AEG

2021 Statewide Load Impact Evaluation of California Capacity Bidding Programs

EX-POST AND EX-ANTE LOAD IMPACTS

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Public Version. Redactions in 2022 Statewide Load Impact Evaluation of California Capacity Bidding Programs and Appendices

Confidential information is removed and blacked out. [redacted]

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ABSTRACT

This report documents the Program Year 2021 (PY2021) statewide load impact evaluation of the Capacity Bidding Program (CBP) operated by the three California investor-owned utilities (IOUs): Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E). The primary goals of this evaluation are to (1) estimate the ex-post load impacts for PY2021 and (2) estimate ex-ante load impacts for years 2022 through 2032.

CBP is an aggregator-based demand response (DR) program. As part of these programs[1], DR aggregators contract with customers to act on their behalf in all aspects of the DR program, including receiving notices from the IOU, arranging for load reductions on event days, receiving incentive payments, and paying penalties (if warranted) to the IOU. Each aggregator forms a portfolio of service accounts, whose aggregated load reductions participate as a single resource for each program. Aggregators can nominate customer service accounts to various products depending on each program's product[2] offerings, including day-ahead (DA) and day-of[3] (DO) notifications and corresponding event triggers. The terms and conditions of service can vary widely, depending on tariffs specific to each IOU and contracts between aggregators and customers.

In PY2021, the number of dispatched customer service accounts[4] on a single event day ranged from one to 694 service accounts, depending on the program and product. Programs dispatched as few as 12 event days, while others dispatched up to 67 event days. These events are dispatched for various combinations of distribution-based geographical locations or Sub-Load Aggregation Points (Sub-LAPs). These Sub-LAP events are based upon CAISO market awards and may not require the IOU to dispatch the entire nominated load reduction.

AEG estimated hourly ex-post load impacts for each program, product, and dispatched event in PY2021 using regression analysis of hourly load, weather, and event data. The estimated load impacts are reported by program, product, and event day. Load impacts for the average event day are also reported by industry type, CAISO local capacity area (LCA), and Sub-LAP where relevant.

Estimated aggregate load impacts for an average Non-residential CBP DA event were 13.0 MW for PG&E, 4.0 MW for SCE, and 0.3 MW for SDG&E. Aggregate load impacts for Non-residential CBP DO were 2.0 MW for SCE and 1.0 MW for SDG&E, on average.

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 be effective in 2022.

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

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

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

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

EXECUTIVE SUMMARY

This report describes the statewide load impact evaluation of the Capacity Bidding Program (CBP) 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). This evaluation only covers CBP since all three IOUs eliminated the Aggregator Managed Portfolio (AMP) program offering in 2018.

The primary goals of the 2021 load impact evaluation are as follows:

- Estimate hourly ex-post load impacts for each program[5], product[6], and dispatched event in PY2021.
- Estimate hourly ex-ante load impacts for each program and product for the years 2022-2032.

We present the program description, evaluation methodology, ex-post load impacts, ex-ante load impacts, key findings, and recommendations in the following subsections.

Program Description

The Capacity Bidding Program is a statewide price-responsive and aggregator-managed program launched in 2007. It is available at the three CA IOUs, although each IOU's program differs slightly in program features and operations.

Aggregators. In CBP, aggregators contract with eligible residential[7] and non-residential utility customers to act on their behalf in all aspects of the program. Aggregators receive dispatch notifications (day-ahead or day-of), incentive payments, and penalties from the IOUs. Each aggregator forms a resource, a portfolio of customers, to provide load reduction during events. Each resource participates collectively, wherein load reduction is measured on an aggregate basis. The aggregators enroll customers under the terms of their own contracts to provide the load reduction capacity and receive corresponding incentives. In other words, IOUs are not directly involved in the contracts between aggregators and customers. CBP may have customers/participants classified as self-aggregated.

Eligibility. Aggregators must have Internet access. Enrolled customers must have a qualifying interval meter and receive Bundled, Direct Access, or Community Choice Aggregation service.[8] Customers enrolled in CBP may dually participate in an energy-only DR program (i.e., cannot have a capacity payment component) that does not have the same notification type (DA or DO).

Incentives. CBP provides monthly capacity payments ($/kW) to aggregators based on the nominated kW load, the specific operating month, the event duration, resource performance during an event, and the event notice option. Delivered capacity determines performance. If an aggregator's delivered capacity is less than the tariff threshold (50% for SCE and SDG&E and 60% for PG&E), the aggregator is assessed a penalty. CBP aggregators receive the full monthly capacity payment for months without

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

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

[7] Since PY2018, the program was open to residential customer enrollment.

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

dispatched events based on their nominations with no energy payments.[9] Additional energy payments ($/kWh) are made to the aggregator[10] based on the measured kWh reductions (relative to the program baseline) achieved when an event is dispatched.[11]

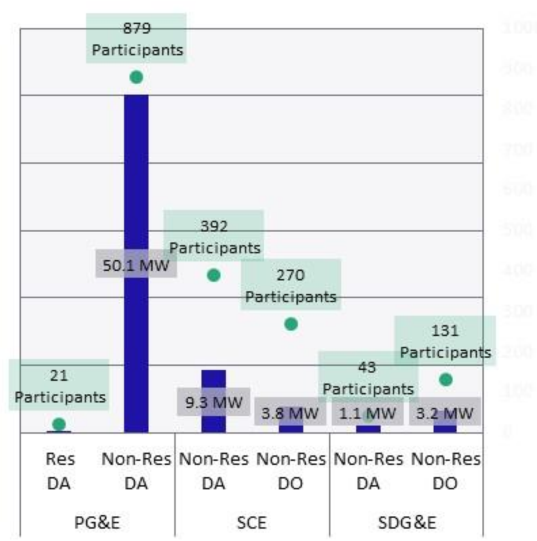
Programs, Products, and Events. All CBP events are determined by California Independent System Operator (CAISO) market awards at varying thresholds specified by each program and product.

- **PG&E** has two programs: Residential and Non-residential DA. Both programs offer three products: Elect, Elect+, and Prescribed. PG&E operating hours are between 1 PM to 9 PM. Events are called Monday through Friday, excluding holidays, during May through October, with a maximum of five events and 30 hours per month (or possibly more hours under Elect and Elect+ Options if the participants so choose).
- **SCE** has two programs: Non-residential DA and DO. Both programs offer one product: DA 1-6 Hour and DO 1-6 Hour. SCE operating hours (dispatch window) are between 3 PM to 9 PM. Events may be called Monday through Friday, excluding holidays, year-round, with a maximum of 5 events and 30 hours per month. Residential CBP is now open to aggregators, but SCE has not yet received nominations.
- **SDG&E** has two programs: Non-residential DA and DO. Both programs currently offer two products: DA 11-7 Hour, DA 1-9 Hour, DO 11-7 Hour, and DO 1-9 Hour. Events may be called Monday through Friday, excluding holidays, from May through October, with a maximum of 24 hours per month. SDG&E can dispatch up to 6 event days per month with up to three consecutive event days per month.

Program Nominations

Figure ES-1 shows the average summer[12] nominations for each program in PY2021. These counts and capacity nominations represent the total resources available for dispatch during the PY2021 summer season.

Figure ES-1 Average Summer Nominations



Nomination vs. Dispatch

Throughout the report, we distinguish between nominations and dispatches. A **Nomination** is a monthly nominated resource by program, product, aggregator, and Sub-LAP. Each nominated resource has a corresponding capacity nomination (MW) and enrolled customers. A **Dispatch** is an entity called to a market-triggered event. For example, a dispatched resource,

[9] Self-aggregated customers 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.

[10] Self-aggregated customers receive additional energy payments directly.

[11] 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.

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

dispatched customers, or dispatched capacity. Not all nominated entities are dispatched.

Dispatched Events

Since CBP events are triggered by CAISO market awards, specific to Sub-LAPs, not all available nominations are dispatched for each event. Some months may dispatch more events than others, and some events may dispatch all or a portion of nominations. Table ES-1 compares the average summer nominations to the average summer dispatches for each program. Note that the dispatched capacity is also separate from the estimated ex-post impact presented in the subsequent section.

Table ES-1 Average Summer Nominations v. Dispatch

IOU	Program	Nomination		Dispatched		
		No. of Accounts	Capacity (MW)	No. of Accounts	Capacity (MW)	Number of Events
PG&E	Res DA	21	[redacted]	21	[redacted]	12
	Non-Res DA	879	50.1	365	13.5	52
SCE	Non-Res DA	392	9.3	312	7.6	32
	Non-Res DO	270	3.8	203	2.9	27
SDG&E	Non-Res DA	43	1.1	46	1.1	28
	Non-Res DO	131	3.2	133	3.4	23

Evaluation Methods

We used the same methodology across all programs to ensure consistency of results. Each program is modeled independently, modifying assumptions to account for CBP program design and implementation, specific to each IOU's CBP tariff. With the addition of PG&E's Residential participation in PY2020, it is important to highlight the key differences in the approach used for the two customer classes:

The Residential program analysis used a matched control group and aggregate hourly regression models. This approach is the best practice for participant populations with less variable loads, which can leverage the higher statistical power with more customers included in each model. A matched control group also more effectively estimates the counterfactual load without a randomized control trial.

The Non-residential programs analyses continued to use a within-subject design using customer-specific hourly regression models. It remains the most flexible, consistent, and appropriate solution for CBP's evaluation goals and population distributions. Non-residential customers often vary significantly from one another in load shape, weather response, and overall size. Customer-specific regressions allow us to control for variation in load due to weather conditions, geography, time-related variables, and other unobservable customer-specific effects. This approach also allows for individual customer impacts to be added together to estimate load impacts at any level or customer segmentation.

AEG used the same hourly regression models to predict the ex-ante load impacts under the Utility and CAISO 1-in-2 and 1-in-10 weather scenarios. AEG estimated load impacts for all five hours of the Resource Adequacy (RA) window, developing IOU-specific adjustments based on historical performance and expected program changes through the 2022-2032 forecast horizon.

Ex-Post Load Impacts

Table ES-2 summarizes each CBP program's PY2021 overall season performance using the following reporting metrics: average nomination, average overall and reporting hour dispatch, the ex-post load impacts, and the overall and adjusted delivery performance. The data presented are for the average summer event day. [13]

Note that in the following tables, we show the average dispatched counts and capacity, which is dependent on CAISO market awards. Low counts are not indicative of low participation rather an indication of necessity. On the other hand, delivering dispatched capacity is the correct measure of the program's success (delivery performance or % delivered). 100% delivery performance means that aggregators and customers curtailed the load obligations when asked to do so.

The delivery performance metrics also allow for an adjusted metric for dispatched capacity coincident with the reporting hour. Our definition of the average event day includes events that did not dispatch capacity during the reporting hour. For example, PG&E's Non-residential DA has a 96% overall delivery performance, just 4% short of meeting dispatched capacity. However, adjusting for dispatched capacity on the reporting hour, hour-ending (HE) 20 or 7–8 PM, shows that PG&E's Non-residential DA exceeded dispatched capacity at 105% adjusted delivery performance.

In PY2021, only PG&E Non-residential DA performed successfully with a 96% delivery performance and a 105% adjusted delivery performance.

Table ES-2 Statewide CBP Delivery Performance

Program		Nominations		Overall Dispatched		Reporting Hour Dispatched		Ex-Post Analysis		
		# Accts	Capacity (MW)	# Accts	Capacity (MW)	# Accts	Capacity (MW)	Impact (MW)	% Delivered	Adj. % Delivered
PG&E	Res DA	21	[redacted]	21	[redacted]	14	[redacted]	[redacted]	[redacted]	[redacted]
PG&E	Non-res DA	879	50.1	365	13.5	345	12.4	13.0	96%	105%
SCE	Non-res DA	392	9.3	312	7.6	308	7.5	4.0	53%	53%
SCE	Non-res DO	270	3.8	203	2.9	198	2.8	2.0	70%	71%
SDG&	Non-res DA	43	1.1	46	1.1	43	1.0	0.3	25%	26%
SDG&	Non-res DO	131	3.2	133	3.4	133	3.4	1.0	30%	30%

Table ES-3 through Table ES-5 show the PY2021 ex-post load impacts and dispatched capacity for each IOU by program and event day. The red font indicates a PG&E test event. In some cases, there were test events and CAISO market-triggered events on the same day for different products.

[13] The average event day is defined as the average of all events called regardless of dispatched 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 dispatched count is calculated as a simple average of the dispatched 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 dispatched counts are summed.

Table ES-3 Summary of PY2021 PG&E Ex-Post Impacts and Dispatched Capacity[14]

Event	Residential Day Ahead				Non-Residential Day Ahead			
	# of Accts	Per Customer Impact (kW)	Aggregate Impact (MW)	Dispatched Capacity (MW)	# of Accts	Per Customer Impact (kW)	Aggregate Impact (MW)	Dispatched Capacity (MW)
May 5, 2021	-	-	-	-	1	[redacted]	[redacted]	[redacted]
May 11, 2021	-	-	-	-	1	[redacted]	[redacted]	[redacted]
May 12, 2021	-	-	-	-	85	103.5	8.8	7.0
Jun 16, 2021	-	-	-	-	518	59.2	30.7	24.4
Jun 17, 2021	-	-	-	-	540	45.1	24.4	24.7
Jun 18, 2021	-	-	-	-	18	51.9	0.9	0.9
Jun 29, 2021	-	-	-	-	**10**	[redacted]	[redacted]	[redacted]
Jul 9, 2021	-	-	-	-	433	18.8	8.1	11.2
Jul 12, 2021	-	-	-	-	480	18.7	9.0	11.7
Jul 13, 2021	-	-	-	-	480	19.1	9.2	11.7
Jul 14, 2021	-	-	-	-	2	[redacted]	[redacted]	[redacted]
Jul 19, 2021	-	-	-	-	348	23.4	8.1	10.1
Jul 20, 2021	-	-	-	-	9	[redacted]	[redacted]	[redacted]
Jul 21, 2021	-	-	-	-	7	[redacted]	[redacted]	[redacted]
Jul 21, 2021	-	-	-	-	**69**	**70.5**	**4.9**	**5.8**
Jul 23, 2021	-	-	-	-	7	[redacted]	[redacted]	[redacted]
Jul 26, 2021	-	-	-	-	7	[redacted]	[redacted]	[redacted]
Jul 27, 2021	-	-	-	-	7	[redacted]	[redacted]	[redacted]
Jul 28, 2021	-	-	-	-	478	17.8	8.5	11.0
Jul 29, 2021	-	-	-	-	478	15.1	7.2	11.0
Jul 29, 2021	-	-	-	-	**6**	[redacted]	[redacted]	[redacted]
Jul 30, 2021	-	-	-	-	186	6.0	1.1	2.3
Aug 3, 2021	-	-	-	-	9	[redacted]	[redacted]	[redacted]
Aug 4, 2021	-	-	-	-	9	[redacted]	[redacted]	[redacted]
Aug 11, 2021	-	-	-	-	9	[redacted]	[redacted]	[redacted]
Aug 12, 2021	-	-	-	-	24	37.1	0.9	1.2
Aug 13, 2021	-	-	-	-	9	[redacted]	[redacted]	[redacted]
Aug 16, 2021	-	-	-	-	7	[redacted]	[redacted]	[redacted]
Aug 20, 2021	-	-	-	-	**5**	**160.2**	**0.8**	**0.9**
Aug 23, 2021	-	-	-	-	**35**	**52.7**	**1.8**	**3.6**

[14] Results shown in red text include dispatched counts for test events.

Event	Residential Day Ahead				Non-Residential Day Ahead			
	# of Accts	Per Customer Impact (kW)	Aggregate Impact (MW)	Dispatched Capacity (MW)	# of Accts	Per Customer Impact (kW)	Aggregate Impact (MW)	Dispatched Capacity (MW)
Aug 26, 2021	-	-	-	-	2	[redacted]	[redacted]	[redacted]
Aug 26, 2021	-	-	-	-	**191**	**6.9**	**1.3**	**3.9**
Aug 27, 2021	-	-	-	-	**17**	**1.6**	**<0.1**	**0.3**
Aug 30, 2021	-	-	-	-	**122**	**14.7**	**1.8**	**2.3**
Sep 7, 2021	23	[redacted]	[redacted]	[redacted]	126	55.0	6.9	6.9
Sep 8, 2021	23	[redacted]	[redacted]	[redacted]	9	[redacted]	[redacted]	[redacted]
Sep 9, 2021	23	[redacted]	[redacted]	[redacted]	497	18.4	9.1	10.4
Sep 13, 2021	23	[redacted]	[redacted]	[redacted]	9	[redacted]	[redacted]	[redacted]
Sep 14, 2021	23	[redacted]	[redacted]	[redacted]	9	[redacted]	[redacted]	[redacted]
Sep 15, 2021	23	[redacted]	[redacted]	[redacted]	7	[redacted]	[redacted]	[redacted]
Sep 17, 2021	-	-	-	-	2	[redacted]	[redacted]	[redacted]
Sep 21, 2021	-	-	-	-	**81**	**7.9**	**0.6**	**1.6**
Sep 24, 2021	-	-	-	-	**124**	**98.0**	**12.1**	**10.7**
Sep 30, 2021	-	-	-	-	**43**	**106.7**	**4.6**	**10.9**
Oct 1, 2021	19	[redacted]	[redacted]	[redacted]	6	[redacted]	[redacted]	[redacted]
Oct 4, 2021	19	[redacted]	[redacted]	[redacted]	17	18.5	0.3	1.1
Oct 5, 2021	19	[redacted]	[redacted]	[redacted]	17	45.1	0.8	1.1
Oct 6, 2021	19	[redacted]	[redacted]	[redacted]	14	[redacted]	[redacted]	[redacted]
Oct 12, 2021	-	-	-	-	3	[redacted]	[redacted]	[redacted]
Oct 13, 2021	-	-	-	-	3	[redacted]	[redacted]	[redacted]
Oct 14, 2021	19	[redacted]	[redacted]	[redacted]	14	[redacted]	[redacted]	[redacted]
Oct 15, 2021	19	[redacted]	[redacted]	[redacted]	17	32.8	0.6	1.1
Oct 19, 2021	-	-	-	-	11	[redacted]	[redacted]	[redacted]
Oct 21, 2021	-	-	-	-	**252**	**28.5**	**7.2**	**12.5**
Oct 26, 2021	-	-	-	-	**1**	[redacted]	[redacted]	[redacted]

Table ES-4 Summary of PY2021 SCE Ex-Post Impacts and Dispatched Capacity

Event	Day Ahead				Day Of			
	# of Accts	Per Customer Impact (kW)	Aggregate Impact (MW)	Dispatched Capacity (MW)	# of Accts	Per Customer Impact (kW)	Aggregate Impact (MW)	Dispatched Capacity (MW)
Nov 2, 2020	4	[redacted]	[redacted]	[redacted]	23	12.2	0.3	0.7
Nov 3, 2020	4	[redacted]	[redacted]	[redacted]	23	12.2	0.3	0.7

Event	Day Ahead				Day Of			
	# of Accts	Per Customer Impact (kW)	Aggregate Impact (MW)	Dispatched Capacity (MW)	# of Accts	Per Customer Impact (kW)	Aggregate Impact (MW)	Dispatched Capacity (MW)
Nov 4, 2020	4	[redacted]	[redacted]	[redacted]	23	10.0	0.2	0.7
Nov 5, 2020	4	[redacted]	[redacted]	[redacted]	23	10.3	0.2	0.7
Nov 6, 2020	4	[redacted]	[redacted]	[redacted]	23	22.8	0.5	0.7
Dec 1, 2020	5	[redacted]	[redacted]	[redacted]	15	26.4	0.4	0.6
Dec 2, 2020	5	[redacted]	[redacted]	[redacted]	15	26.4	0.4	0.6
Dec 3, 2020	5	[redacted]	[redacted]	[redacted]	15	26.4	0.4	0.6
Dec 4, 2020	5	[redacted]	[redacted]	[redacted]	15	26.4	0.4	0.6
Dec 7, 2020	4	[redacted]	[redacted]	[redacted]	10	[redacted]	[redacted]	[redacted]
Dec 8, 2020	1	[redacted]	[redacted]	[redacted]	5	[redacted]	[redacted]	[redacted]
Jan 4, 2021	8	[redacted]	[redacted]	[redacted]	6	[redacted]	[redacted]	[redacted]
Jan 5, 2021	13	[redacted]	[redacted]	[redacted]	10	[redacted]	[redacted]	[redacted]
Jan 6, 2021	1	[redacted]	[redacted]	[redacted]	-	-	-	-
Jan 12, 2021	1	[redacted]	[redacted]	[redacted]	-	-	-	-
Feb 9, 2021	1	[redacted]	[redacted]	[redacted]	-	-	-	-
Feb 10, 2021	1	[redacted]	[redacted]	[redacted]	-	-	-	-
Feb 12, 2021	5	[redacted]	[redacted]	[redacted]	15	20.2	0.3	0.7
Feb 16, 2021	5	[redacted]	[redacted]	[redacted]	15	20.2	0.3	0.7
Feb 17, 2021	5	[redacted]	[redacted]	[redacted]	15	19.0	0.3	0.7
Feb 18, 2021	4	[redacted]	[redacted]	[redacted]	15	15.9	0.2	0.7
Feb 19, 2021	4	[redacted]	[redacted]	[redacted]	15	26.1	0.4	0.7
Mar 1, 2021	10	[redacted]	[redacted]	[redacted]	11	[redacted]	[redacted]	[redacted]
Mar 4, 2021	1	[redacted]	[redacted]	[redacted]	-	-	-	-
Mar 8, 2021	18	48.3	0.9	1.9	15	-1.7	<0.1	0.5
Mar 15, 2021	8	[redacted]	[redacted]	[redacted]	4	[redacted]	[redacted]	[redacted]
Mar 16, 2021	18	50.2	0.9	1.9	15	18.1	0.3	0.5
Mar 17, 2021	18	50.2	0.9	1.9	15	18.1	0.3	0.5
Mar 30, 2021	17	35.9	0.6	1.5	15	18.1	0.3	0.5
Apr 1, 2021	5	[redacted]	[redacted]	[redacted]	15	16.1	0.2	0.5
Apr 12, 2021	5	[redacted]	[redacted]	[redacted]	15	22.7	0.3	0.5
Apr 13, 2021	5	[redacted]	[redacted]	[redacted]	15	21.7	0.3	0.5
Apr 19, 2021	5	[redacted]	[redacted]	[redacted]	15	22.7	0.3	0.5
Apr 28, 2021	1	[redacted]	[redacted]	[redacted]	-	-	-	-
Apr 29, 2021	4	[redacted]	[redacted]	[redacted]	15	21.7	0.3	0.5

Event	Day Ahead				Day Of			
	# of Accts	Per Customer Impact (kW)	Aggregate Impact (MW)	Dispatched Capacity (MW)	# of Accts	Per Customer Impact (kW)	Aggregate Impact (MW)	Dispatched Capacity (MW)
May 4, 2021	416	15.8	6.6	10.2	278	10.5	2.9	4.2
May 5, 2021	416	12.0	5.0	10.2	278	9.5	2.6	4.2
May 6, 2021	416	15.8	6.6	10.2	278	10.5	2.9	4.2
May 11, 2021	416	14.4	6.0	10.2	278	9.5	2.6	4.2
May 12, 2021	416	15.8	6.6	10.2	278	10.5	2.9	4.2
Jun 1, 2021	414	15.7	6.5	9.9	253	13.5	3.4	3.7
Jun 2, 2021	414	15.7	6.5	9.9	253	13.5	3.4	3.7
Jun 3, 2021	414	16.7	6.9	9.9	253	12.5	3.2	3.7
Jun 14, 2021	414	9.6	4.0	9.9	253	8.3	2.1	3.7
Jun 15, 2021	414	10.2	4.2	9.9	279	8.2	2.3	4.4
Jul 1, 2021	402	16.4	6.6	10.6	211	13.9	2.9	2.9
Jul 2, 2021	403	16.1	6.5	10.6	244	16.2	3.9	3.4
Jul 5, 2021	59	6.8	0.4	1.1	27	15.8	0.4	0.4
Jul 6, 2021	403	15.9	6.4	10.6	244	13.5	3.3	3.4
Jul 7, 2021	403	15.8	6.4	10.6	244	13.7	3.3	3.4
Jul 8, 2021	344	11.6	4.0	9.4	244	9.4	2.3	3.4
Jul 9, 2021	1	[redacted]	[redacted]	[redacted]	6	[redacted]	[redacted]	[redacted]
Aug 2, 2021	379	14.4	5.5	8.7	243	10.6	2.6	2.8
Aug 3, 2021	379	14.4	5.5	8.7	243	10.6	2.6	2.8
Aug 4, 2021	379	14.4	5.5	8.7	243	10.6	2.6	2.8
Aug 27, 2021	379	16.7	6.3	8.7	265	19.8	5.3	3.4
Aug 30, 2021	379	14.5	5.5	8.7	265	10.6	2.8	3.4
Sep 7, 2021	141	11.1	1.6	4.1	-	-	-	-
Sep 8, 2021	269	11.6	3.1	6.5	-	-	-	-
Sep 9, 2021	269	11.6	3.1	6.5	214	12.3	2.6	2.6
Sep 10, 2021	141	11.1	1.6	4.1	-	-	-	-
Sep 21, 2021	141	11.2	1.6	4.1	-	-	-	-
Oct 4, 2021	266	9.4	2.5	5.3	-	-	-	-
Oct 15, 2021	139	3.9	0.5	3.2	-	-	-	-
Oct 19, 2021	139	3.9	0.5	3.2	-	-	-	-
Oct 27, 2021	139	3.9	0.5	3.2	-	-	-	-
Oct 28, 2021	266	5.5	1.5	5.3	-	-	-	-

Table ES-5 Summary of PY2021 SDG&E Ex-Post Impacts and Dispatched Capacity[15]

Event	Day Ahead				Day Of			
	# of Accts	Per Customer Impact (kW)	Aggregate Impact (MW)	Dispatched Capacity (MW)	# of Accts	Per Customer Impact (kW)	Aggregate Impact (MW)	Dispatched Capacity (MW)
Jun 15, 2021	48	22.5	1.1	1.2	124	21.0	2.6	3.2
Jun 16, 2021	48	16.0	0.8	1.2	124	21.0	2.6	3.2
Jun 17, 2021	48	6.7	0.3	1.2	124	0.3	<0.1	3.2
Jun 28, 2021	48	4.3	0.2	1.2	124	12.1	1.5	3.2
Jun 29, 2021	48	3.5	0.2	1.2	124	3.1	0.4	3.2
Jun 30, 2021	30	-4.5	-0.1	0.5	-	-	-	-
Jul 9, 2021	18	-0.8	<0.1	0.7	123	0.5	0.1	3.1
Jul 12, 2021	18	-1.6	<0.1	0.7	123	-1.5	-0.2	3.1
Jul 19, 2021	18	6.3	0.1	0.7	123	0.5	0.1	3.1
Jul 27, 2021	18	19.6	0.4	0.7	-	-	-	-
Jul 28, 2021	18	20.2	0.4	0.7	123	7.6	0.9	3.1
Jul 29, 2021	18	11.0	0.2	0.7	-	-	-	-
Jul 30, 2021	18	-4.2	-0.1	0.7	123	-5.5	-0.7	3.1
Aug 26, 2021	30	-1.8	-0.1	0.7	133	14.9	2.0	3.3
Aug 27, 2021	30	-5.8	-0.2	0.7	133	4.1	0.5	3.3
Aug 31, 2021	30	0.8	<0.1	0.7	-	-	-	-
Sep 8, 2021	18	14.8	0.3	0.5	130	15.3	2.0	3.4
Sep 9, 2021	18	27.3	0.5	0.5	130	15.3	2.0	3.4
Sep 10, 2021	35	-1.5	-0.1	0.8	130	3.2	0.4	3.4
Sep 21, 2021	18	31.9	0.6	0.5	130	15.7	2.0	3.4
Sep 22, 2021	18	38.3	0.7	0.5	130	1.1	0.1	3.4
Sep 23, 2021	18	15.9	0.3	0.5	11	13.0	0.1	0.3
Oct 15, 2021	31	8.7	0.3	0.7	-	-	-	-
Oct 19, 2021	17	11.2	0.2	0.3	120	10.3	1.2	2.8
Oct 21, 2021	31	1.3	<0.1	0.7	11	-3.8	<0.1	0.3
Oct 26, 2021	48	6.0	0.3	1.0	-	-	-	-
Oct 27, 2021	48	-3.2	-0.2	1.0	11	-3.8	<0.1	0.3
Oct 28, 2021	48	-0.1	<0.1	1.0	131	9.4	1.2	3.1

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

Ex-Ante Load Impacts

Each program's load impact forecast is based on IOU-specific assumptions that incorporate a combination of the following: aggregator/nomination outlook, delivery performance, ex-ante per-customer load impacts, enrollment growth, and an impact degradation rate across the RA window.

Both PG&E and SCE assume a constant forecast across the forecast horizon, despite PG&E's Residential DA expected slow uptake in enrollments, estimating zero enrollments through August 2022. For this filing, SCE assumes zero enrollment in Residential CBP due to a lack of active nominations. SCE also assumes zero enrollment for its non-summer seasons, given its low enrollment and low delivery performance in PY2021.

SDG&E, on the other hand, anticipates a jump in enrollment and nominations with the addition of CBP Elect products starting in 2022. As in previous years, the enrollment forecast assumes a 2% growth per year from 2022-2027 due to SDG&E's proposed program improvements. In addition, SDG&E forecasts the CBP DO program enrollment will increase by another 1% per year starting in 2022-2023 due to growth in the Technical Incentives (TI) program[16]. The enrollment forecasts for both programs show a flat trend from 2027-2032. SDG&E's forecast does not include a residential forecast.

Table ES-6 summarizes the 11-year enrollment and load impact forecast by IOU and program for an August peak day across the RA window.

Table ES-6 Statewide CBP: 2022-2032 Forecast, August Peak Day

IOU	Program	Number of Service Accounts			Aggregate Impact (MW)		
		2022	2023	2027-2032 (Each Year)	2022	2023	2027-2032 (Each Year)
PGE	Residential Day Ahead	0	6,972	6,972	0.0	1.3	1.3
	Non-Residential Day Ahead	1,505	1,505	1,505	37.1	37.1	37.1
SCE	Non-Residential Day Ahead	410	410	410	4.2	4.2	4.2
	Non-Residential Day Of	290	290	290	1.7	1.7	1.7
SDG&E	Non-Residential Day Ahead	105	107	116	2.3	2.4	2.6
	Non-Residential Day Of	208	212	227	3.5	3.6	3.8

Table ES-7 summarizes the Non-residential RA window load impact forecasts for an August peak day in 2022 by IOU and program for each weather scenario across the RA window. Since CBP impacts are inherently nomination-driven, not weather-driven, we assumed constant per-customer load impacts across the weather scenarios. The per-customer load impacts are also assumed to remain constant across May through October, i.e., constant nominations through the season. However, since participant usage can be weather-dependent, the weather scenarios affect the estimated reference load, resulting in varying percent impacts across the months and weather scenarios.

The above statement does not apply to Residential RA window load impacts. We do not assume load impacts to be flat across months and weather scenarios. Instead, we assume constant HE20 percent impacts, accounting for the available load during each hour of the RA window. However, the

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

differences between weather scenarios are minimal and cannot be distinguished at the per-customer (kw) and aggregate (MW) level.

Table ES-7 Statewide CBP: RA Window Ex-Ante Load Impacts, August Peak Day, 2022

IOU	Program	# of Accts	Per Customer (kW)	Aggregate Impact (MW)	Percent Impact (%)			
					Utility Peak		CAISO Peak	
					1-in-2	1-in-10	1-in-2	1-in-10
PGE	Residential Day Ahead*	4,357	0.2	0.9	32.0%	27.5%	33.7%	29.5%
	Non-Residential Day Ahead	1,505	24.6	37.1	17.3%	17.0%	17.4%	17.3%
SCE	Non-Residential Day Ahead	410	10.1	4.2	12.9%	12.9%	12.9%	12.9%
	Non-Residential Day Of	290	6.0	1.7	5.7%	5.7%	5.7%	5.7%
SDG&E	Non-Residential Day Ahead	105	22.0	2.3	21.7%	21.2%	21.6%	21.7%
	Non-Residential Day Of	208	16.9	3.5	17.2%	16.9%	17.1%	17.2%

*Shown for 2022 Typical event day due to zero forecasted August 2022 enrollments.

Key Findings

In PY2021, we have the following key findings:

- HE20 (7 PM – 8 PM) is the most dispatched event hour for PG&E and SCE programs, while HE19 (6 PM – 7 PM) is the most dispatched event hour for SDG&E.
- Only the PG&E Non-residential DA program performed successfully with a 96% delivery performance and a 105% adjusted delivery performance.
    - SCE's two non-residential programs jointly resulted in 58% summer delivery performance, while SDG&E's two non-residential programs jointly resulted in 29% delivery performance.
- Participation adjusts to fill aggregator nominations. The CBP programs show a combination of slow growth or consistency in capacity nominations despite fluctuating participant counts.
    - SDG&E anticipates an uptake in nominations and enrollment with the addition of the two CBP Elect products in PY2022.

Recommendations

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

- **Aggregator In-Depth Interviews.** We recommend performing in-depth interviews (IDI) for all active PY2022 aggregators. These IDIs will provide valuable insight into aggregator performances and challenges that can:
    - **Inform the ex-post analysis**, allowing the evaluator to appropriately set up the regression analyses. In other words, specify indicators that can isolate special cases such as notification issues, delivery issues, etc. Such specifications will allow for more accurate event-level estimates.

  - **Inform the ex-ante analysis**, receiving feedback on aggregator outlook on CBP participation/nominations will allow evaluators to develop more informed forecast assumptions.
  - In addition, we can potentially collect insight that can inform how the CBP programs can evolve in the future.
- **Continue to Improve on Report Organization.** We recommend two organizational improvements for future reports:
  - **Organize report findings by IOU.** Although we use consistent approaches in analyses and reporting, we recognize that each IOU has a unique story to tell. Organizing the report to have each IOU and program ex-post results, ex-ante results, and key findings in one section may add overall clarity and value.
  - **Move event day tables to the end of each IOU's section or an appendix.** We recommend streamlining the report, putting more focus on program summaries and key takeaways while still giving access to more granular information as needed.
- **System-Level Test Events (PG&E Only).** We recommend dispatching one or two system-level test events in the PG&E Non-residential DA program. System-level events are rare within the PG&E territory since events are dispatched according to CAISO market awards. Measured performance on a system-level event will be valuable in informing the ex-ante analyses, which estimate system-level performance during the RA window.

CONTENTS

LIST OF FIGURES

LIST OF TABLES

1

INTRODUCTION

This report documents the Program Year 2021 (PY2021) statewide load impact evaluation of the Capacity Bidding Program (CBP), an aggregator-based demand response (DR) program 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).

Research Objectives

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

- **Estimate Ex-post load impacts** for the average customer and all customers in aggregate for each hour of each event day and the average event day. We present all estimates at the program level and separately for each product offering. For the Non-residential programs, we provide estimates for the following customer segments: aggregator, size group, industry type, local capacity area (LCA), sub-load aggregation point (Sub-LAP), and enrollment in AutoDR or other DR programs. For Residential programs, we provide estimates for the following customer segments: aggregator, LCA, Sub-LAP, and CARE status.
- **Estimate Ex-ante load impacts** for the average customer and all customers in aggregate for the resource adequacy (RA) window (4 PM to 9 PM). We provide estimates for each year over an 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. We provide estimates for both program-specific and portfolio-adjusted scenarios. As applicable, we also provide estimates for the following customer segments: size group, LCA, Sub-LAP, and busbar.

Key Changes in the PY2021 Report

Based on feedback received on the PY2020 evaluation report, AEG made significant efforts to improve the overall clarity of the PY2021 evaluation report. These efforts include updating the terminology used in the report and carefully reviewing it for consistency. Table 1-1 presents the key terms and corresponding definitions as used in this report.

Table 1-1 Report Terminology

TERM	DEFINITION
PROGRAM	**A combination of IOU, Customer Class, and Notification Type.** For example, SDG&E has two programs: (1) SDG&E Non-residential Day Ahead and (2) SDG&E Non-residential Day Of.
PRODUCT	**A product offering within each program.** For example, the PG&E Day Ahead program has three products: (1) Elect, (2) Elect+, and (3) Prescribed.
CUSTOMER CLASS	Defined as **Residential or Non-residential**.

[17] PG&E and SDG&E has requested a PY2021 back cast as part of the ex-ante impact analysis.

TERM	DEFINITION
NOMINATION	**A monthly nominated resource by program, product, aggregator, and Sub-LAP.** Each nominated resource has a corresponding capacity nomination (MW) and enrolled customers.
DISPATCHED	**An entity called to a market-triggered event.** For example, a dispatched resource, dispatched customers, dispatched capacity, etc. Not all nominated entities are dispatched.
AVERAGE EVENT DAY	For each product, calculated as **the average of all events dispatched** regardless of event hours and number of Sub-LAPS. The program-level average event day is the sum of all product-level average event days. Load impacts are reported for each program and product's most dispatched event hour.
REPORTING HOUR	**The hour reported for the ex-post average event day.** This hour is the most dispatched event hour for each program and product.
DELIVERY PERFORMANCE	A percentage metric equal to the ex-post aggregate load impacts **divided by the overall dispatched capacity**. It was referred to as "nomination achievement" in the PY2020 report.
ADJUSTED DELIVERY PERFORMANCE	A percentage metric equal to the ex-post aggregate load impacts **divided by the reporting hour (HE19 for SDG&E or HE20 for PG&E and SCE) dispatched capacity**. We calculate an adjusted metric to measure performance because our definition of the average event day includes events that did not dispatch capacity during the reporting hour.
IMPACT DEGRADATION RATE	**An assumption developed for a simulated 5-hour RA window** based on historical events. This assumption represents how customers, on average, can maintain impacts throughout events called for longer durations.

Other Report References

For reference, Table 1-2 presents the eight industry-type definitions and corresponding NAICS codes, and Table 1-3 presents the three customer size definitions.

Table 1-2 Non-Residential Industry Type Definitions

Industry Type	NAICS Codes
1. Agriculture, Mining & Construction	11, 21, 23
2. Manufacturing	31-33
3. Wholesale, Transport, Other Utilities	22, 42, 48-49
4. Retail Stores	44-45
5. Offices, Hotels, Finance, Services	51-56, 62, 72
6. Schools	61
7. Institutional/Government	71, 81, 92
8. Other/Unknown	N/A

Table 1-3 Non-Residential Customer Size Definitions

Customer Size Group	Maximum Demand
Large	200 kW and above
Medium	20 kW to 199.99 kW
Small	19.99 kW and below

Report Organization

We organize the remainder of this report into the following sections:

- Section 2 provides program descriptions and expected program changes by CA IOU.
- Section 3 describes the methods used to estimate the ex-post and ex-ante load impacts.
- Section 4 presents the PY2021 ex-post load impact estimates.
- Section 5 presents the PY2021 ex-ante load impact estimates
- Section 6 presents key findings and recommendations.

2

PROGRAM DESCRIPTIONS AND RESOURCES

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

Aggregators. In CBP, aggregators contract with eligible residential[18] and non-residential utility customers to act on their behalf in all aspects of the demand response (DR) program. Aggregators receive dispatch notifications (day-ahead or day-of), incentive payments, and penalties from the IOUs. Each aggregator forms a resource, a portfolio of customers, to provide load reduction during events. Each resource participates collectively, wherein load reduction is measured on an aggregate basis. The aggregators enroll customers under the terms of their own contracts to provide the load reduction capacity and receive corresponding incentives. In other words, IOUs are not directly involved in the contracts between aggregators and customers. CBP may have customers/participants classified as self-aggregated.

Eligibility. Aggregators must have Internet access. Enrolled customers must have a qualifying interval meter and receive Bundled, Direct Access, or Community Choice Aggregation service.[19] Customers enrolled in CBP may dually participate in an energy-only DR program (i.e., cannot have a capacity payment component) that does not have the same notification type (DA or DO).

Incentives. CBP provides monthly capacity payments ($/kW) to aggregators based on the nominated kW load, the specific operating month, the event duration, resource performance during an event, and the event notice option. Delivered capacity determines performance. If an aggregator's delivered capacity is less than the tariff threshold (50% for SCE and SDG&E and 60% for PG&E), the aggregator is assessed a penalty. CBP aggregators receive the full monthly capacity payment for months without dispatched events based on their nominations with no energy payments.[20] Additional energy payments ($/kWh) are made to the aggregator[21] based on the measured kWh reductions (relative to the program baseline) achieved when an event is dispatched.[22]

The following subsections describe each IOU's PY2021 product offerings, expected program changes, and nominations.

[18] Since PY2018, the program was open to residential customer enrollment.

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

[20] Self-aggregated customers 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.

[21] Self-aggregated customers receive additional energy payments directly.

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

PG&E

As of PY2018, PG&E's CBP only offers DA notification. Aggregators nominate a monthly capacity amount for one of three options: Prescribed, Elect, and Elect+.

- **Prescribed DA** – PG&E sets the CAISO market bid price and dispatch strategy within specified operating hours (1-4 hours and 2-6 hours).
- **Elect DA** – Aggregators set their own CAISO market bid price within specified operating hours (1-4 hours, 2-6 hours, and 1-8 hours).
- **Elect+ DA** – Similar to Elect wherein aggregators set their own CAISO market bid price but includes additional hours outside the minimum specified operating hours (1-4 hours, 2-6 hours, and 1-24 hours).

As of PY2020, the PG&E CBP operating hours are between 1 PM to 9 PM. Events are called Monday through Friday, excluding holidays, during May through October, with a maximum of five events and 30 hours per month (or possibly more hours under Elect and Elect+ Options if the participants so choose).

Program Changes

The following list summarizes the program changes effective during the PY2021 season:

- Effective March 8, 2021:
  - Implemented a 5-in-10 baseline option for residential customers,
  - Changed the nomination deadline to the 15th prior to the operating month,
  - Changed the bidding deadline for the Elect and Elect+ offering to three days prior to trade day, and
  - Removed the 100-kW/Sub-LAP requirement for resource nomination.
- Effective March 25, 2021:
  - Introduced the option for resources to participate on weekends, and
  - Increased to a maximum of six events per month.

2021 Nominations

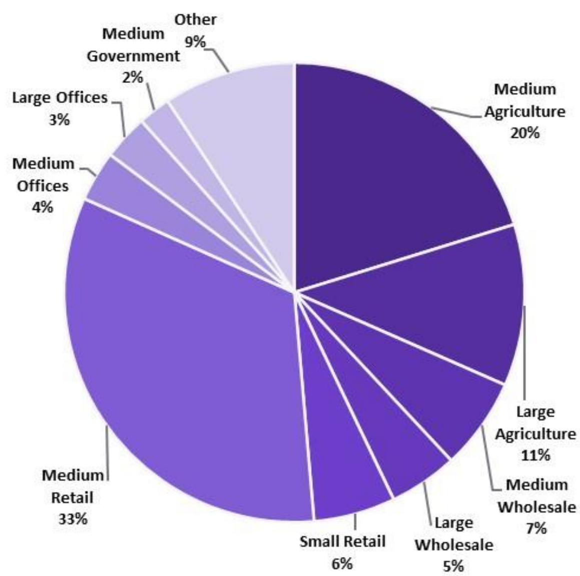
Table 2-1 presents the program-level monthly nominations for PG&E's CBP programs. On average, Residential DA had [redacted] MW consisting of 21 customers, while Non-residential DA had 50.1 MW consisting of 879 customers. Table 2-2 shows the size and industry distribution of Non-residential enrollment, and the accompanying graph highlights the predominant customer segments in PY2021.

Table 2-1 PG&E Monthly Nominations

Month	Residential DA		Non-Residential DA	
	Enrolled Accounts	Nominated Capacity (MW)	Enrolled Accounts	Nominated Capacity (MW)
May	-	-	701	34.2
June	-	-	750	41.6
July	-	-	938	61.3
August	-	-	942	60.8
September	23	[redacted]	980	56.0
October	19	[redacted]	960	47.0
Avg. Summer	**21**	[redacted]	**879**	**50.1**

Table 2-2 PG&E Non-Residential Enrollment

Industry Type	Size Group			Total
	Small	Medium	Large	
1. Agriculture, Mining & Construction	12	222	125	**359**
2. Manufacturing	-	1	25	**26**
3. Wholesale, Transport, Other Utilities	4	71	53	**128**
4. Retail Stores	63	363	31	**457**
5. Offices, Hotels, Finance, Services	7	39	35	**81**
6. Schools	-	-	3	**3**
7. Institutional/ Government	7	25	2	**34**
8. Other/Unknown	7	3	-	**10**
Total	**100**	**724**	**274**	**1,098**



SCE

Effective May 1, 2018, SCE's two CBP programs, Non-residential DA and Non-residential DO, offer one product each:

- DA 1-6 Hour – day-ahead notifications with events from 1-6 hour durations.
- DO 1-6 Hour – day-of notifications with events from 1-6 hour durations.

Effective January 19, 2020, the CBP dispatch window was changed to 3 PM to 9 PM to better align with the RA window (4 PM to 9 PM). SCE CBP events are determined by CAISO market awards and may be called Monday through Friday, excluding holidays, year-round, with a maximum of 5 events and 30 hours per month.

Program Changes

In PY2021, no substantial changes were implemented to SCE Non-residential CBP. Residential CBP is now open to aggregators as a full program using a 5-in-10 baseline, but SCE has not yet received nominations.

2021 Nominations

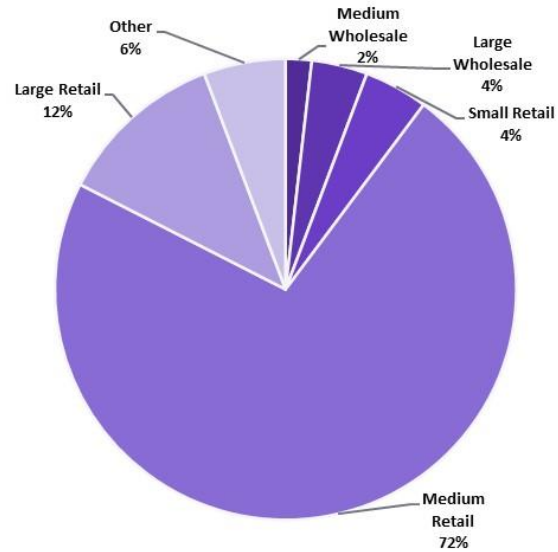
Table 2-3 presents the program-level monthly nominations for SCE's CBP programs. On average, Non-Residential DA had [redacted] MW (9 customers) and 9.3 MW (393 customers) for non-summer and summer, respectively. Non-Residential DO had 0.7 MW (17 customers) and 3.8 MW (270 customers) for non-summer and summer, respectively. Table 2-4 shows the size and industry distribution of Non-residential enrollment, and the accompanying graph highlights the predominant customer segments in PY2021.

Table 2-3 SC&E Monthly Nominations

Month	Non-Residential DA		Non-Residential DO	
	Enrolled Accounts	Nominated Capacity (MW)	Enrolled Accounts	Nominated Capacity (MW)
November	4	[redacted]	28	1.0
December	5	[redacted]	15	0.6
January	14	[redacted]	15	0.7
February	5	[redacted]	15	0.7
March	18	1.9	15	0.5
April	5	[redacted]	15	0.5
Avg. Non-Summer	**9**	[redacted]	**17**	**0.7**
May	416	10.2	278	4.2
June	414	9.9	279	4.4
July	403	10.6	266	4.1
August	379	8.7	265	3.4
September	373	9.0	270	3.6
October	364	7.2	259	3.3
Avg. Summer	**392**	**9.3**	**270**	**3.8**

Table 2-4 SCE Non-Residential Enrollment

Industry Type	Size Group			Total
	Small	Medium	Large	
1. Agriculture, Mining & Construction	-	-	2	**2**
2. Manufacturing	-	1	5	**6**
3. Wholesale, Transport, Other Utilities	1	13	28	**42**
4. Retail Stores	32	517	84	**633**
5. Offices, Hotels, Finance, Services	-	6	8	**14**
6. Schools	-	5	6	**11**
7. Institutional/ Government	-	1	2	**3**
8. Other/Unknown	2	2	-	**4**
Total	**35**	**545**	**135**	**715**



SDG&E

SDG&E currently offers four CBP products under two programs: Non-residential DA and Non-residential DO, summarized in Table 2-5. SDG&E CBP events may be called Monday through Friday, excluding holidays, from May through October, with a maximum of 24 hours per month.

Effective May 1, 2019, SDG&E can call up to 6 event days per month with up to three consecutive event days per month. SDG&E no longer allows dual DR enrollment in CBP. Customers who were dually enrolled before October 1, 2018, were grandfathered in.

Table 2-5 SDG&E Product Types

Program	Product	Operating Hours	Minimum Duration per Event	Maximum Duration per Event	Maximum Cumulative Event Duration per Operational Month	Maximum Events per Day	Maximum Events per Month
Non-Res DA	DA 11-7 Hour	11 AM–7 PM	2 hours	4 hours	24	1	6
	DA 1-9 Hour	1 PM–9 PM	2 hours	4 hours	24	1	6
Non-Res DO	DO 11-7 Hour	11 AM–7 PM	2 hours	4 hours	24	1	6
	DO 1-9 Hour	1 PM–9 PM	2 hours	4 hours	24	1	6

SDG&E has the following program triggers:

- Effective December 15, 2018, Day Ahead Product: SDG&E may call an event whenever the day-ahead market price is equal to or greater than $80/MWh or as utility system conditions warrant. The day-ahead market price is defined as California Independent System Operator (CAISO) DLAP or applicable pnode SDGE-APND day-ahead market locational marginal price (DAM LMP).

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

Program Changes

- SDG&E is currently implementing a Residential CBP pilot, limiting the number of residential enrollments due to system limitations.
- In PY2022, SDG&E is adding two Elect products with three price trigger options: $200/MWh, $400/MWh, or $600/MWh. SDG&E will refer to the previously existing products as Prescribed products. Table 2-6 summarizes the SDG&E product offering effective in PY2022.

Table 2-6 SDG&E Product Types, Effective 2022

Program	Product	Operating Hours	Minimum Duration per Event	Maximum Duration per Event	Maximum Cumulative Event Duration per Operational Month	Maximum Events per Day	Maximum Events per Month
Non-Res DA	Presc DA 11-7 Hour	11 AM–7 PM	2 hours	4 hours	24	1	6
	Presc DA 1-9 Hour	1 PM–9 PM	2 hours	4 hours	24	1	6
	Elect DA 1-9 Hour	1 PM–9 PM	2 hours	4 hours	24	1	6
Non-Res DO	Presc DO 11-7 Hour	11 AM–7 PM	2 hours	4 hours	24	1	6
	Presc DO 1-9 Hour	1 PM–9 PM	2 hours	4 hours	24	1	6
	Elect DO 1-9 Hour	1 PM–9 PM	2 hours	4 hours	24	1	6

2021 Nominations

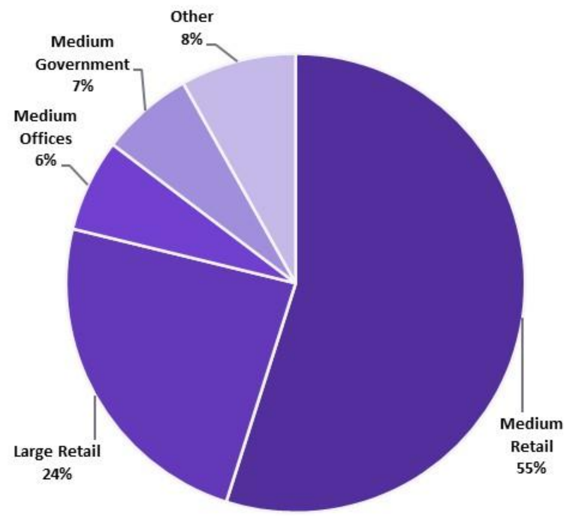
Table 2-7 presents the program-level monthly nominations for SDG&E's CBP programs. On average, Non-residential DA had 1.1 MW consisting of 43 customers, while Non-residential DO had 3.2 MW consisting of 131 customers. Table 2-8 shows the size and industry distribution of Non-residential enrollment, and the accompanying graph highlights the predominant customer segments in PY2021.

Table 2-7 SDG&E Monthly Nominations

Month	Non-Residential DA		Non-Residential DO	
	Enrolled Accounts	Nominated Capacity (MW)	Enrolled Accounts	Nominated Capacity (MW)
May	40	1.4	134	2.9
June	48	1.2	126	3.2
July	36	1.0	133	3.3
August	48	1.0	133	3.3
September	35	0.8	130	3.4
October	48	1.0	131	3.1
Avg. Summer	**43**	**1.1**	**131**	**3.2**

Table 2-8 SDG&E Non-Residential Enrollment

Industry Type	Size Group			Total
	Small	Medium	Large	
1. Agriculture, Mining & Construction	-	-	1	**1**
2. Manufacturing	-	-	1	**1**
3. Wholesale, Transport, Other Utilities	-	2	1	**3**
4. Retail Stores	5	101	44	**150**
5. Offices, Hotels, Finance, Services	-	12	2	**14**
6. Schools	-	-	1	**1**
7. Institutional/ Government	-	12	2	**14**
8. Other/Unknown	-	-	-	-
Total	**5**	**127**	**52**	**184**



3

STUDY METHODS

This section presents the methods used to estimate the ex-post and ex-ante load impacts for statewide CBP.

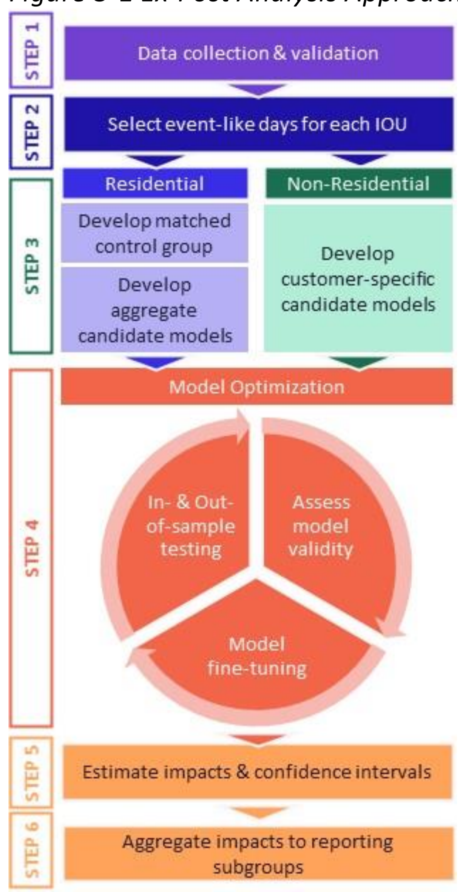
Ex-Post Load Impact Analysis

We explicitly designed the PY2021 ex-post LI analysis to meet each of the objectives listed below, all objectives to be provided at the program level and separately for each product offering.

- To develop hourly load impact estimates for each event in PY2021 and estimate the average event day by season, as applicable,
- To provide Non-residential estimates by various segments: aggregator, size group, industry type, local capacity area (LCA), sub-load aggregation point (Sub-LAP), and enrollment in AutoDR or other DR programs; and Residential estimates by various segments: aggregator, LCA, Sub-LAP, and CARE status, and
- To estimate the distribution of load impacts by customer segment for the average event.

We used the same methodology across all programs to ensure consistency of results. Figure 3-1 presents an overview of our ex-post analysis approach. To account for unique program features specified within each IOU's CBP tariff, each program is modeled independently, modifying assumptions to account for differences in CBP program design and implementation. With the addition of PG&E's Residential participation in PY2020, it is important to highlight the key differences in the approach used for the two customer classes.

Figure 3-1 Ex-Post Analysis Approach



The Residential program analysis used a matched control group and aggregate hourly regression models. This approach is the best practice for participant populations with less variable loads, which can leverage the higher statistical power with more customers included in each model. A matched control group also more effectively estimates the counterfactual load without a randomized control trial.

The Non-Residential programs analyses continued to use a within-subject design using customer-specific hourly regression models. It remains the most flexible, consistent, and appropriate solution for CBP's evaluation goals and population distributions. This approach has the following features:

- The individual customer impacts can be added together to estimate load impacts at any level or customer segmentation.
- Regression models can be easily used to control for variation in load due to weather conditions, geography, and time-related variables (day of the week, month, hour, etc.).
- Estimating models for each customer can also control for unobservable customer-specific effects that are more difficult to account for in aggregate regression models.
- Commercial and industrial customers often vary significantly from one another in load shape, weather response, and overall size. Customer-specific regressions allow us to capture differences between customers; therefore, they can better model changes in energy usage than an aggregated model.
- The data conforms to a repeated-measures design wherein events are called on isolated days over the program year, and customers face similar TOU rates on all other days. A repeated-measures design means that all participants are subjected to the treatment simultaneously, repeatedly throughout the study. In this case, the control is defined as an absence of the treatment or the non-event days.

Each step in the ex-post analysis is detailed in the next subsections.

Step 1: Data Collection and Validation

Data Collection. We collected the data items (listed below) from each IOU, as available, and constructed a database that houses the data collected to perform the analysis across all three IOUs. The database served as the foundation for the data validation process.

- Aggregator monthly bid and nomination data,
- Customer characteristics and participation information,
- Customer characteristics for residential non-participant pool,
- Local capacity area and local busbar identifier,
- CBP dispatched event data including product, dates, time, and duration of each event, and trigger information,
- Other DR program event data (for dually enrolled participants),
- Post-event estimated load impacts provided to CAISO,
- Hourly interval usage data, and
- Actual hourly weather data by weather station

Data Validation. AEG's validation process included screening the interval data for zero usage intervals, missing intervals, potentially erroneous peaks and valleys, and other erroneous intervals while being mindful of the risks posed by over-omitting data. We used this automated approach to flag possible erroneous intervals. We were careful to consider how event days differ from non-event days and how each customer class may require a distinct set of screening algorithms. For example, non-residential participants can potentially have event days that contain zero intervals and outlier reads, depending on their curtailment approach. However, for residential participants, zero intervals and outlier reads more likely to indicate missing data or power outages. *With the addition of Residential participants in*

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

We documented the counts of intervals or customers removed from the analysis for each IOU, customer class, industry type, and customer size (as appropriate) during each step in the data validation process to determine the reasonableness of omissions from a top-down perspective. In addition, we spot-checked a small sample of dropped intervals from each segment to confirm the appropriateness of omissions in those cases and incorporated any updates to the data validation process, as needed, to ensure we use the best available data for the analyses.

Step 2: Event-like Days Selection

The selection of comparable non-event days (i.e., event-like days) is essential to several of the evaluation activities. Event-like days were used in the matched control group development and the out-of-sample testing in model optimization. In matched control group development, these event-like days served as the basis for matching participants to non-participants by ensuring that matched customers consume energy similarly on days comparable to event days. In out-of-sample testing, we used event-like days to test the predictive abilities of each model as part of our model optimization process, employed regardless of the analysis design.

The event-like days include 5 to 15 days (by IOU and customer class) comparable to dispatched CBP events in weather, day of the week, and month of the year. We selected the group of days that collectively minimize the Euclidean distance (ED)[23] across multiple weather-based criteria. We describe the ED matching method in more detail in a subsequent subsection on Matched Control Group Development under Step 3. This approach identified sets of days as similar as possible to dispatched event days. We discuss selected event-like days in the Model Validity Appendix.

Step 3. Analysis Designs by Customer Class

This step discusses the analysis designs for both non-residential and residential customer classes.

Non-Residential Analysis Design

AEG continued using **a within-subjects, customer-specific modeling approach for all non-residential participants** across all three IOUs. Given the evaluation objectives and the potential differences across service territories, customer-specific models offer the most flexible, consistent, and appropriate solution for several reasons:

- Commercial and industrial customers often vary significantly from one another in load shape, weather response, and overall size. Customer-specific models allow us to capture differences between customers; therefore, they can better model changes in energy usage than an aggregated model. The models can easily control for variation in load due to weather conditions, geography, and time-related variables (day of the week, month, hour, etc.). They also control for unobservable customer-specific effects that are more difficult to account for in aggregate regression models.
- The data conforms to a repeated-measures design because the events are called only on isolated days over the program year, and the participants face similar TOU rates on all other days. A repeated-measures design means that all participants are subjected to the treatment

[23] We used weather variables in the Euclidean distance metrics calculation to select event-like days and developed a metric specific to each IOU and customer class. We discuss each metric used in the Model Validity Appendix.

simultaneously, repeatedly throughout the study. In this case, the control is defined as an absence of the treatment or the non-event days.

- The models estimate individual customer impacts that can be summed together to estimate impacts for any reporting subgroup, including but not limited to IOU, program, product, aggregator, LCA, SubLAP, industry type, or customer type.

Develop Candidate Regression Models. It is not practical to develop models individually for thousands of participants; therefore, AEG developed a set of candidate models that will go through our model optimization process to select the best model for each participant.

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. 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] Table 3-1 presents the different explanatory variables used to create candidate models for the CBP 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
$AvgLoad_{i,d}$	The average of each day's load in the specified window[25]
	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
$P*EventWindow_{i,d}$	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, we developed sets of candidate models 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.

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

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

Residential Analysis Design

AEG continued using **a matched control group and aggregate modeling approach for all residential participan**ts across all three IOUs, as applicable. This analysis design is appropriate for several reasons:

- Residential participants do not typically have highly variable loads. This approach allows for the effective use of aggregate models, which have higher statistical power with more customers included in the model.
- Using a matched control group enables us to estimate event-day impacts against counterfactual load developed from non-participant consumption on the actual event day.
- The models will estimate the load impacts for each combination of customer segments required in the CPUC LIP. The results for each combination can be easily aggregated to represent impacts for each of customer segment required by the CPUC LIP.

Matched Control Group Development. To create the matched control group, we used a Stratified Euclidean Distance Matching (SEDM) technique that we have used successfully in previous statewide CBP evaluation. The SEDM technique includes the following steps.

Step 1: Define the populations (participant and non-participant) and the periods (treatment and pre-treatment). At this stage, we assessed the eligibility of participant and non-participant customers for matching based on the availability of event-like day usage data, dual participation in other DR programs, demographic information, etc. We worked with PG&E to develop these criteria. Next, we assigned the participant and eligible control group customers to strata based on categorized characteristics and will match participants to eligible control customers within their assigned strata. For PG&E Residential, we stratified based on weather stations. This stratified approach ensures that we matched customers with similar characteristics to one another, enabling us to better control for some of the unobservable attributes that affect the way customers use energy. Note that each stratum should have an appropriate ratio of eligible control customers to participants to ensure accurate matches. For PG&E Residential, we had a 10-to-1 ratio of control customers to participants, but larger ratios can yield better matches.

Step 2: Perform the one-to-one match based on the hourly demand data of event-like days. As discussed earlier, we use the event-like days to establish that the control and treatment customers would likely have consumed energy similarly on CBP event days in the absence of the program. We used an ED metric to determine the similarity in load shapes on event-like days between each treatment customer and eligible control customer, assessing the similarity in usage patterns using the following three demand variables: morning (HE7-HE9), midday (HE13-HE15), and late evening (HE19-HE22).

Within strata, we matched each treatment customer to every eligible control customer and calculated the ED according to the equation below.

$$ED = \sqrt{\begin{matrix}(morning_{Ti} - morning_{Ci})^2 + (midday_{Ti} - midday_{Ci})^2 \\ + (evening_{Ti} - evening_{Ci})^2\end{matrix}}$$

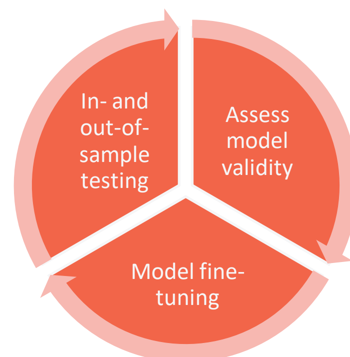
We finalized the one-to-one match of control to treatment customers by selecting the control customer who minimizes the ED. Once the matching process was complete, we thoroughly reviewed the match using the appropriate t-tests and visual inspection of the event-like day load shapes.

Develop Candidate Aggregate Models. AEG developed a set of candidate models that will go through our model optimization process, similar to the process described for non-residential participants. These candidate models were developed for a matched control design using aggregate models. In other words, we included indicator variables for participants in the baseline block and potentially interaction variables with this participant indicator variable.

The PG&E Residential program required only a handful of model subgroups, needing around five candidate models. The model optimization process served as a starting point to our model selection, leveraging automated algorithms that we developed for previous C&I DR evaluations, and play a key role in assessing model validity to justify our confidence in our impact estimates.

Step 4: Model Optimization and Selection

Figure 3-2 Optimization Process



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

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

To meet these two goals, we took each set of candidate models developed in the previous step and ran them through our proposed optimization process that includes a three-part cycle consisting of (1) testing the models' abilities to predict in-sample and out-of-sample, (2) assessing model validity, and (3) fine-tuning the models. We discuss each part below.

In-Sample and Out-of-Sample Testing. We used in-sample tests to assess how well each model performs on the CBP event days, helping us understand how well the model predicts the actual load. We used out-of-sample tests to assess how well each candidate model predicts customers' loads on event-like days, indicating how well each model might predict the reference load.

- **To perform the in-sample test**, we fitted each candidate model to the entire data set. The results of these fitted models were used to predict the usage on CBP event days. The models should be able to accurately predict customers' actual consumption on these days, having controlled for the impacts of the event hours. We assessed the accuracy and bias of the predictions by calculating the mean absolute percent error (MAPE)[26] and mean percent error (MPE)[27], respectively. We refer to these metrics as the in-sample MAPE and MPE.

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

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

- **To perform the out-of-sample test**, we fitted each candidate model to the data set excluding event-like days. The results of these fitted models were used to predict the usage on event-like days. We similarly assessed the accuracy and bias of the event-like day predictions by calculating the MAPE and MPE, which we refer to as the out-of-sample MAPE and MPE.

These two tests resulted in several in-sample and out-of-sample metrics. To determine the best model for each segment in terms of its abilities to predict both the reference load and the actual load for each segment with accuracy and limited bias, we combined the two tests into a single metric as follows:

$$\boldsymbol{metric_{ic}} = (0.4 * MAPE_{in}) + (0.4 * MAPE_{out}) + \big((0.1 * abs(MPE_{in})) + (0.1 * abs(MPE_{out})\big)$$

The best model for each segment will minimize this overall metric.

Assessing Model Validity. AEG confirmed that all best models for each participant (non-residential) or segment (residential) collectively deliver acceptable levels of accuracy and bias by calculating the weighted average MAPE and MPE at the program level. Valid models will result in low or very close to zero MAPE and MPE. We present the metrics of the final models in the Model Validity Appendix.

Model Fine-Tuning. We also routinely used visual inspection of the results as a simple but highly effective tool. We looked for specific aspects of the segment-level predicted and reference load shapes during the inspection to determine how well the models perform. We used any observations from these inspections to make any necessary edits to the model specifications obtained from the optimization process. For example:

- We checked to ensure that the reference load is closely aligned with the actual and predicted loads during the early morning and late evening hours when there is likely to be little effect from the event. Large differences can indicate that there is a problem with the reference load either over or underestimating usage in the absence of the rate.
- We closely examined the reference load for odd increases or decreases in the load that could indicate an effect not properly captured in the model.
- We also looked for bias both visually and mathematically. Identification of bias and its source often allows us to adjust the models to capture and isolate the bias-inducing effects within the model specification.

Step 5. Estimate Load Impacts and Confidence Intervals

The following example illustrates the process of estimating the impacts from the final model for a single modeling segment (i.e., one non-residential participant or one residential program). The process is the same for both residential and non-residential models with the following differences:

- The non-residential load impacts were estimated individually for each participant from the customer-specific models.
- The residential load impacts were estimated for each combination of customer segments required in the CPUC LIP.

In this simple example below, α_t, δ_t, and CDH_t, make up the baseline blocks of the model, and explain variation in kwh_{it} unrelated to demand response events. The remaining variables, $EVNT$, and the interaction term ($\alpha_t * EVNT$) are the impact blocks and explain the variation in kwh_t related to a CBP event.[28] An hourly model like the equation below can be equivalently estimated as one model with hourly dummy variables or as 24 separate hourly models.

$$kwh_{it} = \beta_0 + \beta_1\alpha_t + \beta_2\delta_t + \beta_3 CDH_t + \beta_4 EVNT + \beta_5(\alpha_t * EVNT) + \varepsilon_{it}$$

Where:

kwh_{it} is the consumption of customer i in hour t.

β_0 is the intercept.

β_n is the coefficient associated with each explanatory variable.

α_t is a vector of baseline explanatory variables (e.g., average load, baseline interactions, etc.).

δ_t is a vector of calendar variables (i.e., month, year, and day of the week).

CDH_t represents the cooling degree hours for hour t.

$EVNT$ is a dummy variable indicating that hour t was on a CBP event day.

$(\alpha_t * EVNT)$ is an interaction between the event indicator and baseline explanatory variables.

ε_{it} is the error for customer i in time t.

This type of time-series data is likely to have both autocorrelation and heteroskedasticity. To address autocorrelation, we use two techniques: (1) estimated 24 separate models for each hour to remove autocorrelation from hour to hour, and (2) incorporated seasonal indicators to minimize autocorrelation. To address heteroskedasticity, we used the Huber-White robust error correction.

Using the model above as an example, we estimated the load impacts as follows:

- First, we obtained the actual and predicted load for each segment on each hour and day based on the specification defined in the model equation.
- Next, we used the estimated coefficients and the baseline portion of the model to predict what this segment 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 blocks) and the predicted load (the estimate based on the baseline + impact blocks) on each event day. This difference represents our estimated load impact for each segment.

To avoid confusion between the actual observed load and the predicted load, we re-estimated the reference load as the sum of the observed load and the estimated load impact.

Because the impacts are statistical estimates, it is essential to establish a range or confidence interval around the estimates resulting in the uncertainty-adjusted load impacts required by the CPUC LIP. We used a statistical package to output the standard errors of the point estimates. The standard errors can then were used to calculate a confidence interval at various levels (e.g., 50%, 70%, 90%, etc.) for each segment.

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

Step 6. Aggregate Load Impacts to Reporting Subgroups

For non-residential participants, we estimated the load impacts individually for each participant, which was easily aggregated to represent impacts for each of the required customer segments for each of the three IOUs. In some cases, we applied average per-customer impacts as a proxy for the impacts realized by one or more customers on a given event day if part of the data was invalid and, therefore, omitted during the data validation process. In these cases, we determined the aggregate impact for a particular subgroup based on the per-customer estimate of the customers with valid data within that subgroup and the total dispatched accounts associated with that grouping for the given event. This process allowed us to avoid under-reporting the impacts due to missing or invalid data.

For residential participants, we estimated the load impacts for each combination of customer segments required in the CPUC LIP. This resulted in a per-customer estimate for each combination of customer segments, which was easily aggregated to each customer segment by multiplying by the number of participants within each combination.

To estimate statistical certainty for each customer segments, we can assume that the estimates are independent across participants, and consequently, estimates are independent across modeling segments. Thus, the variance of the sum is the sum of the variances. We can follow this approach to obtain the confidence intervals for each customer segments and each IOU service territory.

Calculating Impacts for an Average Event Day

We defined the average event day consistently across the three IOUs. At the program and product level, we calculate the average event day as the average of all events dispatched regardless of customer count or Sub-LAP count for each program and product. 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 corresponding average customer count is calculated as a simple average of the customer counts of each dispatched event day.

For program-level results (e.g., PG&E Non-residential DA is a combination of Elect DA and Prescribed DA), we summed the average event day aggregate-level results and dispatched counts. We calculate the corresponding per-participant impacts from the summed values.

As in previous years, different sets of service accounts were dispatched for each event; therefore, the average is made up of different customer groups across different days. These differences in customer groups can prove problematic when attempting to sum average impacts and customer counts across the multiple combinations of segments presented as part of this analysis. The approach we used to determine the average involved taking the average of each segment's aggregate impact. Another option would be to create the averages first at the lowest level of disaggregation and then sum them to the desired aggregation level. Though both approaches are equally valid, they often differ slightly. 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.

Reporting Metrics for Program Performance

We developed the following reporting metrics to evaluate each CBP program's overall season performance. The reporting metrics include the following:

- **Nomination** – represents the monthly program enrollment and available capacity for dispatch. The overall program nomination is the average monthly nomination by season.
- **Dispatched** – represents the resources called to a market-triggered event. We show this metric as follows:
  - **Overall dispatched capacity** – the average of the overall event day dispatched capacity regardless of event hours; reported as a monthly average or overall season average,
  - **Reporting hour dispatched capacity –** the average of the event day dispatched capacity oh the reporting hour[29]; reported as a monthly average or overall season average,
- **Ex-post average event day** – represents the average ex-post load impacts of all events dispatched regardless of event hours; reported as a monthly average or overall season average,
- **Delivery performance** – a percentage metric of the ex-post average event day load impacts relative to the dispatched capacity. We express the delivery performance as follows:
  - **Overall delivery performance** – measured relative to overall dispatched capacity:

$$\%Delivered = ExPost/Dispatched_{overall}$$

  - **Adjusted delivery performance** – measured relative to the reporting hour dispatched capacity. We calculate an adjusted metric to measure performance because ur definition of the average event day includes events that did not dispatch capacity during the reporting hour.

$$Adj\ \%Delivered = ExPost/Dispatched_{HE19\ or\ HE20}$$

Estimating Incremental Impacts for Technology-Enabled Participants

AEG did not perform this analysis this year. In previous program years, only SDG&E's AutoDR and TA/TI participants have shown statistically significant incremental impacts. In PY2021, SDG&E did not have CBP participants also enrolled in AutoDR or TA/TI.

Ex-Ante Load Impact Analysis

We designed the PY2021 ex-ante LI analysis to meet each of the objectives listed below, all objectives to be provided at the program level.

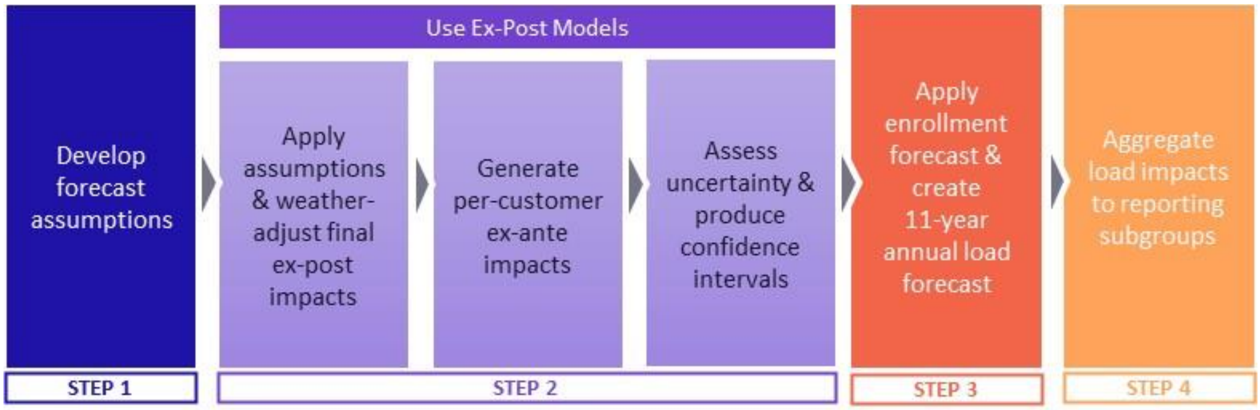
- To develop hourly load impact estimates for the average customer and all customers in aggregate for the resource adequacy (RA) window (4 PM to 9 PM),
- To estimates for each year over an 11-year[30] time horizon based on each IOU's and CAISO's 1-in-2 and 1-in-10 weather conditions for a typical event day and each monthly system peak day,
- To provide estimates for both program-specific and portfolio-adjusted scenarios, and
- To provide estimates by various segments: size group, LCA, Sub-LAP, and busbar.

We used the same methodology across all programs to ensure consistency of results. Figure 3-3 presents an overview of our ex-ante analysis approach.

[29] HE20 for PG&E and SCE; HE19 for SDG&E.

[30] PG&E and SDG&E has requested a PY2021 back cast as part of the ex-ante impact analysis.

Figure 3-3 Ex-Ante Analysis Approach



Step 1. Develop Forecast Assumptions

We collected the data items (listed below) from each IOU for the ex-ante LI analysis:

- IOU and CAISO 1-in-2 and 1-in-10 hourly weather scenarios for monthly peak day and typical event day, and
- Eleven-year enrollment forecast data for each program and reporting subgroup.

Through continued discussions with each IOU regarding each program's proposed and approved program changes, we developed forecast assumptions specific to each IOU. We discuss program-specific assumptions in Section 5, but they generally fall under the following:

- Updated assumptions on the shape of the impacts across the 5-hour RA window based on historical events called for longer durations for each IOU and program,
- Ex-post analysis findings on delivered capacity,
- Program changes such as product offerings, event durations, dispatch windows, resource requirements, event triggers, event notification procedures, etc., and
- Aggregator feedback to IOU program managers on forecasted participant recruitment and deliveries.

Impact Degradation Across the RA Window. We developed assumptions for a simulated the 5-hour RA window based on historical events for each IOU and program. The assumptions represent how customers, on average, can maintain impacts throughout event events called for longer durations. To develop these assumptions, we used the following approach:

1. Calculated hourly impacts as a percent of the estimated reference load,
2. Calculated the average hourly percent impacts by product, program, and program year,
3. Compared the average hourly percent impacts and discussed the findings with each IOU to determine the appropriate set of assumptions for each product and program. For each program, we used a combination of years from PY2019 through PY2021. We discuss each program/product-specific assumption in Section 5.

4. We express the shape as the percent of the maximum impact in each subsequent event hour. In Table 3-2 below, we present an example of the impact degradation shape for SCE's Non-residential DA and DO programs developed in PY2020.

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

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

COVID-19 Adjustments. AEG continued to be mindful of the current circumstances with the COVID-19 global pandemic beginning in March 2020 and discussed with each IOU if any additional adjustments related to the economic effects of the COVID-19 pandemic are necessary for each program year's ex-ante forecast. In PY2020, we did not identify conclusive findings to justify assumptions or adjustments to reflect COVID-19 conditions within the CBP ex-ante forecast. For PY2021, we maintained similar assumptions and did not apply any adjustments to reflect COVID-19 conditions.

Step 2. Use Ex-Post Regression Models

We used the ex-post hourly regression models to apply developed forecast assumptions and predict weather-adjusted impacts for each weather scenario. This step produced a set of impacts under each of the different weather scenarios required by the CPUC LIP, typical event day, and monthly peak for both IOU and CAISO 1-in-2 and 1-in-10 weather years. To do this, we carried out the following steps:

- **Apply Assumptions and Weather-Adjust Impacts.** We assembled an input dataset that includes the appropriate forecast assumptions and required weather scenarios for each non-residential participant with a customer-specific model and each combination of residential customer segments required in the CPUC LIP.
- **Generate Per-Customer Ex-Ante Load Impacts.** Using the final ex-post hourly regression models, we predicted two scenarios of an average customer load for each participant and subgroup: (1) Reference Load – assuming a non-event day; and (2) Predicted Load – assuming a CBP event day. We then calculated the ex-ante load impact for each participant and segment by subtracting the weather-adjusted predicted load from the weather-adjusted reference load. We applied the impact degradation shape to the ex-ante load impact to develop a load impact estimate for all hours of the RA window (HE17 – HE21 year-round).[31]
- **Assess Uncertainty and Produce Confidence Intervals.** Similar to the ex-post analysis, it is vital to establish a confidence interval around the estimates resulting in the uncertainty-adjusted load impacts required by the CPUC LIP. We used a statistical package to output the standard errors of the point estimates. The standard errors can then be used to calculate a confidence interval at various levels (e.g., 50%, 70%, 90%, etc.) for each subgroup and participant.

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

Step 3. Create 11-Year Annual Forecast

Non-residential participant ex-ante load impacts can be grouped together to produce per-customer average impacts for each combination of non-residential customer segments required in the CPUC LIP. Both residential and non-residential per-customer estimates were multiplied to program enrollment counts to create an annual forecast of load impacts over the next 11 years. For PG&E and SDG&E, we included a "back-cast," which consists of weather-adjusted ex-post estimates of the current program year. Each IOU provided an 11-year enrollment forecast, while the "back-cast" used actual program year enrollment counts.

Step 4. Aggregate Load Impacts to Reporting Subgroups

Once ex-ante load impact forecasts have been predicted for each combination of customer segments for each of the desired weather scenarios, it becomes a relatively simple exercise to aggregate the load impacts and generate per-customer average impacts for each of the CPUC LIP required customer segments.

To estimate statistical uncertainty for each customer segment, we can assume that the estimates are independent across participants, and consequently, estimates are independent across customer segments. Thus, the variance of the sum is the sum of the variances. We followed this approach to obtain the confidence intervals for each customer segments and each IOU service territory.

AEG recognizes that there is also be an error in the enrollment forecast. The uncertainty associated with the enrollment forecast was not provided to AEG and is not incorporated into the ex-ante load impact estimates.

4

EX-POST ANALYSIS RESULTS

In 2021, PG&E offered only Day Ahead (DA) programs and had both Residential and Non-residential active programs. SCE and SDG&E offered both DA and Day Of (DO) programs but only had Non-residential active programs.[32]

Table 4-1 presents the PY2021 average summer event day impacts by IOU and program, both at the aggregate and per-customer levels. On average, none of the programs met or exceeded their dispatched capacity (see dispatched capacity v. aggregate impacts in bold text).

Note that we calculate the average event day using all events regardless of dispatched count and event timing (see Average Event Calculation). We present the results for the most dispatched hour (reporting hour) for each program, which is HE20 (7 PM – 8 PM) for PG&E and SCE and HE19 (6 PM – 7 PM) for SDG&E.

Table 4-1 Statewide CBP Impacts Summary, Average Summer Event Day PY2021

IOU	Program	# of Accounts	Dispatched Capacity (MW)	Aggregate Impact (MW)		Per-Customer Impact (kW)	
				Impact	Reference Load	Impact	Reference Load
PG&E	Residential DA	21	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Non-residential DA	365	**13.5**	**13.0**	29.8	35.6	81.6
SCE	Non-residential DA	312	**7.6**	**4.0**	25.3	12.8	81.1
	Non-residential DO	203	**2.9**	**2.0**	19.4	10.0	95.7
SDG&E	Non-residential DA	46	**1.1**	**0.3**	5.1	5.8	110.9
	Non-residential DO	133	**3.4**	**1.0**	13.7	7.8	103.0

Table 4-2 summarizes each CBP program's PY2021 overall season performance using the following reporting metrics: average nomination, average overall and reporting hour dispatch, the ex-post load impacts, and the overall and adjusted delivery performance. Each metric is described in more detail in Section 3, Reporting Metrics for Program Performance.

The delivery performance metrics allow for an adjusted metric for dispatched capacity coincident with the reporting hour. Our definition of the average event day includes events that did not dispatch capacity during the reporting hour. For example, PG&E's Non-residential DA has a 96% overall delivery performance, just 4% short of meeting dispatched capacity. However, adjusting for dispatched capacity on HE20 (the reporting hour) shows that PG&E's Non-residential DA exceeded dispatched capacity at 105% adjusted delivery performance.

[32] SCE's Residential DA and DO programs are open, but did not receive any nominations in PY2021. SDG&E is currently running pilots for their Residential DA and DO programs.

Table 4-2 Statewide CBP Delivery Performance

	Program	Nominations		Overall Dispatched		Reporting Hour Dispatched		Ex-Post Analysis		
		# Accts	Capacity (MW)	# Accts	Capacity (MW)	# Accts	Capacity (MW)	Impact (MW)	% Delivered	Adj. % Delivered
PG&E	Res DA	21	[redacted]	21	[redacted]	14	[redacted]	[redacted]	[redacted]	[redacted]
PG&E	Non-res DA	879	50.1	365	13.5	345	12.4	13.0	96%	105%
SCE	Non-res DA	392	9.3	312	7.6	308	7.5	4.0	53%	53%
SCE	Non-res DO	270	3.8	203	2.9	198	2.8	2.0	70%	71%
SDG&E	Non-res DA	43	1.1	46	1.1	43	1.0	0.3	25%	26%
SDG&E	Non-res DO	131	3.2	133	3.4	133	3.4	1.0	30%	30%

The following sections will discuss each program's overall season performance or delivery. We will also present dispatched counts, dispatched capacity, and estimated ex-post load impacts for each event day to show the distribution of events represented by the averages shown above.

PG&E

Dispatched Events

We present a summary of the 2021 events for PG&E's CBP programs by product offering: Elect DA[33] (Non-residential) and Prescribed DA (Residential and Non-residential). The Non-residential Elect DA participants experienced 20 event days and 13 test events and participated in two products: Elect DA 1-4 Hour, with and without weekends. The Prescribed DA participants experienced a total of 34 event days (Non-residential) and 12 event days (Residential), participating only in one product: Prescribed DA 1-4 Hour.

In PY2021, PG&E did not dispatch any system-level events, meaning that all events dispatched for only some Sub-LAPs. Table 4-4 below shows the number of sub-LAPs, the event hours, and the number of accounts dispatched on each event day. For reference, Table 4-3 presents the total monthly enrollment for the Residential DA and Non-residential DA programs, which would be comparable to dispatched counts for a system-level event. Also, there are 16 Sub-LAPs in the PG&E territory.

As mentioned earlier, we calculate the average event day by including all events called in PY2021 regardless of the event hours and the number of sub-LAPs dispatched and report impacts for the average event day on the most dispatched hour, HE20.

[33] Note that no aggregators chose to participate in the Elect+ product offering in PY2021.

Table 4-3 PG&E Monthly Nominations

Month	Residential DA		Non-Residential DA	
	Enrolled Accounts	Nominated Capacity (MW)	Enrolled Accounts	Nominated Capacity (MW)
May	-	-	701	34.2
June	-	-	750	41.6
July	-	-	938	61.3
August	-	-	942	60.8
September	23	[redacted]	980	56.0
October	19	[redacted]	960	47.0
Avg. Summer	**21**	[redacted]	**879**	**50.1**

Table 4-4 PG&E Event Summary[34]

Date	Day of Week	# of Sub-LAPs	Event Hours (HE)	# Accounts		
				Non-Res Elect DA	Non-Res Prescribed DA	Res Prescribed DA
Avg. Event	**-**	**13**[35]	**20**	**359**	**6**	**21**
May 5, 2021	Wednesday	1	20-20	0	1	0
May 11, 2021	Tuesday	1	20-20	0	1	0
May 12, 2021	Wednesday	1	21-21	85	0	0
Jun 16, 2021	Wednesday	12	20-20	518	0	0
Jun 17, 2021	Thursday	13	19-20, 19-21	540	0	0
Jun 18, 2021	Friday	1	20-20	18	0	0
Jun 29, 2021	Tuesday	3	19-20	10	0	0
Jul 9, 2021	Friday	12	19-20, 20-20	431	2	0
Jul 12, 2021	Monday	13	18-21, 19-20, 20-20	478	2	0
Jul 13, 2021	Tuesday	13	19-21, 20-20	478	2	0
Jul 14, 2021	Wednesday	1	20-20	0	2	0
Jul 19, 2021	Monday	11	18-21, 19-21, 20-20	339	9	0
Jul 20, 2021	Tuesday	2	19-20, 19-21	0	9	0
Jul 21, 2021	Wednesday	6	19-21, 20-21	69	7	0
Jul 23, 2021	Friday	1	19-20	0	7	0
Jul 26, 2021	Monday	1	20-20	0	7	0
Jul 27, 2021	Tuesday	1	19-21	0	7	0
Jul 28, 2021	Wednesday	13	20-20	478	0	0

[34] Counts shown in red text include dispatched counts for test events.

[35] Total number of sub-LAPs included in the average.

Date	Day of Week	# of Sub-LAPs	Event Hours (HE)	# Accounts		
				Non-Res Elect DA	Non-Res Prescribed DA	Res Prescribed DA
Jul 29, 2021	Thursday	13	19-20	**484**	0	0
Jul 30, 2021	Friday	4	19-20	186	0	0
Aug 3, 2021	Tuesday	4	19-20	0	9	0
Aug 4, 2021	Wednesday	4	19-20	0	9	0
Aug 11, 2021	Wednesday	4	18-19, 19-19, 19-20	0	9	0
Aug 12, 2021	Thursday	5	18-18, 19-20	15	9	0
Aug 13, 2021	Friday	4	19-20, 20-20, 20-21	0	9	0
Aug 16, 2021	Monday	3	19-20, 20-20	0	7	0
Aug 20, 2021	Friday	1	16-16	**5**	0	0
Aug 23, 2021	Monday	1	19-20	**35**	0	0
Aug 26, 2021	Thursday	6	20-20	**191**	2	0
Aug 27, 2021	Friday	3	19-20	**17**	0	0
Aug 30, 2021	Monday	2	19-20	**122**	0	0
Sep 7, 2021	Tuesday	5	18-20, 18-21, 19-20	117	9	23
Sep 8, 2021	Wednesday	4	18-21	0	9	23
Sep 9, 2021	Thursday	13	18-21, 19-19	488	9	23
Sep 13, 2021	Monday	4	19-19, 19-20	0	9	23
Sep 14, 2021	Tuesday	4	14-16, 18-19, 19-19	0	9	23
Sep 15, 2021	Wednesday	3	19-19, 19-20	0	7	23
Sep 17, 2021	Friday	1	19-19	0	2	0
Sep 21, 2021	Tuesday	5	18-19, 19-20	81	0	0
Sep 24, 2021	Friday	2	19-19	**124**	0	0
Sep 30, 2021	Thursday	1	19-19	**43**	0	0
Oct 1, 2021	Friday	3	19-19	0	6	19
Oct 4, 2021	Monday	4	18-20	11	6	19
Oct 5, 2021	Tuesday	4	19-19	11	6	19
Oct 6, 2021	Wednesday	3	19-19	11	3	19
Oct 12, 2021	Tuesday	1	19-21	0	3	0
Oct 13, 2021	Wednesday	1	19-19	0	3	0
Oct 14, 2021	Thursday	3	17-19, 17-20	11	3	19
Oct 15, 2021	Friday	4	18-20, 19-19, 19-20	11	6	19
Oct 19, 2021	Tuesday	1	19-19	11	0	0
Oct 21, 2021	Thursday	11	19-19, 19-20	**252**	0	0
Oct 26, 2021	Tuesday	1	19-19	**1**	0	0

Load Impact Summary

This section includes the following:

- Table 4-5 shows an overall impact summary of the PY2021 season, including average dispatched counts, capacity, and load impacts at the aggregate and per-customer levels.
- Figure 4-1, Table 4-6, and Table 4-7 present monthly summaries for each metric (described in more detail in Section 3, Reporting Metrics for Program Performance):
    - Nominations – counts and total capacity,
    - Dispatched – average counts and capacity for all events dispatched,
    - HE20 Dispatched – average counts and capacity for all events dispatched on HE20, and
    - Ex-post load impacts – aggregate impacts, delivery performance relative to the overall dispatched capacity, and adjusted delivery performance relative to HE20 dispatched capacity.

On average, PG&E's CBP programs delivered 13.0 MW out of dispatched 13.5 MW, which amounts to a 96% delivery performance and a 104% adjusted delivery performance.

Table 4-5 PG&E Impacts Summary, Average Event Day PY2021

Program	Product	# of Accounts	Dispatched Capacity (MW)	Aggregate Impact (MW)		Per-Customer Impact (kW)	
				Impact	Reference Load	Impact	Reference Load
Res DA	**Prescribed DA**	**21**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non-Res DA	Elect DA	359	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Prescribed DA	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	All Non-Res DA	**365**	**13.5**	**13.0**	**29.8**	**35.6**	**81.6**
All CBP		**386**	**13.5**	**13.0**	**29.8**	**33.7**	**77.2**

Figure 4-1 visually shows how the ex-post load impacts compare to the overall and HE20 dispatched capacities. For Non-residential DA, we observe the following:

- June and September events exceeded dispatched capacities, amounting to 112% delivery performance and 158% adjusted delivery performance, respectively.
- May events also exceeded HE20 dispatched capacity; however, these HE20 impacts are due to the ramp-up response to an HE21 dispatched event.

Table 4-6 and Table 4-7 present the monthly averages that correspond to Figure 4-1 for Residential DA and Non-residential DA, respectively. The overall aggregate impact for the Non-residential DA participants was 13.0 MW in PY2021, which amounts to a 96% delivery performance and a 105% adjusted delivery performance. Program load impacts are driven mainly by the Elect DA product with [redacted] out of 13.0 MW and 359 out of 365 dispatched participants, on average. In PY2021, only one aggregator participated in PG&E's Residential DA. Thus, all CBP Residential DA impacts are marked confidential.

Figure 4-1 PG&E Monthly Delivery Performance Summary

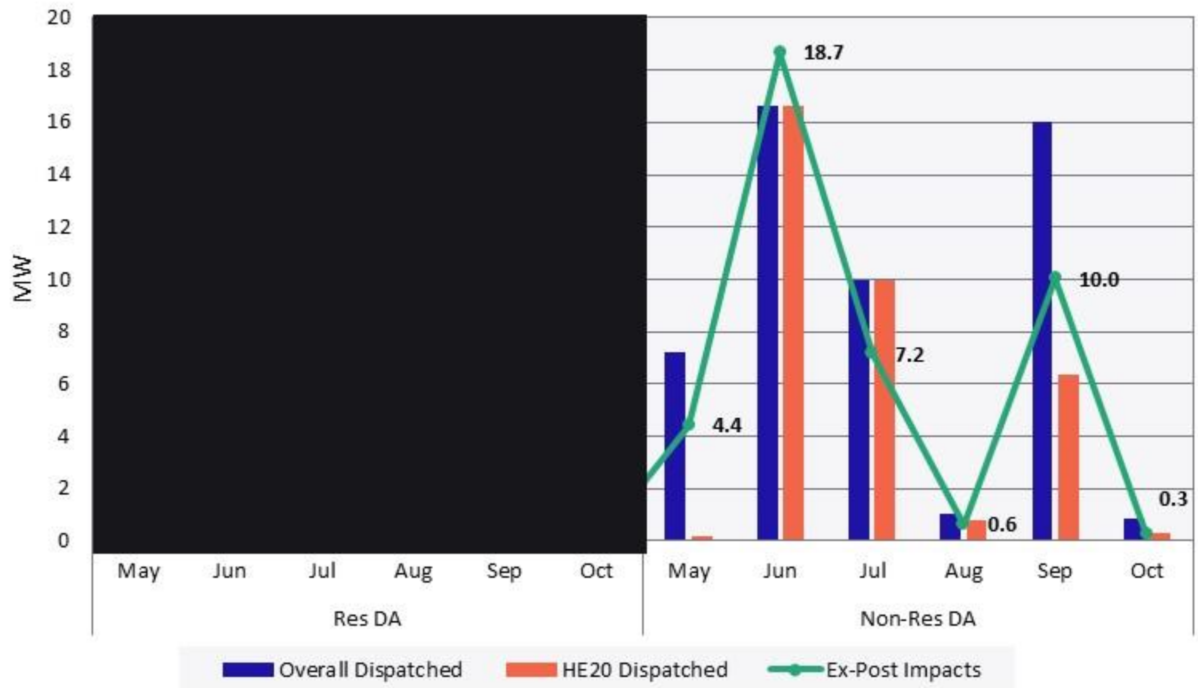


Table 4-6 PG&E Residential DA Monthly Summary

Month	Nominations		Dispatched		HE20 Dispatched		Ex-Post Analysis		
	# Accts	Capacity (MW)	# Accts	Capacity (MW)	# Accts	Capacity (MW)	Impact (MW)	% Delivered	Adj. % Delivered
May	-	-	-	-	-	-	-	-	-
June	-	-	-	-	-	-	-	-	-
July	-	-	-	-	-	-	-	-	-
August	-	-	-	-	-	-	-	-	-
September	23	[redacted]	23	[redacted]	19	[redacted]	[redacted]	[redacted]	[redacted]
October	19	[redacted]	19	[redacted]	10	[redacted]	[redacted]	[redacted]	[redacted]
Overall	**21**	[redacted]	**21**	[redacted]	**14**	[redacted]	[redacted]	[redacted]	[redacted]

Table 4-7 PG&E Non-Residential DA Monthly Summary

Month	Nominations		Dispatched		HE20 Dispatched		Ex-Post Analysis		
	# Accts	Capacity (MW)	# Accts	Capacity (MW)	# Accts	Capacity (MW)	Impact (MW)	% Delivered	Adj. % Delivered
May	701	34.2	86	7.2	1	0.2	4.4	62%	2213%
June	750	41.6	359	16.6	359	16.6	18.7	112%	112%
July	938	61.3	415	9.9	415	9.9	7.2	72%	72%
August	942	60.8	23	1.0	7	0.8	0.6	61%	80%
September	980	56.0	613	16.0	122	6.3	10.0	63%	158%
October	960	47.0	16	0.8	6	0.3	0.3	31%	85%
Overall	**879**	**50.1**	**365**	**13.5**	**345**	**12.4**	**13.0**	**96%**	**105%**

Hourly Load Impacts

Figure 4-2 through Figure 4-4 illustrate the per-customer hourly profiles of the estimated reference load, observed load, and estimated load impacts (in kW) for PG&E's Residential DA and Non-residential DA programs, on an average event day. The hours highlighted in the gray show the hours wherein at least one group is dispatched. The most dispatched hour, HE20, is highlighted by the vertical dotted line. The data underlying the figures are available in the MS Excel-based Protocol table generators that are included as appendices to this report.

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

Figure 4-3 PG&E Non-Residential Elect Day Ahead: Hourly Per-Customer Impact, Average Event

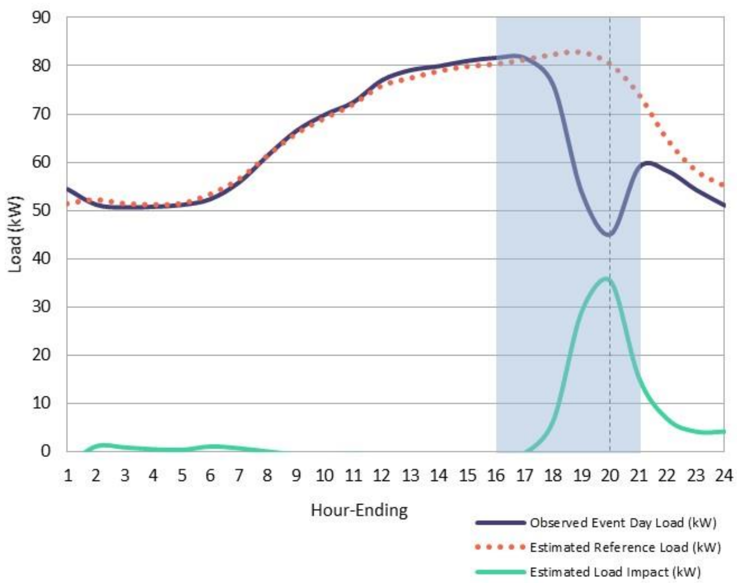


Figure 4-4 PG&E Non-Residential Prescribed Day Ahead: Hourly Per-Customer Impact, Average Event

[redacted]

Comparison of Ex-Post Impacts

This section discusses how the PY2021 ex-post load impacts compare to previous years. These comparisons show how the program has performed over time and relative to the most recent forecast.

Figure 4-5 PG&E Annual Nominations

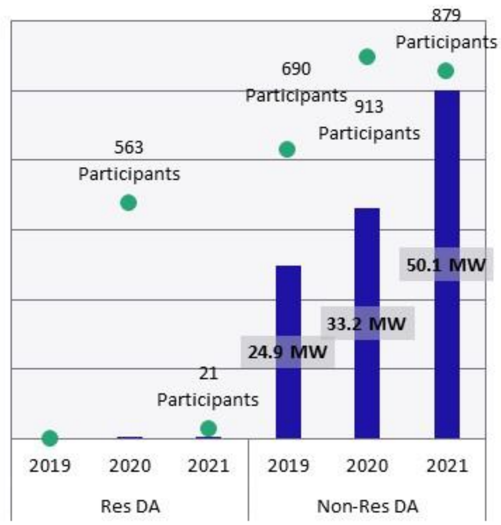


Figure 4-5 presents PG&E's average program nominations for PY2019 through PY2021. The Non-Residential DA program has consistently grown in capacity nominations, despite showing a slight decrease in enrollment counts. The Residential DA program, on the other hand, is still evolving as aggregators determine the appropriate approach for residential participants.

Table 4-8 below presents the ex-post load impacts over time. Note that these impacts are measured based on performance during dispatched events. We saw a decrease in average dispatched accounts but an increase in aggregate load impacts from PY2020 to PY2021. PY2021 also consisted of participants capable of higher load curtailment, showing a 44% load reduction (relative to the reference load) on average compared to 13% and 16% in previous years.

Table 4-8 PG&E: Current v. Previous Ex-Post, Average Event Day

Program	Year	# of Accts	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Ref. Load	Impact	Ref. Load		
Residential DA	2019	-	-	-	-	-	-	-
	2020	623	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	86
	2021	**21**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**70**
Non-Res DA	2019	241	9.8	75.3	40.8	312.6	13%	85
	2020	531	10.0	64.1	18.9	120.5	16%	85
	2021	**365**	**13.0**	**29.8**	**35.6**	**81.6**	**44%**	**87**

Table 4-9 below presents the PY2021 ex-post impacts compared to PY2020 ex-ante impacts. Since the ex-ante impacts forecast performance for a system-level dispatch, we provide ex-post impacts for events closest to a system-level dispatch[36]. Non-residential DA ex-post load impacts fall short by 10 MW in aggregate but exceed PY2020 ex-ante average customer load impacts, again demonstrating that the PY2021 participants are capable of higher load curtailment.

[36] A system-level event would include all PY2021 nominations, which is 879 participants, on average.

Table 4-9 PG&E Current Ex-Post (Largest Dispatched Event) v. Prior Ex-Ante (PG&E 1-in-2, Typical Event Day, 2021)

Program	Estimate	# of Accts	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Ref. Load	Impact	Ref. Load		
Residential DA	PY2020 Ex-Ante	8,247	2.4	11.8	0.3	1.4	21%	85
	Sep 13, 2021	**23**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**71**
Non-Res DA	PY2020 Ex-Ante	2,049	40.5	265.3	19.8	129.5	15%	90
	Jun 16, 2021	**518**	**30.7**	**68.1**	**59.2**	**131.4**	**45%**	**88**

Impacts by Event Day

Table 4-10 through Table 4-12 present the average event hour impacts for the Residential DA and Non-residential DA programs. PG&E also dispatched a number of test[37] events, and those results are presented in Table 4-13. The impacts are reported both at the aggregate and average per-customer levels. 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 4-10 PG&E Residential Prescribed Day Ahead: Impacts by Event

Event	# of Accts	Dispatched Capacity (MW)	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Reference Load	Impact	Reference Load		
Avg. Event	21	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	70
Sep 7, 2021	23	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	73
Sep 8, 2021	23	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	72
Sep 9, 2021	23	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	73
Sep 13, 2021	23	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	71
Sep 14, 2021	23	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	71
Sep 15, 2021	23	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	65
Oct 1, 2021	19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	85
Oct 4, 2021	19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	83
Oct 5, 2021	19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	68
Oct 6, 2021	19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	66
Oct 14, 2021	19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	73
Oct 15, 2021	19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	77

[37] Test events are not triggered by CAISO market awards. However, aggregators and participants experience a similar notification or "experience" as a normal CBP event.

Table 4-11 PG&E Non-Residential Elect Day Ahead: Impacts by Event

Event	# of Accts	Dispatched Capacity (MW)	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Reference Load	Impact	Reference Load		
Avg. Event	**359**	**12.8**	**12.6**	**28.8**	**35.2**	**80.4**	**44%**	**87**
May 12, 2021	85	7.0	8.8	10.9	103.5	128.2	81%	83
Jun 16, 2021	518	24.4	30.7	68.1	59.2	131.4	45%	88
Jun 17, 2021	540	24.7	24.4	69.8	45.1	129.2	35%	95
Jun 18, 2021	18	0.9	0.9	2.2	51.9	121.8	43%	84
Jul 9, 2021	431	10.5	7.5	35.7	17.4	82.8	21%	93
Jul 12, 2021	478	11.0	8.5	34.6	17.7	72.5	24%	81
Jul 13, 2021	478	11.0	8.5	34.6	17.8	72.3	25%	79
Jul 19, 2021	339	9.3	7.5	28.9	22.1	85.2	26%	83
Jul 28, 2021	478	11.0	8.5	37.0	17.8	77.3	23%	86
Jul 29, 2021	478	11.0	7.2	38.8	15.1	81.3	19%	88
Jul 30, 2021	186	2.3	1.1	12.2	6.0	65.8	9%	88
Aug 12, 2021	15	0.1	<0.1	1.0	3.3	70.0	5%	79
Sep 7, 2021	117	5.8	6.8	7.0	57.9	59.8	97%	102
Sep 9, 2021	488	9.3	9.1	40.7	18.7	83.4	22%	85
Oct 4, 2021	11	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	88
Oct 5, 2021	11	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	77
Oct 6, 2021	11	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	71
Oct 14, 2021	11	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	76
Oct 15, 2021	11	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	74
Oct 19, 2021	11	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	67

Table 4-12 PG&E Non-Residential Prescribed Day Ahead: Impacts by Event

Event	# of Accts	Dispatched Capacity (MW)	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Reference Load	Impact	Reference Load		
Avg. Event	**6**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**66**
May 5, 2021	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	68
May 11, 2021	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	75
Jul 9, 2021	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	64
Jul 12, 2021	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	58
Jul 13, 2021	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	59
Jul 14, 2021	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	60
Jul 19, 2021	9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	72
Jul 20, 2021	9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	72

Event	# of Accts	Dispatched Capacity (MW)	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Reference Load	Impact	Reference Load		
Jul 21, 2021	7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	74
Jul 23, 2021	7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	82
Jul 26, 2021	7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	73
Jul 27, 2021	7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	85
Aug 3, 2021	9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	66
Aug 4, 2021	9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	65
Aug 11, 2021	9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	68
Aug 12, 2021	9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	68
Aug 13, 2021	9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	66
Aug 16, 2021	7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	67
Aug 26, 2021	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	60
Sep 7, 2021	9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	70
Sep 8, 2021	9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	67
Sep 9, 2021	9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	66
Sep 13, 2021	9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	68
Sep 14, 2021	9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	65
Sep 15, 2021	7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	63
Sep 17, 2021	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	61
Oct 1, 2021	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	69
Oct 4, 2021	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	62
Oct 5, 2021	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	64
Oct 6, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	62
Oct 12, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	58
Oct 13, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	60
Oct 14, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	67
Oct 15, 2021	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	72

Table 4-13 PG&E Non-Residential Day Ahead Test Events

Event	# of Accts	Dispatched Capacity (MW)	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Reference Load	Impact	Reference Load		
Jun 29, 2021	10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	72
Jul 21, 2021	69	5.8	4.9	21.8	70.5	315.3	22%	72
Jul 29, 2021	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	68
Aug 20, 2021	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	67
Aug 23, 2021	35	3.6	1.8	7.4	52.7	210.7	25%	79
Aug 26, 2021	191	3.9	1.3	26.3	6.9	137.7	5%	77

Event	# of Accts	Dispatched Capacity (MW)	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Reference Load	Impact	Reference Load		
Aug 27, 2021	17	0.3	<0.1	0.6	1.6	35.6	5%	88
Aug 30, 2021	122	2.3	1.8	8.4	14.7	69.1	21%	94
Sep 21, 2021	81	1.6	0.6	14.8	7.9	182.8	4%	87
Sep 24, 2021	124	10.7	12.1	15.9	98.0	127.8	77%	84
Sep 30, 2021	43	10.9	4.6	27.7	106.7	643.1	17%	86
Oct 21, 2021	252	12.5	7.2	36.0	28.5	143.0	20%	72
Oct 26, 2021	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	64

Load Impacts By Industry, LCA, and Sub-LAP

Table 4-14 through Table 4-16 present the impacts for an average event day by Industry, LCA, and Sub-LAP.[38]

Table 4-14 PG&E Non-Residential DA Impacts by Industry

Industry	# of Accts	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
		Impact	Ref. Load	Impact	Ref. Load		
Agriculture, Mining & Construction	118	10.4	11.8	87.8	99.9	88%	100
Manufacturing	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	77
Wholesale, Transport, other utilities	37	3.1	4.0	83.1	105.9	78%	97
Retail stores	299	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	83
Offices, Hotels, Finance, Services	22	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	76
Institutional/Government	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	72
Other or unknown	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	84
Total Non-Residential DA	**365**	**13.0**	**29.8**	**35.6**	**81.6**	**44%**	**87**

[38] The results 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, LCA, or Sub-LAP). 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 4-15 PG&E Impacts by LCA

Local Capacity Area	# of Accts	Aggregate Impact (MW)		Per-Customer Impact (MW)		% Impact	Temp (F)
		Impact	Ref. Load	Impact	Ref. Load		
Greater Bay Area	180	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	73
Greater Fresno Area	205	10.0	17.2	48.7	84.1	58%	101
Kern	19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	77
Northern Coast	31	1.0	3.3	33.3	105.6	32%	85
Sierra	24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	90
Stockton	30	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	90
Other	304	15.0	26.0	49.2	85.6	58%	34
Total CBP	**386**	**13.0**	**29.8**	**33.7**	**77.2**	**44%**	**86**

Table 4-16 PG&E Impacts by Sub-LAP

Sub-LAP	# of Accts	Aggregate Impact (MW)		Per-Customer Impact (MW)		% Impact	Temp (F)
		Impact	Ref. Load	Impact	Ref. Load		
PGCC	32	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	63
PGEB	81	0.7	3.9	9.2	47.9	19%	80
PGF1	207	10.0	17.4	48.3	84.2	57%	101
PGFG	19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	76
PGKN	19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	103
PGNB	15	0.1	1.1	6.6	74.6	9%	78
PGNP	61	0.6	3.7	9.9	60.3	16%	93
PGP2	24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	73
PGSB	48	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	75
PGSF	19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	61
PGSI	25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	86
PGST	20	0.3	1.3	15.8	62.5	25%	89
PGZP	87	5.2	7.2	59.2	83.3	71%	81
Total CBP	**386**	**13.0**	**29.8**	**33.7**	**77.2**	**44%**	**86**

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 PY2021, both Elect DA and Prescribed DA product offerings recruited AutoDR participants. Table 4-17 and Table 4-18 show the per-customer and aggregate ex-post impacts by event day for the AutoDR participants for the Elect DA and Prescribed DA product offerings, respectively. 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 4-17 PG&E Non-Residential Elect Day Ahead: AutoDR Participant Impacts by Event

Event	# of Accts	Aggregate Load Shed Test (MW)	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Reference Load	Impact	Reference Load		
Avg. Event[39]	**127**	**5.3**	**5.2**	**8.0**	**40.7**	**62.7**	**65%**	**96**
May 12, 2021	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	56
Jun 16, 2021	37	1.1	2.0	5.5	55.4	149.7	37%	86
Jun 17, 2021	40	1.2	1.8	5.5	45.6	138.0	33%	93
Jun 18, 2021	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	84
Jul 9, 2021	32	0.5	0.3	3.3	8.1	102.7	8%	91
Jul 12, 2021	39	0.7	0.3	3.4	7.5	87.2	9%	77
Jul 13, 2021	39	0.7	0.4	3.3	9.0	83.9	11%	74
Jul 19, 2021	28	0.5	0.2	2.3	7.9	82.3	10%	78
Jul 28, 2021	39	0.7	0.4	3.6	9.0	93.3	10%	83
Jul 29, 2021	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	72
Jul 30, 2021	18	0.3	0.2	2.0	11.1	109.4	10%	87
Sep 7, 2021	98	4.7	4.7	4.9	47.9	50.2	96%	102
Sep 9, 2021	38	0.6	0.4	3.5	10.3	91.7	11%	83

Table 4-18 PG&E Non-Residential Prescribed Day Ahead: AutoDR Participant Impacts by Event

Event	# of Accts	Aggregate Load Shed Test (MW)	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Reference Load	Impact	Reference Load		
Avg. Event	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	69
Jul 19, 2021	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	65
Jul 20, 2021	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	65
Jul 21, 2021	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	65
Jul 23, 2021	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	70
Jul 26, 2021	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	68
Jul 27, 2021	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	74
Aug 3, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	71
Aug 4, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	70

[39] The September 7th event was an Elect DA 1-4 with Weekend product option, thus calculated separately at the product level. In this case, calculating the product levels separately is driving up the average event day.

Event	# of Accts	Aggregate Load Shed Test (MW)	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Reference Load	Impact	Reference Load		
Aug 11, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	75
Aug 12, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	74
Aug 13, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	68
Aug 16, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	73
Sep 7, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	73
Sep 8, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	72
Sep 9, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	72
Sep 13, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	72
Sep 14, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	71
Sep 15, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	64

Load Impacts of CARE Participants

In PY2021, PG&E’s Residential DA program did not recruit any CARE customers.

SCE

Dispatched Events

We present a summary of the PY2021 events for SCE's CBP Non-residential DA and DO programs. SCE's CBP program is offered year-round, and the PY2021 evaluation period covers November 2020 through October 2021. We report impacts under two seasons: Non-summer (November-April) and Summer (May-October). The DA participants experienced 67 event days over the program year, while DO participants experienced 61 event days. As in previous years, events dispatched various times and durations within the 3 PM to 9 PM dispatch window.

Similar to previous years, SCE dispatched a combination of partial and system-level events. Table 4-20 below shows the number of sub-LAPs, the event hours, and the number of accounts dispatched on each event day. For reference, Table 4-19 presents the total monthly enrollment for both SCE programs, which would be comparable to dispatched counts for a system-level event.

As mentioned earlier, we calculate the average event day (non-summer and summer) by including all events called in PY2021 regardless of the event hours and the number of sub-LAPs dispatched and report impacts for the average event day on the most dispatched hour, HE20.

Table 4-19 SCE Monthly Nominations

Month	Non-Residential DA		Non-Residential DO	
	Enrolled Accounts	Nominated Capacity (MW)	Enrolled Accounts	Nominated Capacity (MW)
November	4	[redacted]	28	1.0
December	5	[redacted]	15	0.6
January	14	[redacted]	15	0.7
February	5	[redacted]	15	0.7
March	18	1.9	15	0.5
April	5	[redacted]	15	0.5
Avg. Non-Summer	**9**	[redacted]	**17**	**0.7**
May	416	10.2	278	4.2
June	414	9.9	279	4.4
July	403	10.6	266	4.1
August	379	8.7	265	3.4
September	373	9.0	270	3.6
October	364	7.2	259	3.3
Avg. Summer	**392**	**9.3**	**270**	**3.8**

Table 4-20 SCE Event Summary

Date	Day of Week	# of Sub-LAPs	Event Hours (HE)	# Accounts	
				Day Ahead	Day Of
Avg. Non-Summer Event	-	**5**[40]	**20**	**6**	**13**
Avg. Summer Event	-	**6**[41]	**20**	**310**	**201**
Nov 2, 2020	Monday	3	17-19	4	23
Nov 3, 2020	Tuesday	3	17-19	4	23
Nov 4, 2020	Wednesday	3	17-20	4	23
Nov 5, 2020	Thursday	3	16-20	4	23
Nov 6, 2020	Friday	3	18-18	4	23
Nov 9, 2020	Monday	1	18-20	-	5
Nov 10, 2020	Tuesday	1	18-18	-	5
Nov 12, 2020	Thursday	1	18-18	-	5
Nov 13, 2020	Friday	1	18-18	-	5
Nov 16, 2020	Monday	1	17-18	-	5
Dec 1, 2020	Tuesday	5	18-18	5	15
Dec 2, 2020	Wednesday	5	18-18	5	15
Dec 3, 2020	Thursday	5	18-18	5	15
Dec 4, 2020	Friday	5	18-18	5	15
Dec 7, 2020	Monday	3	18-19	4	10
Dec 8, 2020	Tuesday	2	18-19	1	5
Jan 4, 2021	Monday	2	18-19	8	6
Jan 5, 2021	Tuesday	3	18-18, 18-19	13	10
Jan 6, 2021	Wednesday	1	18-18	1	-
Jan 12, 2021	Tuesday	1	18-18	1	-
Feb 9, 2021	Tuesday	1	19-19	1	-
Feb 10, 2021	Wednesday	1	19-19	1	-
Feb 12, 2021	Friday	5	17-21	5	15
Feb 16, 2021	Tuesday	5	17-20, 17-21	5	15
Feb 17, 2021	Wednesday	5	16-21	5	15
Feb 18, 2021	Thursday	4	16-21, 17-21	4	15
Feb 19, 2021	Friday	4	18-21	4	15
Mar 1, 2021	Monday	3	19-19	10	11
Mar 4, 2021	Thursday	1	19-19	1	-

[40] Total number of sub-LAPs included in the average.

[41] Total number of sub-LAPs included in the average.

Date	Day of Week	# of Sub-LAPs	Event Hours (HE)	# Accounts	
				Day Ahead	Day Of
Mar 8, 2021	Monday	5	19-19	18	15
Mar 15, 2021	Monday	2	20-20	8	4
Mar 16, 2021	Tuesday	5	20-20	18	15
Mar 17, 2021	Wednesday	5	20-20	18	15
Mar 30, 2021	Tuesday	4	20-20	17	15
Apr 1, 2021	Thursday	5	19-20, 19-21, 20-20	5	15
Apr 12, 2021	Monday	5	20-21	5	15
Apr 13, 2021	Tuesday	5	20-20, 20-21	5	15
Apr 19, 2021	Monday	5	20-20, 20-21	5	15
Apr 28, 2021	Wednesday	1	21-21	1	-
Apr 29, 2021	Thursday	4	20-20	4	15
May 4, 2021	Tuesday	6	20-20	416	278
May 5, 2021	Wednesday	6	20-21	416	278
May 6, 2021	Thursday	6	20-20	416	278
May 11, 2021	Tuesday	6	20-21	416	278
May 12, 2021	Wednesday	6	20-20	416	278
Jun 1, 2021	Tuesday	6	19-21	414	253
Jun 2, 2021	Wednesday	6	19-21	414	253
Jun 3, 2021	Thursday	6	20-20, 20-21	414	253
Jun 14, 2021	Monday	6	16-21, 17-21	414	253
Jun 15, 2021	Tuesday	6	16-21	414	279
Jun 16, 2021	Wednesday	1	16-21	-	26
Jun 17, 2021	Thursday	1	16-21	-	26
Jun 18, 2021	Friday	1	16-21	-	26
Jul 1, 2021	Thursday	5	20-21	402	211
Jul 2, 2021	Friday	6	20-20, 20-21	403	244
Jul 5, 2021	Monday	1	20-20	59	27
Jul 6, 2021	Tuesday	6	20-21	403	244
Jul 7, 2021	Wednesday	6	18-21, 19-21	403	244
Jul 8, 2021	Thursday	6	16-21	344	244
Jul 9, 2021	Friday	2	16-21	1	6
Aug 2, 2021	Monday	6	16-21	379	243
Aug 3, 2021	Tuesday	6	16-21	379	243
Aug 4, 2021	Wednesday	6	16-21	379	243
Aug 27, 2021	Friday	6	19-19, 19-20	379	265

Date	Day of Week	# of Sub-LAPs	Event Hours (HE)	# Accounts	
				Day Ahead	Day Of
Aug 30, 2021	Monday	6	16-21	379	265
Aug 31, 2021	Tuesday	1	19-20	-	22
Sep 7, 2021	Tuesday	1	16-21	141	-
Sep 8, 2021	Wednesday	2	16-21	269	-
Sep 9, 2021	Thursday	2	16-21, 18-21	269	214
Sep 10, 2021	Friday	1	16-21	141	-
Sep 21, 2021	Tuesday	1	16-21	141	-
Oct 4, 2021	Monday	2	16-21, 17-21	266	-
Oct 15, 2021	Friday	1	18-21	139	-
Oct 19, 2021	Tuesday	1	18-21	139	-
Oct 27, 2021	Wednesday	1	18-21	139	-
Oct 28, 2021	Thursday	2	18-21	266	-

Load Impact Summary

This section includes the following:

- Table 4-21 shows an overall impact summary for PY2021, including average dispatched counts, capacity, and load impacts at the aggregate and per-customer levels.
- Figure 4-6 and Table 4-22 (Non-residential DA) and Figure 4-7 and Table 4-23 (Non-residential DO) present monthly summaries for each metric (described in more detail in Section 3, Reporting Metrics for Program Performance):
  - Nominations – counts and total capacity,
  - Dispatched – average counts and capacity for all events dispatched,
  - HE20 Dispatched – average counts and capacity for all events dispatched on HE20, and
  - Ex-post load impacts – aggregate impacts, delivery performance relative to the overall dispatched capacity, and adjusted delivery performance relative to HE20 dispatched capacity.

On average, SCE's CBP programs delivered 6.0 MW out of dispatched 10.5 MW, resulting in a 58% delivery performance.

Table 4-21 SCE Impacts Summary, Average Event Day PY2021

Season & Program	Accounts	Dispatched Capacity (MW)	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact
			Impact	Reference Load	Impact	Reference Load	
Non-Summer DA	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non-Summer DO	13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Non-Summer	**19**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Summer DA	312	7.6	4.0	25.3	12.8	81.1	16%
Summer DO	203	2.9	2.0	19.4	10.0	95.7	10%
Total Summer	**514**	**10.5**	**6.0**	**44.7**	**11.7**	**86.8**	**13%**

Figure 4-6 visually shows how the ex-post load impacts compare to the overall and HE20 dispatched capacities. For Non-residential DA, we observe the following:

- Most events were dispatched on HE20, resulting in very minimal adjusted delivery performances.
- Summer delivery performance was relatively consistent with the season average of 53%.
- December and January events did not dispatch HE20, resulting in negative reported averages.

Table 4-22 presents the monthly averages that correspond to Figure 4-6 Non-residential DA. The overall aggregate impact for the Non-residential DA participants was 4.0 MW for the PY2021 summer season, which amounts to a 53% delivery performance.

Figure 4-6 SCE Monthly Delivery Performance Summary, Non-residential Day Ahead

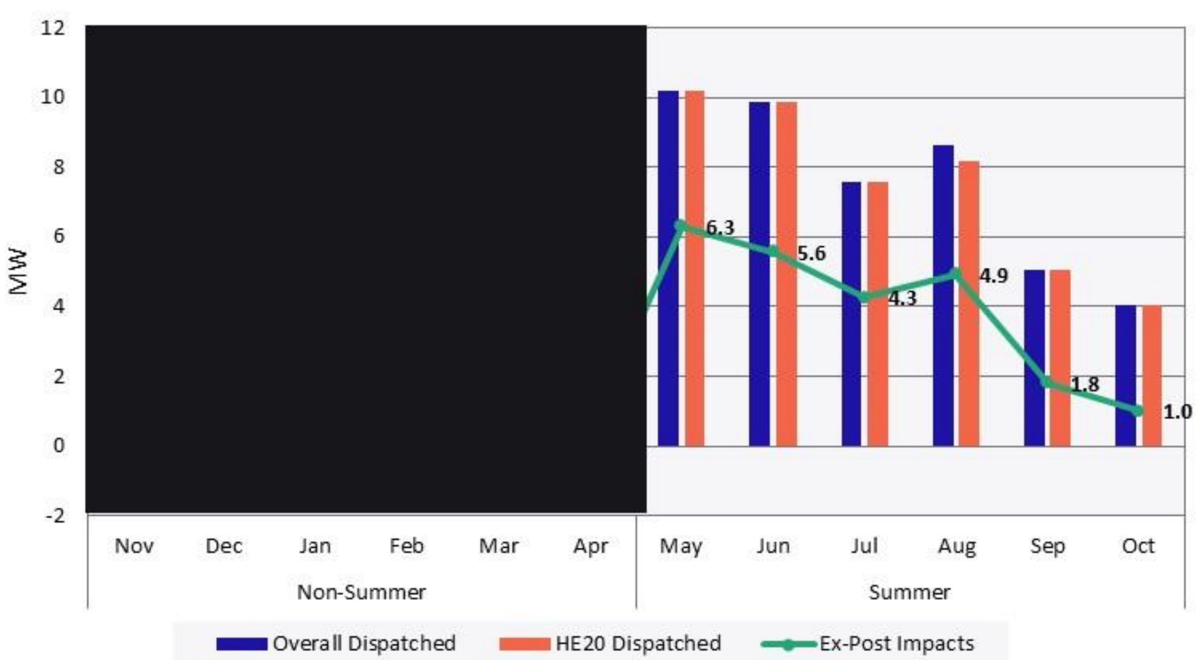


Table 4-22 SCE Non-Residential DA Monthly Summary

Month	Nominations		Dispatched		HE20 Dispatched		Ex-Post Analysis		
	# Accts	Capacity (MW)	# Accts	Capacity (MW)	# Accts	Capacity (MW)	Impact (MW)	% Delivered	Adj. % Delivered
November	4	[redacted]	4	[redacted]	2	[redacted]	[redacted]	[redacted]	[redacted]
December	5	[redacted]	4	[redacted]	-	[redacted]	[redacted]	[redacted]	[redacted]
January	14	[redacted]	6	[redacted]	-	[redacted]	[redacted]	[redacted]	[redacted]
February	5	[redacted]	4	[redacted]	3	[redacted]	[redacted]	[redacted]	[redacted]
March	18	1.9	13	[redacted]	9	[redacted]	[redacted]	[redacted]	[redacted]
April	5	[redacted]	4	[redacted]	4	[redacted]	[redacted]	[redacted]	[redacted]
Avg. Non-Summer	**9**	[redacted]	**6**	[redacted]	**3**	[redacted]	[redacted]	[redacted]	[redacted]
May	416	10.2	416	10.2	416	10.2	6.3	62%	62%
June	414	9.9	414	9.9	414	9.9	5.6	56%	56%
July	403	10.6	288	7.6	288	7.6	4.3	56%	56%
August	379	8.7	379	8.7	353	8.2	4.9	57%	60%
September	373	9.0	192	5.1	192	5.1	1.8	36%	36%
October	364	7.2	190	4.0	190	4.0	1.0	25%	25%
Avg. Summer	**392**	**9.3**	**312**	**7.6**	**308**	**7.5**	**4.0**	**53%**	**53%**

Figure 4-7 visually shows how the ex-post load impacts compare to the overall and HE20 dispatched capacities. For Non-residential DO, we observe the following:

- Most events were dispatched on HE20, resulting in very minimal adjusted delivery performances.
- July is the highest performing month with a 93% delivery performance.
- Similar to DA, December and January events did not dispatch HE20, resulting in negative reported averages.

Table 4-23 presents the monthly averages that correspond to Figure 4-7 Non-residential DO. The overall aggregate impact for the Non-residential DO participants was 2.0 MW for PY2021 summer season, which amounts to a 70% delivery performance and a 71% adjusted delivery performance.

Figure 4-7 SCE Monthly Delivery Performance Summary, Non-residential Day Of

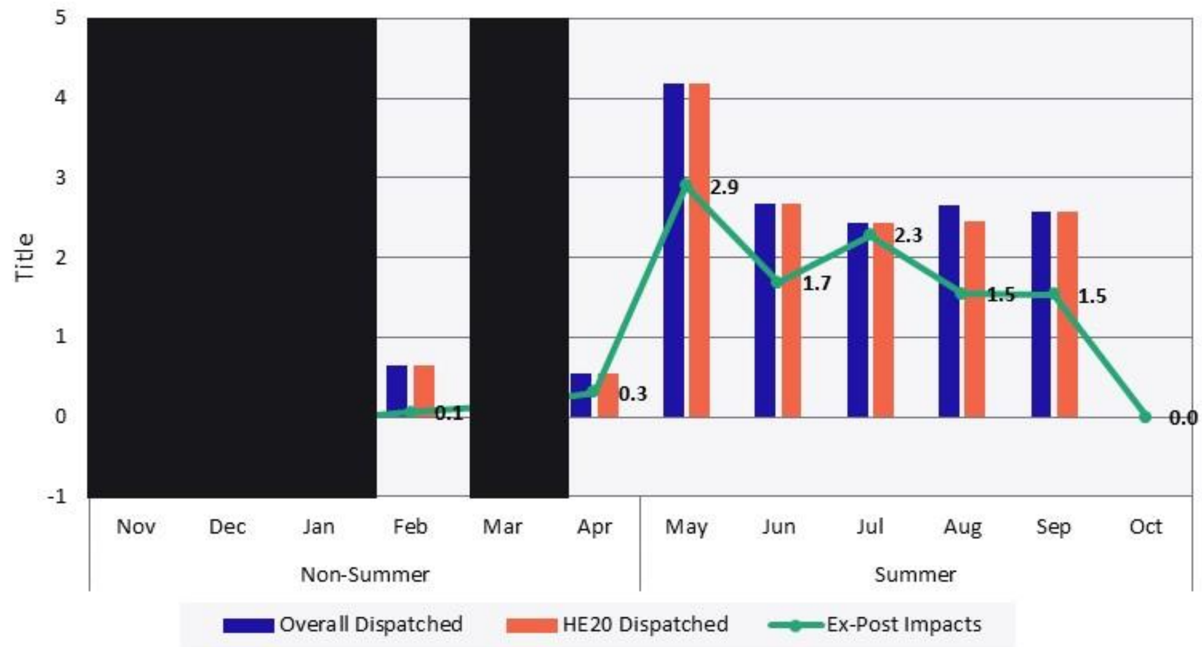


Table 4-23 SCE Non-Residential DO Monthly Summary

Month	Nominations		Dispatched		HE20 Dispatched		Ex-Post Analysis		
	# Accts	Capacity (MW)	# Accts	Capacity (MW)	# Accts	Capacity (MW)	Impact (MW)	% Delivered	Adj. % Delivered
November	28	1.0	14	[redacted]	5	[redacted]	[redacted]	[redacted]	[redacted]
December	15	0.6	13	[redacted]	-	[redacted]	[redacted]	[redacted]	[redacted]
January	15	0.7	8	[redacted]	-	[redacted]	[redacted]	[redacted]	[redacted]
February	15	0.7	15	0.7	15	[redacted]	[redacted]	[redacted]	[redacted]
March	15	0.5	13	[redacted]	8	[redacted]	[redacted]	[redacted]	[redacted]
April	15	0.5	15	0.5	15	[redacted]	[redacted]	[redacted]	[redacted]
Avg. Non-Summer	**17**	**0.7**	**13**	[redacted]	**7**	[redacted]	[redacted]	[redacted]	[redacted]
May	278	4.2	278	4.2	278	4.2	2.9	69%	69%
June	279	4.4	171	2.7	171	2.7	1.7	63%	63%
July	266	4.1	174	2.4	174	2.4	2.3	93%	93%
August	265	3.4	214	2.7	194	2.4	1.5	58%	63%
September	270	3.6	214	2.6	214	2.6	1.5	60%	60%
October	259	3.3	-	-	-	-	-	-	-
Avg. Summer	**270**	**3.8**	**203**	**2.9**	**198**	**2.8**	**2.0**	**70%**	**71%**

Hourly Load Impacts

Figure 4-8 through Figure 4-11 illustrate the per-customer hourly profiles of the estimated reference load, observed load, and estimated load impacts (in kW) for each SCE CBP program on an average event day, by season. The hours highlighted in the gray show the hours wherein at least one group is dispatched. The most dispatched hour, HE20, is highlighted by the vertical dotted line. The data underlying the figures are available in the MS Excel-based Protocol table generators that are included as appendices to this report.

Figure 4-8 SCE Day-Ahead 1-6 Hour: Hourly Per-Customer Impact, Non-Summer Average Event

[redacted]

Figure 4-9 SCE Day-Ahead 1-6 Hour: Hourly Per-Customer Impact, Summer Average Event

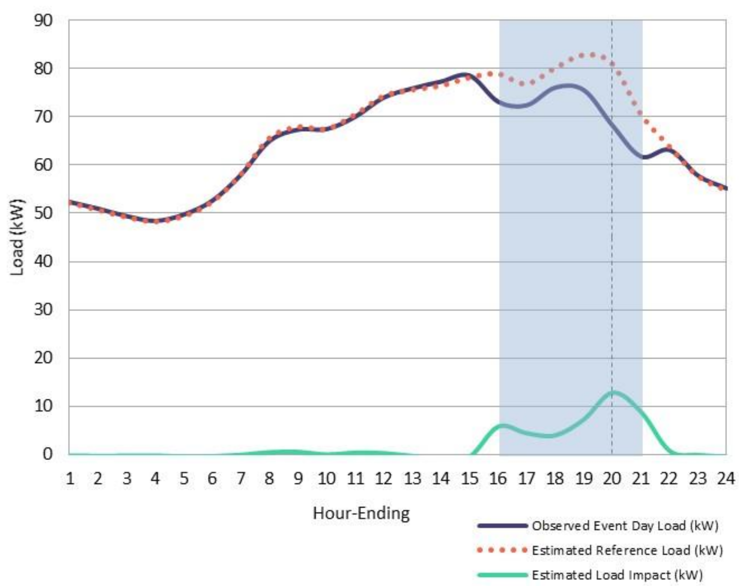
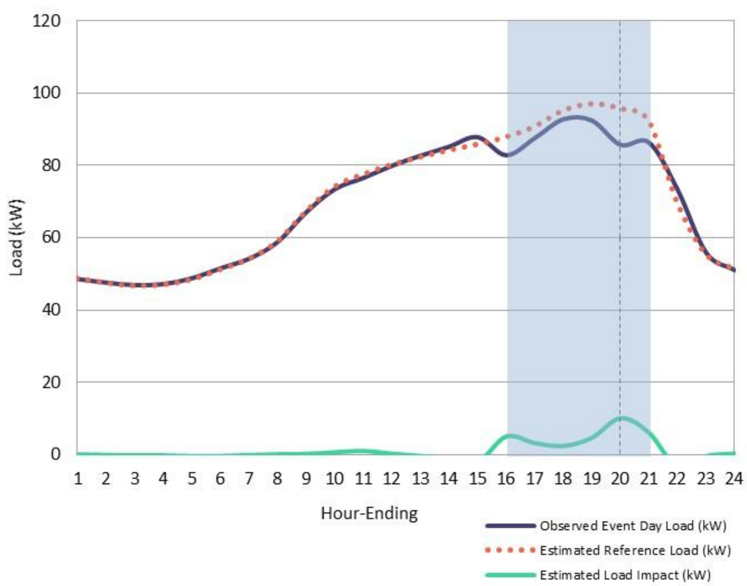


Figure 4-10 SCE Day-Of 1-6 Hour: Hourly Per-Customer Impact, Non-Summer Average Event

[redacted]

Figure 4-11 SCE Day-Of 1-6 Hour: Hourly Per-Customer Impact, Summer Average Event



Comparison of Ex-Post Impacts

This section discusses how the PY2021 ex-post load impacts compare to previous years. These comparisons show how the program has performed over time and relative to the most recent forecast.

Figure 4-12 SCE Summer Nominations

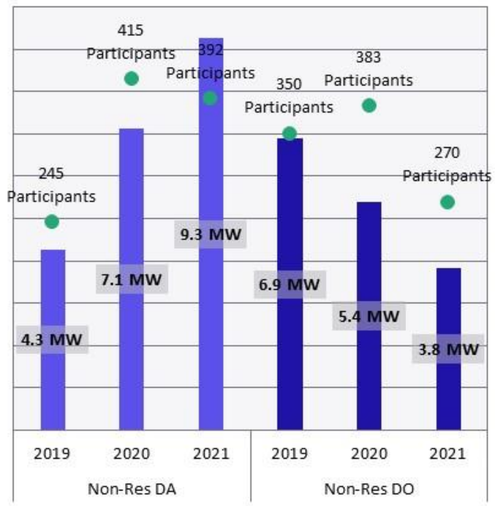


Figure 4-12 presents SCE's average summer nominations for PY2019 through PY2021. The Non-residential DA program has consistently grown in capacity nominations, despite showing fluctuations in enrollment counts. The Non-residential DO program, on the other hand, is seeing a decrease in capacity nominations along with fluctuations in enrollment counts.

Table 4-24 below presents the ex-post load impacts over time. Note that these impacts are measured based on performance during dispatched events. For Non-residential DA, we saw a decrease in average dispatched accounts but an increase in aggregate load impacts from PY2020 to PY2021. PY2021 also consisted of participants capable of higher load curtailment, showing a 16% load reduction (relative to the reference load) on average compared to 11% and 12% in previous years. Non-residential DO, on the other hand, showed relatively consistent per-customer performance but with lower customer counts and aggregate MW.

Table 4-24 SCE: Current v. Previous Ex-Post, Average Summer Event Day

Program	Year	# of Accts	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Ref. Load	Impact	Ref. Load		
Non-Res DA	2019	262	2.7	22.7	10.3	86.7	12%	86
	2020	387	3.9	35.1	10.1	90.7	11%	80
	2021	**312**	**4.0**	**25.3**	**12.8**	**81.1**	**16%**	**82**
Non-Res DO	2019	151	2.4	20.1	15.8	132.9	12%	87
	2020	312	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	78
	2021	**203**	**2.0**	**19.4**	**10.0**	**95.7**	**10%**	**79**

Table 4-25 below presents the PY2021 ex-post impacts compared to PY2020 ex-ante impacts. Note that the ex-ante impacts forecast performance for a system-level dispatch. Since SCE dispatched mostly system-level events, the average summer event day provides a reasonable comparison to the ex-ante estimates. Non-residential DA ex-post load impacts exceeded both aggregate and per-customer load impacts forecasts, despite a lower participant count. Non-residential DO, on the other hand, was slightly under the ex-ante estimates but recruited higher-performing customers with higher per-customer load impacts.

Table 4-25 SCE Current Ex-Post (Average Summer Event Day) v. Prior Ex-Ante (SCE 1-in-2, Typical Event Day, 2021)

Program	Estimate	# of Accts	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Ref. Load	Impact	Ref. Load		
Non-Res DA	PY2020 Ex-Ante	410	2.6	36.2	6.2	88.3	7%	89
	Current Ex-Post	**312**	**4.0**	**25.3**	**12.8**	**81.1**	**16%**	**82**
Non-Res DA	PY2020 Ex-Ante	380	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	93
	Current Ex-Post	**203**	**2.0**	**19.4**	**10.0**	**95.7**	**10%**	**79**

Impacts by Event Day

Table 4-26 to Table 4-29 below show the average event-hour impacts for the SCE's two CBP programs by season. Impacts are included for each event, both at the aggregate and average per-customer levels. For event days with multiple event windows, the values shown in this table represent the average event hour using only the hours that the multiple event windows have in common. The tables include results for the average summer event and average non-summer event.

Table 4-26 SCE Day Ahead 1-6 Hour: Non-Summer Impacts by Event

Event	# of Accts	Dispatched Capacity (MW)	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Reference Load	Impact	Reference Load		
Avg. Non-Summer	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	62
Nov 2, 2020	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	79
Nov 3, 2020	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	79
Nov 4, 2020	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	83
Nov 5, 2020	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	83
Nov 6, 2020	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	66
Dec 1, 2020	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	70
Dec 2, 2020	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	66
Dec 3, 2020	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	62
Dec 4, 2020	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	65
Dec 7, 2020	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	66
Dec 8, 2020	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	58
Jan 4, 2021	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	57
Jan 5, 2021	13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	61
Jan 6, 2021	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	59
Jan 12, 2021	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	54
Feb 9, 2021	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	55
Feb 10, 2021	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	61

Event	# of Accts	Dispatched Capacity (MW)	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Reference Load	Impact	Reference Load		
Feb 12, 2021	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	57
Feb 16, 2021	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	57
Feb 17, 2021	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	57
Feb 18, 2021	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	61
Feb 19, 2021	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	65
Mar 1, 2021	10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	62
Mar 4, 2021	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	68
Mar 8, 2021	18	1.9	0.9	2.5	48.3	136.7	35%	58
Mar 15, 2021	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	43
Mar 16, 2021	18	1.9	0.9	2.4	50.2	135.1	37%	54
Mar 17, 2021	18	1.9	0.9	2.5	50.2	136.4	37%	60
Mar 30, 2021	17	1.5	0.6	2.5	35.9	144.6	25%	68
Apr 1, 2021	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	78
Apr 12, 2021	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	66
Apr 13, 2021	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	59
Apr 19, 2021	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	81
Apr 28, 2021	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	75
Apr 29, 2021	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	87

Table 4-27 SCE Day Ahead 1-6 Hour: Summer Impacts by Event

Event	# of Accts	Dispatched Capacity (MW)	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Reference Load	Impact	Reference Load		
Avg. Summer	312	7.6	4.0	25.3	12.8	81.1	16%	82
May 4, 2021	416	10.2	6.6	30.4	15.8	73.1	22%	77
May 5, 2021	416	10.2	5.0	29.1	12.0	69.9	17%	73
May 6, 2021	416	10.2	6.6	28.8	15.8	69.3	23%	70
May 11, 2021	416	10.2	6.0	25.7	14.4	61.9	23%	71
May 12, 2021	416	10.2	6.6	28.1	15.8	67.6	23%	72
Jun 1, 2021	414	9.9	6.5	29.3	15.7	70.8	22%	77
Jun 2, 2021	414	9.9	6.5	29.2	15.7	70.5	22%	78
Jun 3, 2021	414	9.9	6.9	29.7	16.7	71.8	23%	77
Jun 14, 2021	414	9.9	4.0	30.1	9.6	72.6	13%	88
Jun 15, 2021	414	9.9	4.2	31.8	10.2	76.8	13%	92
Jul 1, 2021	402	10.6	6.6	30.8	16.4	76.5	21%	82
Jul 2, 2021	403	10.6	6.5	34.9	16.1	86.6	19%	82
Jul 5, 2021	59	1.1	0.4	3.4	6.8	58.0	12%	93

Event	# of Accts	Dispatched Capacity (MW)	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Reference Load	Impact	Reference Load		
Jul 6, 2021	403	10.6	6.4	31.2	15.9	77.5	21%	82
Jul 7, 2021	403	10.6	6.4	33.8	15.8	83.8	19%	83
Jul 8, 2021	344	9.4	4.0	30.5	11.6	88.6	13%	85
Jul 9, 2021	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	109
Aug 2, 2021	379	8.7	5.5	31.5	14.4	83.0	17%	91
Aug 3, 2021	379	8.7	5.5	31.7	14.4	83.8	17%	89
Aug 4, 2021	379	8.7	5.5	31.8	14.4	83.9	17%	89
Aug 27, 2021	379	8.7	6.3	34.3	16.7	90.4	18%	90
Aug 30, 2021	379	8.7	5.5	32.4	14.5	85.5	17%	83
Sep 7, 2021	141	4.1	1.6	16.8	11.1	119.1	9%	89
Sep 8, 2021	269	6.5	3.1	25.2	11.6	93.8	12%	84
Sep 9, 2021	269	6.5	3.1	24.6	11.6	91.4	13%	87
Sep 10, 2021	141	4.1	1.6	15.7	11.1	111.5	10%	91
Sep 21, 2021	141	4.1	1.6	16.4	11.2	116.1	10%	93
Oct 4, 2021	266	5.3	2.5	17.4	9.4	65.4	14%	80
Oct 15, 2021	139	3.2	0.5	10.7	3.9	77.0	5%	79
Oct 19, 2021	139	3.2	0.5	10.1	3.9	72.9	5%	67
Oct 27, 2021	139	3.2	0.5	11.0	3.9	79.2	5%	79
Oct 28, 2021	266	5.3	1.5	16.8	5.5	63.3	9%	81

Table 4-28 SCE Day Of 1-6 Hour: Non-Summer Impacts by Event[42]

Event	# of Accts	Dispatched Capacity (MW)	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Reference Load	Impact	Reference Load		
Avg. Non-Summer	13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	61
Nov 2, 2020	23	0.7	0.3	3.6	12.2	157.0	8%	73
Nov 3, 2020	23	0.7	0.3	3.6	12.2	157.5	8%	72
Nov 4, 2020	23	0.7	0.2	3.6	10.0	158.1	6%	76
Nov 5, 2020	23	0.7	0.2	3.8	10.3	163.6	6%	80
Nov 6, 2020	23	0.7	0.5	3.6	22.8	157.4	15%	67
Nov 9, 2020	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	52
Nov 10, 2020	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	59
Nov 12, 2020	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	60
Nov 13, 2020	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	61

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

Event	# of Accts	Dispatched Capacity (MW)	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Reference Load	Impact	Reference Load		
Nov 16, 2020	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	82
Dec 1, 2020	15	0.6	0.4	12.7	26.4	843.4	3%	68
Dec 2, 2020	15	0.6	0.4	12.3	26.4	816.8	3%	68
Dec 3, 2020	15	0.6	0.4	12.1	26.4	807.1	3%	66
Dec 4, 2020	15	0.6	0.4	11.8	26.4	786.4	3%	65
Dec 7, 2020	10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	68
Dec 8, 2020	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	72
Jan 4, 2021	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	59
Jan 5, 2021	10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	61
Feb 12, 2021	15	0.7	0.3	11.5	20.2	770.0	3%	61
Feb 16, 2021	15	0.7	0.3	11.4	20.2	761.4	3%	60
Feb 17, 2021	15	0.7	0.3	11.2	19.0	747.9	3%	61
Feb 18, 2021	15	0.7	0.2	11.3	15.9	750.9	2%	61
Feb 19, 2021	15	0.7	0.4	11.7	26.1	778.2	3%	61
Mar 1, 2021	11	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	63
Mar 8, 2021	15	0.5	<0.1	11.1	-1.7	740.9	<1%	59
Mar 15, 2021	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	48
Mar 16, 2021	15	0.5	0.3	11.1	18.1	738.6	2%	56
Mar 17, 2021	15	0.5	0.3	11.1	18.1	739.5	2%	58
Mar 30, 2021	15	0.5	0.3	11.3	18.1	754.8	2%	66
Apr 1, 2021	15	0.5	0.2	11.3	16.1	754.7	2%	75
Apr 12, 2021	15	0.5	0.3	11.2	22.7	748.7	3%	62
Apr 13, 2021	15	0.5	0.3	11.3	21.7	751.0	3%	60
Apr 19, 2021	15	0.5	0.3	11.6	22.7	776.4	3%	68
Apr 29, 2021	15	0.5	0.3	11.7	21.7	777.4	3%	77

Table 4-29 SCE Day Of 1-6 Hour: Summer Impacts by Event

Event	# of Accts	Dispatched Capacity (MW)	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Reference Load	Impact	Reference Load		
Avg. Summer	203	2.9	2.0	19.4	10.0	95.7	10%	79
May 4, 2021	278	4.2	2.9	28.0	10.5	100.6	10%	75
May 5, 2021	278	4.2	2.6	26.7	9.5	96.1	10%	71
May 6, 2021	278	4.2	2.9	26.1	10.5	94.0	11%	67
May 11, 2021	278	4.2	2.6	25.9	9.5	93.1	10%	69
May 12, 2021	278	4.2	2.9	26.3	10.5	94.6	11%	70
Jun 1, 2021	253	3.7	3.4	17.9	13.5	70.7	19%	75

Event	# of Accts	Dispatched Capacity (MW)	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Reference Load	Impact	Reference Load		
Jun 2, 2021	253	3.7	3.4	18.2	13.5	71.8	19%	76
Jun 3, 2021	253	3.7	3.2	17.3	12.5	68.2	18%	73
Jun 14, 2021	253	3.7	2.1	19.4	8.3	76.5	11%	88
Jun 15, 2021	279	4.4	2.3	31.0	8.2	111.2	7%	91
Jun 16, 2021	26	0.7	0.2	10.2	7.2	391.3	2%	78
Jun 17, 2021	26	0.7	0.2	10.4	7.2	398.8	2%	72
Jun 18, 2021	26	0.7	0.2	9.6	7.2	368.0	2%	71
Jul 1, 2021	211	2.9	2.9	16.5	13.9	78.1	18%	79
Jul 2, 2021	244	3.4	3.9	19.8	16.2	81.0	20%	80
Jul 5, 2021	27	0.4	0.4	2.1	15.8	76.9	21%	89
Jul 6, 2021	244	3.4	3.3	19.5	13.5	79.8	17%	80
Jul 7, 2021	244	3.4	3.3	19.6	13.7	80.5	17%	80
Jul 8, 2021	244	3.4	2.3	19.6	9.4	80.4	12%	85
Jul 9, 2021	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	100
Aug 2, 2021	243	2.8	2.6	20.6	10.6	84.7	13%	89
Aug 3, 2021	243	2.8	2.6	20.1	10.6	82.9	13%	87
Aug 4, 2021	243	2.8	2.6	20.5	10.6	84.3	13%	87
Aug 27, 2021	265	3.4	5.3	31.9	19.8	120.2	16%	87
Aug 30, 2021	265	3.4	2.8	29.5	10.6	111.2	10%	79
Aug 31, 2021	22	0.6	0.3	11.1	11.4	502.5	2%	68
Sep 9, 2021	214	2.6	2.6	18.2	12.3	85.0	14%	84

Load Impacts By Industry, LCA, and Sub-LAP

Table 4-30 through Table 4-35 present the impacts for an average event day by Industry, LCA, and Sub-LAP and by season.[43]

[43] The results 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 4-30 SCE CBP Impacts by Industry and Program, Non-Summer

	Industry	# of Accts	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Ref. Load	Impact	Ref. Load		
Day Ahead	Manufacturing	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	60
	Wholesale, Transport, other utilities	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	58
	Retail Stores	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	62
	Offices, Hotels, Finance, Services	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	56
	Institutional/Government	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	61
	Total Day Ahead	**6**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**62**
Day Of	Manufacturing	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	68
	Wholesale, Transport, other utilities	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	70
	Retail Stores	10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	61
	Offices, Hotels, Finance, Services	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	65
	Schools	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	59
	Institutional/Government	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	69
	Total Day Of	**13**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**61**
Total Non-Summer CBP		**19**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**62**

Table 4-31 SCE CBP Impacts by Industry and Program, Summer

	Industry	# of Accts	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Ref. Load	Impact	Ref. Load		
Day Ahead	Manufacturing	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	86
	Wholesale, Transport, other utilities	34	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	85
	Retail Stores	264	1.5	14.2	5.7	54.0	11%	82
	Offices, Hotels, Finance, Services	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	91
	Schools	10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	95
	Institutional/Government	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	72
	Total Day Ahead	**312**	**4.0**	**25.3**	**12.8**	**81.1**	**16%**	**82**
Day Of	Manufacturing	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	87
	Retail Stores	195	1.9	14.0	9.6	71.6	13%	79
	Offices, Hotels, Finance, Services	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	77
	Schools	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	64
	Total Day Of	**203**	**2.0**	**19.4**	**10.0**	**95.7**	**10%**	**79**
Total Summer CBP		**514**	**6.0**	**44.7**	**11.7**	**86.8**	**13%**	**81**

Table 4-32 SCE CBP Impacts by LCA and Program, Non-Summer

	Local Capacity Area	# of Accts	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Ref. Load	Impact	Ref. Load		
Day Ahead	LA Basin	6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	64
Day Ahead	Outside LA Basin	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	58
Day Ahead	Ventura/Big Creek	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	65
Day Ahead	**Total Day Ahead**	**6**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**62**
Day Of	LA Basin	12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	63
Day Of	Ventura/Big Creek	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	59
Day Of	**Total Day Of**	**13**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**61**
Total Non-Summer CBP		**19**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**62**

Table 4-33 SCE CBP Impacts by LCA and Program, Summer

	Industry	# of Accts	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Ref. Load	Impact	Ref. Load		
Day Ahead	LA Basin	263	3.0	22.0	11.2	83.8	13%	80
Day Ahead	Outside LA Basin	28	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	92
Day Ahead	Ventura/Big Creek	70	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	85
Day Ahead	**Total Day Ahead**	**312**	**4.0**	**25.3**	**12.8**	**81.1**	**16%**	**82**
Day Of	LA Basin	214	2.2	16.3	10.3	76.5	13%	78
Day Of	Outside LA Basin	16	0.2	1.3	9.7	80.7	12%	87
Day Of	Ventura/Big Creek	27	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	85
Day Of	**Total Day Of**	**203**	**2.0**	**19.4**	**10.0**	**95.7**	**10%**	**79**
Total Summer CBP		**514**	**6.0**	**44.7**	**11.7**	**86.8**	**13%**	**81**

Table 4-34 SCE CBP Impacts by Sub-LAP and Program, Non-Summer

	Sub-LAP	# of Accts	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Ref. Load	Impact	Ref. Load		
Day Ahead	SCEC	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	65
Day Ahead	SCEN	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	65
Day Ahead	SCEW	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	56
Day Ahead	SCHD	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	58
Day Ahead	**Total Day Ahead**	**6**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**62**
Day Of	SCEC	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	66
Day Of	SCEW	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	62
Day Of	SCNW	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	59
Day Of	**Total Day Of**	**13**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**61**
Total Non-Summer CBP		**19**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**62**

Table 4-35 SCE CBP Impacts by Sub-LAP and Program, Summer

	Sub-LAP	# of Accts	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Ref. Load	Impact	Ref. Load		
Day Ahead	SCEC	152	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	85
Day Ahead	SCEN	54	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	93
Day Ahead	SCEW	138	1.5	8.1	10.6	58.7	18%	73
Day Ahead	SCHD	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	91
Day Ahead	SCLD	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	102
Day Ahead	SCNW	24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	69
Day Ahead	**Total Day Ahead**	**312**	**4.0**	**25.3**	**12.8**	**81.1**	**16%**	**82**
Day Of	SCEC	96	1.2	7.7	12.1	80.3	15%	85
Day Of	SCEN	27	0.2	2.1	8.8	75.2	12%	89
Day Of	SCEW	117	1.0	8.6	8.8	73.3	12%	72
Day Of	SCHD	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	92
Day Of	SCNW	25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	69
Day Of	**Total Day Of**	**203**	**2.0**	**19.4**	**10.0**	**95.7**	**10%**	**79**
Total Summer CBP		**514**	**6.0**	**44.7**	**11.7**	**86.8**	**13%**	**81**

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.

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 4-36 and Table 4-37 presents the ex-post load impacts achieved in PY2020 by SCE CBP customers that enrolled in AutoDR or TA/TI at some point in the current or previous years for DA and DO, respectively.

Table 4-36 SCE Day Ahead 1-6 Hour: AutoDR and TA/TI Participant Impacts by Event

Event	# of Accts	Aggregate Load Shed Test (MW)	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Reference Load	Impact	Reference Load		
Avg. Non-Summer	**4**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**66**
Avg. Summer	**55**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**78**
Nov 2, 2020	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	83
Nov 3, 2020	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	82
Nov 4, 2020	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	87
Nov 5, 2020	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	87
Nov 6, 2020	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	70
Dec 1, 2020	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	76
Dec 2, 2020	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	70
Dec 3, 2020	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	64
Dec 4, 2020	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	70
Dec 7, 2020	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	68
Jan 4, 2021	7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	57
Jan 5, 2021	10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	60
Feb 12, 2021	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	61
Feb 16, 2021	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	60
Feb 17, 2021	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	61
Feb 18, 2021	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	62
Feb 19, 2021	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	66
Mar 1, 2021	9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	61
Mar 8, 2021	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	58
Mar 15, 2021	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	44
Mar 16, 2021	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	55
Mar 17, 2021	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	60
Mar 30, 2021	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	67
Apr 1, 2021	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	81
Apr 12, 2021	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	65

Event	# of Accts	Aggregate Load Shed Test (MW)	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Reference Load	Impact	Reference Load		
Apr 13, 2021	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	58
Apr 19, 2021	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	78
Apr 29, 2021	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	87
May 4, 2021	72	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	74
May 5, 2021	72	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	69
May 6, 2021	72	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	66
May 11, 2021	72	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	68
May 12, 2021	72	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	68
Jun 1, 2021	72	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	72
Jun 2, 2021	72	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	72
Jun 3, 2021	72	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	71
Jun 14, 2021	72	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	85
Jun 15, 2021	72	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	89
Jul 1, 2021	73	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	78
Jul 2, 2021	73	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	77
Jul 5, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	89
Jul 6, 2021	73	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	78
Jul 7, 2021	73	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	78
Jul 8, 2021	70	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	82
Aug 2, 2021	57	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	86
Aug 3, 2021	57	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	84
Aug 4, 2021	57	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	84
Aug 27, 2021	57	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	85
Aug 30, 2021	57	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	77
Sep 7, 2021	25	2.4	1.2	7.7	47.6	306.8	16%	85
Sep 8, 2021	49	4.8	2.0	12.2	40.1	248.9	16%	82
Sep 9, 2021	49	4.8	2.0	11.9	40.1	242.3	17%	83
Sep 10, 2021	25	2.4	1.2	7.6	47.6	302.9	16%	87
Sep 21, 2021	25	2.4	1.2	7.8	49.5	311.3	16%	90
Oct 4, 2021	46	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	78
Oct 15, 2021	22	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	76
Oct 19, 2021	22	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	64
Oct 27, 2021	22	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	77
Oct 28, 2021	46	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	79

Table 4-37 SCE Day Of 1-6 Hour: AutoDR and TA/TI Participant Impacts by Event

Event	# of Accts	Aggregate Load Shed Test (MW)	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Reference Load	Impact	Reference Load		
Avg. Non-Summer	**13**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**62**
Avg. Summer	**165**	**5.8**	**1.8**	**16.9**	**10.7**	**102.8**	**10%**	**79**
Nov 2, 2020	22	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	73
Nov 3, 2020	22	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	72
Nov 4, 2020	22	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	76
Nov 5, 2020	22	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	80
Nov 6, 2020	22	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	67
Nov 9, 2020	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	52
Nov 10, 2020	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	59
Nov 12, 2020	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	60
Nov 13, 2020	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	61
Nov 16, 2020	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	82
Dec 1, 2020	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	68
Dec 2, 2020	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	68
Dec 3, 2020	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	67
Dec 4, 2020	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	65
Dec 7, 2020	9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	69
Dec 8, 2020	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	72
Jan 4, 2021	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	60
Jan 5, 2021	9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	62
Feb 12, 2021	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	62
Feb 16, 2021	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	60
Feb 17, 2021	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	62
Feb 18, 2021	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	61
Feb 19, 2021	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	62
Mar 1, 2021	10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	63
Mar 8, 2021	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	59
Mar 15, 2021	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	48
Mar 16, 2021	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	56
Mar 17, 2021	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	59
Mar 30, 2021	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	67
Apr 1, 2021	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	76
Apr 12, 2021	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	62
Apr 13, 2021	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	60

Event	# of Accts	Aggregate Load Shed Test (MW)	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Reference Load	Impact	Reference Load		
Apr 19, 2021	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	68
Apr 29, 2021	14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	78
May 4, 2021	227	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	75
May 5, 2021	227	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	71
May 6, 2021	227	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	67
May 11, 2021	227	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	69
May 12, 2021	227	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	70
Jun 1, 2021	205	6.7	3.0	15.0	14.6	73.0	20%	75
Jun 2, 2021	205	6.7	3.0	15.3	14.6	74.5	20%	76
Jun 3, 2021	205	6.7	2.8	14.5	13.5	70.8	19%	73
Jun 14, 2021	205	6.7	1.8	16.0	8.8	78.0	11%	88
Jun 15, 2021	226	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	91
Jun 16, 2021	21	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	77
Jun 17, 2021	21	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	72
Jun 18, 2021	21	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	71
Jul 1, 2021	176	5.8	2.6	14.2	14.7	80.7	18%	79
Jul 2, 2021	199	6.6	3.4	16.6	17.2	83.5	21%	80
Jul 5, 2021	19	0.7	0.4	1.5	18.6	78.8	24%	90
Jul 6, 2021	199	6.6	2.9	16.5	14.5	83.1	17%	80
Jul 7, 2021	199	6.6	3.0	16.6	15.0	83.3	18%	80
Jul 8, 2021	199	6.6	2.0	16.3	10.1	81.8	12%	84
Jul 9, 2021	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	100
Aug 2, 2021	197	6.5	2.2	17.1	11.2	86.7	13%	89
Aug 3, 2021	197	6.5	2.2	16.6	11.2	84.3	13%	87
Aug 4, 2021	197	6.5	2.2	16.9	11.2	85.6	13%	87
Aug 27, 2021	214	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	87
Aug 30, 2021	214	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	79
Aug 31, 2021	17	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	68
Sep 9, 2021	175	5.8	2.3	15.4	13.0	88.1	15%	84

SDG&E

Dispatched Events

We present a summary of the 2021 events for SDG&E's CBP programs by product offering. The Non-residential DA participants experienced 28 event days and participated in two products: DA 11-7 Hour and DA 1-9 Hour. The Non-residential DO participants experienced 23 event days and participated in two products: DO 11-7 Hour and DO 1-9 Hour.

SDG&E's service territory falls under one Sub-LAP, making all SDG&E dispatched events are system-level events. Table 4-39 below shows the event hours and the number of accounts dispatched on each event day by product offering. For reference, Table 4-38 presents the total monthly enrollment for the Non-residential DA and DO programs, which would be comparable to dispatched counts for a system-level event.

As mentioned earlier, we calculate the average event day by including all events called in PY2021 regardless of the event hours dispatched and report impacts for the average event day on the most dispatched hour, HE19.

Table 4-38 SDG&E Monthly Nominations

Month	Non-Residential DA		Non-Residential DO	
	Enrolled Accounts	Nominated Capacity (MW)	Enrolled Accounts	Nominated Capacity (MW)
May	40	1.4	134	2.9
June	48	1.2	126	3.2
July	36	1.0	133	3.3
August	48	1.0	133	3.3
September	35	0.8	130	3.4
October	48	1.0	131	3.1
Avg. Summer	**43**	**1.1**	**131**	**3.2**

Table 4-39 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**	**22**	**24**	**11**	**122**
Jun 15, 2021	Tuesday	17-19, 19-20	18	30	-	124
Jun 16, 2021	Wednesday	18-19, 19-20	18	30	-	124
Jun 17, 2021	Thursday	18-19, 19-21	18	30	-	124
Jun 28, 2021	Monday	16-19, 18-21, 19-21	18	30	-	124
Jun 29, 2021	Tuesday	16-19, 18-21, 19-21	18	30	-	124
Jun 30, 2021	Wednesday	20-21	-	30	-	-

Date	Day of Week	Event Hours (HE)	# Accounts			
			DA 11AM to 7PM	DA 1PM to 9PM	DO 11AM to 7PM	DO 1PM to 9PM
Jul 9, 2021	Friday	18-19, 19-20	18	-	-	123
Jul 12, 2021	Monday	18-19, 19-21	18	-	-	123
Jul 19, 2021	Monday	18-19, 19-20	18	-	-	123
Jul 27, 2021	Tuesday	18-19	18	-	-	-
Jul 28, 2021	Wednesday	18-19, 19-20	18	-	-	123
Jul 29, 2021	Thursday	18-19	18	-	-	-
Jul 30, 2021	Friday	16-19, 18-20	18	-	-	123
Aug 26, 2021	Thursday	18-19, 19-20	30	-	11	122
Aug 27, 2021	Friday	16-19, 18-19, 18-20	30	-	11	122
Aug 31, 2021	Tuesday	18-19	30	-	-	-
Sep 8, 2021	Wednesday	18-19, 19-20	18	-	11	119
Sep 9, 2021	Thursday	18-19, 18-21	18	-	11	119
Sep 10, 2021	Friday	17-19, 18-20	18	17	11	119
Sep 21, 2021	Tuesday	16-19, 17-19, 18-20	18	-	11	119
Sep 22, 2021	Wednesday	17-19, 18-19	18	-	11	119
Sep 23, 2021	Thursday	18-19	18	-	11	-
Oct 15, 2021	Friday	18-19	31	-	-	-
Oct 19, 2021	Tuesday	19-20	-	17	-	120
Oct 21, 2021	Thursday	18-19	31	-	11	-
Oct 26, 2021	Tuesday	18-19, 18-21	31	17	-	-
Oct 27, 2021	Wednesday	18-19, 18-21	31	17	11	-
Oct 28, 2021	Thursday	18-19, 18-21, 19-20	31	17	11	120
Oct 29, 2021	Friday	18-19	-	-	11	120

Load Impact Summary

This section includes the following:

- Table 4-40 shows an overall impact summary for PY2021, including average dispatched counts, capacity, and load impacts at the aggregate and per-customer levels.
- Figure 4-13, Table 4-41, and Table 4-42 present monthly summaries for each metric (described in more detail in Section 3, Reporting Metrics for Program Performance):
  - Nominations – counts and total capacity,
  - Dispatched – average counts and capacity for all events dispatched,
  - HE19 Dispatched – average counts and capacity for all events dispatched on HE19, and

- Ex-post load impacts – aggregate impacts, delivery performance relative to the overall dispatched capacity, and adjusted delivery performance relative to HE19 dispatched capacity.

On average, SDG&E's CBP programs delivered 1.3 MW out of dispatched 4.5 MW, resulting in a 29% delivery performance.

Table 4-40 SDG&E Impacts Summary, Average Event Day PY2021

Program & Product	Accounts	Dispatched Capacity (MW)	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact
			Impact	Reference Load	Impact	Reference Load	
DA 11AM-7PM	22	0.6	0.2	3.6	9.4	165.1	6%
DA 1PM-9PM	24	0.4	0.1	1.5	2.6	61.7	4%
Total Day Ahead	**46**	**1.1**	**0.3**	**5.1**	**5.8**	**110.9**	**5%**
DO 11AM-7PM	11	0.3	0.1	2.6	5.7	233.5	2%
DO 1PM-9PM	122	3.1	1.0	11.1	8.0	91.3	9%
Total Day Of	**133**	**3.4**	**1.0**	**13.7**	**7.8**	**103.0**	**8%**
Total CBP	**179**	**4.5**	**1.3**	**18.8**	**7.3**	**105.1**	**7%**

Figure 4-13 visually shows how the ex-post load impacts compare to the overall and HE19 dispatched capacities. For both programs, we observe the following:

- Non-residential DA dispatched August events under the DA 11-7 Hour product, delivering impacts in earlier hours HE16 and HE17.
- Non-residential DO saw a deficient delivery performance in July. The July 28, 2021 event delivered the most impacts with 0.9 MW out of 3.1 MW dispatched, a 30% delivery performance.

Table 4-41 and Table 4-42 present the monthly averages that correspond to Figure 4-13 for Non-residential DA and Non-residential DO, respectively. The overall aggregate impact for the Non-residential DA participants was 0.3 MW in PY2021, which amounts to a 25% delivery performance and a 26% adjusted delivery performance. The overall aggregate impact for the Non-residential DO participants was 1.0 MW in PY2021, which amounts to a 30% delivery performance. Both programs showed substantially lower deliveries in PY2021 compared to PY2020 deliveries at 71% and 74% for DA and DO, respectively.

Figure 4-13 SDG&E Monthly Delivery Performance Summary

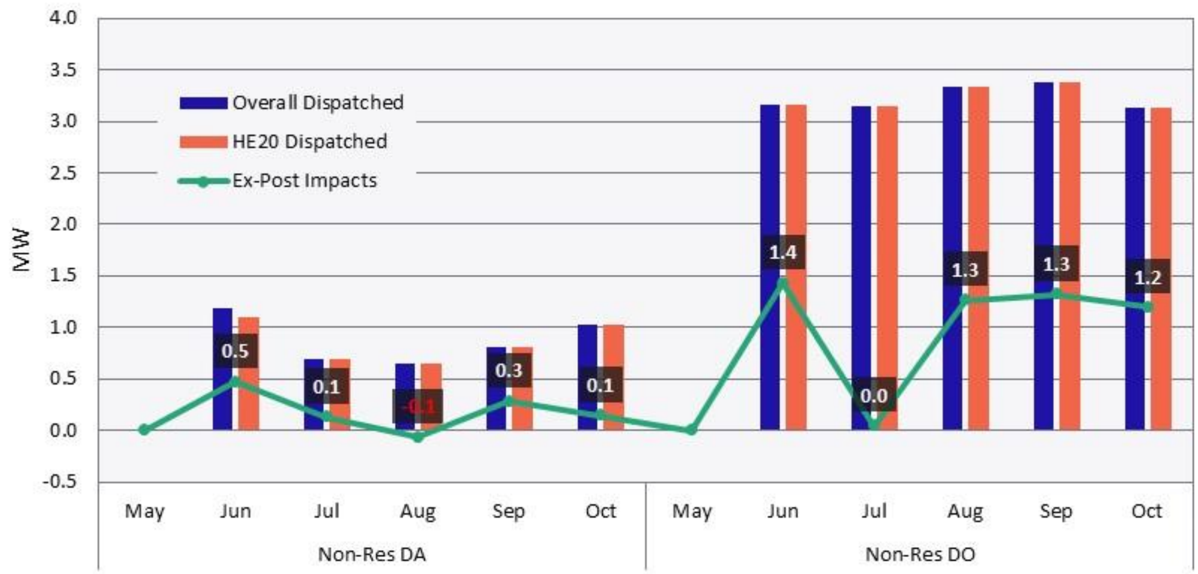


Table 4-41 SDG&E Non-Residential DA Monthly Summary

Month	Nominations		Dispatched		HE19 Dispatched		Ex-Post Analysis		
	# Accts	Capacity (MW)	# Accts	Capacity (MW)	# Accts	Capacity (MW)	Impact (MW)	% Delivered	Adj. % Delivered
May	40	1.4	-	-	-	-	-	-	-
June	48	1.2	48	1.2	43	1.1	0.5	39%	43%
July	36	1.0	18	0.7	18	0.7	0.1	19%	19%
August	48	1.0	30	0.7	30	0.7	-0.1	-10%	-10%
September	35	0.8	35	0.8	35	0.8	0.3	35%	35%
October	48	1.0	48	1.0	48	1.0	0.1	14%	14%
Overall	**43**	**1.1**	**46**	**1.1**	**43**	**1.0**	**0.3**	**25%**	**26%**

Table 4-42 SDG&E Non-Residential DO Monthly Summary

Month	Nominations		Dispatched		HE19 Dispatched		Ex-Post Analysis		
	# Accts	Capacity (MW)	# Accts	Capacity (MW)	# Accts	Capacity (MW)	Impact (MW)	% Delivered	Adj. % Delivered
May	134	2.9	-	-	-	-	-	-	-
June	126	3.2	124	3.2	124	3.2	1.4	45%	45%
July	133	3.3	123	3.1	123	3.1	0.0	1%	1%
August	133	3.3	133	3.3	133	3.3	1.3	38%	38%
September	130	3.4	130	3.4	130	3.4	1.3	39%	39%
October	131	3.1	131	3.1	131	3.1	1.2	38%	38%
Overall	**131**	**3.2**	**133**	**3.4**	**133**	**3.4**	**1.0**	**30%**	**30%**

Hourly Load Impacts

Figure 4-14 and Figure 4-15 illustrate the per-customer hourly profiles of the estimated reference load, observed load, and estimated load impacts (in kW) for SDG&E's CBP programs. In both figures, we combined results for the 11 AM to 7 PM and 1 PM to 9 PM products. The hours highlighted in the gray show the hours wherein at least one group is dispatched. The most dispatched hour, HE19, is highlighted by the vertical dotted line. The data underlying the figures are available in the MS Excel-based Protocol table generators that are included as appendices to this report.

Figure 4-14 SDG&E All Day-Ahead: Hourly Per-Customer Impact, Summer Average Event

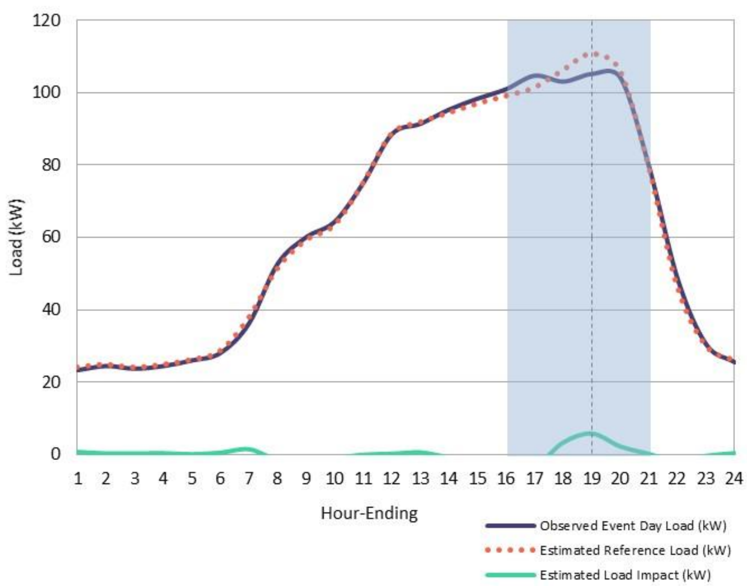
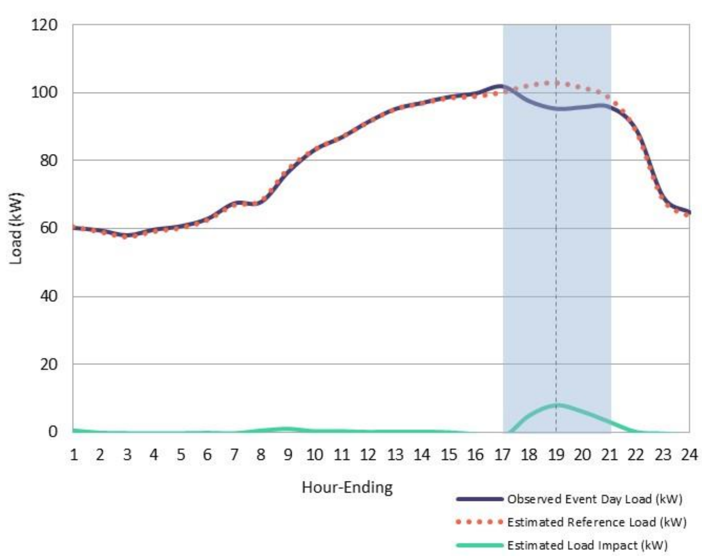


Figure 4-15 SDG&E All Day-Of: Hourly Per-Customer Impact, Summer Average Event



Comparison of Ex-Post Impacts

This section discusses how the PY2021 ex-post load impacts compare to previous years. These comparisons show how the program has performed over time and relative to the most recent forecast.

Figure 4-16 SDG&E Annual Nominations

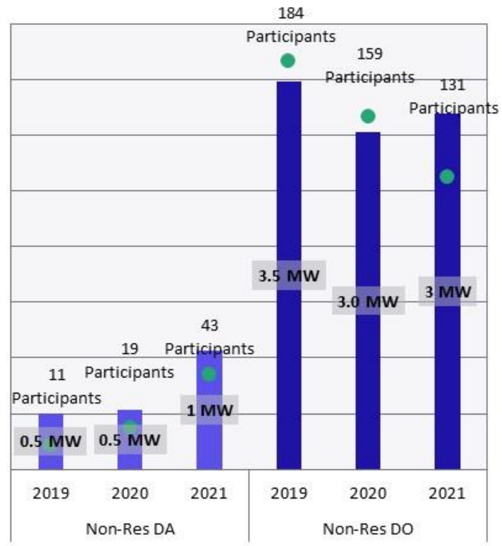


Figure 4-16 presents SDG&E's average program nominations for PY2019 through PY2021. The Non-residential DA program has steadily grown in both customer enrollments and capacity nominations. The Non-residential DO program, on the other hand, is seeing a decrease in customer enrollments along with fluctuations in capacity nominations.

Table 4-43 below presents the ex-post load impacts over time. Note that these impacts are measured based on performance during dispatched events, thus showing a slightly different average dispatched count compared to nomination counts. For Non-residential DA, we saw an increase in average dispatched accounts but a decrease in aggregate load impacts from PY2020 to PY2021, consistent with findings showing overall deliveries being lower in PY2021. Non-residential DO, on the other hand, showed a decrease in both average dispatched counts and aggregate load impacts, also consistent with findings showing overall lower deliveries in PY2021.

Table 4-43 SDG&E: Current v. Previous Ex-Post, Average Summer Event Day

Program	Year	# of Accts	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Ref. Load	Impact	Ref. Load		
Non-Res DA	2019	15	0.4	6.1	26.3	408.7	6%	76
	2020	23	0.4	2.8	18.0	121.3	15%	78
	2021	**46**	**0.3**	**5.1**	**5.8**	**110.9**	**5%**	**75**
Non-Res DO	2019	185	3.6	22.3	19.6	120.6	16%	77
	2020	158	2.2	18.3	13.8	115.4	12%	77
	2021	**133**	**1.0**	**13.7**	**7.8**	**103.0**	**8%**	**76**

Table 4-44 below presents the PY2021 ex-post impacts compared to PY2020 ex-ante impacts. Note that the ex-ante impacts forecast performance for a system-level dispatch. Since SDG&E dispatches all system-level events, the average summer event day provides a reasonable comparison to the ex-ante estimates. Non-residential DA ex-post load impacts exceeded both aggregate and per-customer load impacts forecasts, despite a lower delivery performance. Non-residential DO, on the other hand, was slightly under the ex-ante estimates in both customer enrollment and aggregate impacts.

Table 4-44 SDG&E Current Ex-Post (Average Summer Event Day) v. Prior Ex-Ante (SDG&E 1-in-2, Typical Event Day, 2021)

Program	Estimate	# of Accts	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Ref. Load	Impact	Ref. Load		
Non-Res DA	PY2020 Ex-Ante	18	0.2	2.2	11.8	120.0	10%	84
	Current Ex-Post	**46**	**0.3**	**5.1**	**5.8**	**110.9**	**5%**	**75**
Non-Res DA	PY2020 Ex-Ante	164	1.5	15.7	9.1	95.8	9%	83
	Current Ex-Post	**133**	**1.0**	**13.7**	**7.8**	**103.0**	**8%**	**76**

Impacts by Event Day

Table 4-45 through Table 4-48 show the average event-hour impacts for the four CBP products. The impacts are reported both at the aggregate and average per-customer levels. 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.

Note that some events show small negative impacts that 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 increasing their load in response to events.

Table 4-45 SDG&E Day Ahead 11 AM to 7 PM Product: Impacts by Event

Event	# of Accts	Dispatched Capacity (MW)	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Reference Load	Impact	Reference Load		
Avg. Event	**22**	**0.63**	**0.20**	**3.61**	**9.4**	**165.1**	**6%**	**78**
Jun 15, 2021	18	0.67	0.46	3.48	25.3	193.1	13%	93
Jun 16, 2021	18	0.67	0.40	3.31	22.0	183.9	12%	77
Jun 17, 2021	18	0.67	0.26	3.60	14.6	200.0	7%	77
Jun 28, 2021	18	0.67	0.33	3.22	18.5	179.1	10%	73
Jun 29, 2021	18	0.67	0.14	3.34	7.6	185.5	4%	73
Jul 9, 2021	18	0.69	0.04	3.73	2.2	207.5	1%	83
Jul 12, 2021	18	0.69	0.05	3.68	2.6	204.3	1%	76
Jul 19, 2021	18	0.69	0.14	3.89	7.8	216.0	4%	82
Jul 27, 2021	18	0.69	0.22	3.33	12.2	184.7	7%	79
Jul 28, 2021	18	0.69	0.26	3.37	14.2	187.3	8%	83
Jul 29, 2021	18	0.69	0.29	3.34	16.0	185.7	9%	82
Jul 30, 2021	18	0.69	0.18	3.51	9.9	195.2	5%	81
Aug 26, 2021	30	0.65	0.11	4.03	3.6	134.2	3%	85
Aug 27, 2021	30	0.65	0.08	4.07	2.8	135.7	2%	84
Aug 31, 2021	30	0.65	0.02	4.02	0.5	133.9	<1%	72
Sep 8, 2021	18	0.48	0.47	3.79	25.9	210.6	12%	83

Event	# of Accts	Dispatched Capacity (MW)	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Reference Load	Impact	Reference Load		
Sep 9, 2021	18	0.48	0.45	3.81	25.2	211.6	12%	87
Sep 10, 2021	18	0.48	0.14	3.79	7.7	210.6	4%	85
Sep 21, 2021	18	0.48	0.51	3.60	28.3	199.8	14%	88
Sep 22, 2021	18	0.48	0.47	3.71	26.1	206.4	13%	84
Sep 23, 2021	18	0.48	0.28	3.54	15.4	196.6	8%	77
Oct 15, 2021	31	0.70	0.14	3.44	4.5	110.9	4%	79
Oct 21, 2021	31	0.70	0.03	3.14	1.0	101.4	1%	68
Oct 26, 2021	31	0.70	0.12	3.02	3.7	97.3	4%	63
Oct 27, 2021	31	0.70	-0.23	3.17	-7.3	102.2	-7%	73
Oct 28, 2021	31	0.70	0.03	3.55	0.9	114.6	1%	79

Table 4-46 SDG&E Day Ahead 1 PM to 9 PM Product: Impacts by Event

Event	# of Accts	Dispatched Capacity (MW)	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Reference Load	Impact	Reference Load		
Avg. Event	**24**	**0.43**	**0.06**	**1.5**	**2.6**	**61.7**	**4%**	**72**
Jun 15, 2021	30	0.53	0.21	1.7	7.0	57.5	12%	81
Jun 16, 2021	30	0.53	0.21	1.7	7.0	57.7	12%	72
Jun 17, 2021	30	0.53	-0.02	1.7	-0.6	57.4	-1%	69
Jun 28, 2021	30	0.53	0.11	1.6	3.8	52.9	7%	68
Jun 29, 2021	30	0.53	0.11	1.8	3.8	58.7	6%	69
Jun 30, 2021	30	0.53	-0.10	1.7	-3.3	57.9	-6%	67
Sep 10, 2021	17	0.33	-0.11	1.4	-6.8	83.6	-8%	77
Oct 19, 2021	17	0.32	0.17	1.2	9.9	70.3	14%	61
Oct 26, 2021	17	0.32	0.10	1.1	6.0	63.1	10%	62
Oct 27, 2021	17	0.32	0.10	1.1	6.0	64.8	9%	69
Oct 28, 2021	17	0.32	0.10	1.1	6.0	67.3	9%	74

Table 4-47 SDG&E Day Of 11 AM to 7 PM: Impacts by Event

Event	# of Accts	Dispatched Capacity (MW)	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Reference Load	Impact	Reference Load		
Avg. Event	**11**	**0.33**	**0.06**	**2.6**	**5.7**	**233.5**	**2%**	**73**
Aug 26, 2021	11	0.33	0.09	2.9	8.3	266.5	3%	81
Aug 27, 2021	11	0.33	0.09	2.7	8.3	249.8	3%	78
Sep 8, 2021	11	0.33	0.15	3.2	13.5	287.9	5%	76

Event	# of Accts	Dispatched Capacity (MW)	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Reference Load	Impact	Reference Load		
Sep 9, 2021	11	0.33	0.15	3.0	13.5	270.8	5%	83
Sep 10, 2021	11	0.33	0.07	3.0	6.5	270.3	2%	79
Sep 21, 2021	11	0.33	0.07	2.8	6.5	253.9	3%	81
Sep 22, 2021	11	0.33	0.15	2.6	13.5	239.5	6%	77
Sep 23, 2021	11	0.33	0.15	2.5	13.5	228.5	6%	70
Oct 21, 2021	11	0.33	-0.05	2.2	-4.8	195.5	-2%	65
Oct 27, 2021	11	0.33	-0.05	2.0	-4.8	186.1	-3%	70
Oct 28, 2021	11	0.33	-0.05	2.2	-4.8	199.1	-2%	76

Table 4-48 SDG&E Day Of 1 PM to 9 PM: Impacts by Event

Event	# of Accts	Dispatched Capacity (MW)	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Reference Load	Impact	Reference Load		
Avg. Event	**122**	**3.06**	**0.97**	**11.1**	**8.0**	**91.3**	**9%**	**76**
Jun 15, 2021	124	3.17	2.45	11.8	19.8	95.1	21%	82
Jun 16, 2021	124	3.17	2.45	11.6	19.8	93.2	21%	72
Jun 17, 2021	124	3.17	0.04	11.0	0.3	88.9	<1%	69
Jun 28, 2021	124	3.17	1.49	9.8	12.0	79.2	15%	67
Jun 29, 2021	124	3.17	0.36	11.1	2.9	89.8	3%	68
Jul 9, 2021	123	3.15	0.09	11.8	0.7	95.8	1%	77
Jul 12, 2021	123	3.15	-0.13	11.8	-1.0	96.3	-1%	71
Jul 19, 2021	123	3.15	0.09	12.4	0.7	100.9	1%	78
Jul 28, 2021	123	3.15	0.95	10.6	7.7	86.0	9%	76
Jul 30, 2021	123	3.15	-0.40	11.3	-3.2	91.8	-4%	75
Aug 26, 2021	122	3.02	1.79	12.0	14.7	98.3	15%	80
Aug 27, 2021	122	3.02	0.52	12.1	4.3	99.4	4%	79
Sep 8, 2021	119	3.05	1.69	11.4	14.2	96.0	15%	75
Sep 9, 2021	119	3.05	1.58	11.5	13.3	96.3	14%	80
Sep 10, 2021	119	3.05	0.28	12.5	2.3	105.3	2%	78
Sep 21, 2021	119	3.05	1.46	11.2	12.3	93.8	13%	81
Sep 22, 2021	119	3.05	<0.01	11.2	<0.1	93.8	<1%	80
Oct 19, 2021	120	2.80	1.25	8.3	10.4	69.0	15%	61
Oct 28, 2021	120	2.80	1.29	9.5	10.8	79.5	14%	73
Oct 29, 2021	120	2.80	1.22	9.4	10.2	78.1	13%	72

Load Impacts By Industry Type

Table 4-49 presents the impacts for an average event day by industry group.[44]

Table 4-49 SDG&E Impacts by Industry[45]

	Industry	# of Accts	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Ref. Load	Impact	Ref. Load		
Day Ahead	Agriculture, Mining & Construction	1	0.1	0.2	99.0	193.5	51%	86
	Retail stores	29	0.2	4.0	6.5	141.7	5%	73
	Offices, Hotels, Finance, Services	6	<0.1	0.4	-0.5	75.0	-1%	82
	Schools	1	-0.1	0.1	-56.9	70.3	-81%	71
	Institutional/Government	24	<0.1	1.0	1.0	41.5	2%	73
	Total Day Ahead	**46**	**0.3**	**5.1**	**5.8**	**110.9**	**5%**	**75**
Day Of	Manufacturing	1	<0.1	1.6	32.9	1,562.6	2%	73
	Wholesale, Transport, other utilities	3	0.1	0.2	23.2	54.5	43%	75
	Retail stores	119	0.8	10.7	6.7	90.0	7%	76
	Offices, Hotels, Finance, Services	8	<0.1	0.6	1.4	73.7	2%	73
	Institutional/Government	2	0.1	0.7	66.0	359.9	18%	76
	Total Day Of	**133**	**1.0**	**13.7**	**7.8**	**103.0**	**8%**	**76**
Total CBP		**179**	**1.3**	**18.8**	**7.3**	**105.1**	**7%**	**75**

Load Impacts of TA/TI and AutoDR Participants

SDG&E did not have any TA/TI or AutoDR participants in PY2021.

[44] The results 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.

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

5

EX-ANTE ANALYSIS RESULTS

Table 5-1 summarizes the 11-year enrollment and average Resource Adequacy (RA) window load impact forecast by IOU and program for an August peak day scenario. Table 5-2 summarizes the average RA window load impact estimates for an August peak day in 2022 by IOU and program for each weather scenario.

Table 5-1 Statewide CBP: 2022-2032 Forecast, August Peak Day

IOU	Program	Number of Service Accounts			Aggregate Impact (MW)		
		2022	2023	2027-2032 (Each Year)	2022	2023	2027-2032 (Each Year)
PGE	Residential Day Ahead	0	6,972	6,972	0.0	1.3	1.3
	Non-Residential Day Ahead	1,505	1,505	1,505	37.1	37.1	37.1
SCE	Non-Residential Day Ahead	410	410	410	4.2	4.2	4.2
	Non-Residential Day Of	290	290	290	1.7	1.7	1.7
SDG&E	Non-Residential Day Ahead	105	107	116	2.3	2.4	2.6
	Non-Residential Day Of	208	212	227	3.5	3.6	3.8

Table 5-2 Statewide CBP: RA Window Ex-Ante Impacts, August Peak Day, 2022

IOU	Program	# of Accts	Per Customer (kW)	Aggregate Impact (MW)	Percent Impact (%)			
					Utility Peak		CAISO Peak	
					1-in-2	1-in-10	1-in-2	1-in-10
PGE	Residential Day Ahead*	4,357	0.2	0.9	32.0%	27.5%	33.7%	29.5%
	Non-Residential Day Ahead	1,505	24.6	37.1	17.3%	17.0%	17.4%	17.3%
SCE	Non-Residential Day Ahead	410	10.1	4.2	12.9%	12.9%	12.9%	12.9%
	Non-Residential Day Of	290	6.0	1.7	5.7%	5.7%	5.7%	5.7%
SDG&E	Non-Residential Day Ahead	105	22.0	2.3	21.7%	21.2%	21.6%	21.7%
	Non-Residential Day Of	208	16.9	3.5	17.2%	16.9%	17.1%	17.2%

*Shown for 2022 Typical event day due to zero forecasted August 2022 enrollments.

Note that since CBP impacts are inherently nomination-driven, not weather-driven, we assumed constant non-residential per-customer load impacts across the weather scenarios. This assumption results in varying percent impacts across the months and weather scenarios. The per-customer load impacts are also estimated to remain constant across months by season, i.e., constant nominations through each program and season. However, since participant usage can be weather-dependent, the weather scenarios still affect the estimated reference load.

The above statement does not apply to Residential RA window load impacts. We do not assume load impacts to be flat across months and weather scenarios. Instead, we assume constant HE20 percent impacts, accounting for the available load during each hour of the RA window. However, the differences between weather scenarios are minimal and cannot be distinguished at the per-customer (kw) and aggregate (MW) level.

PG&E

Enrollment and Load Impact Summary

PG&E forecasts growth in 2022 relative to 2021 and maintains a constant forecast through the remainder of the forecast horizon. This assumption is applied to both Residential and Non-residential DA programs. However, PG&E forecasts a slow uptake in Residential enrollments, expecting zero enrollments through August 2022. Figure 5-1 shows PG&E's CBP DA enrollment and load impact forecast for an August peak day under the PG&E 1-in-2 weather scenario.

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

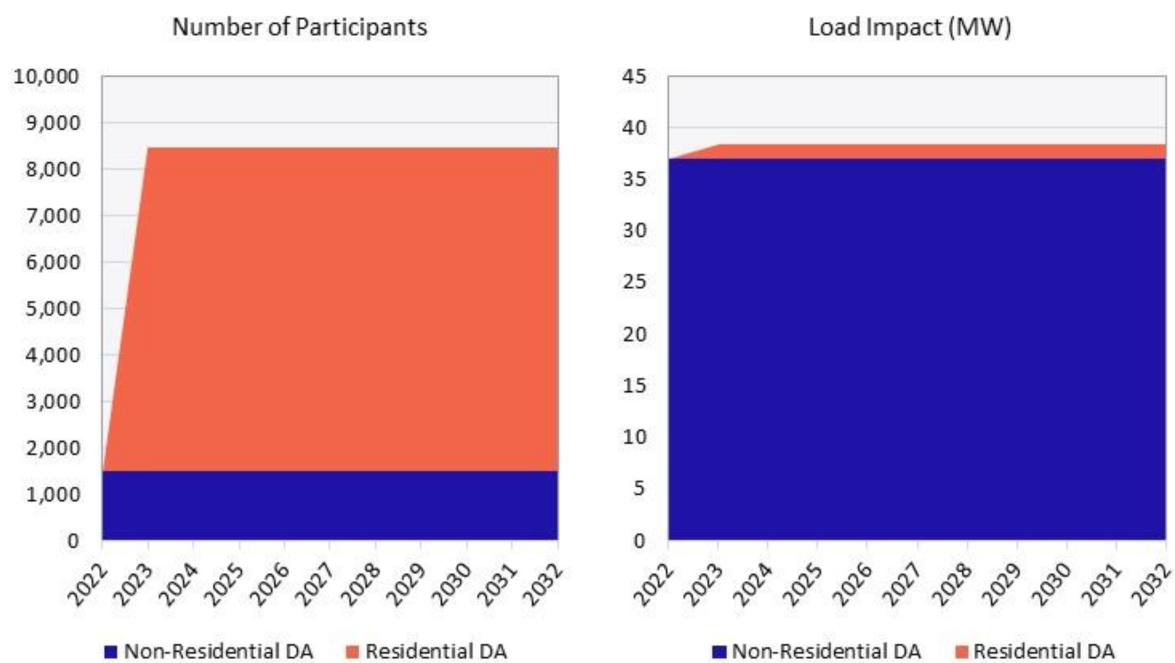


Table 5-3 summarizes the average RA window load impact forecasts for PG&E's CBP DA on an August peak day in 2022. The table includes the per-customer, aggregate, and corresponding percent impacts under the utility and CAISO 1-in-2 and 1-in-10 weather scenarios. As mentioned earlier, PG&E forecasts zero enrollment for Residential DA through August 2022, thus we show the 2022 Typical event day estimates.

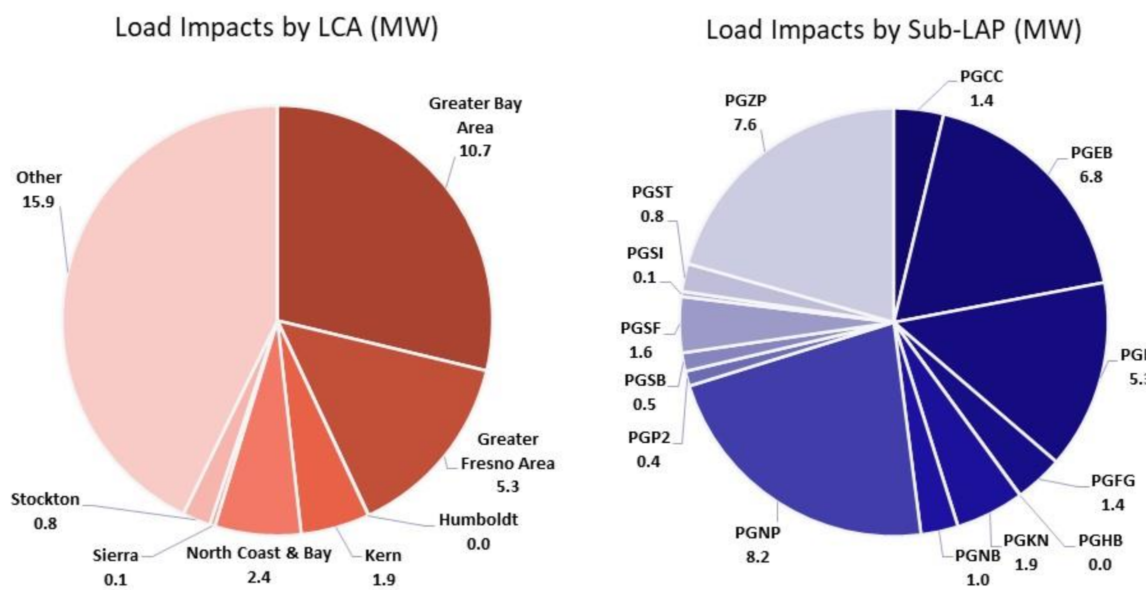
Table 5-3 PG&E: RA Window Ex-Ante Impacts for an August Peak Day, 2022

Program	# of Accts	Per Customer Impact (kW)	Aggregate Impact (MW)	Percent Impact (%)			
				Utility Peak		CAISO Peak	
				1-in-2	1-in-10	1-in-2	1-in-10
Residential DA*	4,357	0.2	0.9	32.0%	27.5%	33.7%	29.5%
Non-Residential DA	1,505	24.6	37.1	17.3%	17.0%	17.4%	17.3%

*Shown for 2022 Typical event day due to zero forecasted August 2022 enrollments.

Figure 5-2 illustrates the average RA window load impact distribution by LCA and Sub-LAP for Non-residential CBP DA on an August peak day in 2022. The results shown are for 1-in-2 weather conditions for the utility peak.

Figure 5-2 PG&E: RA Window Load Impacts by LCA and Sub-LAP (PG&E 1-in-2, August Peak Day, 2022)



Forecast Assumptions

This section discusses the assumptions used to develop the Residential and Non-residential DA forecasts.

Residential Day Ahead Forecast Assumptions. The residential forecast uses a combination of the following:

- **Capacity nomination forecast (MW) based on aggregator outlook** – PG&E maintained this forecast assumption at 4 MW for an August peak day.

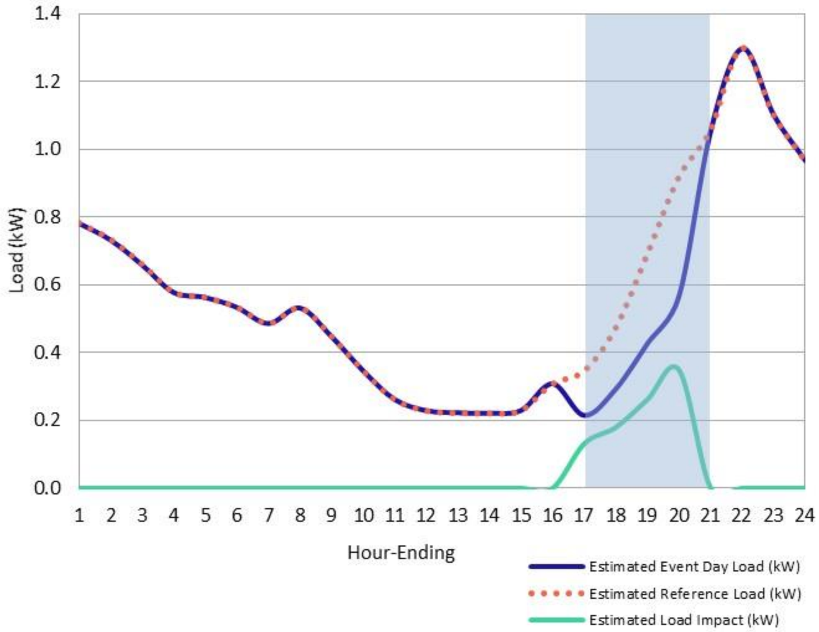
- **Delivery performance** – Given PY2021's low delivery performance, PG&E assumes the 61% minimum delivery performance, which is the minimum threshold before aggregators are charged a penalty.
- **Percent load impacts from HE20** – the PY2021 Residential DA participants are predominantly solar customers, having less available load to curtail during earlier hours of the RA window. As a result, we applied the percent impacts from HE20 (reporting hour and most dispatched event hour) to all hours of the RA window.
- **No Impact Degradation Rate** – the Residential DA program does not have enough historical performance data to develop this assumption.
- **Four-hour RA window response** – historical participation shows a preference for products with 1- to 4-hour event durations. As a result, we assume that the Residential DA program can respond for a maximum of four hours and assume zero impacts during the fifth hour of the RA window (HE21).

These assumptions result in a flat 1.3 MW forecast for an August peak day from 2023-2032. As mentioned earlier, PG&E forecasts a slow uptake in Residential enrollments, expecting zero enrollments through August 2022.

PY2021's low delivery performance results from inexperience in the operation of the residential CBP product and a low rate of automation. PG&E worked with PY2021's sole residential aggregator to incorporate performance feedback in its offerings. The actual performance from PY2021 informs the reduced forecast, and the lower target is more realistic and achievable. PG&E also expects new aggregators to participate in residential CBP and anticipates increased automation for residential customers, further supporting the MW forecast's realization.

Figure 5-3 shows the PG&E's Residential DA per-customer estimated reference load, estimated event day load, and resulting load impact estimates for an August peak day in 2022 for the PG&E 1-in-2 weather condition. The hours highlighted in the blue show the RA window, 4 PM to 9 PM.

Figure 5-3 PG&E Residential Day Ahead: Hourly Per-Customer Load Impacts (PG&E 1-in-2, August Peak Day, 2022)



Non-Residential Day Ahead Forecast Assumptions. The non-residential forecast uses a combination of the following:

- **Capacity nomination forecast (MW) based on aggregator outlook** – PG&E forecasts growth in Non-residential DA nominations, forecasting approximately 55 MW nominations for an August peak day. This forecast shows a slight increase from PY2021's 50 MW average summer nomination.
- **Delivery performance** – PG&E assumes 100% delivery performance based on PY2021 performance.
- **Per-customer load impacts from HE20** – we assume the per-customer load impacts on HE20 (reporting hour and most dispatched event hour) as the maximum impact during the RA window.
- **Impact Degradation Rate** – we developed assumptions to represent how customers can maintain impacts throughout events called for longer durations, similar to the 5-hour RA window. The approach used to develop these assumptions is discussed in Section 3 Impact Degradation Across the RA Window. For PG&E, we used PY2020-21 historical data to update the Impact Degradation Rate. Table 5-4 shows the shape of the RA window impacts as a percent of the maximum impact for non-residential DA.
- **Four-hour RA window response** – historical participation shows a preference for products with 1- to 4-hour event durations. As a result, we assume that the Non-residential DA program can respond for a maximum of four hours and assume zero impacts during the fifth hour of the RA window (HE21).

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

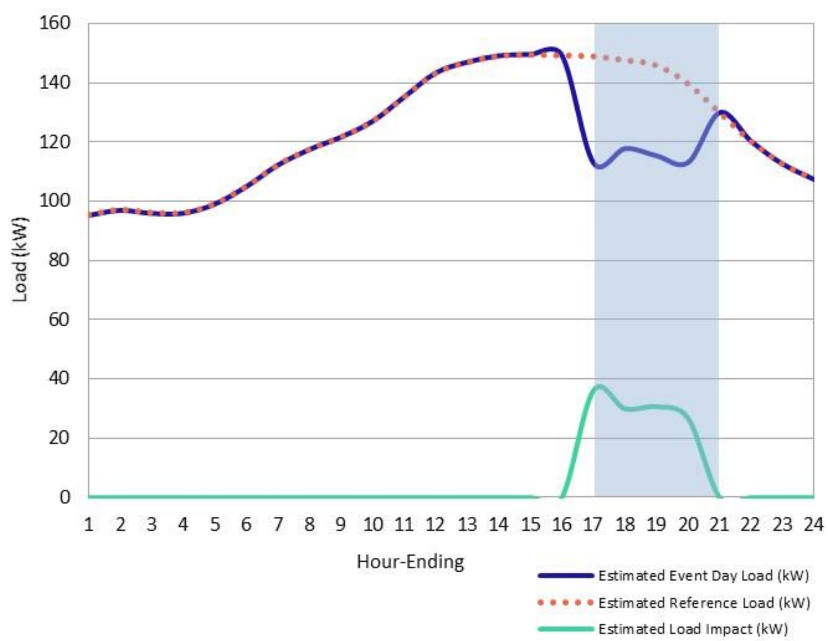
Program	Percent of Maximum Impact					
	HE17	HE18	HE19	HE20	HE21	Overall RA
Non-Res DA	100%	83%	85%	74%	0%	68%

These assumptions result in a flat 37.1 MW load impact forecast for an August peak day from 2022-2032, which creates a more accurate and realistic forecast that better integrates aggregator performance. This forecast is lower than PY2020's 44 MW forecast for a 2022 August peak day.

PG&E expects the program to produce more reliable MW nominations due to key program changes implemented in PY2021, especially the increase of the max number of events per month and the shift of the bidding window closer to event days.

Figure 5-4 shows the PG&E's Non-residential DA per-customer estimated reference load, estimated event day load, and resulting load impact estimates for an August peak day in 2022 for the PG&E 1-in-2 weather condition. The hours highlighted in the blue show the RA window, 4 PM to 9 PM.

Figure 5-4 PG&E Non-Residential Day Ahead: Hourly Per-Customer Load (PG&E 1-in-2, August Peak Day, 2022)



Comparison of Ex-Ante Impacts

This section discusses how the PY2021 ex-ante load impacts compare to:

- PY2021 (current) ex-post load impacts – demonstrates the effect of adjusting the impacts and reference loads to reflect the various weather scenarios, and

- PY2020 (previous) ex-ante load impact – demonstrates the updates to the load impact forecast using current program performance.

Table 5-5 compares **the current ex-post estimates with the current ex-ante estimates**. The current ex-post estimates show average load impacts for PY2021 dispatched events, while the current ex-ante estimates show how the program would have performed in a 1-in-2 weather year for a system-level event. Note that the ex-ante estimates in this comparison are for a 2021 Typical event day on the maximum impact hour (HE21 for residential and HE17 for non-residential), which is most comparable to the ex-post average event day reporting hour HE20.

For Residential DA, this comparison shows minor differences since all dispatched events were system-level events. For Non-residential DA, this comparison indicates that PY2021 participants had the potential to deliver close to 40 MW if the market triggered a system-level event.

Table 5-5 PG&E: Current Ex-Ante (PG&E 1-in-2, 2021 Typical Event Day, Maximum Impact) v. Current Ex-Post (Average Event Day, HE20)

Program	Estimate	# of Accts	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Ref. Load	Impact	Ref. Load		
Residential DA	**Current Ex-Ante**	**21**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**72**
	Current Ex-Post	21	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	70
Non-Res DA	**Current Ex-Ante**	**925**	**39.71**	**131.18**	**42.93**	**141.81**	**30%**	**91**
	Current Ex-Post	365	13.00	29.78	35.63	81.62	44%	87

Table 5-6 compares **the previous ex-ante forecast to the current ex-ante forecast, both for the year 2022**. This comparison demonstrates how the program forecast changed since last year. These changes are the following:

- The Residential forecast was updated to reflect an expected slower uptake in enrollments with participation starting in September 2022.
- The Non-residential enrollment forecast is updated to reflect higher per-customer load impacts. However, the aggregate impact is lower at 37 MW since we assume zero impacts during the fifth hour of the RA window.

Table 5-6 PG&E: Current v. Prior Ex-Ante (PG&E 1-in-2, August Peak Day, 2022), RA Window

Program	Estimate	# of Accts	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Ref. Load	Impact	Ref. Load		
Res DA*	**PY2021 Forecast**	4,357	0.9	2.7	0.2	0.6	32%	80
	PY2020 Forecast	16,494	4.9	23.6	0.3	1.4	21%	85
Non-Res DA	**PY2021 Forecast**	**1,505**	**37.1**	**214.5**	**24.6**	**142.5**	**17%**	**85**
	PY2020 Forecast	2,258	44.7	292.8	19.8	129.7	15%	90

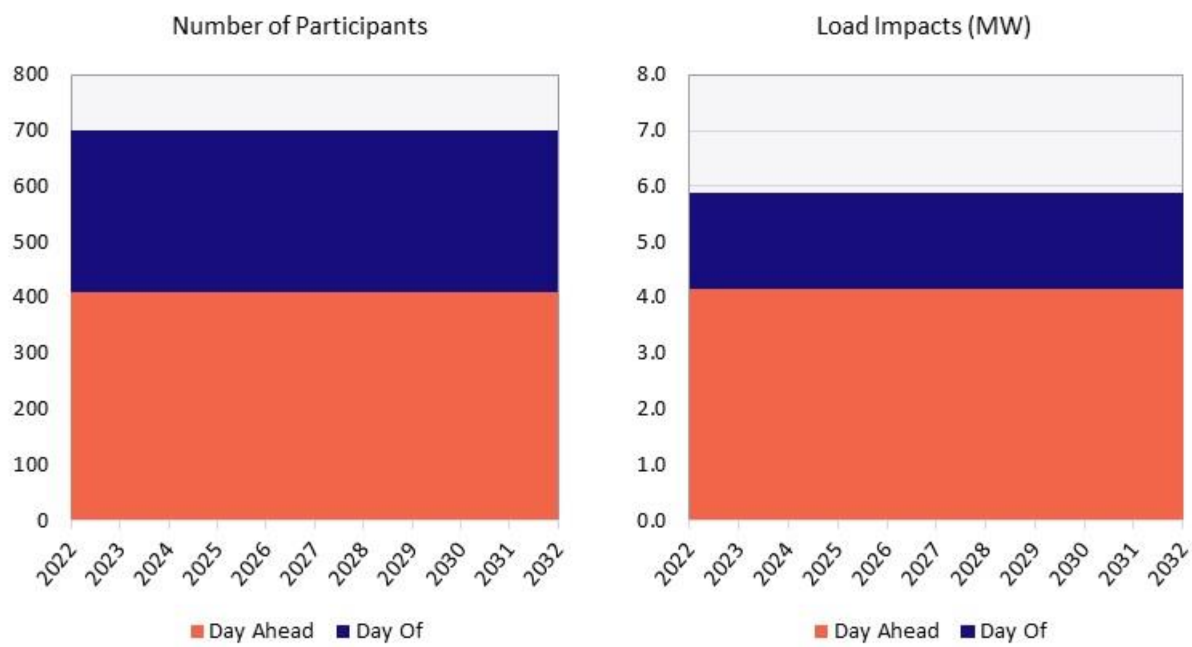
*Shown for 2022 Typical event day due to zero forecasted August 2022 enrollments.

SCE

Enrollment and Load Impact Summary

SCE maintains a constant forecast through the duration of the 11-year forecast. The enrollment forecasts for both Non-residential DA and DO are derived from the average nominations during each season in PY2021, incorporating known and anticipated PY2022 participation. Figure 5-5 shows SCE's Non-residential DA and DO enrollment and load impact forecast for an August peak day (summer season) under the SCE 1-in-2 weather scenario.

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



For this filing, SCE assumes zero residential participation in CBP. Of the three counterparties that have expressed interest in PG&E's residential CBP since its inception, SCE has active bilateral DR contracts with two and is in active litigation with the third.

Also, for this filing, SCE assumes zero enrollment for its non-summer seasons from 2022-2032, given its low enrollment and low delivery performance in PY2021.

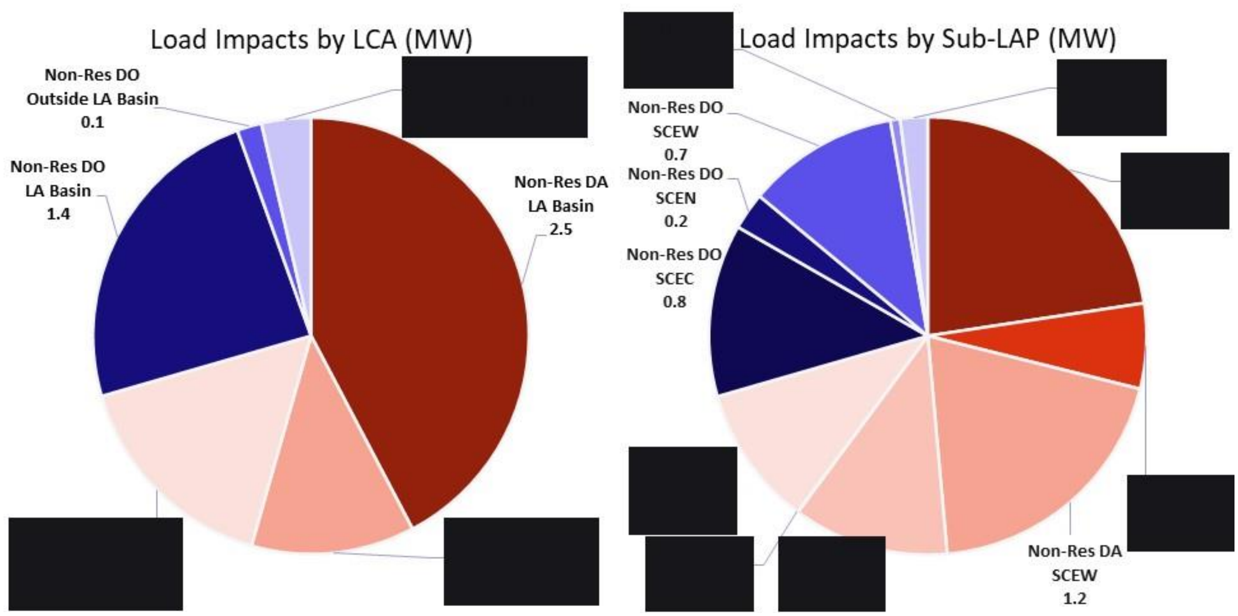
Table 5-7 summarizes the average RA window load impact forecasts for the Non-residential DA and DO products on a January peak day (non-summer) and an August peak day (summer) in 2022. The table includes the per-customer, aggregate, and corresponding percent impacts under the utility and CAISO 1-in-2 and 1-in-10 weather scenarios. Similar to PG&E, we assume constant per-customer average impacts across the weather scenarios. The varying percent impacts are due to the reference load's response to each weather scenario.

Table 5-7 SCE Non-Residential: RA Window Ex-Ante Impacts, 2022

Season	Program	# of Accts	Per Customer Impact (kW)	Aggregate Impact (MW)	Percent Impact (%)			
					Utility Peak		CAISO Peak	
					1-in-2	1-in-10	1-in-2	1-in-10
Non-Summer	Day Ahead	-	-	-	-	-	-	-
	Day Of	-	-	-	-	-	-	-
Summer	Day Ahead	410	10.1	4.2	12.9%	12.9%	12.9%	12.9%
	Day Of	290	6.0	1.7	5.7%	5.7%	5.7%	5.7%

Figure 5-6 illustrates the average RA window load impact distribution by LCA and Sub-LAP for Non-residential DA and DO on an August peak day in 2022. The results shown are for 1-in-2 weather conditions for the utility peak.

Figure 5-6 SCE: RA Window Load Impacts by LCA and Sub-LAP (SCE 1-in-2, August Peak Day, 2022)



Forecast Assumptions

This section discusses the assumptions used to develop the Non-residential DA and DO forecasts. Both forecasts use a combination of the following:

- **Enrollment Outlook** – SCE assumes a flat enrollment forecast based on PY2021 average summer enrollment. This assumption is driven by SCE's Non-residential programs maintaining consistent summer enrollment through the previous years.
- **Delivery Performance** – based on PY2021 findings, SCE assumes 0% delivery performance for the non-summer months, and consequently zero enrollment.

- **Per-customer load impacts from HE20** – we assume the per-customer load impacts on HE20 (reporting hour and most dispatched event hour) as the maximum impact during the RA window.
- **Impact Degradation Rate** – we developed assumptions to represent how customers can maintain impacts throughout events called for longer durations, similar to the 5-hour RA window. The approach used to develop these assumptions is discussed in Section 3 Impact Degradation Across the RA Window. For SCE, we used PY2019-21 historical data to update the Impact Degradation Rate. Table 5-8 shows the estimated shape of the impacts as a percent of the maximum load impact for each program and season.

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

Season	Program	Percent of Maximum Impact					
		HE17	HE18	HE19	HE20	HE21	Overall RA
Non-Summer	Day Ahead	90%	100%	55%	1%	1%	49%
	Day Of	100%	68%	57%	80%	70%	75%
Summer	Day Ahead	100%	89%	72%	64%	64%	78%
	Day Of	100%	72%	52%	37%	40%	60%

Figure 5-7 and Figure 5-8 shows the SCE's Non-residential DA and DO per-customer estimated reference load, estimated event day load, and resulting load impact estimates for an August peak day in 2022 for the SCE 1-in-2 weather condition. The hours highlighted in the blue show the RA window, 4 PM to 9 PM.

Figure 5-7 SCE Non-Residential Day Ahead: Hourly Per-Customer Load (SCE 1-in-2, August Peak Day, 2022)

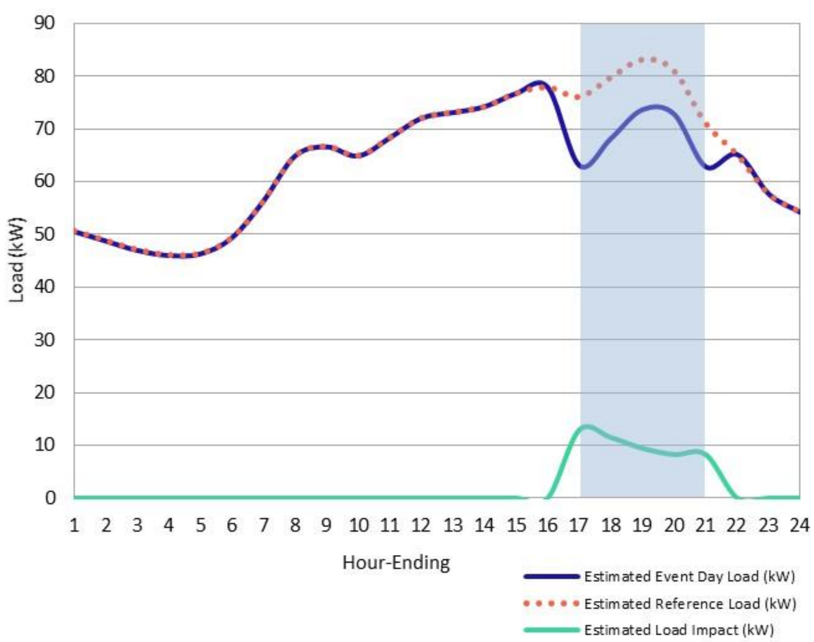
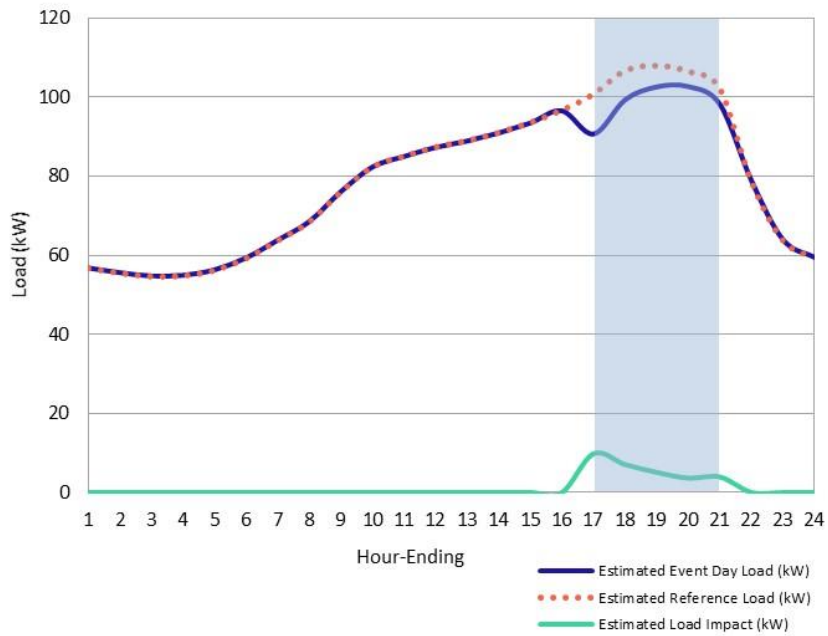


Figure 5-8 SCE Non-Residential Day Of: Hourly Per-Customer Load (SCE 1-in-2, August Peak Day, 2022)



Comparison of Ex-Ante Impacts

This section discusses how the PY2021 ex-ante load impacts compare to:

- PY2021 (current) ex-post load impacts – demonstrates the effect of adjusting the impacts and reference loads to reflect the various weather scenarios, and
- PY2020 (previous) ex-ante load impact – demonstrates the updates to the load impact forecast using current program performance.

Table 5-9 compares **the current ex-post estimates with the current ex-ante estimates**. The current ex-post estimates show average load impacts for PY2021 dispatched events, while the current ex-ante estimates show how the program would have performed in a 1-in-2 weather year for a system-level event. Note that the ex-ante estimates in this comparison are for a 2021 Typical event day on the maximum impact hour (HE17), which is most comparable to the ex-post average event day reporting hour HE20. The comparison shows minor differences for both programs since SCE dispatched mostly system-level events.

Table 5-9 SCE: Current Ex-Ante (SCE 1-in-2, 2021 Typical Event Day, Maximum Impact) v. Current Ex-Post (Average Summer Event, HE20)

Program	Estimate	# of Accts	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Ref. Load	Impact	Ref. Load		
Day Ahead	**Current Ex-Ante**	**392**	**5.1**	**29.8**	**13.0**	**76.0**	**17%**	**91**
	Current Ex-Post	312	4.0	25.3	12.8	81.1	16%	82
Day Of	**Current Ex-Ante**	**270**	**2.7**	**27.2**	**9.9**	**100.6**	**10%**	**90**
	Current Ex-Post	203	2.0	19.4	10.0	95.7	10%	79

Table 5-10 compares **the previous ex-ante forecast to the current ex-ante forecast, both for the year 2022**. This comparison demonstrates how the program forecast changed since last year. These changes are the following:

- The Non-residential DA enrollment forecast is consistent with last year's forecast. The per-customer load impacts were updated based on PY2021 performance, which resulted in higher aggregated load impacts.
- The Non-residential DO enrollment forecast, on the other hand, is lower than last year's forecast. PY2020 and PY2021 saw comparable per-customer load impacts, resulting in lower aggregate load impacts.

Table 5-10 SCE: Current v. Prior Ex-Ante (SCE 1-in-2, August Peak Day, 2022), RA Window

Program	Estimate	# of Accts	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Ref. Load	Impact	Ref. Load		
Day Ahead	**PY2021 Forecast**	**410**	**4.2**	**32.1**	**10.1**	**78.3**	**13%**	**89**
	PY2020 Forecast	410	2.6	36.2	6.2	88.3	7%	89
Day Of	**PY2021 Forecast**	**290**	**1.7**	**30.4**	**6.0**	**104.7**	**6%**	**88**
	PY2020 Forecast	380	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	89

SDG&E

Enrollment and Load Impact Summary

Starting 2022, SDG&E is adding two Elect products with three price trigger options: $200/MWh, $400/MWh, or $600/MWh. SDG&E will continue to offer their existing products, referring to them as Prescribed products. Both Non-residential DA and DO programs will have three products: (1) Prescribed 11-7 Hour, (2) Prescribed 1-9 Hour, and (3) Elect 1-9 Hour.

Note that SDG&E is currently implementing a Residential CBP pilot, limiting the number of residential enrollments due to system limitations. The Residential CBP pilot evaluation is not included in this evaluation report.

SDG&E anticipates an uptake in nominations and enrollment with the addition of the two CBP Elect products. For an August peak day, SDG&E forecasts 2.3 MW and 3.5 MW load impacts the Non-residential DA and DO[46] programs, respectively. Figure 5-9 shows SDG&E's Non-residential CBP enrollment and load impact forecast for an August peak day under the SDG&E 1-in-2 weather scenario.

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

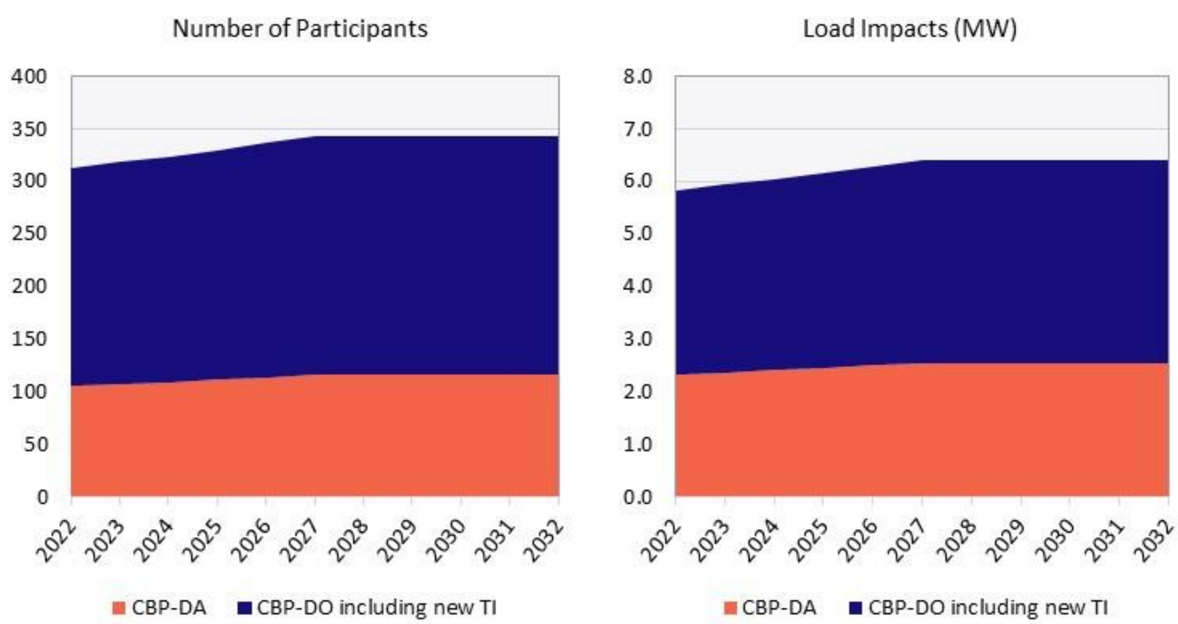


Table 5-11 summarizes the average RA window load impact forecasts for the Non-residential DA and DO programs on an August peak day in 2022. The table includes the per-customer, aggregate, and corresponding percent impacts under the utility and CAISO 1-in-2 and 1-in-10 weather scenarios. Similar to PG&E and SCE, we assume constant per-customer average impacts across the weather scenarios. The varying percent impacts are due to the reference load's response to each weather scenario. The impacts are also estimated to remain constant during each program year.

[46] SDG&E has two CBP DO forecasts. The forecast include in this report includes new enrollments in the Technical Incentives (TI) program.

Table 5-11 SDG&E Non-Residential: RA Window Ex-Ante Impacts, 2022

Program	# of Accts	Per Customer Impact (kW)	Aggregate Impact (MW)	Percent Impact (%)			
				Utility Peak		CAISO Peak	
				1-in-2	1-in-10	1-in-2	1-in-10
Non-Res Day Ahead	105	22.0	2.3	21.7%	21.2%	21.6%	21.7%
Non-Res Day Of	208	16.9	3.5	17.2%	16.9%	17.1%	17.2%

Forecast Assumptions

This section discusses the assumptions used to develop the Non-residential DA and DO forecasts. Both forecasts use a combination of the following:

- **Aggregator Feedback** – SDG&E solicited feedback from PY2021 aggregators to determine interest in CBP Elect products and willingness to shift to the 1 PM to 9 PM dispatch window. We used the aggregator feedback to establish the following assumptions:
    - Product shifting from Prescribed to Elect products and from 11-7 to 1-9 dispatch windows,
    - New CBP nominations (counts and capacity) from current participants in other DR programs due to interest in CBP Elect products, and
    - Overall nominations (counts and capacity) by program and product.
- **Delivery Performance** – we calculated product-level delivery performance based on PY2020 and PY2021 performance to produce modest estimates, 48% on average. PY2020 had substantially high deliveries, 72% on average, while PY2021 had substantially low deliveries, 30% on average. We applied the product-level delivery performances to capacity nominations to estimate maximum ex-ante load impacts.
- **Enrollment Growth** – As in previous years, the enrollment forecast assumes a 2% growth per year from 2022-2027 due to the CBP program improvements proposed by SDG&E. In addition, SDG&E forecasts the CBP DO program enrollment will increase by another 1% per year starting in 2022-2023 due to growth in the Technical Incentives (TI) program. The enrollment forecasts for both programs show a flat trend from 2027-2032.
- **Impact Degradation Rate** – we developed assumptions to represent how customers can maintain impacts throughout events called for longer durations, similar to the 5-hour RA window. The approach used to develop these assumptions is discussed in Section 3 Impact Degradation Across the RA Window. For SDG&E, we used PY2019-21 historical data to update the Impact Degradation Rate. Table 5-12 shows the estimated shape of the impacts as a percent of the maximum load impact for each program and product. Note that both 11-7 Hour products show zero impacts on HE20-HE21 since these products are not available for these hours.

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

Season	Program	Percent of Maximum Impact					
		HE17	HE18	HE19	HE20	HE21	Overall RA
Day Ahead	DA 11-7 Hour	75%	100%	99%	0%	0%	55%
	DA 1-9 Hour	100%	70%	72%	67%	63%	74%
Day Of	DO 11-7 Hour	64%	100%	87%	0%	0%	50%
	DO 1-9 Hour	100%	85%	62%	67%	73%	77%

Figure 5-10 and Figure 5-11 show the SDG&E's Non-residential DA and DO per-customer estimated reference load, estimated event day load, and resulting load impact estimates for an August peak day in 2022 for the SCE 1-in-2 weather condition. The hours highlighted in the blue show the RA window, 4 PM to 9 PM.

Figure 5-10 SDG&E Non-Residential Day Ahead: Hourly Per-Customer Load (SDG&E 1-in-2, August Peak Day, 2022)

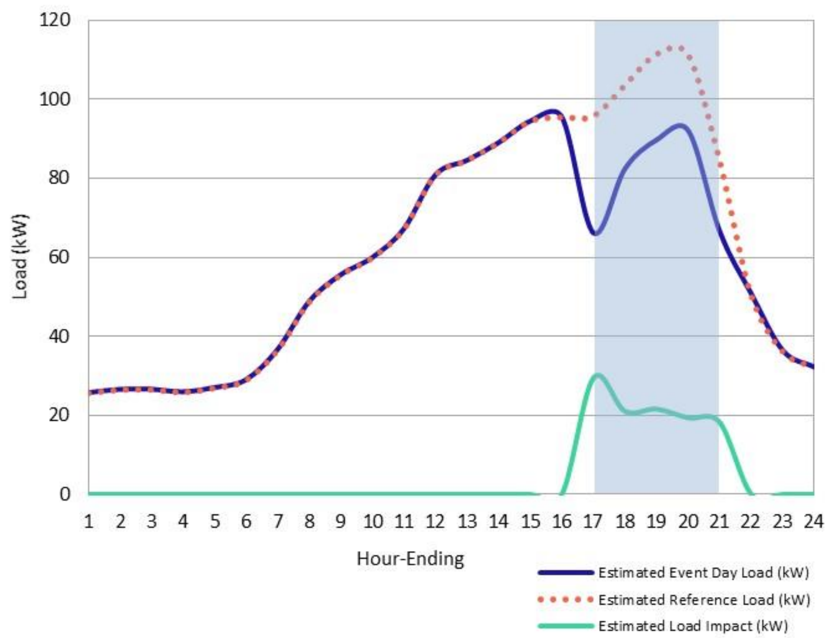
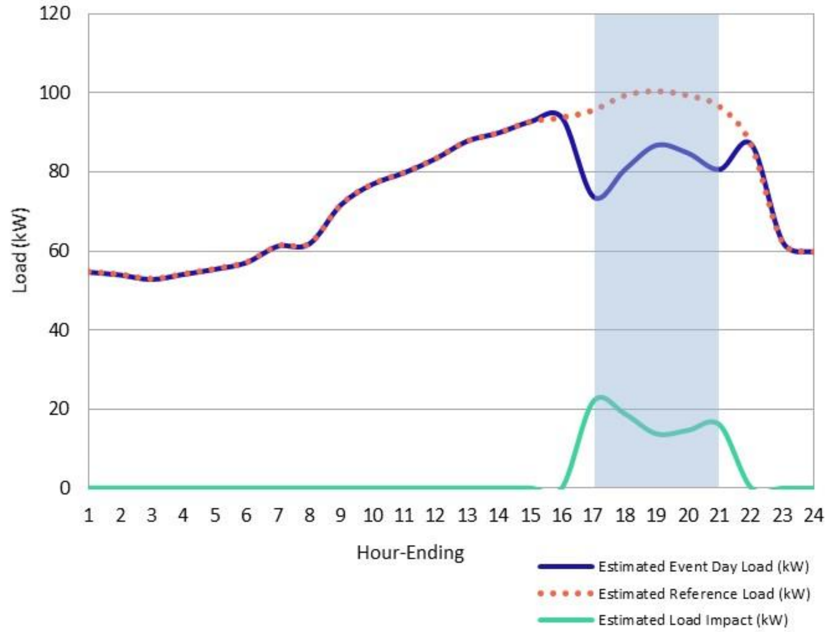


Figure 5-11 SDG&E Non-Residential Day Of: Hourly Per-Customer Load (SDG&E 1-in-2, August Peak Day, 2022)



Comparison of Ex-Ante Impacts

This section discusses how the PY2021 ex-ante load impacts compare to:

- PY2021 (current) ex-post load impacts – demonstrates the effect of adjusting the impacts and reference loads to reflect the various weather scenarios, and
- PY2020 (previous) ex-ante load impact – demonstrates the updates to the load impact forecast using current program performance.

Table 5-13 compares **the current ex-post estimates with the current ex-ante estimates**. The current ex-post estimates show average load impacts for PY2021 dispatched events, while the current ex-ante estimates show how the program would have performed in a 1-in-2 weather year for a system-level event. Note that the ex-ante estimates in this comparison are for a 2021 Typical event day on the maximum impact hour (HE17), which is most comparable to the ex-post average event day reporting hour HE19. The comparison shows minor differences for both programs since SDG&E dispatched all system-level events.

Table 5-13 SDG&E: Current Ex-Ante (SDG&E 1-in-2, 2021 Typical Event Day, Maximum Impact) v. Current Ex-Post (Average Summer Event, HE19)

Program	Estimate	# of Accts	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Ref. Load	Impact	Ref. Load		
Day Ahead	**Current Ex-Ante**	**48**	**0.3**	**5.3**	**5.6**	**109.6**	**5%**	**84**
	Current Ex-Post	46	0.3	5.1	5.8	110.9	5%	75
Day Of	**Current Ex-Ante**	**133**	**1.0**	**13.8**	**7.7**	**103.8**	**7%**	**85**
	Current Ex-Post	133	1.0	13.7	7.8	103.0	8%	76

Table 5-14 compares **the previous ex-ante forecast to the current ex-ante forecast, both for the year 2022**. This comparison demonstrates how the program forecast changed since last year. These changes are the following:

- The addition of CBP Elect products in PY2022 estimates a substantial uptake in enrolment and load impacts for both programs.
- Due to limited data availability for new CBP enrollments (participants from other DR programs), the ex-ante analysis used the PY2021 participants to estimate a per-customer reference load, likely resulting in much higher percent impacts at 22% and 17% for DA and DO, respectively.

Table 5-14 SDG&E: Current v. Prior Ex-Ante (SDG&E 1-in-2, August Peak Day, 2022), RA Window

Program	Estimate	# of Accts	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
			Impact	Ref. Load	Impact	Ref. Load		
Day Ahead	**PY2021 Forecast**	**105**	**2.3**	**10.6**	**22.0**	**101.4**	**22%**	**85**
	PY2020 Forecast	19	0.2	2.3	11.8	120.0	10%	84
Day Of	**PY2021 Forecast**	**208**	**3.5**	**20.4**	**16.9**	**98.3**	**17%**	**83**
	PY2020 Forecast	167	1.5	16.0	9.1	95.8	9%	83

6

KEY FINDINGS AND RECOMMENDATIONS

In this section, we present the key findings from the Statewide PY2021 CBP evaluation and recommendations for future program year evaluations.

Overview of Results

Ex-Post Results. Table 6-1 summarizes each CBP program's PY2021 overall season performance using the following reporting metrics: average nomination, average overall and reporting hour dispatch, the ex-post load impacts, and the overall and adjusted delivery performance. Each metric is presented for the average summer event day, which is calculated using all events regardless of dispatched count and event timing (see Average Event Calculation). We also described each metric in more detail in Section 3, Reporting Metrics for Program Performance.

Table 6-1 Statewide CBP Delivery Performance

Program		Nominations		Overall Dispatched		Reporting Hour Dispatched		Ex-Post Analysis		
		# Accts	Capacity (MW)	# Accts	Capacity (MW)	# Accts	Capacity (MW)	Impact (MW)	% Delivered	Adj. % Delivered
PG&E	Res DA	21	[redacted]	21	[redacted]	14	[redacted]	[redacted]	[redacted]	[redacted]
PG&E	Non-res DA	879	50.1	365	13.5	345	12.4	13.0	96%	105%
SCE	Non-res DA	392	9.3	312	7.6	308	7.5	4.0	53%	53%
SCE	Non-res DO	270	3.8	203	2.9	198	2.8	2.0	70%	71%
SDG&E	Non-res DA	43	1.1	46	1.1	43	1.0	0.3	25%	26%
SDG&E	Non-res DO	131	3.2	133	3.4	133	3.4	1.0	30%	30%

Note that in Table 6-1, we show the average dispatched counts and capacity, which is dependent on CAISO market awards. Low counts are not indicative of low participation rather an indication of necessity. On the other hand, delivering dispatched capacity is the correct measure of the program's success (delivery performance or % delivered). 100% delivery performance means that aggregators and customers curtailed the load obligations when asked to do so.

The delivery performance metrics also allow for an adjusted metric for dispatched capacity coincident with the reporting hour. Our definition of the average event day includes events that did not dispatch capacity during the reporting hour. For example, PG&E's Non-residential DA has a 96% overall delivery performance, just 4% short of meeting dispatched capacity. However, adjusting for dispatched capacity on HE20 (the reporting hour) shows that PG&E's Non-residential DA exceeded dispatched capacity at 105% adjusted delivery performance.

In PY2021, only PG&E Non-residential DA performed successfully with a 96% delivery performance and a 105% adjusted delivery performance.

Ex-Ante Results. Each program's load impact forecast is based on IOU-specific assumptions that incorporate a combination of the following: aggregator/nomination outlook, delivery performance, ex-ante per-customer load impacts, enrollment growth, and an impact degradation rate across the RA window.

Both PG&E and SCE assume a constant forecast across the forecast horizon, despite PG&E's Residential DA expected slow uptake in enrollments, estimating zero enrollments through August 2022. For this filing, SCE assumes zero enrollment in Residential CBP due to a lack of active nominations. SCE also assumes zero enrollment for its non-summer seasons, given its low enrollment and low delivery performance in PY2021.

SDG&E, on the other hand, anticipates a jump in enrollment and nominations with the addition of CBP Elect products starting in 2022. As in previous years, the enrollment forecast assumes a 2% growth per year from 2022-2027 due to SDG&E's proposed program improvements. In addition, SDG&E forecasts the CBP DO program enrollment will increase by another 1% per year starting in 2022-2023 due to growth in the Technical Incentives (TI) program[47]. The enrollment forecasts for both programs show a flat trend from 2027-2032. SDG&E's forecast does not include a residential forecast.

Table 6-2 summarizes the 11-year enrollment and load impact forecast by IOU and program for an August peak day.

Table 6-2 Statewide CBP: 2022-2032 Forecast, August Peak Day

IOU	Program	Number of Service Accounts			Aggregate Impact (MW)		
		2022	2023	2027-2032 (Each Year)	2022	2023	2027-2032 (Each Year)
PGE	Residential Day Ahead	0	6,972	6,972	0.0	0.9	0.9
	Non-Residential Day Ahead	1,505	1,505	1,505	37.1	37.1	37.1
SCE	Non-Residential Day Ahead	410	410	410	4.2	4.2	4.2
	Non-Residential Day Of	290	290	290	1.7	1.7	1.7
SDG&E	Non-Residential Day Ahead	105	107	116	2.3	2.4	2.6
	Non-Residential Day Of	208	212	227	3.5	3.6	3.8

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

Key Findings by IOU. This section discusses each IOU's CBP PY2021 findings.

PG&E

PG&E's two CBP programs: Residential and Non-residential DA, jointly resulted in 104% adjusted delivery performance. Table 6-3 summarizes the program-level average ex-post load impacts and the corresponding overall and adjusted delivery performances.

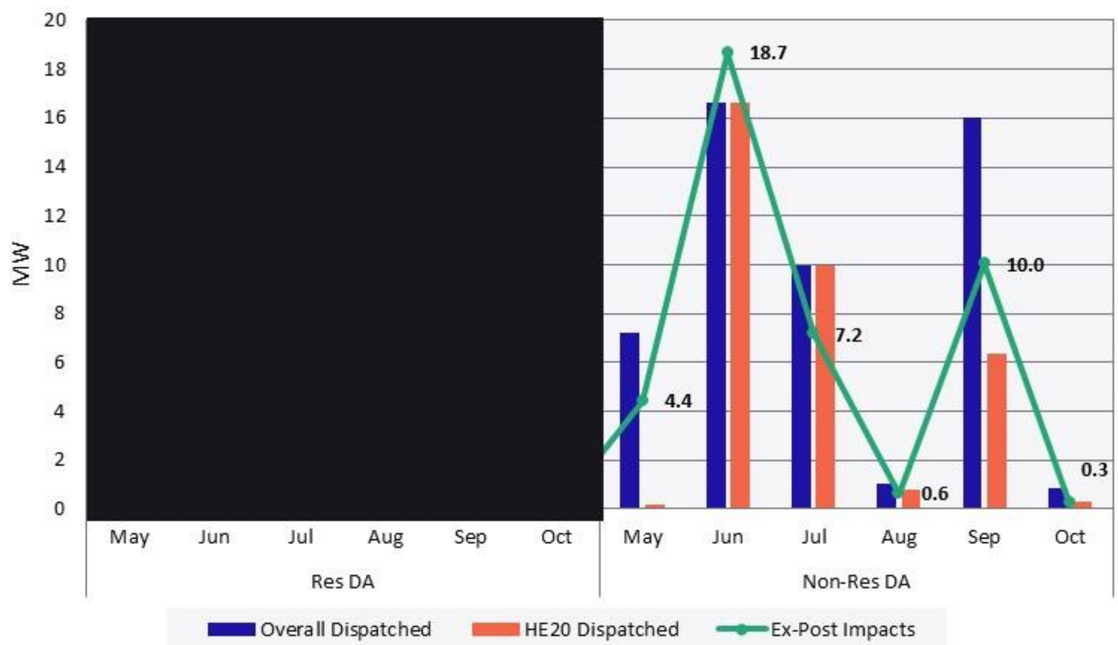
Table 6-3 PG&E PY2021 Delivery Performance

Program	Aggregate Load Impact (MW)	% Delivered	Adj. % Delivered
Residential DA	[redacted]	[redacted]	[redacted]
Non-Residential DA	13.0	96%	105%
Overall PG&E	**13.0**	**96%**	**104%**

This year, we have the following key findings:

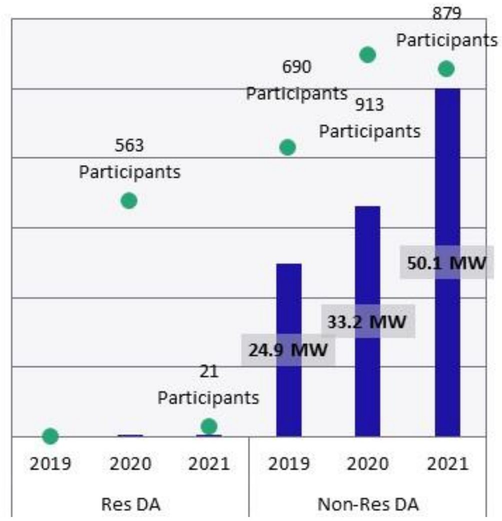
- **HE20 (7 PM – 8 PM) is the most dispatched event hour in PY2021** for both PG&E programs, with a combined 13.5 MW and 359 participants dispatched on average.
- **Non-residential DA is the main driver of PY2021's high delivery performance.** Figure 6-1 visually shows how the ex-post load impacts compare to the overall and HE20 dispatched capacities. Non-residential DA's June impacts exceeded the overall and HE20 dispatched capacities, while September impacts exceeded the HE20 dispatched capacity, both contributing to 105% adjusted delivery performance.

Figure 6-1 PG&E Monthly Delivery Performance Summary



- **Participation adjusts to fill aggregator nominations.** Comparisons of program year nominations (Figure 6-2) show growth in capacity nominations despite fluctuating participant counts. PG&E estimates approximately 55 MW nominations in PY2022 based on aggregator outlook.

Figure 6-2 PG&E Annual Nominations



SCE

SCE's two CBP programs: Non-residential DA and DO, jointly resulted in [redacted] and 58% delivery performances in the non-summer and summer seasons, respectively. Table 6-4 Table 6-3summarizes the program-level average ex-post load impacts and the corresponding overall and adjusted delivery performances by season.

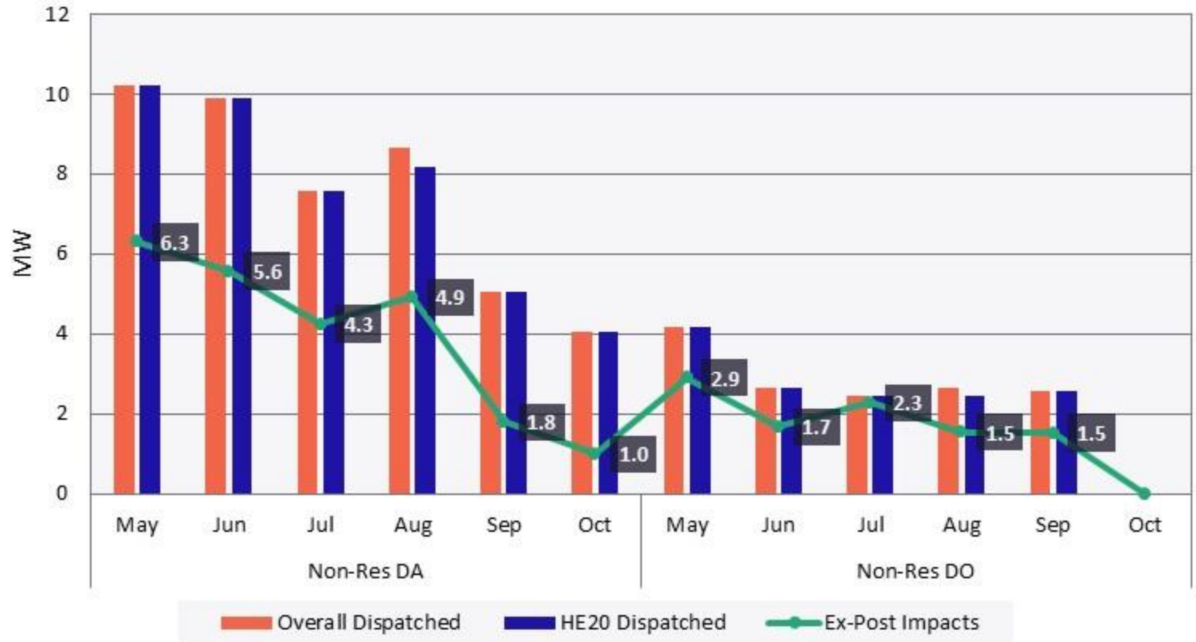
Table 6-4 SC&E PY2021 Delivery Performance

Season	Program	Aggregate Load Impact (MW)	% Delivered	Adj. % Delivered
Non-Summer	Non-Residential DA	[redacted]	[redacted]	[redacted]
	Non-Residential DO	[redacted]	[redacted]	[redacted]
	Overall Non-Summer	[redacted]	[redacted]	[redacted]
Summer	Non-Residential DA	4.0	53%	53%
	Non-Residential DO	2.0	70%	71%
	Overall Summer	**6.0**	**58%**	**58%**

This year, we have the following key findings:

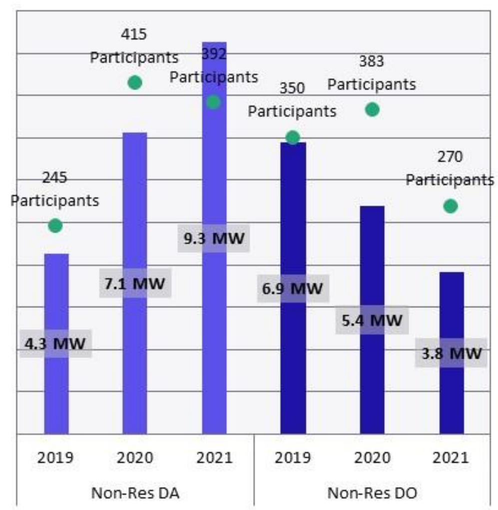
- **HE20 (7 PM – 8 PM) is the most dispatched event hour in PY2021** for both SCE programs and both seasons, with a combined 6.0 MW and 506 participants summer dispatched on average.
- **Non-residential DO's summer season is SCE's top performer in delivery performance** at 71% (adjusted) on average. **Non-residential DA's summer season is SCE's top performer in aggregate load impacts** with 4.0 MW on average. Figure 6-3 visually shows how the ex-post load impacts compare to the overall and HE20 dispatched capacities.

Figure 6-3 SCE Monthly Delivery Performance Summary, Summer



- **Participation adjusts to fill aggregator nominations.** Comparisons of program year nominations (Figure 6-4) show growth in the Non-residential DA capacity nominations despite fluctuating participant counts. The Non-residential DO program, on the other hand, is seeing a decrease in capacity nominations along with fluctuations in enrollment counts.

Figure 6-4 SCE Summer Nominations



SDG&E

SDG&E's two CBP programs: Non-residential DA and DO, jointly resulted in 29% adjusted delivery performance. Table 6-5 summarizes the program-level average ex-post load impacts and the corresponding overall and adjusted delivery performances.

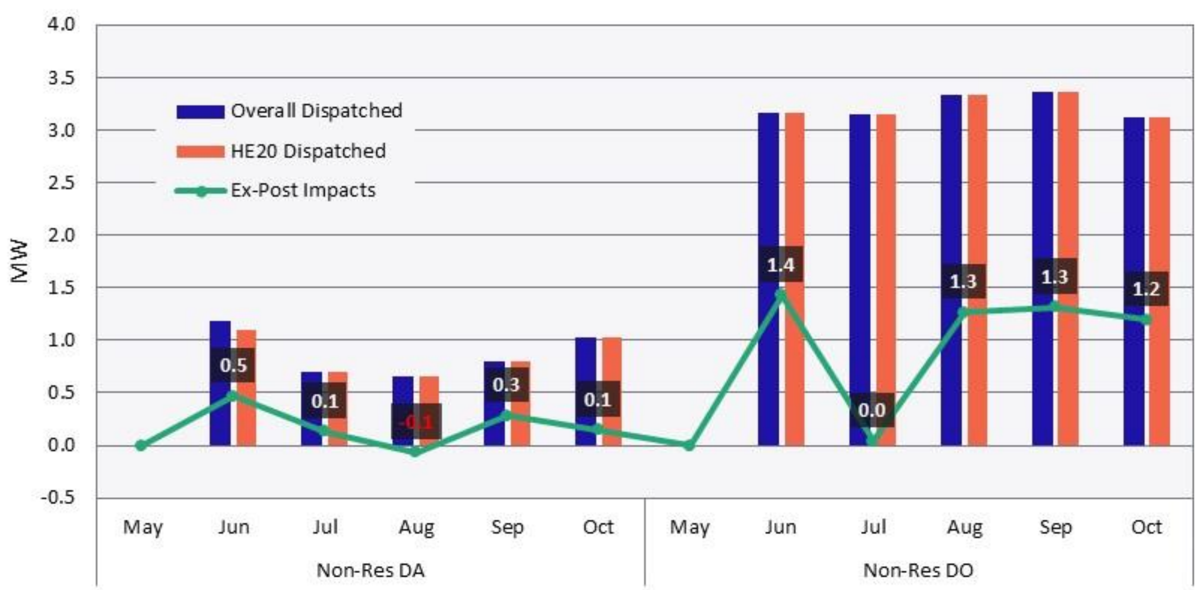
Table 6-5 SDG&E PY2021 Delivery Performance

Program	Aggregate Load Impact (MW)	% Delivered	Adj. % Delivered
Non-Residential DA	0.3	25%	26%
Non-Residential DO	1.0	30%	30%
Overall SDG&E	**1.3**	**29%**	**29%**

This year, we have the following key findings:

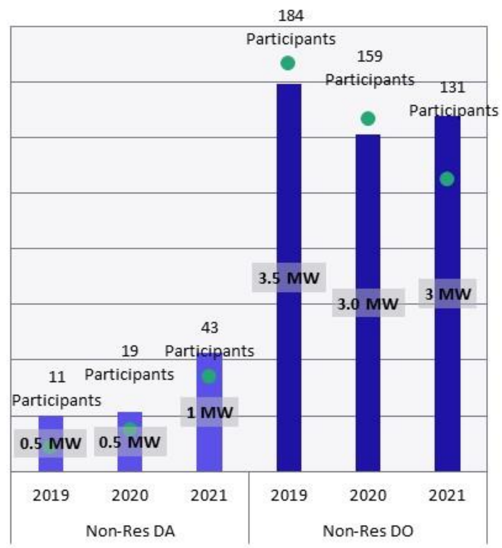
- **HE19 (6 PM – 7 PM) is the most dispatched event hour in PY2021** for both SDG&E programs, with a combined 1.3 MW and 176 participants dispatched on average.
- **Both SDG&E programs resulted in low delivery performances in PY2021.** Figure 6-5 visually shows how the ex-post load impacts compare to the overall and HE19 dispatched capacities.

Figure 6-5 SDG&E Monthly Delivery Performance Summary



- **Both SDG&E program nominations show slow growth and consistency in previous years.** Figure 6-6 presents SDG&E's average program nominations for PY2019 through PY2021. The Non-residential DA program has steadily grown in both customer enrollments and capacity nominations. The Non-residential DO program, on the other hand, is seeing a decrease in customer enrollments along with fluctuations in capacity nominations.
- **SDG&E anticipates an uptake in nominations and enrollment with the addition of the two CBP Elect products in PY2022.** Consequently, SDG&E forecasts an overall 5.8 MW ex-ante load impact in 2022, steadily increasing through 2027 due to continuous program improvements.

Figure 6-6 SDG&E Annual Nominations



Recommendations

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

- **Aggregator In-Depth Interviews.** We recommend performing in-depth interviews (IDI) for all active PY2022 aggregators. These IDIs will provide valuable insight into aggregator performances and challenges that can:
  - **Inform the ex-post analysis**, allowing the evaluator to appropriately set up the regression analyses. In other words, specify indicators that can isolate special cases such as notification issues, delivery issues, etc. Such specifications will allow for more accurate event-level estimates.
  - **Inform the ex-ante analysis**, receiving feedback on aggregator outlook on CBP participation/nominations will allow evaluators to develop more informed forecast assumptions.
  - In addition, we can potentially collect insight that can inform how the CBP programs can evolve in the future.
- **Continue to Improve on Report Organization.** We recommend two organizational improvements for future reports:
  - **Organize report findings by IOU.** Although we use consistent approaches in analyses and reporting, we recognize that each IOU has a unique story to tell. Organizing the report to have each IOU and program ex-post results, ex-ante results, and key findings in one section may add overall clarity and value.

- **Move event day tables to the end of each IOU's section or an appendix.** We recommend streamlining the report, putting more focus on program summaries and key takeaways while still giving access to more granular information as needed.

- **System-Level Test Events (PG&E Only).** We recommend dispatching one or two system-level test events in the PG&E Non-residential DA program. System-level events are rare within the PG&E territory since events are dispatched according to CAISO market awards. Measured performance on a system-level event will be valuable in informing the ex-ante analyses, which estimate system-level performance during the RA window.

A

APPENDICES

PG&E CBP Ex-Post Table Generator

PG&E CBP Ex-Ante Table Generator

SCE CBP Ex-Post Table Generator

SCE CBP Ex-Ante Table Generator

SDG&E CBP Ex-Post Table Generator

SDG&E CBP Ex-Ante Table Generator

B

MODEL VALIDITY

We selected and validated regression models during our optimization process. The regression 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 the absence of an event.

To meet these two specific goals, our optimization process included an analysis of both the in-sample and out-of-sample mean absolute percent error (MAPE) and mean percent error (MPE) for each of the candidate regression models for each IOU and program. 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. 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 similar to actual event days; this test gave us an estimate of how well each model could predict the reference load.

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

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

Selecting Event-Like Days

To select similar non-event days, we used a Euclidean Distance matching approach. Euclidean distance is a simple and highly effective way of creating matched pairs. We calculated a Euclidean distance metric defined as the square root of the sum of the squared differences between the matching variables to determine how close event day temperature is to a potential event-like day. Any number of relevant variables could be included in the Euclidean distance. The equation below shows an example of a Euclidean distance metric, and Table B-1 summarizes the ED metric used by IOU and customer class.

$$ED = \sqrt{(var\_1_{event} - var\_1_{non-event})^2 + \cdots + (var\_n_{event} - var\_n_{non-event})^2}$$

Table B-1 ED Metrics by Program

IOU/Customer Class	Metric Variables
PG&E Residential	Temp17, Temp19, Temp20, Temp21
PG&E Non-Residential	Mean(Temp3-Temp6), Mean(Temp16-Temp18), Mean(Temp22-Temp24)
SCE Non-Residential	Mean(Temp3-Temp6), Mean(Temp16-Temp18), Mean(Temp22-Temp24); segmented by season
SDG&E Non-Residential	Mean(Temp7-Temp11), Mean(Temp14-Temp19), Temp15

In Figure B-1 to Figure B-3, we show comparisons of the distributions of the average daily temperature of event days and event-like days. We show a single utility level comparison because these dates were chosen by utility and customer-class, i.e. each utility and customer class combination has the same set of event and event-like dates.

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

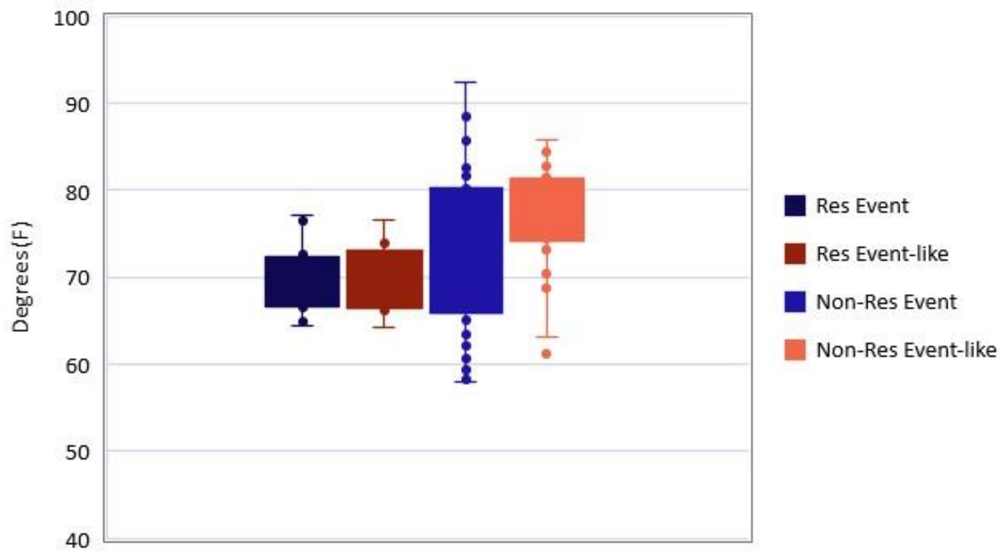


Figure B-2 SCE Average Daily Temperatures of Event Days v. Event-Like Days

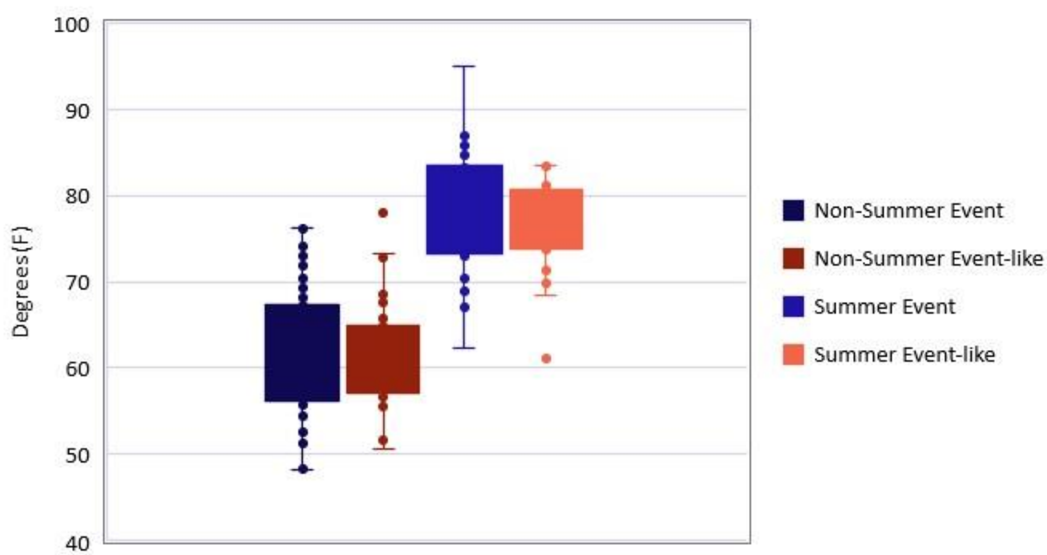
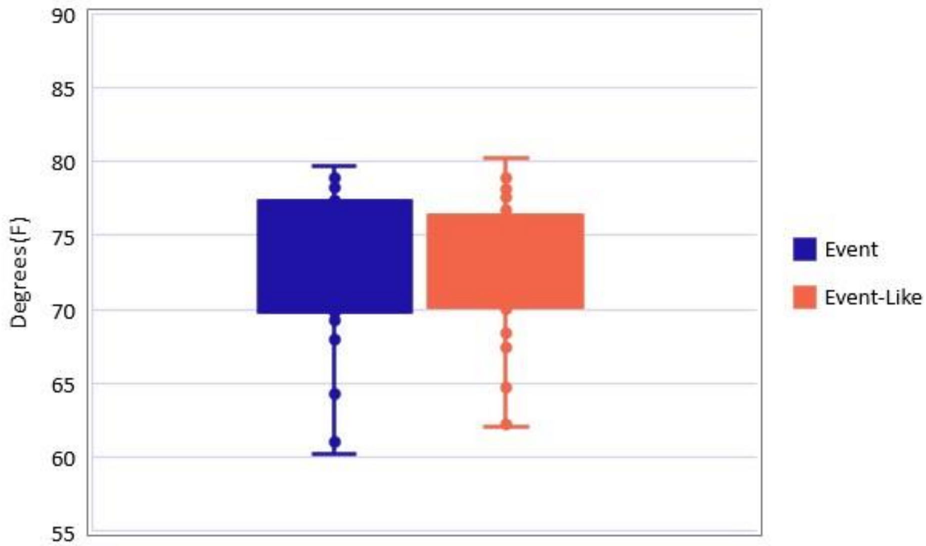


Figure B-3 SDG&E Average Daily Temperatures of Event Days v. Event-Like Days



Optimization Process and Results

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

- **To perform the in-sample test**, we fitted each candidate model to the entire data set. The results of these fitted models were used to predict the usage on CBP event days. The models should be able to accurately predict customers' actual consumption on these days, having controlled for the impacts of the event hours. We assessed the accuracy and bias of the predictions by calculating the mean absolute percent error (MAPE) and mean percent error (MPE), respectively. We refer to these metrics as the in-sample MAPE and MPE.
- **To perform the out-of-sample test**, we fitted each candidate model to the data set excluding event-like days. The results of these fitted models were used to predict the usage on event-like days. We similarly assessed the accuracy and bias of the event-like day predictions by calculating the MAPE and MPE, which we refer to as the out-of-sample MAPE and MPE.

These two tests resulted in several in-sample and out-of-sample metrics. To determine the best model for each segment in terms of its abilities to predict both the reference load and the actual load for each segment with accuracy and limited bias, we combined the two tests into a single metric as follows:

$$\boldsymbol{metric_{ic}} = (0.4 * MAPE_{in}) + (0.4 * MAPE_{out}) + \big(0.1 * abs(MPE_{in})\big) + \big(0.1 * abs(MPE_{out})\big)$$

Where,

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

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

Table B-2 presents the weighted average MAPE and MPE for each IOU and program's final set of programs. Most MAPE values are below 5%, indicating high accuracy. MPE values very close to zero, indicating low levels of bias.

Two programs show high MAPE and MPE values: PG&E Residential DA and SCE Non-residential DA (non-summer). Both of these programs have very low participant counts with highly variable loads.

Table B-2 Weighted Average MAPE and MPE by Utility and Program

IOU	Program		Out-of-Sample		In-Sample	
			MAPE	MPE	MAPE	MPE
PG&E	Residential DA		23.83%	-11.25%	26.31%	-13.06%
	Non-Residential DA		2.64%	0.38%	2.24%	-0.07%
SCE	Non-Summer	Non-Res DA	0.41%	0.01%	44.65%	-28.35%
		Non-Res DO	0.46%	-0.32%	0.66%	-0.11%
	Summer	Non-Res DA	0.80%	0.39%	1.32%	0.08%
		Non-Res DO	0.36%	0.02%	1.13%	-0.11%
SDG&E	Non-Residential DA		4.33%	0.08%	3.94%	-0.20%
	Non-Residential DO		2.37%	0.54%	1.64%	0.05%

Figure B-4 to Figure B-6 present the average event-like day predicted loads (dotted lines) and actual loads (solid lines) from the in-sample and out-of-sample tests by IOU and program. In each case, the predicted load is very close to the actual load, which 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, can produce very accurate reference loads.

Due to confidentiality, PG&E Residential and SCE non-summer loads are not shown below.

Figure B-4 PG&E Actual and Predicted Loads, Non-Residential

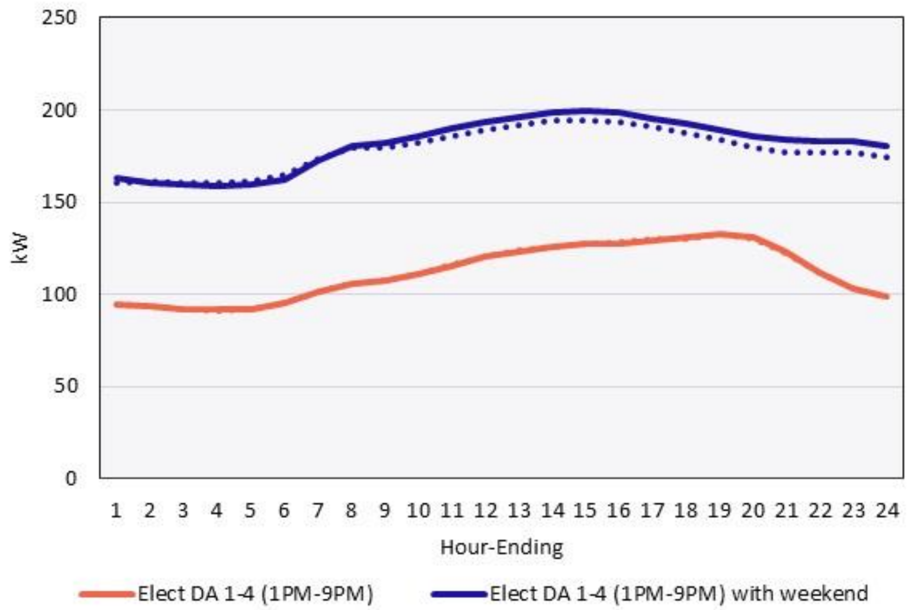


Figure B-5 SCE Actual and Predicted Loads

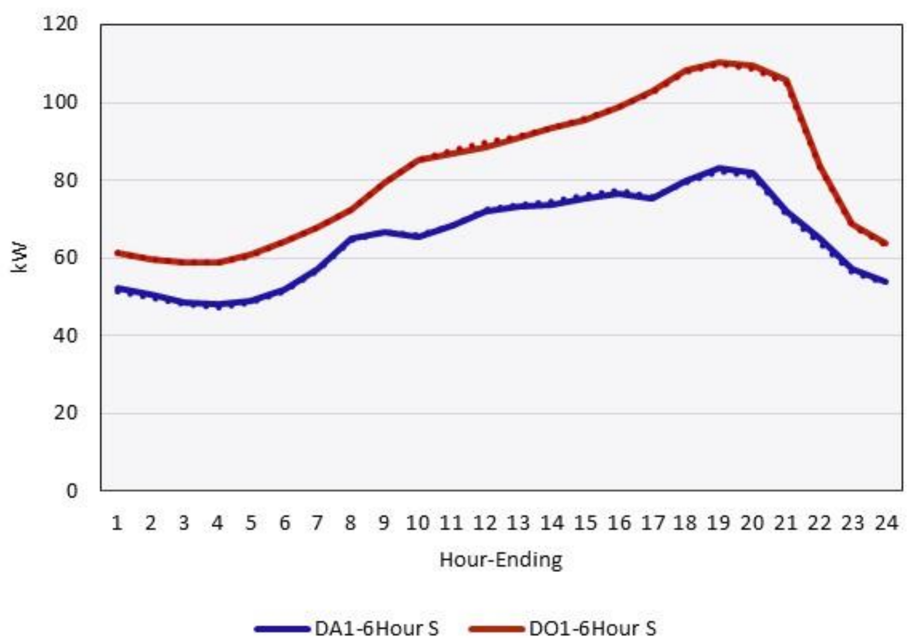
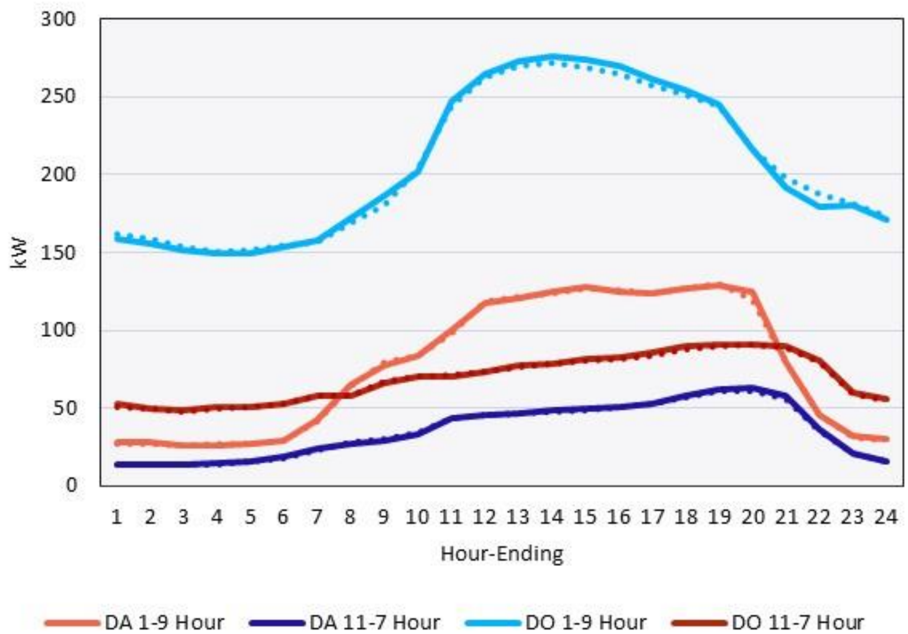


Figure B-6 SDG&E Actual and Predicted Loads



Additional Checks

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

- We checked to ensure that the reference load is closely aligned with the actual and predicted loads during the early morning and late evening hours when there is likely to be little effect from the event. Large differences can indicate a problem with the reference load, either over- or under-estimating usage in the absence of the event.
- We closely examined the reference load for odd increases or decreases in the load that could indicate an effect not correctly 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 temperature-related bias, under-predicting on hot days, and over-predicting on cool days. We have also seen bias that is time-based, over-predicting at 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	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
		Impact	Reference Load	Impact	Reference Load		
Nov 2, 2020	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	83
Nov 3, 2020	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	82
Nov 4, 2020	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	87
Nov 5, 2020	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	87
Nov 6, 2020	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	70
Dec 1, 2020	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	76
Dec 2, 2020	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	70
Dec 3, 2020	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	64
Dec 4, 2020	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	70
Dec 7, 2020	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	68
Jan 5, 2021	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	69
Feb 12, 2021	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	61
Feb 16, 2021	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	60
Feb 17, 2021	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	61
Feb 18, 2021	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	62
Feb 19, 2021	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	66
Mar 8, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	59
Mar 15, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	44
Mar 16, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	57
Mar 17, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	66
Mar 30, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	77
Apr 1, 2021	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	81
Apr 12, 2021	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	65
Apr 13, 2021	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	58
Apr 19, 2021	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	78
Apr 29, 2021	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	87
May 4, 2021	86	1.5	9.8	17.0	113.5	15%	81
May 5, 2021	86	0.9	9.4	10.7	109.4	10%	77

Event	# of Accts	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
		Impact	Reference Load	Impact	Reference Load		
May 6, 2021	86	1.5	9.7	17.0	112.5	15%	68
May 11, 2021	86	1.2	9.0	13.5	105.2	13%	71
May 12, 2021	86	1.5	9.3	17.0	108.0	16%	72
Jun 1, 2021	84	1.3	10.4	15.0	123.5	12%	78
Jun 2, 2021	84	1.3	10.0	15.0	119.0	13%	81
Jun 3, 2021	84	1.6	10.1	19.5	119.8	16%	77
Jun 14, 2021	84	0.9	10.1	10.4	120.5	9%	92
Jun 15, 2021	84	0.9	10.7	10.4	127.1	8%	97
Jul 1, 2021	81	1.9	11.2	23.6	137.9	17%	85
Jul 2, 2021	81	2.2	11.7	27.5	144.5	19%	86
Jul 6, 2021	81	1.9	11.1	23.6	137.1	17%	85
Jul 7, 2021	81	1.5	11.6	17.9	143.4	12%	86
Jul 8, 2021	81	1.0	11.6	11.8	143.6	8%	90
Aug 2, 2021	75	1.2	10.8	15.3	143.7	11%	95
Aug 3, 2021	75	1.2	10.2	15.3	135.7	11%	94
Aug 4, 2021	75	1.2	10.9	15.3	144.9	11%	93
Aug 27, 2021	75	2.1	11.4	28.3	152.1	19%	95
Aug 30, 2021	75	1.2	10.5	15.3	140.0	11%	84
Sep 7, 2021	71	1.3	11.5	18.3	162.2	11%	88
Sep 8, 2021	71	1.3	11.8	18.3	166.5	11%	91
Sep 9, 2021	71	1.3	11.1	18.3	156.4	12%	92
Sep 10, 2021	71	1.3	10.2	18.3	144.3	13%	91
Sep 21, 2021	71	1.3	11.7	18.5	164.2	11%	95
Oct 4, 2021	69	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	81
Oct 15, 2021	69	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	78
Oct 19, 2021	69	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	65
Oct 27, 2021	69	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	78
Oct 28, 2021	69	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	82

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

Event	# of Accts	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
		Impact	Reference Load	Impact	Reference Load		
Nov 2, 2020	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	83
Nov 3, 2020	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	82
Nov 4, 2020	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	87
Nov 5, 2020	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	87

Event	# of Accts	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
		Impact	Reference Load	Impact	Reference Load		
Nov 6, 2020	4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	70
Dec 1, 2020	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	76
Dec 2, 2020	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	70
Dec 3, 2020	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	64
Dec 4, 2020	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	70
Dec 7, 2020	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	68
Jan 5, 2021	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	69
Feb 12, 2021	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	61
Feb 16, 2021	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	60
Feb 17, 2021	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	61
Feb 18, 2021	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	62
Feb 19, 2021	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	66
Mar 8, 2021	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	59
Mar 15, 2021	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	44
Mar 16, 2021	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	57
Mar 17, 2021	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	66
Mar 30, 2021	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	77
Apr 1, 2021	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	81
Apr 12, 2021	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	65
Apr 13, 2021	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	58
Apr 19, 2021	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	78
Apr 29, 2021	2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	87
May 4, 2021	49	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	83
May 5, 2021	49	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	79
May 6, 2021	49	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	69
May 11, 2021	49	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	72
May 12, 2021	49	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	73
Jun 1, 2021	49	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	79
Jun 2, 2021	49	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	82
Jun 3, 2021	49	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	78
Jun 14, 2021	49	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	94
Jun 15, 2021	49	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	99
Jul 1, 2021	48	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	86
Jul 2, 2021	48	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	88
Jul 6, 2021	48	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	87
Jul 7, 2021	48	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	87
Jul 8, 2021	48	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	91

Event	# of Accts	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
		Impact	Reference Load	Impact	Reference Load		
Aug 2, 2021	49	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	97
Aug 3, 2021	49	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	96
Aug 4, 2021	49	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	94
Aug 27, 2021	49	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	97
Aug 30, 2021	49	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	85
Sep 9, 2021	50	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	92

South Orange County

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

Event	# of Accts	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
		Impact	Reference Load	Impact	Reference Load		
Jan 4, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	58
Jan 5, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	58
Mar 1, 2021	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	65
Mar 8, 2021	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	59
Mar 16, 2021	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	56
Mar 17, 2021	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	58
Mar 30, 2021	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	64
May 4, 2021	85	1.0	4.9	12.0	57.2	21%	69
May 5, 2021	85	0.9	4.2	11.2	49.2	23%	66
May 6, 2021	85	1.0	4.7	12.0	55.3	22%	64
May 11, 2021	85	0.9	4.0	11.2	46.8	24%	66
May 12, 2021	85	1.0	4.6	12.0	54.6	22%	66
Jun 1, 2021	84	1.2	4.6	14.7	54.3	27%	66
Jun 2, 2021	84	1.2	4.6	14.7	55.3	26%	65
Jun 3, 2021	84	1.0	4.3	12.1	50.7	24%	64
Jun 14, 2021	84	0.8	5.0	9.8	59.4	17%	82
Jun 15, 2021	84	0.8	5.2	9.8	61.5	16%	85
Jul 1, 2021	81	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	75
Jul 2, 2021	81	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	72
Jul 6, 2021	81	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	73
Jul 7, 2021	81	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	72
Jul 8, 2021	81	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	75
Aug 2, 2021	75	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	86
Aug 3, 2021	75	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	80

Event	# of Accts	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
		Impact	Reference Load	Impact	Reference Load		
Aug 4, 2021	75	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	78
Aug 27, 2021	75	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	81
Aug 30, 2021	75	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	73
Sep 8, 2021	75	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	80
Sep 9, 2021	75	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	83
Oct 4, 2021	74	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	79
Oct 28, 2021	74	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	80

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

Event	# of Accts	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
		Impact	Reference Load	Impact	Reference Load		
Nov 2, 2020	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	68
Nov 3, 2020	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	67
Nov 4, 2020	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	73
Nov 5, 2020	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	79
Nov 6, 2020	8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	66
Dec 1, 2020	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	66
Dec 2, 2020	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	67
Dec 3, 2020	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	71
Dec 4, 2020	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	67
Dec 7, 2020	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	70
Jan 4, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	59
Jan 5, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	58
Feb 12, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	62
Feb 16, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	59
Feb 17, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	60
Feb 18, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	64
Feb 19, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	61
Mar 1, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	65
Mar 8, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	59
Mar 16, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	55
Mar 17, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	58
Mar 30, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	63
Apr 1, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	80
Apr 12, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	61
Apr 13, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	60

Event	# of Accts	Aggregate Impact (MW)		Per-Customer Impact (kW)		% Impact	Temp (F)
		Impact	Reference Load	Impact	Reference Load		
Apr 19, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	66
Apr 29, 2021	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	82
May 4, 2021	78	0.8	5.6	9.8	71.3	14%	69
May 5, 2021	78	0.7	5.1	8.5	65.3	13%	65
May 6, 2021	78	0.8	5.1	9.8	65.0	15%	64
May 11, 2021	78	0.7	5.0	8.5	63.8	13%	65
May 12, 2021	78	0.8	5.1	9.8	65.6	15%	66
Jun 1, 2021	78	0.9	5.5	11.7	70.2	17%	65
Jun 2, 2021	78	0.9	5.4	11.7	69.6	17%	65
Jun 3, 2021	78	0.8	5.2	10.7	66.9	16%	63
Jun 14, 2021	78	0.5	6.0	6.4	76.5	8%	82
Jun 15, 2021	78	0.5	6.3	6.4	81.4	8%	84
Jul 1, 2021	78	1.0	6.1	12.7	77.6	16%	74
Jul 2, 2021	78	1.1	6.3	14.7	81.2	18%	71
Jul 6, 2021	78	1.0	6.1	12.7	78.7	16%	73
Jul 7, 2021	78	1.1	6.2	13.9	79.1	18%	71
Jul 8, 2021	78	0.6	6.1	8.0	77.9	10%	75
Aug 2, 2021	77	0.7	6.4	9.4	83.5	11%	85
Aug 3, 2021	77	0.7	6.2	9.4	79.9	12%	79
Aug 4, 2021	77	0.7	6.2	9.4	79.9	12%	78
Aug 27, 2021	77	1.5	6.6	18.9	85.2	22%	80
Aug 30, 2021	77	0.7	5.8	9.4	75.6	12%	73
Sep 9, 2021	78	0.7	6.4	9.2	81.5	11%	79

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