised primarily of retail and institutional/government industries. The DO program experienced very little change in participant populations, showing a very small decrease in enrollment in PY2019. Consequently, we see very similar, slightly higher, per-customer impacts (19.6 kW v. 18.6 kW) and

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

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

slightly higher impacts in aggregate (3.6 MW v. 3.5 MW) in PY2019 compared to the previous year.

Ex-Post 2019 v. Ex-Ante 2019: The previous ex-ante estimates were developed based on PY2018 ex-post estimates and enrollment. Again, in DO, we see actual PY2019 per-customer impacts to be similar and slightly higher to previously projected estimates, which we attribute to the very little change in the participant population. Despite the absence of growth in customer enrollment, the DO program retained higher performers, resulting in higher MW reductions in PY2019, 3.6 MW delivered v. 2.7 MW projected. Similarly, in DA, the program also exhibited growth, although not in number of customers, but in recruitment of higher performers. The DA program also resulted in higher MW reductions in PY2019, 0.4 MW delivered v. 0.2 MW projected.

Ex-Post 2019 v. Ex-Ante 2020: For both programs, the current ex-ante estimates for PY2020 uses the current ex-post estimates (PY2019), assuming system-level participation. Therefore, these two estimates are very comparable at the per-customer level. With the modest assumptions in the customer enrollment growth, the current 2020 ex-ante impacts show lower MW reductions in the aggregate than the current 2019 ex-post with 0.2 MW and 3.2 MW projected for DA and DO, respectively.

Ex-Ante 2019 v. Ex-Ante 2020: The current ex-ante estimates for PY2020 have been updated according to what was achieved in PY2019. The enrollment projections for both DA and DO programs have also been updated to reflect the current enrollment in PY2019, assuming modest growth. Both programs showed increases in per-customer reductions, allowing the DA program to maintain the PY2020 projection of 0.2 MW despite the drop in enrollment. The DO program shows an increase aggregate MW impact in the PY2020 projection (3.2 MW vs. 2.7 MW previously projected), despite the slight decrease in participant enrollment.

7

KEY FINDINGS AND RECOMMENDATIONS

In this section, we present the key findings from the Statewide PY2019 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[49], are more valid and straightforward than in previous years.

Table 7-1 presents the PY2019 average summer event day nominated capacity and impacts by program and IOU, in aggregate. On average, PG&E's DA program and SDG&E's DO program are the largest contributors with 9.8 MW and 3.6 MW reductions on an average event day, respectively. These two programs are also the only programs to meet/exceed their nominated capacities of 9.2 MW and 3.6 MW, respectively.

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	241	9.2	9.8	-	-	-
SCE	262	3.8	2.7	151	[redacted]	[redacted]
SDG&E	15	0.7	0.4	185	3.6	3.6

Table 7-2 compares the average RA window ex-ante impact estimates, in aggregate, for an August peak day in 2020 versus 2030. Note that these estimates only include non-residential participants. SCE assumes a flat 11-year enrollment forecast, while PG&E and SDG&E assume program growth through 2022. The SDG&E DO forecast shown below includes new enrollments in the TI program.

[49] 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 RA Window Ex-Ante Impacts, August Peak Day, 2020 v. 2030

Utility	Day Ahead				Day Of			
	PY 2020		PY 2030		PY 2020		PY 2030	
	# of Accts	Aggregate Impact (MW)	# of Accts	Aggregate Impact (MW)	# of Accts	Aggregate Impact (MW)	# of Accts	Aggregate Impact (MW)
PG&E	1,503	36.0	1,670	40.0	-	-	-	-
SCE	384	[redacted]	384	[redacted]	233	[redacted]	233	[redacted]
SDG&E	11	0.2	12	0.2	188	3.2	195	3.4

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, and these adjustments have carried over into PY2019. 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. We now 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.

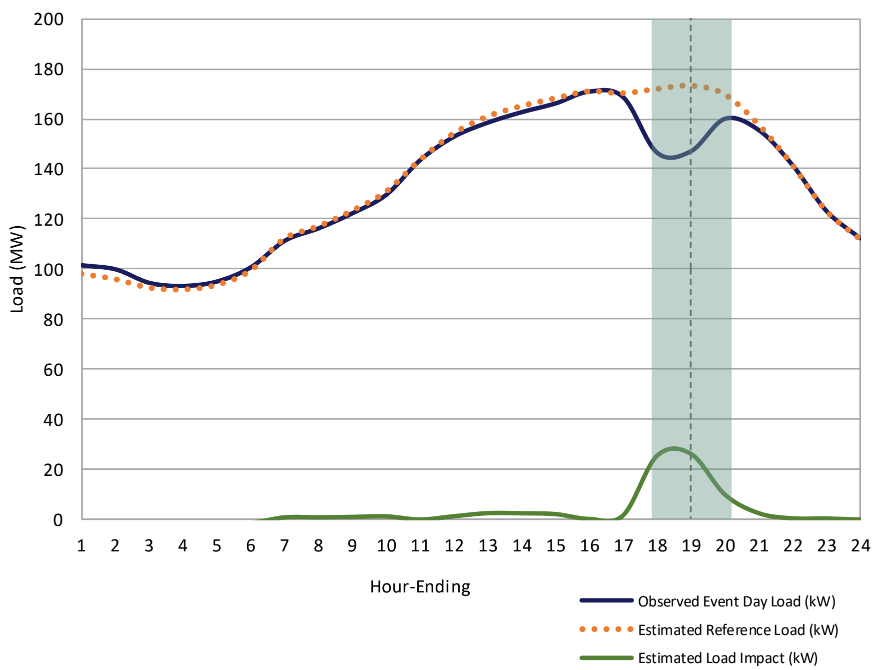
PG&E

In PY2019, PG&E implemented minor changes in their Capacity Bidding Program, having only Day Ahead product offerings. PG&E's CBP remains a more geographically targeted DR, calling only 1 to 5 Sub-LAPs (out of 14 total) in most of PY2019 events. They also called only one system-level event on October 22, 2019.

This year, we have the following key findings:

- PG&E's CBP program called the most diverse events among the 3 IOUs with 1 to 14 Sub-LAPs called, 1 to 806 participants nominated, and event windows between the hours of 4 PM and 8 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 one event called on HE18 (5 PM – 6 PM) and one event on HE20 (7 PM – 8 PM). Table 4-3 summarizes the PY2019 events in more detail. Figure 7-1 shows an example of an event day that calls 3 products, 14 Sub-LAPs, 2 event windows, and 806 participants. The hours highlighted in blue-green show the hours where in at least one group is called. The vertical dashed line on HE19) represents the hour where in all groups were called.

Figure 7-1 PG&E All Day-Ahead: Aggregate Hourly Impact, October 22, 2019



- The entire DA program, on average, met/exceeded their capacity nominations, successfully doing so in 7 out of 14 events. PG&E's DA program is also the largest contributor with 9.8 MW reductions, on average.
- Participant retention and enrollment has improved since the program revamping, suggesting that aggregators and participants adjusted to most of the program changes at the end of PY2018. PG&E's monthly nominations picked up through the PY2019 season, starting at 427 nominations in May and ending at 843 nominations in October. Growths in the ex-ante forecast can be credited to the program's success in retention and enrollment in PY2019.
- Residential participation is expected to begin in PY2020, picking up quickly by PY2022. PG&E forecasts residential capacity nominations to reach 2 MW in 2020, 10 MW in 2021, and 22 MW in 2022.

SCE

SCE also had minimal changes in PY2019, with both DA and DO programs continuing to have only 1-6 hour durations. SCE's CBP is essentially a geographically targeted DR, calling individual Sub-LAPs as awarded by CAISO. However, in PY2019, SCE only called a handful of localized events, calling mostly system-level events. The variability in event characteristics is due to the variability in monthly nominations both across the two seasons (summer v. non-summer) and the one-time spike in enrollments (due to the CPP rate defaulting).

This year, we have the following key findings:

- Similar to PG&E, the average event day represents a wide range of events with 1 to 6 Sub-LAPs called, 6 to 540 participants nominated, and event widows between the hours of 1 PM and 7 PM. Both the average summer and non-summer event days show results for HE19 (6 PM – 7 PM), which is the window that most events have in common.
- Both the DA and DO programs were unsuccessful in meeting or exceeding their nominated capacities, on average. SCE's CBP was only able to successfully meet capacity nominations on one non-summer event under the DA product offering. However, results for this event are considered confidential under the 15/15 rule. Program management attributes this to several aggregators having struggles in deliveries through the course of the program year.
- Participant retention and enrollment stabilized in PY2019. SCE's drop in summer and non-summer enrollments were mainly due to the CPP rate defaulting in PY2019 and the CPP opt-out process required to re-enroll into the CBP program. By August 2019, both DA and DO programs are back to anticipated program nominations.
- Ex-ante impacts are no longer 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's advice letter (AL 4131-E) requesting to change the dispatch window to 3 PM to 9PM, currently at 1 PM to 7 PM, was approved to be effective retroactive to January 19th, 2020.

SDG&E

SDG&E currently offers four CBP products and continues to have both Day Ahead and Day Of programs with two sets of operating hours: 11 AM – 7 PM and 1 PM – 9 PM. SDG&E made several program changes, limiting the maximum number of events called per month (discussed in more detail in Section 2).

This year, we have the following key findings:

- SDG&E's CBP program continued to call events as needed by calling on different products on different event windows within the same day. For example, the DA 11 AM – 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.
- The DO program successfully met its capacity nominations in both products, on average. The DA program was able to deliver relatively consistent results through PY2019, but did not successfully meet capacity nominations, on average. 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 PY2019 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	10	0.52	0.30	97	1.2	1.2
1 PM to 9 PM	5	0.22	0.09	88	2.4	2.4

- Similar to PG&E, participant retention and enrollment has improved since the program revamping, suggesting that aggregators and participants adjusted to most of the program changes at the end of PY2018. SDG&E's DA program experienced a significant drop in enrollment in August 2018, likely due to the shift in calling events later in the day. In PY2019, SDG&E exhibited good participant retention with some small growth in the DA program with 6 participants as of October 2018 and ranging from 10-12 participants in PY2019.

Recommendations

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

- Incorporate monthly average event days in reporting. A monthly average event day is not required under the DR Load Impact Protocols. However, given that CBP participation is driven by monthly MW nominations, we believe that monthly average events can facilitate better conclusions. Examples of reporting items that can be done at the monthly level are identifying system-level events v. localized events and meeting or exceeding capacity nominations. Although these reporting items are still required for the entire program year (via the average event day), having these monthly comparisons are also quite telling of the program's success.

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. In PY2018, we limited selection of event-like days to only PY2018 due to implemented program changes. We saw success using this approach and did the same this year, limiting selection of event-like days to only PY2019.
- 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 PY2019. 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 PY2019 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

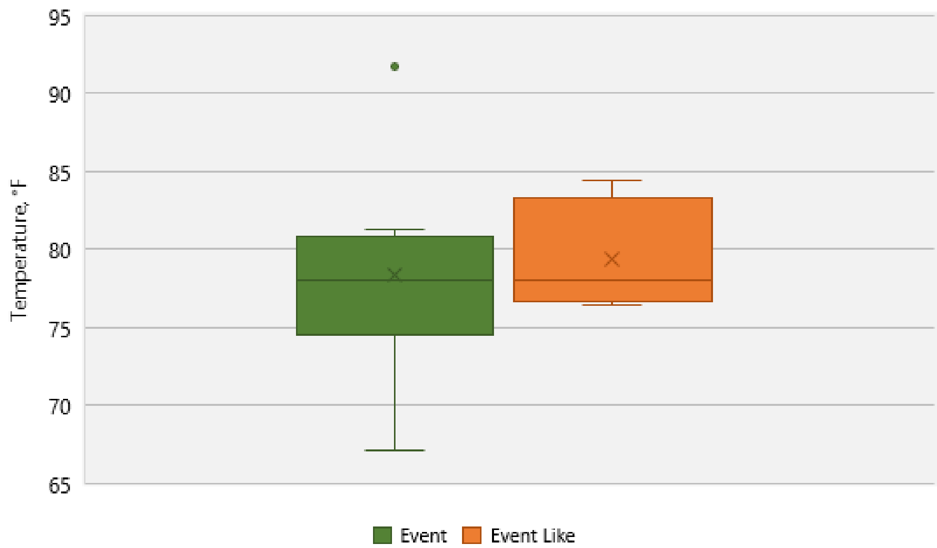


Figure B-2 SCE Average Daily Temperatures of Event Days v. Event-Like Days

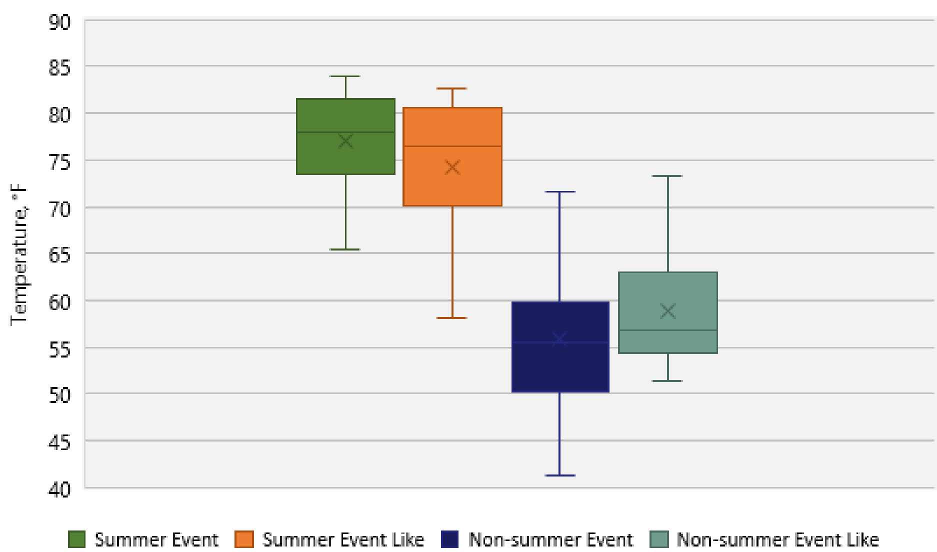
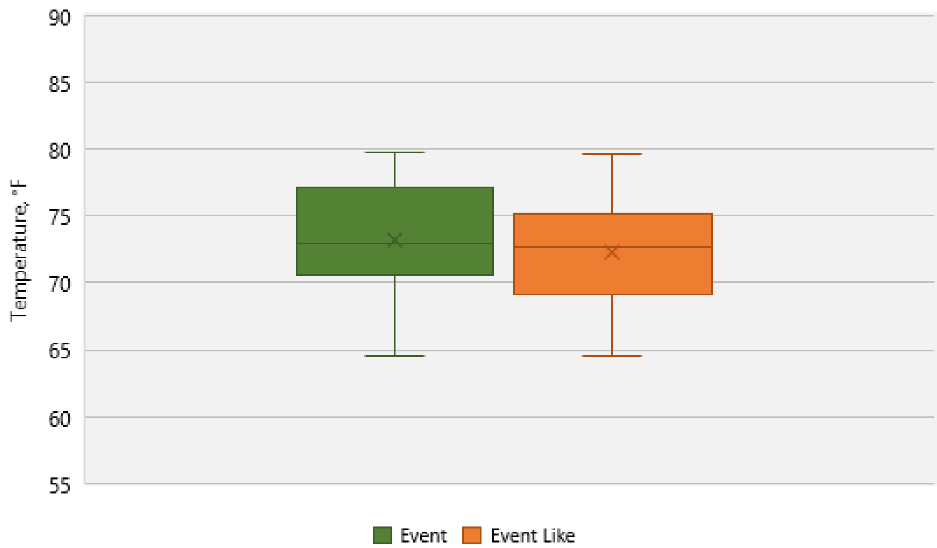


Figure B-3 SDG&E Average Daily Temperatures of Event Days v. Event-Like Days



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.[50] We present a weighted average where the MAPE and MPE

[50] 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 4%. 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. PG&E's Prescribed DA product offering shows the largest MAPE and MPE values but are still relatively small and promote confidence in our regression models in PY2019.

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	1.3%	0.4%	1.1%	0.1%
	Prescribed DA	3.6%	-1.5%	3.3%	-0.5%
SCE	CBP DA	1.6%	0.4%	2.1%	-0.1%
	CBP DO	2.2%	-0.2%	1.7%	-0.1%
SDG&E	CBP DO	3.2%	0.9%	2.5%	0.0%
	CBP DA	2.2%	0.7%	2.7%	0.1%

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.

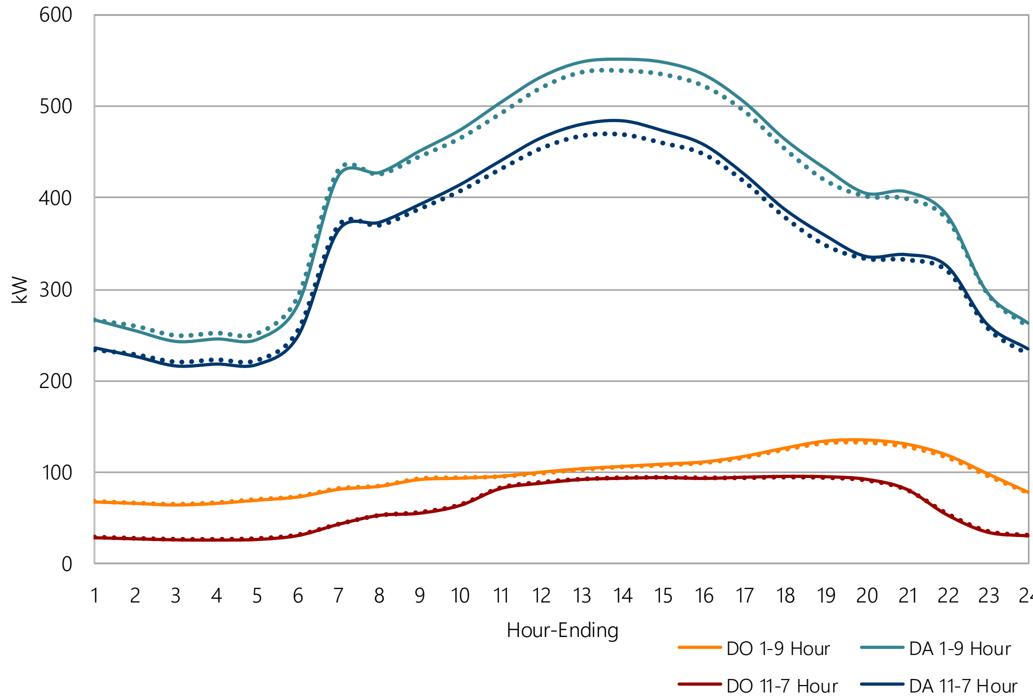
Figure B-4 PG&E Actual and Predicted Loads on Event-Like Days

[redacted]

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

[redacted]

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

South of Lugo

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

Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
		Reference Load	Impact	Reference Load	Impact		
Nov 1, 2018	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	81
Nov 2, 2018	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	88
Nov 5, 2018	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	75
Nov 6, 2018	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	73
Nov 16, 2018	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	74
Jun 11, 2019	41	231.1	33.9	9.5	1.4	15%	95
Jun 12, 2019	41	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	87
Jul 23, 2019	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	89
Jul 24, 2019	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	87
Jul 25, 2019	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	91
Aug 6, 2019	104	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	93
Aug 14, 2019	104	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	95
Aug 15, 2019	104	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	94
Aug 27, 2019	104	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	90
Aug 28, 2019	104	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	88
Sep 4, 2019	104	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	95
Sep 5, 2019	104	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	95
Sep 6, 2019	104	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	92
Sep 9, 2019	104	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	83
Sep 12, 2019	104	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	91
Oct 8, 2019	21	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	73
Oct 15, 2019	102	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	86
Oct 16, 2019	102	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	83
Oct 21, 2019	102	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	88
Oct 22, 2019	102	123.6	8.9	12.6	0.9	7%	92
Oct 23, 2019	81	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	89

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

Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
		Reference Load	Impact	Reference Load	Impact		
Nov 1, 2018	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	80
Nov 2, 2018	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	86
Nov 5, 2018	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	73
Nov 6, 2018	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	71
Nov 14, 2018	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	75
Nov 16, 2018	23	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	74
Dec 3, 2018	24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	64
Dec 4, 2018	24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	63
Dec 5, 2018	24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	53
Dec 6, 2018	24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	48
Dec 7, 2018	24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	62
Jan 2, 2019	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	57
Jan 3, 2019	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	62
Jan 4, 2019	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	64
Jan 7, 2019	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	60
Jan 8, 2019	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	67
Feb 4, 2019	21	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	52
Feb 5, 2019	21	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	50
Feb 6, 2019	21	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	53
Feb 7, 2019	21	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	60
Feb 8, 2019	21	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	60
Mar 1, 2019	21	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	65
Mar 4, 2019	21	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	62
Mar 5, 2019	21	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	66
Mar 6, 2019	21	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	60
Mar 7, 2019	21	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	57
Jun 11, 2019	63	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	95
Jun 12, 2019	63	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	87
Jul 23, 2019	76	96.0	21.5	7.3	1.6	22%	97
Jul 24, 2019	76	98.5	23.3	7.5	1.8	24%	95
Jul 25, 2019	76	97.2	21.5	7.4	1.6	22%	95
Aug 5, 2019	76	95.7	25.7	7.3	2.0	27%	93
Aug 6, 2019	76	95.0	25.7	7.2	2.0	27%	92
Aug 14, 2019	76	95.6	25.7	7.3	2.0	27%	94
Aug 15, 2019	76	93.5	25.7	7.1	2.0	27%	93
Aug 26, 2019	76	94.6	25.7	7.2	2.0	27%	91

Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
		Reference Load	Impact	Reference Load	Impact		
Sep 3, 2019	77	98.4	21.6	7.6	1.7	22%	94
Sep 4, 2019	77	94.5	15.9	7.3	1.2	17%	94
Sep 5, 2019	77	95.9	21.0	7.4	1.6	22%	95
Sep 6, 2019	77	95.7	19.9	7.4	1.5	21%	92
Sep 12, 2019	77	93.0	21.6	7.2	1.7	23%	91
Oct 7, 2019	77	76.8	9.2	5.9	0.7	12%	85
Oct 8, 2019	20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	74
Oct 14, 2019	77	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	73
Oct 15, 2019	77	88.4	9.2	6.8	0.7	10%	86
Oct 16, 2019	77	89.6	9.2	6.9	0.7	10%	82
Oct 21, 2019	57	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	90

South Orange County

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

Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
		Reference Load	Impact	Reference Load	Impact		
Jun 11, 2019	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	77
Jun 12, 2019	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	72
Jul 23, 2019	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	85
Jul 24, 2019	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	82
Jul 25, 2019	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	87
Aug 6, 2019	15	71.7	6.7	1.1	0.1	9%	78
Aug 14, 2019	15	73.0	6.7	1.1	0.1	9%	80
Aug 15, 2019	15	73.7	6.7	1.1	0.1	9%	77
Aug 27, 2019	15	74.3	6.7	1.1	0.1	9%	77
Aug 28, 2019	15	70.8	6.7	1.1	0.1	9%	76
Sep 4, 2019	15	87.1	10.5	1.3	0.2	12%	84
Sep 5, 2019	15	90.2	9.1	1.4	0.1	10%	85
Sep 6, 2019	15	85.4	7.0	1.3	0.1	8%	84
Sep 9, 2019	15	68.1	7.0	1.0	0.1	10%	75
Sep 12, 2019	15	75.3	9.8	1.1	0.1	13%	79
Oct 8, 2019	15	59.7	1.8	0.9	<0.1	3%	71
Oct 15, 2019	15	67.2	1.8	1.0	<0.1	3%	76
Oct 16, 2019	15	62.8	1.8	0.9	<0.1	3%	77
Oct 21, 2019	15	87.5	1.8	1.3	<0.1	2%	84
Oct 22, 2019	15	89.2	1.8	1.3	<0.1	2%	87

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

Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
		Reference Load	Impact	Reference Load	Impact		
Nov 1, 2018	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	75
Nov 2, 2018	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	80
Nov 5, 2018	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	66
Nov 6, 2018	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	67
Nov 14, 2018	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	73
Dec 3, 2018	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	63
Dec 4, 2018	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	65
Dec 5, 2018	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	54
Dec 6, 2018	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	56
Dec 7, 2018	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	65
Jan 2, 2019	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	58
Jan 3, 2019	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	59
Jan 4, 2019	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	59
Jan 7, 2019	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	61
Jan 8, 2019	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	64
Feb 4, 2019	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	57
Feb 5, 2019	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	54
Feb 6, 2019	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	55
Feb 7, 2019	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	59
Feb 8, 2019	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	58
Mar 1, 2019	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	61
Mar 4, 2019	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	59
Mar 5, 2019	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	62
Mar 6, 2019	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	60
Mar 7, 2019	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	58
Jun 11, 2019	18	107.6	17.8	1.9	0.3	17%	76
Jun 12, 2019	18	104.2	17.8	1.9	0.3	17%	72
Jul 23, 2019	18	123.3	22.7	2.2	0.4	18%	85
Jul 24, 2019	18	122.3	25.8	2.2	0.5	21%	81
Jul 25, 2019	18	120.1	22.7	2.2	0.4	19%	87
Aug 5, 2019	19	113.9	12.4	2.2	0.2	11%	80
Aug 6, 2019	19	110.6	12.4	2.1	0.2	11%	78
Aug 14, 2019	19	110.0	12.4	2.1	0.2	11%	79
Aug 15, 2019	19	108.4	12.4	2.1	0.2	11%	76
Aug 26, 2019	19	110.3	12.4	2.1	0.2	11%	77
Sep 3, 2019	18	120.4	11.0	2.2	0.2	9%	85

Event	# of Accts	Per Customer Impact (kW)		Aggregate Impact (MW)		% Impact	Temp (F)
		Reference Load	Impact	Reference Load	Impact		
Sep 4, 2019	18	121.7	9.2	2.2	0.2	8%	84
Sep 5, 2019	18	118.4	10.5	2.1	0.2	9%	85
Sep 6, 2019	18	123.4	11.0	2.2	0.2	9%	84
Sep 12, 2019	18	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	79
Oct 7, 2019	18	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	78
Oct 8, 2019	18	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]%	71
Oct 14, 2019	18	126.7	-2.8	2.3	<0.1	-2%	68
Oct 15, 2019	18	130.1	-2.8	2.3	<0.1	-2%	76
Oct 16, 2019	18	131.1	-2.8	2.4	<0.1	-2%	77

Applied Energy Group, Inc.
500 Ygnacio Valley Road, Suite 250
Walnut Creek, CA 94596

P: 510.982.3525