San Diego Gas and Electrics 2019 Demand Response Executive Summary

April 1st, 2020

SDGE
A Sempra Energy utility℠

Contents

List of Tables and Figures

1. Background

San Diego Gas & Electric (SDG&E) presents this Executive Summary for its Demand Response (DR) activities for program year 2019 in accordance with (D.) 08-4-050. In Decision (D.) 08-04-050 the California Public Utility Commission (Commission) required the Investor Owned Utilities (IOUs) - San Diego Gas & Electric Company (SDG&E), Southern California Edison (SCE) and Pacific Gas and Electric (PG&E) to perform annual studies of their DR activities in accordance with the load impact protocols[1] and to file the load impact reports by April 1st each year. The original load impact protocols require the preparation of a voluminous number of tables that resulted in the load impact reports being too large to be filed in hard copy. On April 6th, 2009 the investor owned utilities (IOUs) filed a petition to modify D.08-41-050. The petition asked for two things: 1) the removal of the requirement to file the load impact reports in their entirety and 2) to provide the reports to the energy division of the Commission. On April 8th, 2010, D.10-04-006 granted the utilities requests and added an Executive Summary requirement. The executive summaries were to include an overview of the evaluation findings, recommendations for changes to the demand response resource. Additionally, the executive summaries were to include brief descriptions of the methodology, the enrollment forecast, and the inputs and assumptions used for calculating both the ex post and ex ante load impact estimates. The IOUs should also report the regression model specifications for each demand response program.

[1] On April 24, 2008 D.08-04-050 adopted the protocols used in estimation of demand response load impacts.

In 2014 SDG&E was directed to include weather scenarios for load impacts that were coincident with the CAISO's system peak.[2]

Six CPUC decisions over the past three years made changes that affected SDG&E's Demand Response Activities.

- TOU periods were changed in D.17-08-030
- 2018-2022 Demand Response programs were approved in D.17-12-003
- D.18-06-030 Adopting Local Capacity Obligations for 2019
- Default Residential TOU D.18-12-004 approved mass default for 2019
- D.17-01-006 and D.17-10-018 allowed Grandfathering for certain customers

In August 2017 D.17-08-030 provided GRCP2 approval and directed SDG&E to file an advice letter by December 1, 2017 for implementation of time of use period changes for the 2018 calendar year. Since TOU period definitions changed for all SDG&E's TOU customers, the 2018 load Impact studies that estimated dynamic rate reductions also attempted to estimate load impacts associated with the change in TOU periods. Estimating the associated load impacts attributed to the TOU changes was also attempted for 2019.

On January 17, 2017 SDG&E filed its 2018-2022 Demand Response Program Application. In this application SDG&E proposed several modifications to its existing DR programs and proposed two new DR pilots. Among those modifications were requests to improve the Capacity Bidding Program (CBP) by reducing the number of products offered and simplifying the program. On December 13, 2017 the CPUC issued D.17-12-003 that provided approval of SDG&E's DR program application and among other things directed the Permanent Load Shifting (PLS) program to be suspended after 2018. Additionally, SDG&E was directed to file Advice Letters for the modifications to its CBP program.

In June of 2018, the CPUC issued D.18-06-030 Adopting Local Capacity Obligations for 2019 and Refining the Resource Adequacy Program. Ordering Paragraphs 13 and 14 address changes to the Resource Adequacy measurement hours. Specifically, they were modified from

[2] In October of 2014 SDG&E received a letter from the Director the CPUC's Energy Division. The letter informed the IOUs that they needed to include ex ante forecasts that are to be used for RA should be with respect to the CAISO's system peak.

1:00 pm to 6:00 pm to 4:00 pm to 9:00 pm (HE17-HE21) for each month of the year beginning in 2019. Additionally, combined storage and demand response projects are eligible to participate in the Resource Adequacy program.

In December of 2018 SDG&E received D.18-12-004 which allowed SDG&E to default all eligible residential customers onto TOU rates in 2019. About 700,000 of SDG&E's residential customers were transitioned to TOU rates by December 2019.

SDG&E grandfather certain SDG&E residential and commercial customers per D.17-01-006 and D.17-10-018. Under these decisions those customers who TOU period definitions were allowed to use the old Time of Use Rates "grandfathered" TOU Period Grandfathering permits certain eligible behind-the-meter solar customers to continue billing under grandfathered TOU period definitions for a specific period of time after new TOU Periods are implemented. Generally, these customers had to have opted into a TOU tariff prior to July 31, 2017. Residential customers were grandfathered up to 5 years, and commercial customers up to 10 years.

2. Introduction

This Executive Summary provides all relevant information regarding the load impact evaluations as prescribed in D10-04-006. Included are program descriptions, program options, ex post load impact methodology, program year 2019 event results, ex ante forecasts, methodology and ex ante load impacts. Much of the information presented in the executive summary are excerpts taken directly from the individual load impact reports. The following reports are included in this executive summary.

1. 2019 Statewide Load Impact Evaluation of California's Capacity Bidding Programs, Ex Post and Ex Ante Impacts, Applied Energy Group, April 1st, 2020
2. 2019 Statewide Load Impact Evaluation of California's Critical Peak Pricing Programs, Ex Post and Ex Ante Impacts, Applied Energy Group, April 1st, 2020
3. 2019 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers: Ex-post and Ex-ante Report, Christensen Associates, April 1st, 2020

4. 2019 Load Impact Evaluation of San Diego Gas and Electric's AC Saver Day Of Program, Nexant Inc, April 1st, 2020
5. 2019 Load Impact Evaluation for San Diego Gas and Electric's Residential Technology Deployment Program, Demand Side Analytics LLC, April 1st, 2020
6. 2019 Load Impact Evaluation for San Diego Gas and Electric's Small Commercial and Agricultural Critical Peak Pricing and Time-of-Use rates and Technology Deployment Program, Demand Side Analytics LLC, April 1st, 2020
7. 2019 Load Impact Evaluation of San Diego Gas and Electric's Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates, Christensen Associates, April 1st, 2020
8. 2019 Load Impact Evaluation of San Diego Gas and Electric's Electric Vehicle Rates, Christensen Associates, April 1st, 2020
9. 2019 Load Impact Evaluation of San Diego Gas and Electric's Residential Default Time-Of-Use Rates

This report contains a summary of the load impact evaluations of SDG&E's Demand Response activities and organized by the following:

Supply Side Resources

Emergency Programs:
Base Interruptible Program (BIP)

Aggregator Programs:
Capacity Bidding Program (CBP)

Price Responsive Programs:
AC Saver Day Of
AC Saver Day Ahead Residential
AC Saver Day Ahead Commercial

Load Modifying Rates/Programs

Price Responsive Programs:
Critical Peak Pricing Default (CPP-D)
Default Small Commercial CPP and TOU
Voluntary Residential CPP and TOU
Electric Vehicle Time of Use
Default Residential TOU

Table 2-1 presents the Program Year (PY) 2019 ex post estimates for the average event day Load Impact in MWs across all SDG&E events, and the load impacts in MWs for SDG&E's

Peak Day (September 3rd, 2019). The table presents the ex post estimates by DR category – Supply Side or Load Modifying. Supply Side resources are bid into the CAISO market during the event season which typically runs from April 1st through October 31st. Dynamic and time of use rates are Load Modifying resources. It is noteworthy that SDG&E did not call any CPP events during 2019. In 2018 SDG&E's temperature at Miramar was 90 degrees or warmer 33 times as compared to 27 degrees in 2019.[3] SDG&E maintains that it was well resourced during the summer of 2019 and therefore there was not a local need for SDG&E to call CPP events. SDG&E's peak load hit 4,000 MWs twice during the summer as opposed to 12 times during 2018. Additionally, SDG&E had no DR events on Tuesday September 3rd which was SDG&E's system peak day in 2019. The number of participants for SDG&E's dynamic rates were taken from the ex-ante 1in2 SDGE weather scenario for the month of September and for SDG&E's TOU rates the number of participants was taken from the ex-ante 1in2 SDGE weather conditions for the month of December.

[3] Of the 27 times the temperature was 90 degrees or warmer in 2019, more than 1/3 of those occurrences happened in October and November. Typically, evenings are cooler during those months as compared to July – September evening temperatures.

Table 2-1: Program Year (PY) 2019 Ex post estimates

Program Type and Name	# of Customers on Average Event Day	Event Window Average Event Day	Average Event Day Load Impact (MW)
Supply Side Demand Response			
BIP	3	HE13-HE16*	2.87
AC Saver Day Ahead Residential	17,197	HE19-HE20	3.79
AC Saver Day Ahead Commercial (including Quasi-Residential)	1,452	HE19-HE20	0.52
AC Saver Day Of Commercial	3,707	HE19-HE20	0.33
AC Saver Day Of Residential	7,913	HE19-HE20	0.91
CBP DA (Including products 11am-7pm)	10	HE19	0.30
CBP DA (Including products 1pm-9pm)	5	HE19	0.09
CBP DO (Including products 11am-7pm)	97	HE19	1.20
CBP DO (Including products 1pm-9pm)	88	HE19	2.41
Load Modifying			
CPPD Large (Excluding TD)***	1,277		
CPPD Medium (Excluding TD)***	13,011		
Default Small Commercial TOU and CPP Rates (Excluding TD)	111,149		
Small Commercial Agricultural	124		
D-TOU Rate 1 **	696,775	HE17-HE21	6.97
D-TOU Rate 2 **	28,647	HE17-HE21	.23
EVTOU2 (Including NEM plus Non-NEM) **	9,472	HE17-HE21	1.07
EVTOU5 (Including NEM plus Non-NEM **	7,660	HE17-HE21	2.83
Technology Deployment (TD) C&I	1,744		
Voluntary Residential grandfathered CPP on Technology Deployment (TD)***	0		
Voluntary Residential CPP customers on Technology Deployment (TD)***	554		-
Voluntary Residential CPP excluding Technology Deployment (TD) customers***	13,363		-
Voluntary Residential grandfathered CPP excluding Technology Deployment (TD) customers***	331		-
Total	**914,579**		**12**

* HE means hour ending

**The load impacts for residential Default TOU Rates 1 and 2, EVTOU2 (Including NEM plus Non-NEM), EVTOU5 (Including NEM plus Non-NEM) are non-event based, energy reported is the average consumption over the RA window for a summer weekday

***SDGE did not trigger any dynamic pricing events in 2019, therefore the impacts are intentionally left in blank.

All ex ante load impact summaries are averaged over the current Resource Adequacy (RA) hours of 4pm to 9pm for all programs and/or dynamic rates. It should also be noted that ex post weather conditions are typically not the same as the 1 in 2, or 1 in 10 weather scenarios used in the ex ante tables. In other words, the actual weather conditions when DR activities are called can be different, i.e. an event could be called on a 1 in 4 peak weather condition or much cooler weather than a 1 in 2 peak condition and therefore the ex post load impact estimates may or will not match up the forecasts required in this filing.

Located in Appendix A are the model specifications for each of the studies, ex post and ex ante. The ex ante tables located in Appendix B[4] contain both SDG&E and CAISO load impacts. Appendix B is a separate document provided in pdf and excel formats. The ex ante tables include the following:

- 1 in 2 weather scenario for individual programs
- 1 in 2 weather scenario for the portfolio,
- 1 in 10 weather scenario for individual programs, and
- 1 in 10 weather scenario for the portfolio

Table 2-2 presents SDG&E's 2020 ex ante estimates for all DR programs, Dynamic and TOU rates. The MW load impacts are for SDGE 1 in 2 weather conditions for September 2020. New for SDG&E's Load Impact filing are ex ante estimates for Residential Default TOU and Electric Vehicle TOU rates. An additional 15 MWs of peak load reduction (4pm – 9pm) through TOU rate pricing signals can be expected in September 2020. SDG&E's AC Saver Day Ahead Program is expected to continue to grow in 2020 contributing 9 MWs in expected load impacts. SDG&E's AC Saver Day Of program continues to decline in enrollment as it is not being marketed to.

[4] File names are: AppendixB.TablesforExecutiveSummary_formatted_Mar302020.pdf and AppendixB.TablesforExecutiveSummary_formatted_Mar302020.xlxs

Table 2-2: Program Year (PY) 2019 Portfolio Ex ante estimates* based on 1 in 2 SDG&E weather scenarios for the year of 2020

Program Type and Name	Forecasted Customers in September 2020	Ex ante estimates for the month of September 2020 (MW)
Supply Side Demand Response		
BIP	5	1.01
AC Saver Day Ahead Commercial (including Quasi-Residential)	1,592	1.00
AC Saver Day Ahead Residential	21,581	8.08
AC Saver Day Of Commercial	3,558	0.64
AC Saver Day Of Residential	7,272	2.06
CBP DA (Including products 11am-7pm)	9	0.16
CBP DA (Including products 1pm-9pm)	2	0.05
CBP DO with new TI (Including products 11am-7pm)	94	0.68
CBP DO with new TI (Including products 1pm-9pm)	96	2.54
Load Modifying Demand Response		
CPPD Large (Excluding TD)	1,303	3.36
CPPD Medium (Excluding TD)	12,887	1.75
Default Small Agricultural TOU and CPP Rates (Excluding TD)	120	0.01
Default Small Commercial TOU and CPP Rates (Excluding TD)	107,603	1.84
D-TOU Rate 1	706,172	14.89
D-TOU Rate 2	28,744	0.61
EVTOU2 (Including NEM plus Non-NEM)	9,442	1.48
EVTOU5 (Including NEM plus Non-NEM)	8,708	6.75
Technology Deployment (TD) Commercial on PSW (Small Commercial CPP) plus CPP (Large and Medium)	1,677	0.30
Voluntary Residential CPP customers on Technology Deployment (TD)	599	0.03
Voluntary Residential grandfathered CPP customers on Technology Deployment (TD)*		
Voluntary Residential CPP and TOU excluding Technology Deployment (TD) customers on grandfathered PSH	954	0.05
Voluntary Residential CPP and TOU excluding Technology Deployment (TD) customers on PSH	14,392	2.63
Total	**926,809**	**49.93**

*There are no customers on Voluntary Residential grandfathered CPP customers on Technology Deployment (TD), therefore is intentionally left in blank

3. Program Descriptions

3.1 Supply Side Demand Response

3.1.1 Emergency Programs

3.1.1.1 Base Interruptible Program

The Base Interruptible Program (BIP) is an emergency demand response (DR) program intended to provide load reduction on a “day-of” basis when the California Independent System Operator (CAISO) issues a notice that loads should be curtailed on the same day because of a statewide emergency (i.e., a shortage of electricity). SDG&E can also call a BIP event when extreme temperature conditions are impacting system demand. If SDG&E does not foresee a CAISO statewide emergency each year, it will call a yearly test event on what it believes will be the highest load day of the year. BIP is a statewide program, offered by PG&E and SCE as well, with minor differences in the tariffs that exist across the three Investor Owned Utilities (IOUs).

BIP offers a monthly bill credit as a capacity payment to customers or aggregators that can commit to curtail at least 100 kW and 15% of their Monthly Average Peak Demand, calculated by the customer’s energy usage during the hours from 1pm – 6pm. The Committed Load is the difference of the Monthly Average Peak Demand minus the contracted Firm Service Level (FSL). The capacity payment is a monthly flat rate of $6.30 per kW of Committed Load. BIP was designed to be an emergency program where large customers (and aggregators who can mimic large customers) are able to shed large amounts of load on short notice (20 minutes) of a load shed event. It is available to be called year-round, not to exceed four (4) hours for any calendar day, or 10 Interruption Periods per calendar month, or 120 hours during any calendar year. Customers are given a 20-minute notice and must curtail their load down to their contracted level (their FSL) when events are initiated. Otherwise, customers will pay an excess energy charge of $4.50kWh for every 15-minute interval during the event period for any usage in excess of their contracted FSL. The program’s tariff with full details can be found at SDG&E’s website.[5]

[5] http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_BIP.pdf

3.1.2 Aggregator Programs

3.1.2.1 Capacity Bidding Program (CBP)

CBP is a statewide price-responsive program launched in 2007. The Capacity Bidding Program (CBP) is a supply side program that provides incentives to aggregators to sign up commercial customers who commit to shed load when triggered. Currently, In CBP, aggregators are entities that contract with non-residential utility customers to act on their behalf with respect to all aspects of the demand response program, including the receipt of notices (day-ahead, DA, or day-of, DO) from the utility under this program, the receipt of incentive payments, and the payment of penalties to the utility. The program is open to bundled as well as Direct Access (DA) customers. SDG&E bids aggregators' nominated load shed into the California Independent System Operator (CAISO) market at predetermined trigger prices. CBP is triggered when those bids are awarded and scheduled in the CAISO market. SDG&E has four products: two Day-Ahead and two Day-Of products as shown in Table 1. CBP events can only be called during the products' hours, which are between 11am – 7pm and 1pm – 9pm. The aggregator selects a product to nominate their customer(s) into. CBP is a seasonal DR program that runs yearly from May 1 to October 31. CBP has its own tariff, Schedule CBP.[6] Customers on the CBP tariffs offered by the IOUs are also eligible to participate in Technology Incentives (TI) and Automated Demand Response (AutoDR) programs. SDG&E's Technology Incentives Program offers incentives for the purchase and installation of qualified automated demand-response measures that provide verified, dispatchable, on-peak load reduction at customer-owned facilities. Eligible customers can receive up to $200 per kilowatt (kW) of verified, dispatchable, fully automated on-peak load reduction. The total incentive is limited to 75% of the total project cost.[7]

---

[6] http://regarchive.sdge.com/tm2/ssi/inc_elec_rates_misc.html

[7] The TI program requires customers receiving incentives to enroll in a qualified DR program for 3 years after installation. Qualifying programs for TI enrollment are the Capacity Bidding Program (CBP), Critical Peak Pricing (CPP) or other eligible pilots such as DRAM.

3.1.3 Price Response Programs

3.1.3.1 AC Saver Program

AC Saver is a supply side Demand Response (DR) program available to all qualifying customers with air conditioning (AC) units with SDG&E-approved and installed technology capable of curtailing the customer's AC use. AC Saver offers two products to customers to choose from. Those products are: (1) "Day-Ahead", meaning the customer is typically notified the day before the event based on a forecasted grid need; and (2) "Day-Of" which refers to the fact the customer is notified to drop load on the same day the load is needed.

Apart from the types of products, there are different types of technologies used to signal to customers that load must be dropped. The types of technologies that the program currently uses are direct load control switches and thermostats. Events last between two and four hours and may be called between April and October. Residential net energy metering (NEM) customers with self-generation (usually solar) installed at the premise are not eligible for the program.

Customers with direct load control switches participate in the AC Saver Day-Of product.[8] Within the Day-Of product there are two options available to residential customers: (1) a 50% cycling option, meaning that the customer's air conditioning run-time is reduced by 50%; and (2) a 100% cycling option where the AC is turned off for the entire duration of the event. Commercial customers may choose between a 30% cycling and a 50% cycling option. Customers enrolled on the Day-Of option are not permitted to override individual events. Customers receive an annual capacity payment based on the size of their air-conditioner and the cycling option that they choose.

Customers with Nest or Ecobee thermostats participate in the AC Saver Day-Ahead product. For customers enrolled on AC Saver Day-Ahead, the vendor either increases the customer's thermostat's setpoint by 4-degrees Fahrenheit or uses some other comparable strategy. Customers may override individual events. Residential customers receive an annual capacity payment of $20.

[8] "Day-Of" refers to programs in which customers are notified the day of an event, formerly known as Summer Saver.

The program is usually activated when SDG&E bids in and then receives an award from the CAISO market.[9] SDG&E bids the program into the CAISO market daily using an energy price based on the tariff-specified heat rate.

3.2 Load Modifying Demand Response

3.2.1 Pricing Programs (Critical Peak Pricing Rates)

3.2.1.1 Critical Peak Pricing – Default (CPP-D)

CPP is a statewide price responsive rate that qualifies as load modifying demand response. California's CPP programs provide participating customers with lower rates during non-CPP summer season hours and higher rates during CPP periods when an event is called. These "dynamic" pricing rates are designed to encourage price-responsive demand reductions during the higher priced critical periods. Customers benefit financially from the longer periods of the lower rates for electricity consumed outside of the CPP periods. New customers on the program may also be eligible for bill protection for an initial period, such as 12 months, so that their energy costs on CPP do not exceed their pre-CPP costs while they learn how to respond. All CPP tariffs are designed for bundled service customers. In addition to CBP customers, customers on SDG&E's CPP tariffs are also eligible to participate in Technology Incentives (TI) which includes Automated Demand Response (AutoDR) programs. SDG&E's Technology Incentives Program offers incentives for the purchase and installation of qualified automated demand-response measures that provide verified, dispatchable, on-peak load reduction at customer-owned facilities. Eligible customers can receive up to $200 per kilowatt (kW) of verified, dispatchable, fully automated on-peak load reduction. The total incentive is limited to 75% of the total project cost.[10]

SDG&E started defaulting its large commercial and industrial customers onto CPP rates in 2008. SDG&E's CPP rate is year-round, customers are notified the day before by 3pm and can be triggered up to 18 CPP days a year and the CPP period is from 2pm to 6pm.

---

[9] There are other triggers for AC Saver, most of which are reliability-based, but they are less commonly used. See Schedule AC Saver Sheets 2 and 3: http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_AC_SAVER.pdf

[10] The TI program requires customers receiving incentives to enroll in a qualified DR program for 3 years after installation. Qualifying programs for TI enrollment are the Capacity Bidding Program (CBP), Critical Peak Pricing (CPP) or other eligible pilots such as DRAM.

3.2.1.2 Default Small Commercial Critical Peak Pricing and Time of Use

This dynamic rate is similar to SDG&E's Large and Medium CPP rates. SDG&E's small commercial and industrial customers do not have demand charges, therefore there are there are demand components. In April 2016, SDG&E transitioned over 120,000 small business customers onto time of use rates with a critical peak component (CPP-TOU). While customers were defaulted onto TOU-CPP rates, they could elect to opt-out to a time-of-use (TOU) rate and 5% of them did. As of PY 2019, about 112,000 sites remain on the CPP-TOU rate, implying a three year opt-out rate of about 7%, which is relatively stable relative to the initial 5% opt-out rate. In tandem, SDG&E also transitioned small agricultural customers from flat rates onto time of use rates and offered a CPP-TOU rate on a voluntary (opt-in) basis. By April 2016, electricity rates without a time varying component were no longer available for small commercial and agricultural customers. In the years leading up to and after the rate transition, SDG&E offered customers smart thermostats, free of charge, to help them manage their energy bills and automate response to critical peak prices.

3.2.1.3 Voluntary Residential Critical Peak Pricing (CPP) and Time of Use (TOU)

SDG&E's voluntary residential CPP is considered a dynamic rate with an underlying TOU rate structure. Similar to the commercial and industrial CPP rates, these "dynamic" pricing rates are designed to encourage price-responsive demand reductions during the higher priced critical periods. Customers benefit financially from the longer periods of the lower rates for electricity consumed outside of the CPP periods. The (non-grandfathered) TOU and CPP rates, referred to collectively as residential smart pricing project (SPP) rates, are TOU-DR (a traditional non-event TOU rate) and TOU-DR-P (a TOU rate with an event-based CPP component). Both rates are voluntary and became active in February 2015.

The TOU periods for all non-Grandfathered rates are centered around an on-peak period of 4 p.m. to 9 p.m. on non-holiday weekdays, which is surrounded by morning and evening off-peak periods, and an overnight super-off-peak period. The super-off-peak hours are longer for weekends and holidays as well as during the months of March and April. The CPP rate may be called during the 2 p.m. to 6 p.m. period on any day (including weekends) throughout the year

For Grandfathered customers, the summer TOU on-peak period is 11 a.m. to 6 p.m. on non-holiday weekdays, which is surrounded by morning and evening semi-peak periods, and an overnight off-peak period. On winter weekdays, the on-peak period is 5 p.m. to 8 p.m., with semi-peak periods in the morning, afternoon and evening hours, and an overnight off-peak period. Weekend and holiday hours are all off-peak.

3.3.1 Nonevent based programs

3.3.1.1 Electric Vehicle Time of Use 2 (EVTOU2) and Electric Vehicle Time of Use 5 (EVTOU5) and Vehicle to Grid Integration (VGI)

SDG&E offers different time of use rates for its customers that have electric vehicles. This study focuses on whole premise electric vehicle rates. Currently SDG&E offers EV-TOU2, EV-TOU5 and VGI rates to its residential customers that own electric vehicles.

The TOU periods for both EVTOU2 and EVTOU5 are centered around an on-peak period of 4 p.m. to 9 p.m. on non-holiday weekdays, which is surrounded by morning and evening off-peak periods, and an overnight super-off-peak period. The super-off-peak hours are longer for weekends and holidays as well as during the months of March and April. SDG&E's VGI rate is SDG&E's most progressive dynamic electric rate. The VGI rate includes a number of VGI Program Facilities which provide electric vehicle charging under the VGI rate.[11] The dynamic rate consists of three components: an hourly base rate, an hourly commodity base rate, and an hourly distribution base rate. The commodity base rate includes an adjustment based on the California Independent System Operator (CAISO) day-ahead hourly price, an adder to reflect the system's top 150 system peak hours, and an adjustment to reflect day-of CAISO surplus energy hours. The hourly distribution base rate includes an adder to reflect the top 200 annual hours of peak demand for the individual circuit feeding the VGI charging station. The rates are applicable to either the individual vehicle customer charging through the VGI Program Facility or the Site Host providing the charging.[12]

---

[11] VGI Program Facilities are installed, operated, and maintained by SDG&E, pursuant to D.16-01-045, and are located at workplaces and multi-unit dwellings.

[12] The Site Host is an applicable site that allows SDG&E to install, operate, and maintain VGI Program Facilities on its property. Site Hosts agree to participate in and follow the requirements of the VGI program. The Site Host determines if the VGI Program Facilities on its property will be billed to the driver or the Site Host.

3.3.1.2 Default Residential Time of Use (D-TOU)

SDG&E's D-TOU rate options started out as a pilot in 2018. The pilot was implemented in response to California Public Utilities Commission (CPUC) Decision 15-07-001. A key objective of the pilot is to develop insights that will help guide SDG&E's approach to implementation of default TOU pricing for the majority of its residential customers and the CPUC's policy decisions regarding default pricing. Prior to 2018 SDG&E had fewer than 5% of its residential customers on TOU rates.

Findings from the first summer of the pilot—June through October 2018—are documented in the "Default Time-Of-Use Pricing Pilot Interim Evaluation" dated April 1, 2019 (hereafter referred to as the Interim Report). The Interim Report contains detailed background information on the pilot, describes the pilot design and the load impact evaluation methodology, discusses SDG&E's pilot implementation and treatments, and presents load impacts for the first summer period. It also presents structural bill impacts and summarizes pre-enrollment opt-out rates. Findings from the first winter and the full first year of the pilot are documented in the "Default Time-Of-Use Pricing Pilot Final Evaluation" dated November 1, 2019 (hereafter referred to as the Final Report). The Final Report focuses primarily on load impacts from the winter period in 2018 and 2019 as well as bill impacts for the first year of the pilot. The winter results provide load impacts for the entire winter rate period of November 2018 through May 2019. Behavioral bill impacts and total bill impacts are provided for the full first year of the pilot, from June 2018 through May 2019. Customer attrition throughout the first year is also included in the Final Report.

4. Methodology

A summary of ex-post and ex-ante methods are provided in Table 4-1. Each DR activity uses its unique method to analyze results. Ex-post methods are used to calculate reductions for actual demand response events. Many factors go into each result such as weather conditions, day of the week, season, whether the customer received notification, number of participants, and connected versus disconnected devices for technology deployment programs. Additionally, all events have different hours and days of when they were called. While ex-post methods are used for actual events, ex-ante methods are used to get load reductions for each month under two peak weather planning conditions: 1-in-2 and 1-in-10 for both SDG&E and CAISO. The ex ante estimates are used in establishing Resource Adequacy (RA) credit for supply side demand response activities. Supply side resources are bid into the CAISO market during the event season which typically runs from April 1st through October 31st. Dynamic and Time of Use rates are Load Modifying resources, and those ex ante estimates are utilized and accounted for in SDG&E's peak forecast.

Table 4-1: Summary of Analysis Methodologies by Program

Supply Side Demand Response Programs			
Program	**Method**	**Evaluation**	**Key Assumptions**
AC Saver Day Ahead Commercial	Ex-Post/Ex-Ante: Panel Regression with a multiple matched control group	The approach is implemented on a time series of individual customer loads. It relies on multiple non-equivalent control sites that did not experience the intervention, plus weather and day characteristics, to estimate the counterfactual. The panel model estimates a counterfactual load using weather and loads for the matched control sites. A separate model is estimated for each hour of day. Reductions are the difference between the participant and counterfactual loads.	• All reductions are delivered only by connected devices. • Impacts are directly driven by connected thermostats controlling cooling loads, therefore ex ante impacts were estimated as a function of cooling loads on a per thermostat basis.
AC Saver Day Ahead Residential	Ex-Post/Ex-Ante: Panel Regression with a multiple matched control group	The approach is implemented on a time series of individual customer loads. It relies on multiple non-equivalent control sites that did not experience the intervention, plus weather and day characteristics, to estimate the counterfactual. The panel model estimates a counterfactual load using weather and loads for the matched control sites. A separate model is estimated for each hour of day. Reductions are the difference between the participant and counterfactual loads.	• A failure rate of 8.16% is assumed for the residential ACSDA program.
AC Saver Day Of Commercial	Ex-Post: Statistical matching design	Under the matching design, a matched control selected for all the commercial AC Saver Day Of program participants. This approach was chosen for the commercial segment due to the smaller size of the program population and the larger relative effect of holding back a control group from program from program dispatch.	• Commercial snapback is assumed to be zero. • Enrollment is projected to decrease over the next few program years.

Table 4-1 continued: Summary of Analysis Methodologies by Program

Program	Method	Evaluation	Key Assumptions
AC Saver Day Of Residential	Ex-Post: Randomized Controlled Trial (RCT)	Random samples of residential AC Saver Day Of customers were selected from each cycling strategy.	• Enrollment is projected to decrease over the next few program years. • Snapback for residential customer was calculated based on cycling strategy.
Base Interruptible Program	Ex-Post: Regression analysis of customer-level hourly load data	BIP load impacts for each event were obtained by summing the estimated hourly event coefficients from the customer-level regressions.	• Average program FSL achievement rate is assumed • Enrollment increases by one each year until 2022, then remains constant
Capacity Bidding Commercial CBP	Ex-Post/Ex-Ante: Customer-specific regression models as the primary evaluation method	Customer-specific regressions allow for granularity in the results and can readily be used to control for variables such as weather, geography, and time, as well as for unobservable customer-specific effects.	• Enrollment to increase 3% annually from 2020-2022 based on improvements made to the program. • Day Of enrollment to increase by 1% based on the TI program.

Table 4-1 continued: Summary of Analysis Methodologies by Program

Load Modifying Demand Response (Dynamic and TOU Rates)			
Program	**Method**	**Evaluation**	**Key Assumptions**
Critical Peak Pricing CPP	Ex-Post: Within Subjects	The within subjects design leverages the participant's own load on event-like days to estimate the reference load	• No CPP events were called in 2019
Default Residential Time-Of-Use: Rate 1	Ex-Post: Matched control group using propensity score matching Ex-Ante impact estimates were developed using a multi-step process.	In this procedure, a probit model is used to estimate a score for each customer based on a set of observable variables. A probit model is a regression model designed to estimate probabilities.	• A match within specific customer segments: climate zone, CARE/FERA and account enrollment status was performed.
Default Residential Time-Of-Use: Rate 2	Ex-Post: Randomized encouragement experimental design (RED) Ex-Ante impact estimates were developed using a multi-step process.	This study sample is randomly divided into two groups. One group is offered the treatment and the other is not. The group offered the treatment is referred to as the encouraged group and the group not offered the treatment is referred to as the control group.	• Some people in the encouraged will accept the treatment and others will not.
Default Small Commercial CPP	Ex-Post/Ex-Ante: In program year 2018 analysis propensity score matching was used to select a matched control group	This method was used to select a matched control of about 115,000 TOU-CPP sites. A difference-in-difference panel regression model with fixed effects was then used to assess impacts and standard errors.	• No CPP events were called in 2019 • Program year 2018 impacts were used to estimate ex ante impacts.
Electric Vehicle Time-Of-Use: EVTOU2 & EVTOU5	Ex-Post: Difference-in-difference analysis method	Difference-in-difference analysis involve selecting quasi-experimental matched control groups and then comparing the usage of treatment and control group customers on relevant days or time periods, where the comparisons are then adjusted by usage differences on pre-treatment or non-event days.	• To calculate TOU load impacts for EVTOU2 and EVTOU5 customers, seasonal percentage peak load impacts from the ex-post analysis are applied to weather-sensitive reference loads that are developed.
Voluntary Residential CPP & TOU	Ex-Post: Difference-in-Difference analysis method Ex-Ante: Program year 2018 event load impacts are applied for 2019	Selects a quasi-experimental matched control groups, comparing the usage of treatment and control group customers on relevant days or time periods, comparisons are then adjusted by usage difference on pre-treatment or non-event days.	• No CPP events were called in 2019 • The proportion of NEM customers is assumed to remain constant

5. Ex-Post Load Impact Estimates

Ex-post load impact results are calculated for each demand response event that was initiated during the previous event year. Table 5-1 below shows the average load reduction for each demand response activity. When looking at these results it's important to keep in mind that each DR activity is unique, and dispatches can be based on multiple factors. DR activities vary in the number of participants, the number of events called and not all of SDG&E's DR is weather sensitive. Though some load impacts might be smaller than others, each DR activity faces challenges, like AC Saver Day Ahead. SDG&E's AC Saver Day Ahead program's impacts only measure connected devices which is only a subset of all the participants. SDG&E has learned that devices can be disconnected for a variety of reasons. It can be simple as a change in a Wi-Fi password, or the customer installs a new router and forgets to set up the communicating thermostat. As a result, in those cases the thermostats are not dispatched and therefore add no value to the load impacts.

Table 5-1: Summary of 2019 SDG&E Average Demand Response Events by Date and Program

Supply Side Demand Response							
Program	Reference Load	Load with DR	Load Impact per Customer	% Load Impact	Aggregate Impact	Accounts Called	Number of Events
AC Saver Day Ahead Commercial	18.75 MWh	18.23 MWh	0.36 kWh	2.80%	0.52 MWh	1,452	1
AC Saver Day Ahead Residential	21.53 MWh	17.77 MWh	0.22 kWh	17.40%	3.76 MWh	17,197	20
AC Saver Day Of Commercial	22.58 MWh	22.24 MWh	0.09 kWh	1.5%	0.33 MWh	3,707	20
AC Saver Day Of Residential	10.22 MWh	9.31 MWh	0.115 kWh	8.9%	0.91 MWh	7,913	20
Base Interruptible Program	3.4 MWh	0.5 MWh	573 kWh	84.8%	2.9 MWh	5	1
Capacity Bidding Program	28.4 MWh	24.4 MWh	20.1 kWh	14%	4 MWh	200	23

Table 5-1 continued: Summary of 2019 SDG&E Average Demand Response Events by Date and Program

Load Modifying Demand Response (Dynamic and TOU rates)							
Critical Peak Pricing	No CPP Events Called					1,620	0
Default Small Commercial CPP	No CPP Events Called					111,149	0
Voluntary Residential CPP & TOU	No CPP Events Called					6,277	0
Electric Vehicle Time-Of-Use: EVTOU2	11.16 MWh	10.29 MWh	0.10 kWh	7.67%	0.87 MWh	8,442	TOU
Electric Vehicle Time-Of-Use: EVTOU5	7.62 MWh	5.69 MWh	0.33 kWh	25.70%	1.93 MWh	5,742	TOU
Default Residential Time-Of-Use: Rate 1	515.61 MWh	508.65 MWh	0.01 kWh	1.1 %	6.96 MWh	696,775	TOU
Default Residential Time-Of-Use: Rate 2	13.01 MWh	12.78 MWh	0.01 kWh	1.8%	0.23 MWh	16,942	TOU

6. Ex-Ante Load Impacts

This section presents PY19 ex ante load impact estimates for SDG&E's portfolio. Ex ante load impacts represents weather conditions under normal (1-in-2 year) and extreme (1-in-10 year) conditions when SDG&E system peaks according to DR Load Impact Protocols and Regulatory Guidance.[13] Normal conditions are defined as those that would be expected to occur once every 2 years (1-in-2 conditions) and extreme conditions are defined as those that would be expected to occur once every 10 years (1-in-10 conditions).

The load impact estimates for each program align with the peak period now used for resource adequacy planning, which is 4 to 9 PM, year-round.

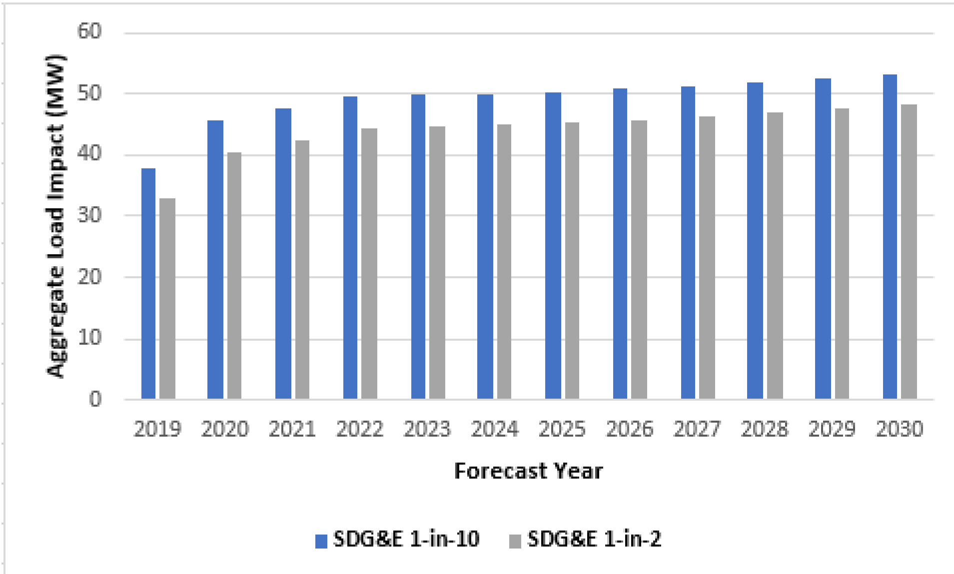
6.1 Projected Change in PY19 Portfolio Load Impacts from 2019–2030

Figure 6-1 presents the portfolio-adjusted aggregate load impact estimates for the August system peak day under 1-in-2 and 1-in-10 SDG&E weather conditions.

Overall, SDG&E's portfolio is projected to increase by 16% from 2020 to 2030 (from 46 MW in 2020 to 53 MW in 2030) under 1-in-10 weather conditions. On the other hand, SDG&E's portfolio is projected to increase by 19% from 2020 to 2030 (from 41 MW in 2020 to 48 MW in 2030) under 1-in-2 weather conditions.

[13] DR Load Impact Protocols and Regulatory Guidance (Protocols 17-23) by CPUC (Apr 2008) - page 93-110

Figure 6-1: Projected Change in PY19 Portfolio Load Impacts from August 2019–2030

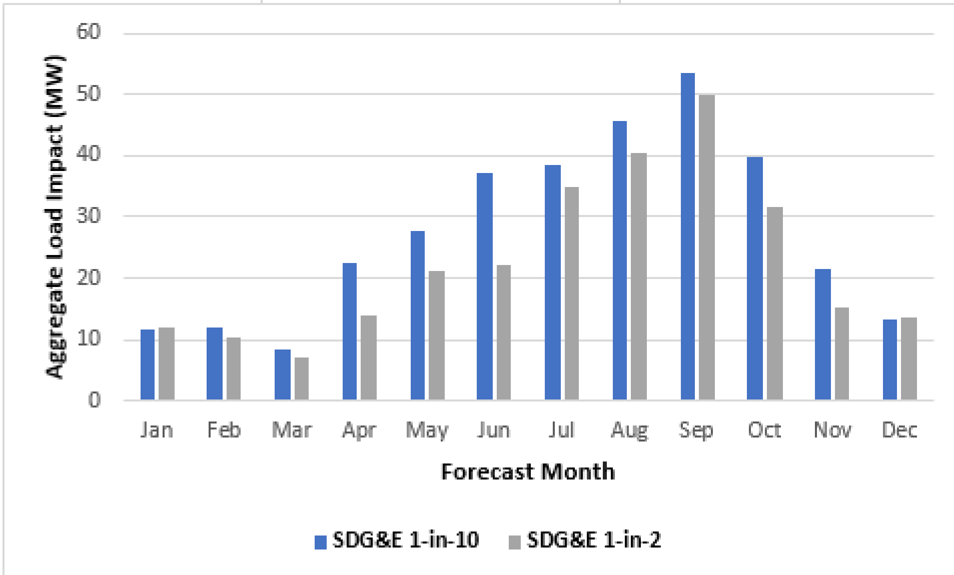


6.2 2020 Portfolio Aggregate Load Impacts by Month

Figure 6-2 shows the 2020 load impact estimates under 1-in-2 and 1-in-10 SDG&E weather conditions. The impacts across the 12 months vary for summer versus winter months. Winter months show a lower reduction due to load modifying and supply side programs provide significant load impact reductions only during summer months.

In 2020, SDGE's DR portfolio projects 54MW of load reduction during the September monthly system peak day under SDGE's 1-in-10 weather conditions. The months of June, July, and August load impacts are little bit smaller than the month of September delivering 37, 39, and 46 MW respectively under SDGE's 1-in-10 conditions.

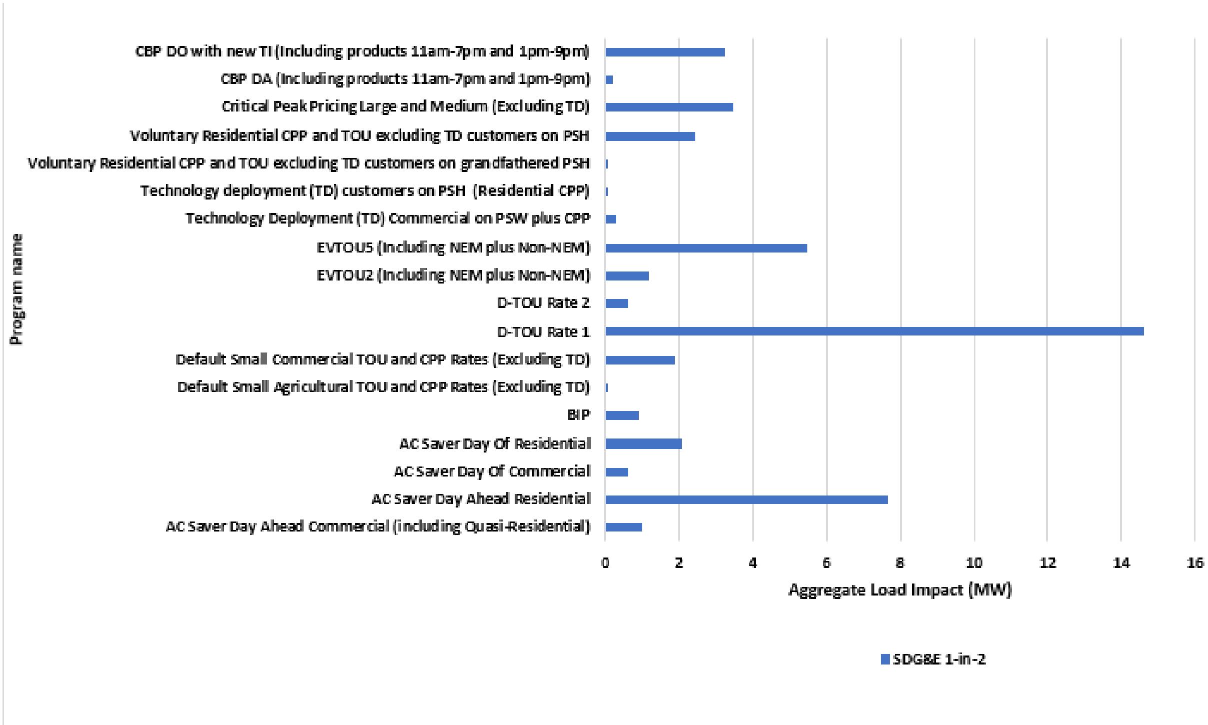
Figure 6-2: PY19 Portfolio Aggregate Ex Ante Load Impact Estimates (MW) for the year of 2020 by 1-in-2 and 1-in-10 SDG&E-specific System Conditions and Monthly System Peak Day



6.3 Portfolio Load Impacts by Program Type

Figure 6-3 shows the distribution of portfolio aggregate load impacts by program type in August 2020. In August 2020, the load impacts from price responsive programs are forecast to comprise 43% of SDGE's DR portfolio, 48% from non-event programs and 8% from aggregator and 2% from emergency programs. A greater percentage of load impacts are projected to come from D-TOU Rate 1 followed by AC Saver Day Ahead Residential. The smaller impacts come from Default Small Agricultural TOU and CPP Rates (Excluding TD) and Technology deployment (TD) customers on PSH (Residential CPP).

Figure 6-3: Distribution of PY19 Portfolio Aggregate Load Impacts by Program Type 2020 August System Peak Day under 1-in-2 SDG&E-specific System Conditions



6.4 Portfolio Load Impacts by Program

Table 6-4 summarizes the portfolio load impacts by program for 2019 through 2030 under 1-in-2 SDG&E weather conditions.

In August 2030, the load impacts from load modifying programs are forecast to comprise 78% of SDGE's DR portfolio and 22% from supply side programs.

The supply side programs are divided into three groups: emergency programs, price responsive and aggregator DR. The load impacts from emergency programs are forecast to comprise 10% of SDGE's DR supply side portfolio. The price responsive programs represent 56% of SDGE's DR supply side portfolio and most of this percentage is derivate from AC Saver Day Ahead Residential. The aggregator DR represents 34%, the majority of this percentage is attribute of CBP DO with new TI (Including products 11am-7pm and 1pm-9pm).

Table 6-4: Portfolio Aggregate PY19 Load Impact Estimates (MW) for the August System Peak Day Under 1-in-2 SDG&E-specific System Conditions by Program and Forecast Year

Supply Side	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Supply Side Total MWs	13.17	14.03	14.83	15.55	14.69	13.92	13.22	12.58	12.01	11.49	11.02	10.59
Emergency	0.79	0.89	0.99	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09
BIP	0.79	0.89	0.99	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09
Price Responsive	9.04	9.70	10.33	10.89	10.03	9.26	8.56	7.92	7.35	6.83	6.35	5.92
AC Saver Day Ahead Commercial (including Quasi-Residential)	0.75	0.88	1.00	1.10	0.93	0.78	0.66	0.55	0.47	0.39	0.33	0.28
AC Saver Day Ahead Residential	5.92	6.60	7.21	7.75	7.07	6.44	5.86	5.33	4.84	4.40	3.99	3.61
AC Saver Day Of Commercial	0.56	0.53	0.52	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
AC Saver Day Of Residential	1.82	1.68	1.61	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54
Aggregator DR	3.34	3.43	3.50	3.57	3.57	3.57	3.57	3.57	3.57	3.57	3.57	3.57
CBP DA (Including products 11am-7pm and 1pm-9pm)	0.21	0.21	0.21	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22
CBP DO with new TI (Including products 11am-7pm and 1pm-9pm)	3.13	3.23	3.29	3.36	3.36	3.36	3.36	3.36	3.36	3.36	3.36	3.36

The load modifying programs are divided into two groups: price responsive programs and non-event based. The load impacts from price responsive programs are forecast to comprise 22% of SDGE's DR load modifying portfolio where the greater percentage of load impacts are projected to come from Voluntary Residential CPP and TOU excluding Technology Deployment (TD) customers on PSH. The load impacts from non-event based are forecast to embrace 78% of SDGE's DR load modifying portfolio most of this percentage is related to D-TOU Rate 1.

Table 6-4 Continued: Portfolio Aggregate PY19 Load Impact Estimates (MW) for the August System Peak Day Under 1-in-2 SDG&E-specific System Conditions by Program and Forecast Year

Load Modifying	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Load Modifying Total MWs	19.79	26.56	27.66	28.75	29.86	30.97	32.08	33.20	34.29	35.45	36.63	37.82
Price Responsive	6.71	6.88	6.92	7.02	7.16	7.30	7.43	7.58	7.70	7.88	8.08	8.30
Critical Peak Pricing Large and Medium (Excluding TD)	2.12	2.18	2.23	2.32	2.42	2.50	2.57	2.64	2.72	2.79	2.87	2.95
Default Small Agricultural TOU and CPP Rates (Excluding TD)	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Default Small Commercial TOU and CPP Rates (Excluding TD)	1.97	1.91	1.85	1.79	1.73	1.68	1.63	1.57	1.52	1.47	1.43	1.38
Technology Deployment (TD) Commercial on PSW (Small Commercial CPP) plus CPP (Large and Medium)	0.30	0.23	0.17	0.11	0.08	0.06	0.04	0.02	0.01	0.00	0.00	0.00
Technology deployment (TD) customers on PSH (Residential CPP)	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.06
Voluntary Residential CPP and TOU excluding Technology Deployment (TD) customers on grandfathered PSH	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05				
Voluntary Residential CPP and TOU excluding Technology Deployment (TD) customers on PSH	2.23	2.46	2.58	2.70	2.83	2.96	3.10	3.24	3.39	3.55	3.72	3.90
Non-event based	13.07	19.68	20.74	21.74	22.70	23.68	24.65	25.62	26.59	27.57	28.55	29.53
D-TOU Rate 1	12.51	12.67	12.89	13.04	13.17	13.30	13.44	13.57	13.71	13.85	13.99	14.13
D-TOU Rate 2	0.56	0.56	0.57	0.57	0.56	0.56	0.55	0.55	0.54	0.54	0.53	0.52
EVTOU2 (Including NEM plus Non-NEM)		1.15	1.14	1.14	1.14	1.13	1.13	1.12	1.12	1.11	1.11	1.11
EVTOU5 (Including NEM plus Non-NEM)		5.29	6.14	6.99	7.84	8.68	9.53	10.38	11.23	12.07	12.92	13.77
Supply Side plus Load Modifying Total MWs	**32.95**	**40.58**	**42.49**	**44.30**	**44.56**	**44.89**	**45.30**	**45.79**	**46.30**	**46.94**	**47.65**	**48.41**

Table 6-5 summarizes the portfolio number of customers forecasted by program for 2019 through 2030 under 1-in-2 SDG&E weather conditions.

The supply side programs are divided into three groups: emergency programs, price responsive and aggregator DR. The customers from emergency programs are forecast to comprise 0.02% of SDGE’s DR supply side portfolio. The price responsive programs represent 99.4% of SDGE’s DR supply side portfolio and most of this percentage is derivate from AC Saver

Day Ahead Residential. The aggregator DR represents 0.54%, the majority of this percentage is attribute of CBP DO with new TI (Including products 11am-7pm and 1pm-9pm)

In August 2030, the number of customers from load modifying programs are forecast to comprise 96% of SDGE's DR portfolio and 4% from supply side programs.

As was presented in the ex ante load impacts, the load modifying programs are divided into two groups: price responsive programs and non-event based. The customers from price responsive programs are forecast to comprise 12% of SDGE's DR load modifying portfolio where the greater percentage of the number of customers are projected to come from Default Small Commercial TOU and CPP Rates (Excluding TD) customers. The customers from non-event based are forecast to embrace 88% of SDGE's DR load modifying portfolio the majority of this percentage is related to D-TOU Rate 1.

Table 6-5: Portfolio Aggregate PY19 number of customers forecasted for the August System Peak Day Under 1-in-2 SDG&E-specific System Conditions by Program and Forecast Year

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Supply Side	32,139	34,209	36,564	38,943	38,943	38,943	38,943	38,943	38,943	38,943	38,943	38,943
Emergency	5	5	6	7	7	7	7	7	7	7	7	7
BIP	5	5	6	7	7	7	7	7	7	7	7	7
Price Responsive	31,939	34,003	36,354	38,727	38,727	38,727	38,727	38,727	38,727	38,727	38,727	38,727
AC Saver Day Ahead Commercial (including Quasi-Residential)	1,524	1,592	1,660	1,728	1,728	1,728	1,728	1,728	1,728	1,728	1,728	1,728
AC Saver Day Ahead Residential	18,892	21,581	24,271	26,960	26,960	26,960	26,960	26,960	26,960	26,960	26,960	26,960
AC Saver Day Of Commercial	3,719	3,558	3,452	3,349	3,349	3,349	3,349	3,349	3,349	3,349	3,349	3,349
AC Saver Day Of Residential	7,804	7,272	6,971	6,690	6,690	6,690	6,690	6,690	6,690	6,690	6,690	6,690
Aggregator DR	195	201	205	209	209	209	209	209	209	209	209	209
CBP DA (Including products 11am-7pm and 1pm-9pm)	11	11	11	12	12	12	12	12	12	12	12	12
CBP DO with new TI (Including products 11am-7pm and 1pm-9pm)	184	190	193	197	197	197	197	197	197	197	197	197

Table 6-5 Continued: Portfolio Aggregate PY19 number of customers forecasted for the August System Peak Day Under 1-in-2 SDG&E-specific System Conditions by Program and Forecast Year

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Load Modifying	866,528	891,459	902,422	909,440	915,372	921,521	927,890	934,483	940,351	947,401	954,678	962,184
Price Responsive	141,663	139,535	136,713	134,061	131,635	129,349	127,207	125,210	122,411	120,714	119,165	117,765
Critical Peak Pricing Lrg & Med (Excluding TD)	14,288	14,190	14,085	13,999	13,923	13,839	13,749	13,659	13,574	13,491	13,410	13,330
Default Small Agricultural TOU and CPP Rates (Excluding TD)	124	120	116	113	109	105	102	99	96	93	90	87
Default Sm Com TOU and CPP Rates (Excluding TD)	111,149	107,603	104,170	100,846	97,629	94,514	91,498	88,579	85,753	83,017	80,369	77,804
TD Commercial on PSW (Sm Com CPP) + CPP (Lrg & Med)	1,744	1,677	1,611	1,544	1,544	1,544	1,544	1,544	1,544	1,544	1,544	1,544
TD customers on PSH (Residential CPP)	530	599	630	663	698	734	773	813	856	901	948	998
Voluntary Residential CPP and TOU excluding TD customers on grandfathered PSH	941	954	954	954	954	954	954	954				
Voluntary Residential CPP and TOU excluding TD customers on PSH	12,887	14,392	15,147	15,942	16,779	17,659	18,586	19,561	20,588	21,668	22,805	24,002
Non-event based	724,865	751,925	765,709	775,379	783,737	792,172	800,684	809,273	817,940	826,687	835,513	844,419
D-TOU Rate 1	696,194	705,185	717,123	725,559	732,848	740,210	747,646	755,157	762,743	770,405	778,145	785,962
D-TOU Rate 2	28,671	28,704	29,190	29,066	28,776	28,490	28,206	27,925	27,647	27,372	27,100	26,830
EVTOU2 (Including NEM plus Non-NEM)		9,445	9,407	9,370	9,332	9,295	9,257	9,220	9,182	9,145	9,107	9,070
EVTOU5 (Including NEM plus Non-NEM)		8,591	9,988	11,385	12,781	14,178	15,574	16,971	18,368	19,764	21,161	22,557
Supply Side plus Load Modifying Total number of customers	**898,667**	**925,668**	**938,986**	**948,382**	**954,315**	**960,464**	**966,833**	**973,425**	**979,294**	**986,343**	**993,621**	**1,001,127**

7. Recommendations

The 2019 DR program evaluations contain the evaluators' recommendations for each program. The recommendations pertain to steps that can be taken to improve the measurement and evaluation of DR resources and to improve program performance. This section summarizes the recommendations for each program.

7.1 Supply Side Demand Response

7.1.1 Emergency Programs

7.1.1.1 Base interruptible program (BIP)

The following recommendation was made by Christensen:[14]

BIP continues to perform well, with its customers providing substantial load impacts with short notice. SDG&E may want to consider calling earlier events to ensure that its customers are capable of consistently meeting their obligation during hours in which their loads are above their FSL. However, this decision is likely offset by the need to call events during the RA window.

7.1.2 Aggregator Programs

7.1.2.1 Capacity Bidding Program (CBP)

AEG has the following recommendations for future research and evaluation related to the Capacity Bidding Programs: [15]

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

[14] 2019 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers: Ex-post and Ex-ante Report by Christensen (Mar 2020) – page 51

[15] 2019 Statewide Load Impact Evaluation of California Capacity Bidding Programs by AEG (Mar 2020)

the average event day), having these monthly comparisons are also quite telling of the program's success.

7.1.3 Price Responsive Programs

7.1.3.1 AC Saver Day Ahead commercial and residential programs

DSA made the following recommendation[16]:

- **If possible, avoid bidding sites that lack connected thermostats into the CAISO markets**. Sites with loads that cannot be controlled or dispatched do not deliver any detectable demand reduction. They simply dilute the demand reductions and make them harder to detect.
- **Test different ways to nudge customers with disconnected thermostats to reconnect them.** Only connected thermostats deliver reductions and roughly half of installed thermostats are now disconnected. Without an intervention, a larger share of those devices will become disconnected as more time elapses. In specific, we recommend randomized control trial four different groups:
    - Control (n = 100)
    - Postcard or letter reminder (n = 100)
    - Postcard or letter reminder + follow up phone call (n = 100)
    - Postcard or letter reminder + incentive (n =100)
    - Postcard or letter reminder + follow up phone call + incentive (n=100)

  This will allow SDG&E to quantify how well different methods work at getting customers to reconnect and assess their cost-effectiveness.

7.1.3.2 AC Saver Day Of commercial and residential programs

Nexant made the following recommendations: [17]

- In order to ensure that the program's direct load control devices are dispatching during events and producing load reductions, a field study should be conducted that examines the fleet of devices for functionality, prioritizing those that have been installed for the longest period of time. Alternatively, a data-based analysis could be designed that uses clustering or similar techniques to identify specific devices that do not exhibit evidence of cycling during program events.

[16] SDG&E Small Commercial Time Varying Pricing and Technology Deployment Evaluation for Program Year 2019 by DSA (Mar 2020) -page 44

[17] AC Saver Day Of 2019 Load Impact Program Evaluation by Nexant (Mar 2020) -page 52&53

- The possibility of low or negative impacts should be considered when calling events after a long period of cool weather
- The possibility of large-scale de-enrollments should be considered when calling AC Saver Day Of events on consecutive days.

7.2 Load Modifying DR

7.2.1 Price responsive Programs

7.2.1.1 *Critical Peak Pricing (CPP):*

AEG has developed three recommendations for future research and evaluation related to the non-residential CPP programs:[18]

- **Investigate the experiences of small and medium participants**. Through future or ongoing process evaluations, ensure that special care is taken to better understand the experiences of small and medium customers on the CPP rates. Participant surveys and focus groups can be used to understand aspects of participation including, awareness and understanding of the rate, awareness of participation, awareness of events, ability to respond to events, and actions taken during events. Conducting research while maintaining statistically significant samples by key industry group and size may provide invaluable insights for both program staff and future impact evaluations.
- **Investigate the effect of notifications on customer impacts**. Again, through the use of participant surveys and/or focus groups, conduct research to better understand participant choices regarding notification, their awareness of notifications, and how they respond to notifications on event days.
- **Consider opportunities to improve robustness of within-subjects designs**. For most of the subgroups, we elected not to develop a matched control group for this evaluation because of the small ratios of participants to non-participants and the opt-out nature of the CPP/PDP rates which would likely lead to poor matches and introduce self-selection bias. Unfortunately, the within-subjects design may also have led to the introduction of bias, particularly among those groups with very small

[18] 2019 Statewide Load Impact Evaluation of California Non-Residential Critical Peak Pricing Programs Ex-Post and Ex-Ante Load Impacts by AEG (Mar 2020) – page 80

impacts due to a lack truly comparable event like days. Since all utilities expect their participant population to grow (and the non-participant pools to continue to shrink) we recommend considering the following opportunities to mitigate this bias in the future. We propose two options for consideration:

- **Intentionally call test events on cooler days and, unless absolutely necessary, try not to call events on all the hottest days of the season**. This will provide the models with better information as to how participants would behave during events on a wider range of temperatures and improve their performance.
- **Consider using the non-notified participants as a control group for the notified participants when appropriate**. This would accurately estimate the incremental effect of notification, rather than the overall program impact, but this may not be undesirable given that we know the impacts for non-notified customers are very small.

7.2.1.2 Default Small Commercial CPP:

SDG&E did not trigger any CPP events in 2019, however DSA has two recommendations from PY18:[19]

- Assess if additional communications encouraging response improve reductions using randomized controlled trials. The magnitude of demand reductions during events is small on a percentage basis, about 1%, providing ample room to improve reductions. Additional communications require resources and their effectiveness at improving price response is unknown. Because of the potential, however, we recommend testing the effectiveness of more education regarding event response. It is critical, however, for the test to be implemented using randomized control trials, so it is possible to assess if the communications had any impact on price response.
- Notification rates for small CPP can be improved further. Customers elect whether or not to sign up for notifications and by which channels they receive notification.

[19] SDG&E Small Commercial Time Varying Pricing and Technology Deployment Evaluation for Program Year 2019 by DSA (Mar 2020) -page 45

Because notification is closely linked to response, additional efforts to improve notification rates are recommended. From 2016 to 2017, the notification rate improved from under 25% to 44%. Because many customers have multiple sites (and don't always sign up all sites), customers for roughly 60% sites received notification. Despite the improvement, there is further room to improve notifications. Notification rate remained largely unchanged in PY 2018.

7.2.1.3 Voluntary Residential CPP and TOU

According to Christensen, the rising level of residential customers being defaulted onto a TOU rate limits the experimental leverage of estimating TOU load impacts for future program years. Specifically, customers enrolled on a standard tiered rate have served as potential control group customers that provide counterfactual usage. Without a suitable control group, TOU estimates may be more susceptible to between year usage changes that are caused by unobserved (to the researcher) factors[20].

7.2.2 Nonevent Based Programs

7.2.2.1 Electric Vehicle Time of Use

The ability to reliably estimate TOU load impacts for EV customers depends on knowing when the customer acquired and began charging the EV. In the absence of this information, the analysis runs the risk of confounding TOU price response with load changes due to EV adoption. While we believe we have developed a method that effectively identifies customers who have had an EV during our entire analysis period (before and after switching to an EVTOU rate), it would be helpful for SDG&E to consider whether it is feasible to collect additional information on customer EV adoption dates[21].

[20] 2019 Load Impact Evaluation of San Diego Gas and Electric's Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates by Christensen (Mar 2020) – page 59

[21] 2019 Load Impact Evaluation of San Diego Gas and Electric's Electric Vehicle Rates by Christensen (Mar 2020) – page 46

7.2.2.2 Residential Default TOU

The following recommendations were made by Nexant:[22]

During SDG&E's Default TOU Pilot, a portion of customers were set aside to act as a control group in order to allow for estimation of load impacts under a Randomized Encouragement Design evaluation framework. Now that SDG&E has completed the customer transition to default TOU rates, there are no longer any customers available to serve as a valid control group to estimate load impacts under a similar evaluation framework.

The Default TOU load impact evaluation has shown that there are statistically significant impacts to customer load attributable to the TOU rates; impacts that need to be properly accounted for in utility load forecasting for resource adequacy. In the future, these changes in residential customer load could be captured in several ways. Alternative ex post evaluation approaches could be considered, or the customer load under TOU rates could be moved outside of measurement & evaluation and become integrated into the residential load forecast.

[22] 2019 Load Impact Evaluation of San Diego Gas and Electric's Residential Default Time-Of-Use Rates (Mar 2020) -page 55

Appendix A: Regression Specifications

A.1 Supply Side Demand Response

A.1.1 Emergency Programs

A.1.1.1 Base interruptible program (BIP)

The paragraphs below describe the ex-post and ex-ante methodologies[23]:

a) Ex-post

The following is a general form of the model that was separately estimated for each enrolled BIP customer. Table A.1-1 below describes the terms included in this equation for the observed demand in a given hour *h* and date *d:*

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

[23] 2019 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers: Ex-post and Ex-ante Report by Christensen (Mar 2020)

Table A.1-1: Descriptions of Variables included in the *Ex post* Regression Equation

Variable Name	Variable Description
Q_t	the demand in hour *t* for a BIP customer
The various *b*'s	the estimated parameters
$h_{i,t}$	an indicator variable for hour *i*, equal to one when *t* corresponds to hour *i* of a given day
BIP_t	an indicator variable for program event days
E	the number of program event days that occurred during the program year
$OtherEvt_{i,t}^{DR}$	an indicator variable for event day *DR* of other demand response programs in which the customer is enrolled (e.g. *DR* = CPP Event 1, CPP Event 2, ...)
$Weather_t$	the weather variables selected using our model screening process
$MornLoad_t$	a variable equal to the average of the day's load in hours 1 through 10 (may be excluded via model screening)
$DTYPE_{j,t}$	a series of indicator variables for each day of the week
MON_t, FRI_t,	indicator variables for Monday and Friday (Sunday hourly indicator variable are included in models that include weekend dates)
$MONTH_{j,t}$	a series of indicator variables for each month (model screening may include separate hourly profiles by month)
$SUMMER_t$	an indicator variable for the summer pricing season[24]
e_t	the error term

B) Ex-ante

Because BIP events may be called in any month of the year, separate regression models were estimated to allow for simulated winter reference loads. The winter model is shown below. This model is estimated separately from the summer *ex ante* model. It only differs from the summer model in two ways: it includes different weather variables; and the month dummies relate to a different set of months. Table A.1-2 describes the terms included in the equation.

[24] The summer pricing season is June through October for SDG&E.

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

Table A.1-2: Descriptions of Terms included in the *Ex ante* Regression Equation

Variable Name	Variable Description
Q_t	the demand in hour *t* for a customer enrolled in BIP prior to the last event date
The various *b*'s	the estimated parameters
$h_{i,t}$	an indicator variable for hour *i*, equal to one when *t* corresponds to hour *i* of a given day
BIP_t	an indicator variable for program event days
E	the number of program event days that occurred during the program year
$OtherEvt_{i,t}^{DR}$	an indicator variable for event day *DR* of other demand response programs in which the customer is enrolled (e.g. *DR* = CPP Event 1, CPP Event 2, ...)
$Weather_t$	the weather variables selected using our model screening process
$DTYPE_{j,t}$	a series of indicator variables for each day of the week
MON_t, FRI_t,	indicator variables for Monday and Friday
$MONTH_{j,t}$	a series of indicator variables for each month
e_t	the error term

A1.2 Aggregator Programs

A.1.2.1 Capacity Bidding Program (CBP)

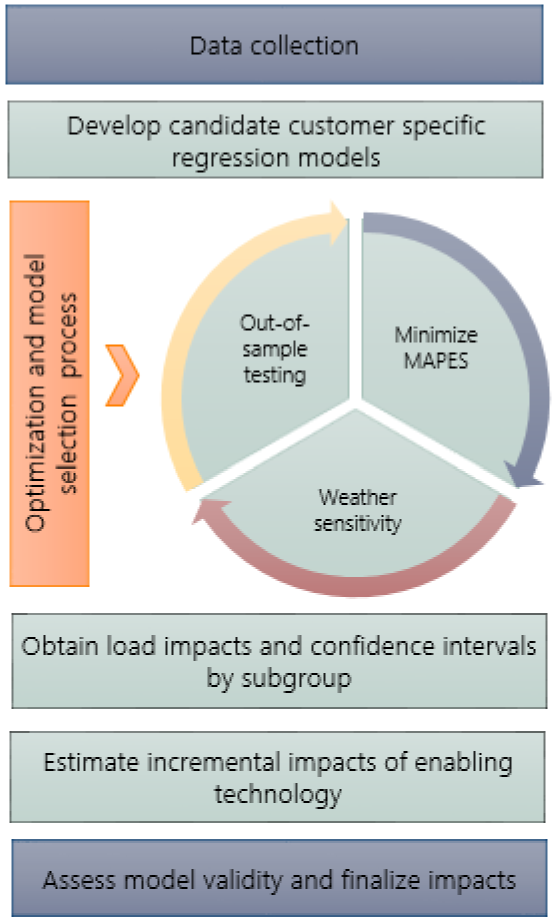
The paragraphs below describe the ex-post and ex-ante methodologies[25]:

a) Ex-post

[25] 2019 Statewide Load Impact Evaluation of California Capacity Bidding Programs by AEG (Mar 2020)

Figure A.2-1 illustrates a high-level overview of the approach AEG used to develop *ex post* impacts. The subsections that follow describe the process in more detail.

Figure A.2-1: *Ex post* Analysis Approach



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

Simple weather sensitive example:

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

where:

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

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

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

and, all other terms are defined above.

Simple non-weather sensitive example:

$$kwh_{i,d} = \alpha_{i,d} + MornLoad_{i,d} + DayofWeek_{i,d} + P_{i,d} + \varepsilon_{i,d}$$

where:

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

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

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

and, all other terms are defined **Error! Reference source not found.**above.

Table A.2-1 presents the different explanatory variables used to create candidate models for the CBP.

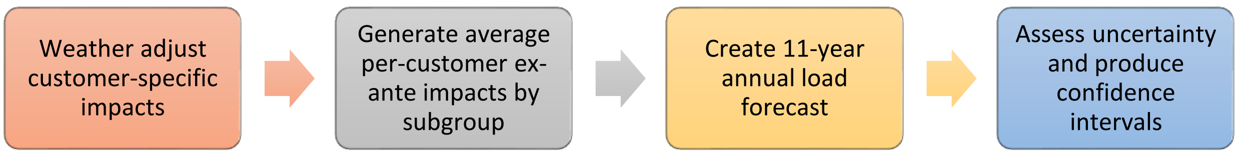
Table A.2-1: Explanatory Variables Included in Candidate Regression Models

Variable Name	Variable Description
Weatheri,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
Monthi,d	A series of indicator variables for each month
DayOfWeeki,d	A series of indicator variables for each day of the week
OtherEvti,d	Equals one on event days of other demand response programs in which the customer is enrolled
MornLoadi,d	The average of each day's load in hours 4 AM through 10 AM
MidLoadi,d	The average of each day's load in hours 10 AM through 2 PM
EveLoadi,d	The average of each day's load in hours 9 PM through 12 AM
	Impact Variables
Pi,d	An indicator variable for aggregator program event days
P * Monthi,d	An indicator variable for aggregator program event days interacted with the month
P*EventHouri,d	An indicator variable for aggregator program event days interacted with an indicator for the hour the event is called

b) Ex-ante

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

Figure A.2-1: *Ex ante* Analysis Approach



A.1.3 Price Responsive Programs

A1.3.1 AC Saver Day Ahead commercial and residential programs

Panel regressions with multiple control groups were used as the primary method for estimating load impacts for PY 2019 impacts for ACSDA. The use of a panel model allows for incorporation of multiple control sites and does not rely on finding a single ideal match. The equation for the model is presented below. A separate model was estimated for each intervention and hour of the day for each of the analysis segments identified as part of the evaluation plan. Pre and post event terms (single hour with two-hour buffer) were added to the Technology Deployment models to implement the same calibration for these load control programs[26]:.

$$kW_{i,t} = \mathrm{a} + \mathrm{b} \cdot kW\_1 - kW\_5_i + \sum_{n=1}^{max} \mathrm{c}_n \cdot Event_n + \mathrm{d} \cdot CDH_{i,t} + \delta_t + \varepsilon_{i,t}$$

Table A.3-1: Explanatory Variables included in Regression Models

Variable Name	Variable Description
$kW_{i,t}$	Is the usage for each individual customer and time period
a	Is the model intercept
b	Loads for the five most closely matched control sites based on Euclidean distance matching. They did not experience the treatment and are weighted based on their predictive power.
c	Controls for differences between event and non-event days

[26] SDG&E Small Commercial Time Varying Pricing and Technology Deployment Evaluation for Program Year 2019 by DSA (Mar 2020)

Table A.3-1 continued: Explanatory Variables included in Regression Models

Variable Name	Variable Description
d	Is the parameter for weather sensitivity of loads
Event	Is a binary variable indicating if day is an event. Separate variables are used for each event so impacts are estimated for each event. It has a value of zero on event-like proxy days. The five closest non-event days were included as proxy days for each event. Separate proxy days were selected for each event using Euclidean distance matching.
δ_t	Represents time effects for each time period. This accounts for observed and unobserved factors that vary by time but affect all customers equally.
$\varepsilon_{i,t}$	Represents the error term for each individual customer and time period.

A1.3.2 AC Saver Day Ahead commercial and residential programs

The paragraphs below describe the ex-post and ex-ante methodologies[27]:

a) Ex-post

Two distinct approaches were used for estimating the ex post reference loads: a randomized controlled trial (RCT) design and a statistical matching design. Residential customer impacts were estimated using an RCT. The commercial customer impacts were estimated with a matching study.

A matched control group was selected for the commercial program population whereby one nonparticipant was selected as a match for each participant on each event. The entire SDG&E small and medium business (SMB) customer population was made available for the statistical matching analysis. Each matched customer was chosen because they most closely resembled their matched participant in terms of the dissimilarity statistic described in the equation below:

Dissimilarity Statistic for Commercial Matching

$$Dissimilarity_i = \left(PeakProxy_i - PeakProxy_j\right)^2 + \left(EventMorn_i - EventMorn_j\right)^2 + \left(EventMidday_i - EventMidday_j\right)^2$$

[27] AC Saver Day Of 2019 Load Impact Program Evaluation by Nexant (Mar 2020)

Table A.4-1: Explanatory Variables included in Regression Models

Variable Name	Variable Description
$PeakProxy$	Average demand across the 2019 proxy days during the event window hours
$EventMorn$	Average demand on the event day from midnight to 10 AM
$EventMidday$	Average demand on the event day from 10 AM to the start of the event
$j\,j$	Commercial AC Saver Day Of participant to be matched
i	Index of the pool of control customers

Ex post event impacts were estimated for a broad collection of program segments including customer class, cycling strategy, NEM status, climate zone, industry, and status of dual-enrollment in other pricing and demand response programs at SDG&E.

Within each of these program segments, load impacts were estimated for each hour of each event day for both RCT and matched customers. The regression below essentially uses variation among the group that was not cycled to establish the relationship between the demand before the event and on proxy days and the demand during the event window and afterward.

LDV Model for Estimating Impacts

$$Demand_i = a + t * Cycled_i + b * Proxy_i + c * ProxyWindow_i + d * ProxyEve_i + e * EventMorn1_i + f * EventMorn2_i + g * EventMorn3_i + h * PreEvent_i + u_i$$

Table A.4-2: Explanatory Variables included in Regression Models

Variable Name	Variable Description
$Demand$	Average demand in the event hour being studied
$Cycled$	An indicator for whether customer *i* was cycled
$Proxy$	Average demand in the hour being studied on the average proxy day
$ProxyWindow$	Average demand in the event window on the average proxy day
$ProxyEve$	Average demand after the event window on the average proxy day
$EventMorn1$	Average demand from midnight to 7 AM on the event day
$EventMorn2$	Average demand from 7 AM to 10 AM on the event day
$EventMorn3$	Average demand from 10 AM to four hours before the event on the event day
$PreEvent$	Average demand during the four hours before the event
i	Customer index
t	Estimated impact
$a - h$	Estimated regression coefficients
u	Error term

b) Ex-ante

The methodology for estimating ex ante impacts in 2019 is the same for residential and commercial participants. The equation below presents the model that is used to predict average ex post impacts as a function of weather. This model is estimated separately by customer class (residential and commercial) and cycling strategy. The estimated parameters from the models are used to predict load impacts under 1-in-2 and 1-in-10-year ex ante weather conditions.

Ex Ante Model for Predicting Ex Post Load Impacts' Weather Response

$$impact_d = b_0 + b_1 \cdot mean17_{\mathrm{d}} + \varepsilon_d$$

Table A.4-3: Explanatory Variables included in Regression Models

Variable Name	Variable Description
$impact_d$	Core 2018-2019 ex post load impacts
b_0	Estimated constant
b_1	Estimated parameter coefficient
$mean17_d$	Average temperature over the first 17 hours of the day for each event day
ε_d	The error term for each day *d*

A.2 Load Modifying DR

A.2.1 Price responsive Programs

A.2.1.1 Critical Peak Pricing (CPP):

The paragraphs below describe the ex-post and ex-ante methodologies[28]:

a) Ex-post

The equation below illustrates a high-level overview of the approach AEG used to develop *ex post* impacts:

$$kwh_{it} = \beta_0 + \alpha_t + \delta_t + CDH_t + EVNT + (\alpha_t * EVNT) + \varepsilon_{it} \text{ s}$$

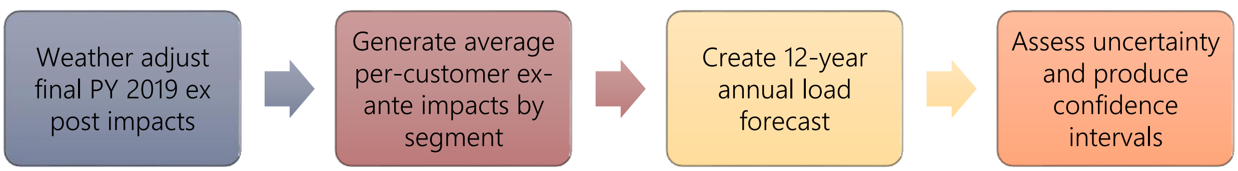
[28] 2019 Statewide Load Impact Evaluation of California Non-Residential Critical Peak Pricing Programs Ex-Post and Ex-Ante Load Impacts by AEG (Mar 2020)

Table A.5-1: Explanatory Variables included in Regression Models

Variable Name	Variable Description
kwh_{it}	is the consumption of customer i in hour t
β_0	is the intercept
α_t	is a vector of segment indicators, i.e. AutoDR, LCA, etc.
δ_t	is a vector of calendar variables, i.e. month, year, and day of week
CDH_t	represents the cooling degree hours for hour t
$EVNT$	is a dummy variable indicating that hour t was on a CPP or PDP event day
$(\alpha_t * EVNT)$	is an interaction between the event indicator and the segment indicator variables
ε_{it}	is the error for participant i in time t

b) Ex-ante

The figure below provides an overview of the ex-ante analysis approach.



A.2.1.2 Default Small Commercial CPP and TOU

The paragraphs below describe the ex-post and ex-ante methodologies[29]:

a) Ex-post

No CPP events were called in PY 2019 so there are no event impacts to assess.

b) Ex-ante

PY 2018 impacts were used to estimate ex ante impacts. The process of estimating ex ante impacts included five main steps:

1. Estimate the relationship between customer loads (absent DR) and weather

[29] SDG&E Small Commercial Time Varying Pricing and Technology Deployment Evaluation for Program Year 2019 by DSA (Mar 2020)

2. Use the models to predict customers loads (absent DR) for 1-in-2 and 1-in-10 weather year conditions

3. Apply the average percent reductions, at an hourly level, from historical events. The average reduction was employed because experience with small business default CPP is limited and there is less of a history of program performance across events.

4. Estimate reductions for 1-in-2 and 1-in-10 weather year conditions

5. Incorporate the enrollment forecast

A.2.1.3 Voluntary Residential CPP and TOU

The paragraphs below describe the ex-post and ex-ante methodologies[30]:

a) Ex-post

The equation below illustrates a high-level overview of the approach Christensen used to develop *ex post* impacts.

$$kWh_{c,d} = \beta_0 + \beta_1 \text{ x } (TOU_c \text{ x } Post_{c,d}) + \Sigma_{Cust} (\beta_{2,Cust} \text{ x } C_c) + \Sigma_{dates} (\beta_{3,dates} \text{ x } D_{dates})$$
$$+ \beta_4 \text{ x } Evt_{c,d} + \beta_5 \text{ x } AC\_Evt_{c,d} + \beta_6 \text{ x } TD\_Evt_{c,d} + \varepsilon_{c,d}$$

The variables and coefficients in the equation are described in Table A.7-1. Incremental customers are used to estimate the TOU load impacts in each regression. Results are then scaled to the program level of enrollments.

[30] 2019 Load Impact Evaluation of San Diego Gas and Electric's Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates by Christensen (Mar 2020)

Table A.7-1: Description of Variables Used in the TOU Analysis Regressions

Variable Name	Variable Description
$kWh_{c,d}$	Load in a particular hour for customer *c* on date *d*
TOU_c	Variable indicating whether customer *c* is a TOU or CPP (1) or Control (0) customer
$Evt_{c,d}$	Variable indicating whether date ***d*** is an event day for customer *c* [31]
$Post_{c,d}$	Variable indicating that date ***d*** is in the post-enrollment period for customer *c*
$TD\_Evt_{c,d}$	Variable indicating that date ***d*** is a *TD* event day (1= event, 0 if not) for customer *c*
$SS\_Evt_{c,d}$	Variable indicating that date ***d*** is an *AC Saver Day Of* event day (1=event, 0 if not) for customer *c*
β_0	Estimated constant coefficient
β_1	Estimate of TOU load impact
$\beta_{2,Cust}$ and $\beta_{3,date}$	Estimated customer and date fixed effects
β_4	Estimate of average event-day load impact
β_5 and β_6	Estimated average *TD* and SS event event-day load impacts
C_c	Variable indicating that the observation is associated with customer *c*
D_{date}	Variable indicating that the observation is for date *d*
$\varepsilon_{c,d}$	Error term

b) Ex-ante

SDG&E did not call any CPP in 2019, the *ex-ante* analysis for CPP events applies CPP event load impacts from PY2018 to reference loads calculated using PY2019 customer load data. The forecasts are based on analyses of per-customer load impact findings from *ex-post* evaluations, development of weather-sensitive reference loads, and incorporation of utility forecasts of program enrollments.

A.2.2 Nonevent Based Programs

A.2.2.1 Electric Vehicle Time Of Use

The paragraphs below describe the ex-post and ex-ante methodologies[32]:

a) Ex-post

The following regression specification is estimated for each customer separately to account for changes in their average daily consumption each week:

[31] For CPP customers, the *Evt* variable indicates that a day is a CPP event day. For TOU customers who are also enrolled to receive PTR-
RYU alerts, that variable indicates that a day is a PTR-RYU event day.

[32] 2019 Load Impact Evaluation of San Diego Gas and Electric's Electric Vehicle Rates by Christensen (Mar 2020)

$$kWh_w = \beta_0 + \beta_1 \times CDD60_w + \beta_2 \times HDD60_w + \Sigma_m (\beta_{3,m} \times Month_{w,m}) + \varepsilon_w$$

The variables and coefficients in the equation are described in the Table A.8-1.

Table A.8-1: Description of Variables Used in the Identification of Electric Vehicle Adoption Regressions

Variable Name	Variable Description
kWh_s	Average daily kWh during week *w* (weekends, holidays, and event days excluded)
$CDD60_w$	Average cooling degree days[33] during week *w*
$HDD60_w$	Average heating degree days[34] during week *w*
$Month_w$	Monthly indicator variables
β_0	Estimated constant coefficient
β_1	Estimated effect of *CDD60* on daily kWh
β_2	Estimated effect of *HDD60* on daily kWh
$\beta_{3,m}$	Estimated effect of month *m* on daily kWh
ε_w	Error term

b) Ex-ante

To calculate TOU ex-ante load impacts for EVTOU2 and EVTOU5 customers, seasonal percentage peak load impacts from the *ex-post* analysis are applied to weather-sensitive reference loads.

NEM customer reference loads and load impacts are estimated separately from non-NEM customers. Ex-post seasonal TOU load impacts are applied to reference loads and scaled to the count of enrolled customers. The proportion of NEM customers is assumed to remain constant throughout the forecast period. Non-NEM and NEM results are customer weighted to produce program TOU outcomes.

A.2.2.2 Default TOU

The paragraphs below describe the ex-post and ex-ante methodologies[35]:

a) Ex-post

[33] Cooling degree days (CDD) are defined as MAX[0, (Max Temp + Min Temp) / 2 – 60], where Max Temp is the daily maximum temperature in degrees Fahrenheit and Min Temp is the daily minimum temperature. Customer-specific CDD values are calculated using data from the most appropriate weather station.

[34] Heating degree days (HDD) are defined as MAX[0, 60 – (Max Temp + Min Temp) / 2], where Max Temp is the daily maximum temperature in degrees Fahrenheit and Min Temp is the daily minimum temperature. Customer-specific HDD values are calculated using data from the most appropriate weather station.

[35] Nexant has used similar model specifications in a number of load impact evaluations. It was originally chosen based on extensive validation analysis of many different model specifications conducted in conjunction with these prior evaluations.

Rate 1 Matched Control Group Methodology. Nexant developed a matched control group using propensity score matching. Nexant performed the match within specific customer segments: climate zone, CARE/FERA status, and My Account enrollment status. A typical regression specification for estimating impacts is shown below:

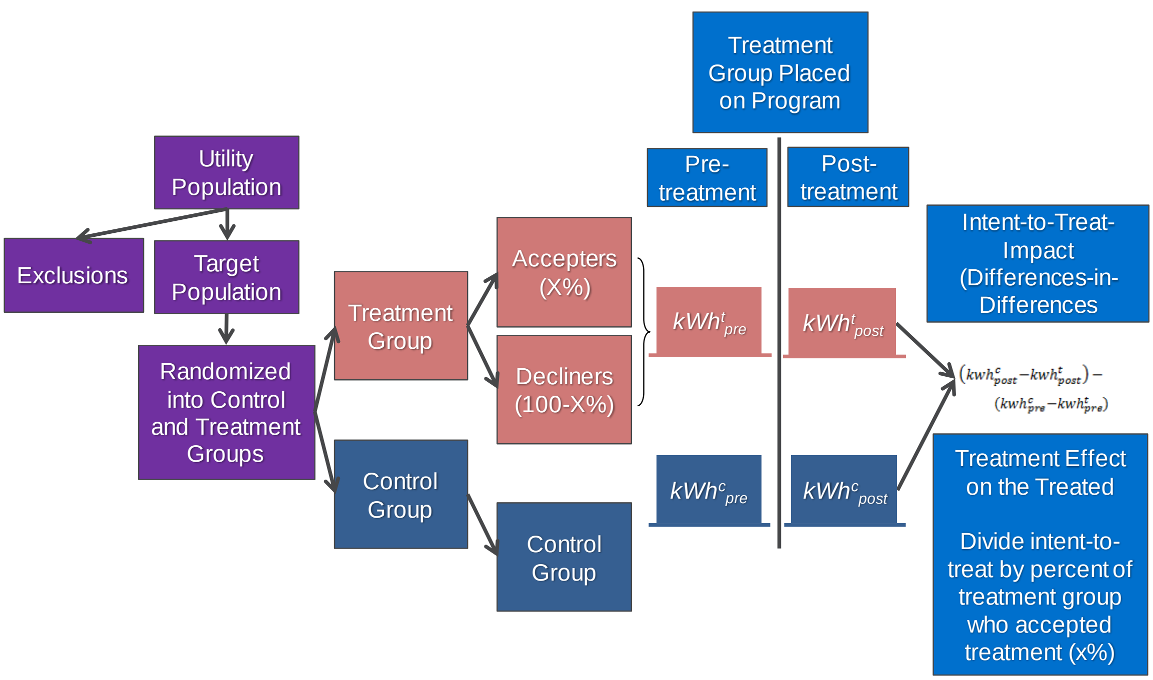
$$kW_{i,t} = \alpha_i + \delta \text{treat}_i + \gamma \text{post}_t + \beta(\text{treatpost})_{i,t} + \nu_i + \varepsilon_{i,t}$$

Rate 2 Randomized Encouragement Design (RED)

Rate 2 was analyzed as a RED. RED structure involving a single rate treatment of interest (for simplicity), the study sample is randomly divided into two groups. One group is offered the treatment and the other is not. The group offered the treatment is referred to as the encouraged group and the group not offered the treatment is referred to as the control group.

The first stage ITT impact was estimated using the same DiD analysis used for Rate 1. A conceptual overview of the RED design and analysis for estimating load impacts is shown in Figure .

Figure A.9-1 Design and Analysis Schematic for a RED Experiment



b) Ex-ante

Ex ante impact estimates were calculated by making predictions for ex ante weather conditions using a regression model of ex post impacts from 2018 and 2019. The ex ante model specification takes as its dependent variable the average hourly ex post impact for each week from November 2018 through October 2019. The independent variables for each hour were the average temperature from midnight to hour ending 17 (mean17) and a binary indicator for the calendar month. There is a positive relationship between temperature and load impacts; as temperatures rise, so do load impacts. The model specification is presented in the equation below:

Hourly Ex Ante Load Impact Model Specification

$$Impact_h = a + b \cdot mean17_h + \sum_{i=1}^{12} c_i \cdot month_{hi} + \boldsymbol{\varepsilon}$$

Table A.9-1: Description of Ex Ante Load Impact Regression Variables

Variable Name	Variable Description
$Impact_h$	Per customer ex post load impact for each week, for the hour h
a	Estimated constant
b	Estimated parameter coefficient
c	Estimated parameter coefficient
$mean17_h$	Average temperature from midnight to hour ending 17
$month_{hi}$	A binary indicator for each month *i* of the year, January through December, for the hour *h* of interest
$\boldsymbol{\varepsilon}$	The error term, assumed to be a mean zero and uncorrelated with any of the independent variables

References

Applied Energy Group (2020). “2019 Statewide Load Impact Evaluation of California Non-Residential Critical Peak Pricing Programs: Ex-Post and Ex-Ante”

Applied Energy Group (2020). “2019 Statewide Load Impact Evaluation of California Aggregator Demand Response Programs: Ex-Post and Ex-Ante Load Impacts”

Bode, Josh., Lemarchand, Alana. & Totten, Alaina. Demand Side Analytics (2020). “SDG&E Small Commercial Time Varying Pricing and Technology Deployment Program Year 2019”

Bode, Josh., Lemarchand, Alana. & Totten, Alaina. Demand Side Analytics (2020). “SDG&E Residential Technology Deployment Evaluation for Program Year 2019”

Clark, Michael T., Crowley, N., Armstrong D. & Hansen, D. & Clark, M. Christensen Associates (2020). “2019 Load Impact Evaluation of San Diego Gas and Electric’s Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates”

Clark, Michael T., Crowley, N., Hansen, D. & Clark, M. Christensen Associates (2020). “2019 Load Impact Evaluation of San Diego Gas and Electric’s Electric Vehicle Rates”

George, S., Bell, E., Savage, A. & Jiang, G., Nexant, Inc. (2020). “Default Time-of-Use 2019 Load Impact Program Evaluation”

Hansen, D., Clark, M. Christensen Associates (2020). “2019 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers: Ex-post and Ex-ante Report”

Potter, C., Jiang G. & Gottlieb, R., Nexant, Inc. (2020). “2019 Load Impact Evaluation of San Diego Gas and Electric’s AC Saver Day Of Program”