



**2020 Load Impact Evaluation of
San Diego Gas and Electric's
Voluntary Residential Critical
Peak Pricing (CPP) and Time-of-
Use (TOU) Rates**

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Abstract

This report documents *ex-post* and *ex-ante* load impact evaluations for San Diego Gas and Electric Company's ("SDG&E") voluntary residential time-of-use (TOU) and critical peak pricing (CPP) rates for 2020, along with their grandfathered counterparts. The two 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 the TOU and CPP rates are voluntary rates that became active in February 2015.

Both summer and winter TOU periods in the two 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. During the months of March and April, a super off-peak period is carved into the off-peak period between 10 a.m. and 2 p.m. Weekend and holiday hours are all off-peak. The analysis includes Net Energy Metered ("NEM") customers. These customers were estimated separately but included in the results for each rate using a customer-weighted average. Due to the growing proportion of residential solar customers on each rate, this year's protocol tables contain separate results for NEM and Non-NEM customers, along with combined results of all customers regardless of NEM status.

The analysis also evaluates load impacts for TOU-DR-P customers on a "grandfathered" rate, which maintains the time of use period before it was changed in December 2017. The "grandfathered" summer TOU periods in the two rates are centered around an on-peak period of 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. No additional customers may be added to the grandfathered rate after its inception.

Residential CPP events may be called during the 2 p.m. to 6 p.m. period on any day (including weekends) throughout the year. In 2020, SDG&E called nine CPP events, six on weekdays (August 17th, August 18th, August 19, August 20th, September 30th, and October 1st) and three on weekends or holidays (September 5th, September 6th, and September 7th).

The *ex-post* impact evaluations for the TOU and CPP rates apply difference-in-differences analysis methods that 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. The control groups were selected by matching each treatment customer to one of an initial sample of eligible non-treatment customers in relevant population segments (*e.g.*, climate zone, NEM, CARE status), based on the closest match of load profiles.

In 2020, the *ex-post* CPP average weekday load impacts (*i.e.*, all events) indicate that, on average, customers reduced their usage by 0.13 kW for customers in the Coastal climate zone, representing 13 percent of their reference load, and 0.23 kW, or 14 percent, for the Inland climate zone. CPP enrollment averaged 15,384 customers on the weekday event days, with a majority of customers in the Coastal climate zone. The aggregate reference load was 19.28 MW.

Among grandfathered customers, those in the Coastal climate zone *increased* their usage by 0.10 kW, and those in the Inland climate zone reduced their usage by 0.21 kW. CPP enrollment among grandfathered customers averaged 250 customers during the event days. The aggregate reference load was 0.30 MW.

TOU enrollment rose from 6,274 customers in October 2019 to 9,980 in September 2020. The estimated seasonal percentage load impacts were approximately a 5.2 percent *decrease* in summer and 0.5 percent *increase* in winter. Summer peak load impacts were slightly larger in percentage terms for the Inland climate zone. Combining results across months and considering the effect of TOU on average *daily* usage, we find that TOU customers *increased* their energy consumption by an annual average of approximately 2.5 percent.

Similarly, we evaluated the TOU load impacts for CPP customers. Enrollment in CPP grew from 11,838 in October 2019 to approximately 15,735 in September 2020. Summer TOU peak load impacts varied across months, with load reductions in all months except August. Load impacts in winter months were larger in percentage terms. Winter peak load impacts were similar between the Coastal and Inland climate zones, with Inland percentage load impacts slightly larger in both summer and winter. Summer peak load impacts were larger in the Coastal climate zone.

Among grandfathered customers, average enrollment in winter was 444 customers while average summer enrollment was 460 customers. Both Inland and Coastal grandfathered customers increased peak load usage during the summer season. During the winter, Coastal customers reduced usage slightly, while Inland customers increased usage.

Executive Summary

This report documents *ex-post* and *ex-ante* load impact evaluations for San Diego Gas and Electric Company's ("SDG&E") voluntary residential time-of-use (TOU) and critical peak pricing (CPP) rates for 2020. The two 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 the TOU and CPP rates are voluntary rates that became active in February 2015. In addition, this report includes *ex-post* and *ex-ante* load impacts for grandfathered customers on the rate GTOU-DR-P. Pursuant to D.17-01-006 and D.17-10-018, TOU Period Grandfathering permits certain eligible behind-the-meter solar customers to continue billing under grandfathered TOU period definitions until July 31, 2022.

ES.1 Resources Covered

The TOU periods for the two 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 weekend 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. SDG&E called nine CPP events in 2020: 8/17, 8/18, 8/19, 8/20, 9/5, 9/6, 9/7, 9/30, and 10/1. Three of the CPP events were called on weekends or holidays (9/5, 9/6, and 9/7).

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.

ES.2 Evaluation Methodologies

The *ex-post* impact evaluations for the TOU and CPP rates apply difference-in-differences analysis methods that 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. The control groups were selected by matching each treatment customer to one of an initial sample of eligible non-treatment customers in relevant population segments (*e.g.*, climate zone, CARE status, and solar PV size), based on the closest match of load profiles.

ES.3 Ex-Post Load Impacts

ES.3.1 CPP event load impacts (TOU-DR-P and GTOU-DR-P)

Table ES.1 summarizes average event-hour reference load and residential CPP load impact results for the residential CPP customers on the average weekday event in

2020.¹ Results are shown by Coastal and Inland climate zones. The first two columns show the climate zone and numbers of enrolled customers. The next two columns show aggregate estimated reference loads and load impacts for the average event hour, in units of MWh. The next two columns show the same variables for the average customer, in units of kWh. The last two columns show the load impacts as a percentage of the reference loads, and the average temperature during the event window.

Table ES.1: Residential CPP Event-Hour Load Impacts – Average Weekday Event

Climate Zone	Enrolled	Aggregate		Per-Customer		% Load Impact	Ave. Event Temp.
		Ref. Load (MWh/h)	Load Impact (MWh/h)	Ref. Load (kWh/h)	Load Impact (kWh/h)		
Coastal	9,387	9.67	1.21	1.03	0.13	13%	87
Inland	5,997	9.51	1.35	1.59	0.23	14%	92
All	15,384	19.28	2.57	1.25	0.17	13%	89

Program enrollment was 15,384 customers, skewed somewhat toward the Coastal climate zone.² The aggregate reference load was 19.28 MWh/h. Per-customer load impacts averaged 0.13 kWh/h for customers in the Coastal climate zone, representing 13 percent of their reference load, and 0.23 kWh/h, or 14 percent, for the Inland climate zone. Average event-window temperatures were somewhat cooler in the Coastal zone, at 87 degrees, than the 92-degree temperature for the Inland zone.

Table ES.2 summarizes average event-hour reference load and CPP load impact results for the grandfathered CPP customers on the average weekday event in 2020. Program enrollment was 250 customers, with more customers in the Inland climate zone. The aggregate reference load was 0.30 MWh/h. Per-customer load impacts averaged -0.10 kWh/h for customers in the Coastal climate zone, an increase in load during event hours, and 0.21 kWh/h for customers in the Inland climate zone.

¹ CPP residential customers are those that voluntarily enrolled on rate TOU-DR-P or are grandfathered on rate GTOU-DR-P.

² These enrollment numbers differ from the number of customers that were used in the regression models, for whom all required data were available (*e.g.*, all selected event-like days, as well as the event day).

**Table ES.2: Grandfathered Residential CPP Event-Hour Load Impacts
– Average Weekday Event**

Climate Zone	Enrolled	Aggregate		Per-Customer		Ave. Event Temp.
		Ref. Load (MWh/h)	Load Impact (MWh/h)	Ref. Load (kWh/h)	Load Impact (kWh/h)	
Coastal	110	0.05	-0.01	0.44	-0.10	88
Inland	140	0.23	0.03	1.64	0.21	93
All	250	0.30	0.04	1.20	0.15	91

ES.3.2 TOU peak load impacts – TOU (TOU-DR)

Table ES.3 summarizes the average reference loads and load impacts for customers on the TOU-DR rate for the TOU peak period (*i.e.*, 4 p.m. to 9 p.m. for all months), for the average weekday *by month*, on an aggregate and per-customer basis. The months are shown starting with the first month included in the analysis (October 2019). The winter months are indicated by light blue shading. Enrollment continued throughout the period, with the numbers of enrolled customers rising from 6,274 in October 2019 to 9,980 in September 2020.³ The estimated seasonal percentage load impacts were largest during the summer months. All winter months exhibited an *increase* in load usage during the TOU peak period.

³ The enrollment numbers shown differ from the number of customers used in the regression models, which use only those customers with sufficient program-year and pre-treatment period load data needed for matching to control groups and estimating load impacts. Specifically, there were 1,015 incremental customers on the TOU-DR rate with quality load data that were used in estimating the TOU load impacts. The aggregate TOU load impacts are then scaled to total enrollments.

Table ES.3: TOU Peak Load Impacts for TOU Customers – Average Weekday by Month

Month	Climate Zone	Enrolled	Aggregate		Per-Customer		% Peak Load Impact	Ave. Peak Temp.
			Peak Ref. Load (MWh/h)	Peak Load Impact (MWh/h)	Peak Ref. Load (kWh/h)	Peak Load Impact (kWh/h)		
Oct-19	All	6,274	5.48	0.37	0.87	0.06	6.7%	72
Nov-19	All	6,641	6.56	-0.04	0.99	-0.01	-0.6%	62
Dec-19	All	7,056	8.38	-0.03	1.19	0.00	-0.4%	57
Jan-20	All	7,561	7.52	-0.04	0.99	-0.01	-0.5%	58
Feb-20	All	7,960	6.77	-0.04	0.85	-0.01	-0.7%	60
Mar-20	All	8,227	5.07	-0.13	0.62	-0.02	-2.5%	60
Apr-20	All	8,387	4.69	-0.13	0.56	-0.02	-2.7%	64
May-20	All	8,516	4.46	-0.04	0.52	0.00	-0.9%	70
Jun-20	All	8,664	5.50	0.50	0.63	0.06	9.1%	72
Jul-20	All	8,963	7.63	0.52	0.85	0.06	6.8%	74
Aug-20	All	9,418	13.60	0.54	1.44	0.06	4.0%	78
Sep-20	All	9,980	14.46	0.56	1.45	0.06	3.9%	78

Table ES.4 shows peak load impact results by season and climate zone. The Inland and Coastal climate zones had similar percentage load impacts for in the summer, but in winter, the Inland climate zone exhibited a usage increase while the Coastal climate zone decreased usage slightly.

Table ES.4: TOU Peak Load Impacts for TOU Customers – Average Weekday by Season & Climate Zone

Season	Climate Zone	Enrolled (Average)	Aggregate		Per-Customer		% Peak Load Impact	Ave. Peak Temp.
			Peak Ref. Load (MWh/h)	Peak Load Impact (MWh/h)	Peak Ref. Load (kWh/h)	Peak Load Impact (kWh/h)		
Summer	Coastal	4,362	4.02	0.20	0.92	0.05	5.0%	74
	Inland	4,298	5.28	0.28	1.23	0.07	5.4%	76
	All	8,660	9.30	0.49	1.07	0.06	5.2%	75
Winter	Coastal	3,883	3.16	0.07	0.81	0.02	2.3%	62
	Inland	3,881	3.08	-0.10	0.79	-0.03	-3.4%	61
	All	7,764	6.24	-0.03	0.80	0.00	-0.5%	62

Combining results across months and considering the effect of TOU on average *daily* usage, CA Energy Consulting finds that TOU customers *increased* their energy consumption by an annual average of approximately 3 percent.

ES.3.3 TOU peak load impacts – CPP (TOU-DR-P)

Since TOU-DR-P customers experience TOU prices on all weekdays that are not residential CPP event days, it is of interest to examine their average usage changes on non-event days, similar to TOU-only customers. Table ES.5 shows load and load impacts for the average summer (October 2019, and June through September 2020) and winter (November 2019 through May 2020) weekdays, by month. Enrollment in CPP grew from 11,838 in October 2019 to approximately 15,735 in September 2020.⁴ Peak load impacts varied across months, with estimated load reductions in all months except for August.

**Table ES.5: TOU Peak Load Impacts for Residential CPP Customers –
Average Weekday by Month**

Month	Climate Zone	Enrolled	Aggregate		Per-Customer		% Peak Load Impact	Ave. Peak Temp.
			Peak Ref. Load (MWh/h)	Peak Load Impact (MWh/h)	Peak Ref. Load (kWh/h)	Peak Load Impact (kWh/h)		
Oct-19	All	11,838	10.34	1.04	0.87	0.09	10.1%	72
Nov-19	All	12,071	10.40	0.33	0.86	0.03	3.2%	62
Dec-19	All	12,383	12.81	0.66	1.03	0.05	5.2%	58
Jan-20	All	12,799	11.70	0.51	0.91	0.04	4.3%	58
Feb-20	All	13,216	11.04	0.49	0.84	0.04	4.4%	60
Mar-20	All	13,611	10.33	0.17	0.76	0.01	1.7%	60
Apr-20	All	14,102	10.99	0.23	0.78	0.02	2.1%	64
May-20	All	14,412	11.69	0.79	0.81	0.05	6.8%	70
Jun-20	All	14,689	11.57	0.25	0.79	0.02	2.2%	72
Jul-20	All	15,075	13.54	0.14	0.90	0.01	1.1%	73
Aug-20	All	15,533	17.04	-0.02	1.10	0.00	-0.1%	76
Sep-20	All	15,735	17.22	0.22	1.09	0.01	1.3%	77

Table ES.6 summarizes TOU load impact for results for residential CPP customers by season and climate zone. In the summer, load impacts are larger in the Coastal climate zone than Inland, while winter load impacts are slightly larger for the Inland climate zone.

⁴ The number of CPP customers included in the regressions is substantially smaller than the number used for the same group of customers in the context of measuring CPP load impacts. This difference is due to the need to have data available for both the program year and the pre-treatment period, which served as the basis for control group matching, whereas load data for only the event day and event-like non-event days in 2020 were required for measuring CPP load impacts.

Table ES.6: TOU Peak Load Impacts for Residential CPP Customers – Average Weekday by Season & Climate Zone

Season	Climate Zone	Enrolled (Average)	Aggregate		Per-Customer		% Peak Load Impact	Ave. Peak Temp.
			Peak Ref. Load (MWh/h)	Peak Load Impact (MWh/h)	Peak Ref. Load (kWh/h)	Peak Load Impact (kWh/h)		
Summer	Coastal	8,864	7.66	0.27	0.86	0.03	3.6%	73
	Inland	5,710	6.25	0.05	1.10	0.01	0.8%	76
	All	14,574	13.92	0.32	0.95	0.02	2.3%	74
Winter	Coastal	7,976	6.54	0.24	0.82	0.03	3.7%	63
	Inland	5,252	4.73	0.21	0.90	0.04	4.4%	62
	All	13,228	11.27	0.45	0.85	0.03	4.0%	62

In contrast to the TOU customers, residential CPP customers *increased* their average daily usage during June through September, as well as March and April, but *decreased* usage in all other months. The overall annual effect was an average annual *decrease* of usage per-customer near zero, about 0.01 percent.

ES.3.4 TOU peak load impacts – Grandfathered (GTOU-DR-P)

Table ES.7 summarizes TOU peak-period load impact results for grandfathered customers by season and climate zone. Monthly results are similar within each season because seasonal level load impacts were estimated by climate zone. In the summer period, both Coastal and Inland climate zones exhibited an *increase* in usage during peak hours. During the winter period, only the Coastal climate zone decreased usage during the peak period. The overall effect of *daily* usage is an average annual *increase* of about 3.25 kWh/h per customer.

Table ES.7: TOU Peak Load Impacts for Grandfathered Residential CPP Customers – Average Weekday by Season & Climate Zone

Season	Climate Zone	Enrolled (Average)	Aggregate		Per-Customer		Ave. Peak Temp.
			Peak Ref. Load (MWh/h)	Peak Load Impact (MWh/h)	Peak Ref. Load (kWh/h)	Peak Load Impact (kWh/h)	
Summer	Coastal	217	-0.35	-0.08	-1.62	-0.38	78
	Inland	243	-0.26	0.00	-1.09	-0.02	81
	All	460	-0.62	-0.05	-1.26	-0.11	80
Winter	Coastal	210	0.28	0.02	1.33	0.09	62
	Inland	234	0.22	-0.08	0.94	-0.35	61
	All	444	0.50	-0.08	1.09	-0.17	62

ES.4 Ex-Ante Load Impacts

SDG&E called nine residential CPP events in 2020, six on weekdays and three spanning Labor Day weekend. Load impacts for different weather scenarios were developed by applying the estimated load impact from the *ex-post* analysis to weather-sensitive reference loads. The reference loads were developed by obtaining weather-specific coefficients using regression models similar to those used in the *ex-post* analysis, and applying the coefficients to four alternative weather scenarios.

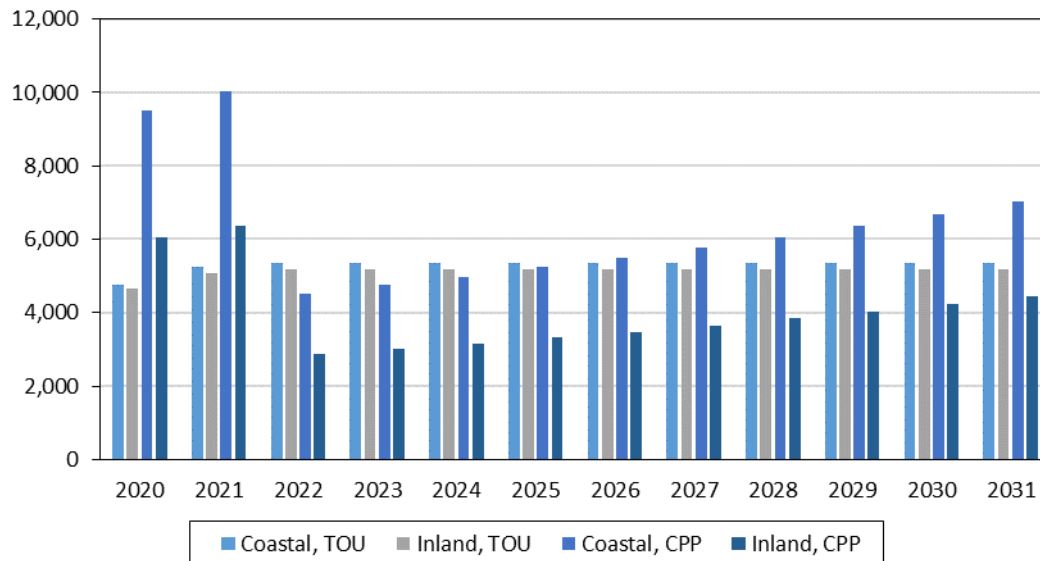
An issue in producing the *ex-ante* load impact forecasts for CPP is that the Protocols call for estimating load impacts for the Resource Adequacy (RA) hours of 4 to 9 p.m. for all months, while the CPP events are called during the program hours of 2 to 6 p.m. year-round. The load impacts were simulated using the event hours that are indicated by the tariff but are summarized across the RA window as required.

For the TOU rate and the TOU portion of the CPP rate, hourly percentage load impacts from the *ex-post* analysis (developed from monthly values for CPP and seasonal values for TOU) are applied to weather-sensitive reference loads that were developed as described above. Level load from *ex-post* are used for NEM customers.

ES.4.1 Enrollment forecast

Figure ES.1 shows SDG&E's enrollment forecasts for the TOU and CPP rates. Enrollment is anticipated to be essentially flat for TOU after 2021, while enrollment in CPP is forecasted to increase in 2021, and then fall substantially in 2022 as 8,990 customers shift to the Community Choice Aggregator program. Enrollment is expected to be greater in the Coastal climate zone than in the Inland for both rates. Enrollment for grandfathered customers (GDRTOPH) is assumed to remain constant at 477 customers until the grandfathering term expires on July 31, 2022.

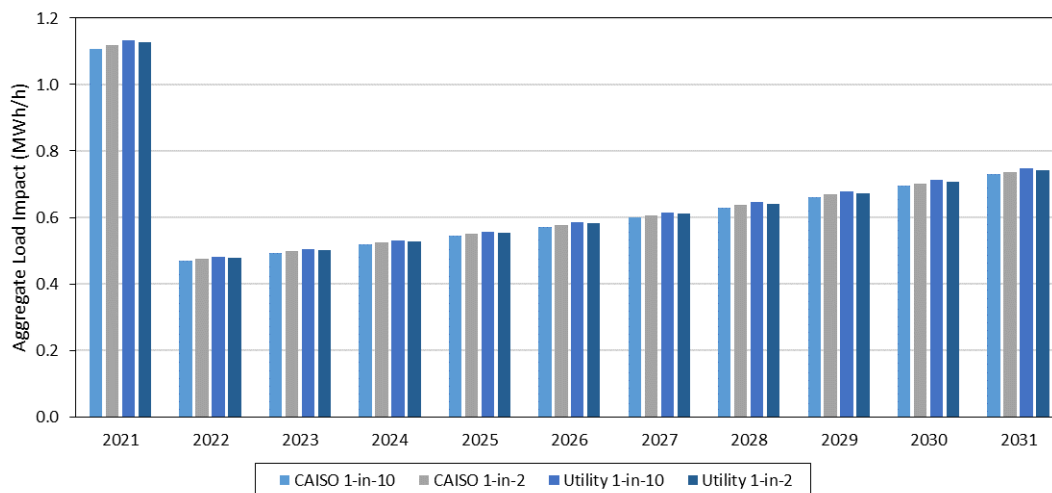
Figure ES.1: Enrollments in TOU and CPP Rates



ES.4.2 Ex-Ante load impacts – Residential CPP

Figure ES.2 illustrates the growth in forecasted CPP load impacts over the forecast period following a significant decline in enrollments in 2022 due to a migration of customers to the Community Choice Aggregator program. The figure also shows relatively minor differences between the aggregate *ex-ante* load impacts for the alternative weather scenarios. Load impacts under the SDG&E 1-in-2 weather scenario are forecast to grow from just less than 0.48 MWh/h in 2022 to over 0.74 MWh/h in 2031.

Figure ES.2: Aggregate CPP Load Impacts (MWh/h), by Year and Weather Scenario (SDG&E 1-in-2 Peak Day, RA Window)

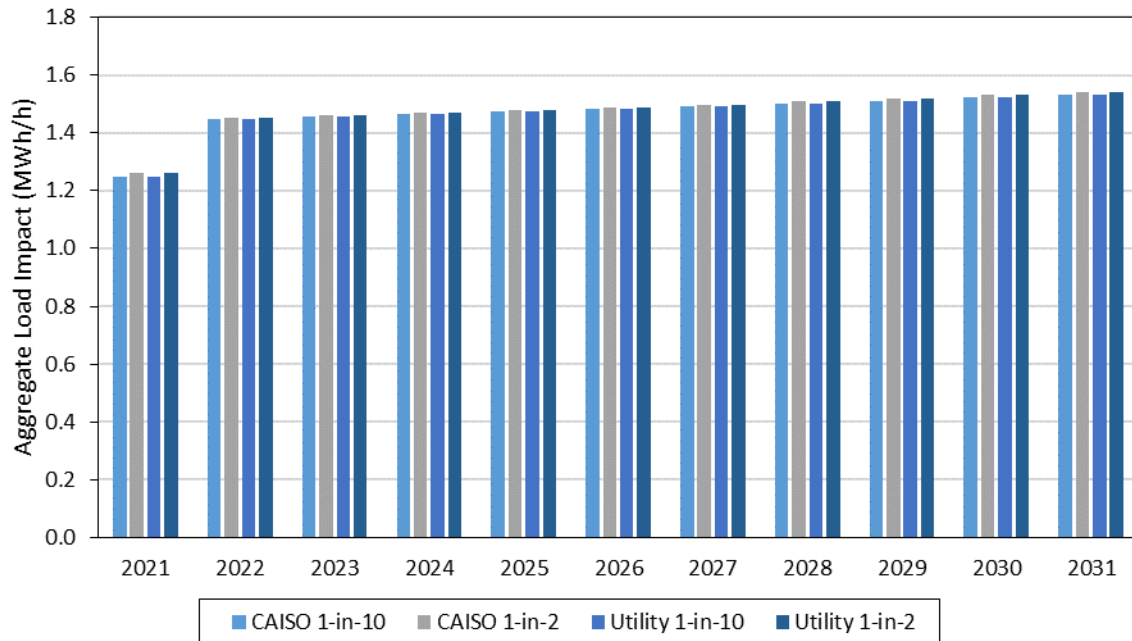


The *ex-ante* CPP load impact forecasts for grandfathered customers is assumed to remain constant at -0.046 MWh/h during the RA window for each weather scenario and year up to the grandfathered term expiration on July 31, 2022.

ES.4.3 Ex-Ante load impacts – Residential TOU

Aggregate peak load impacts for TOU customers are forecast to remain constant after 2021, given the flat enrollment forecast. Figure ES.3 shows differences in the aggregate peak TOU load impact forecasts for customers enrolled in the SPP rates (representing both TOU-DR and TOU-DR-P customers) over the entire period for the average August weekday weather scenarios. Values for the two 1-in-10 scenarios are identical, rising to 1.5 MWh/h in the final year. Load impacts in the SDG&E 1-in-2 scenario are nearly identical to the CAISO 1-in-2 scenario as well, rising to just over 1.5 MWh/h in 2031. Aggregate load impacts increase in 2022 with the loss of TOU-DR-P customers, which exhibited a slight load *increase* during peak hours.

Figure ES.3: Aggregate TOU Load Impacts (MWh/h) – TOU-DR and TOU-DR-P Customers, by Year and Weather Scenario, (Average August Weekday, RA Window)



The August weekday *ex-ante* TOU load impact forecasts for grandfathered customers is assumed to shift from -0.048 MWh/h during 2021, to 0.035 MWh/h for all subsequent years as the impact of Covid-19 disappears. Similar to the CPP load impact forecast for grandfathered customers, the TOU load impact does not vary by weather scenario and year. Therefore, the monthly load impacts are forecasted to remain constant until the grandfathering term expires on July 31, 2022.

1. Introduction and Purpose of the Study

This report documents *ex-post* and *ex-ante* load impact evaluations for San Diego Gas and Electric Company's ("SDG&E") voluntary residential time of use (TOU) and critical peak pricing (CPP) rates for 2020. The two 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).⁵ Both rates are voluntary and became active in February 2015. Since the TOU/CPP customers experience TOU rates on days that are not CPP event days, TOU load impacts are estimated for customers enrolled in both rates, while CPP load impacts are estimated only for residential CPP customers.⁶ The evaluation also develops *ex-ante* load impacts for both rates, with the evaluations conforming to the Load Impact Protocols adopted by the CPUC in D-08-04-050.

The TOU periods in the two 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 weekend 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.

Given a rapid increase in Net Energy Metered (NEM) enrollments in recent years, NEM customers now constitute a significant proportion of residential TOU customers, as shown in the Table 1.1 below. As in the past two years, NEM customers were included in this year's analysis. Unlike prior years, the results for NEM customers are presented separately from Non-NEM customers in the protocol tables associated with this report, in addition to all customers being presented together.

⁵ Results are also reported for a subset of CPP customers who also participated in the Technology Deployment (TD) program.

⁶ CPP *ex-post* load impacts are estimated for *all* customers enrolled in CPP (TOU-DR-P) during the 2020 program year. TOU load impacts are estimated for only those customers who enrolled in either of the rates during the October 2019 to September 2020 period, also referred to as *incremental* TOU customers. The *incremental* TOU load impacts are applied to all customers on SPP rates (TOU-DR and TOU-DR-P).

Table 1.1: NEM and Non-NEM Customer Enrollments

Date	TOU			TOU + CPP		
	Regular Enrollments	NEM Enrollments	NEM Share of Enrollments	Regular Enrollments	NEM Enrollments	NEM Share of Enrollments
Oct-19	2,373	3,901	62.2%	10,114	1,724	14.6%
Nov-19	2,461	4,180	62.9%	10,241	1,830	15.2%
Dec-19	2,575	4,481	63.5%	10,440	1,943	15.7%
Jan-20	2,809	4,752	62.8%	10,726	2,073	16.2%
Feb-20	2,988	4,972	62.5%	11,045	2,171	16.4%
Mar-20	3,123	5,104	62.0%	11,357	2,254	16.6%
Apr-20	3,207	5,180	61.8%	11,767	2,335	16.6%
May-20	3,257	5,259	61.8%	11,993	2,419	16.8%
Jun-20	3,323	5,341	61.6%	12,196	2,493	17.0%
Jul-20	3,470	5,493	61.3%	12,481	2,594	17.2%
Aug-20	3,731	5,687	60.4%	12,816	2,717	17.5%
Sep-20	4,073	5,907	59.2%	12,944	2,791	17.7%

This report also documents *ex-post* and *ex-ante* load impacts for grandfathered customers on the rate GTOU-DR-P. Pursuant to D.17-01-006 and D.17-10-018, TOU Period Grandfathering permits certain eligible behind-the-meter solar customers to continue billing under grandfathered TOU period definitions until July 31, 2022. The grandfathered 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 under the grandfathered rates.

The SPP rates are voluntary TOU rates, as part of the Residential Rate Reform decision, the CPUC ruled that the California Investment Owned Utilities were to implement default TOU rates. In 2016 SDG&E began conducting its Opt-In TOU pilot, and in 2018 its Default TOU pilot which was considered phase 1 of the full TOU rollout which begins in March of 2019. SDG&E defaulted more than 750,000 residential customers in 2019 through 2020.

The report is organized as follows. Section 2 contains descriptions of the TOU and CPP rates; Section 3 describes the evaluation methods used in the study; Section 4 contains the CPP *ex-post* load impact results; and Section 5 contains the TOU *ex-post* load impact results. Section 6 describes the methods used to develop the CPP and TOU *ex-ante* load impacts. Section 7 contains the TOU and CPP *ex-ante* load impact results. Section 8 provides a series of comparisons of *ex-post* and *ex-ante* results. Section 9 provides recommendations.

2. Description of SPP Rates

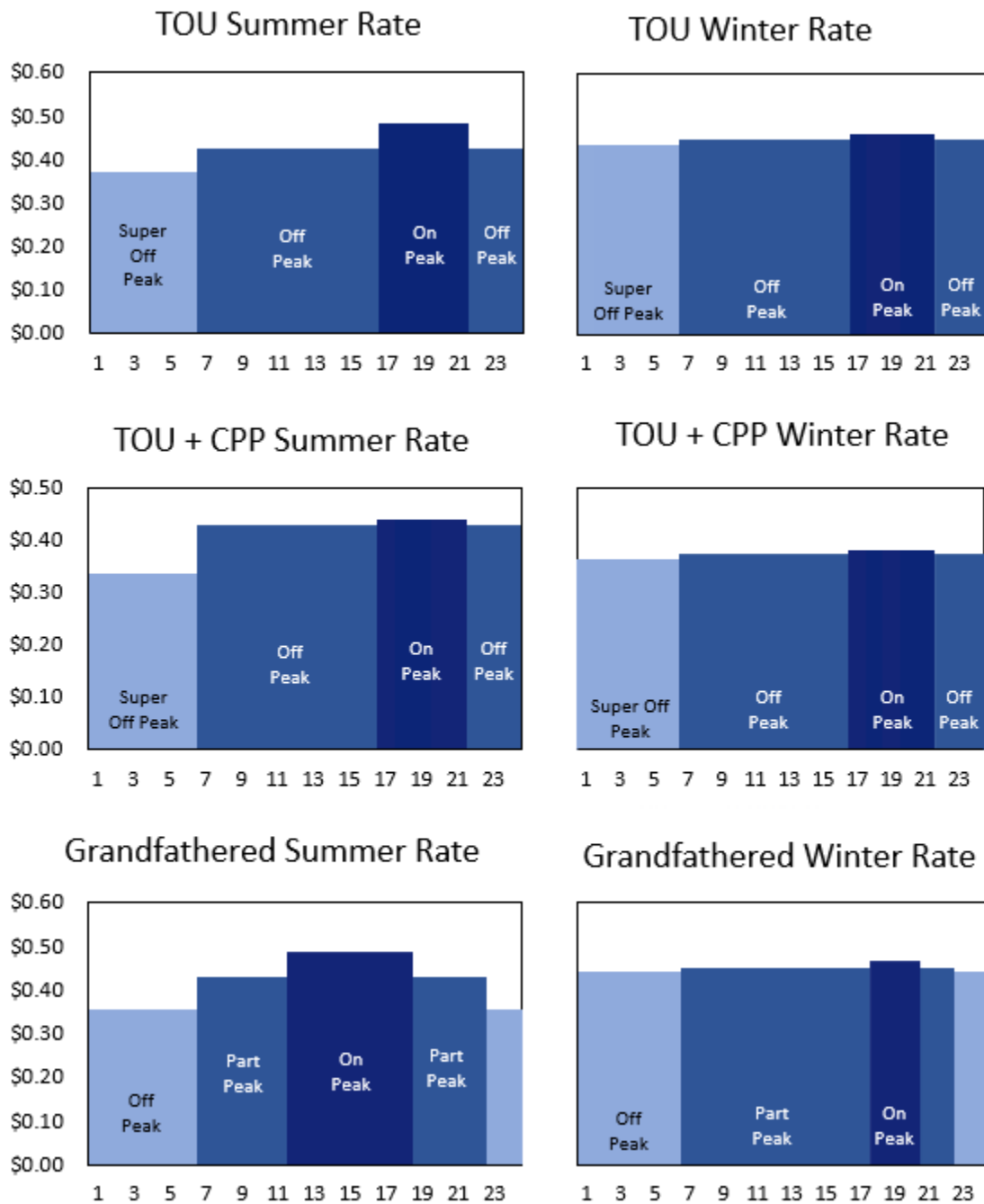
As noted in the introduction, the current TOU on-peak period in summer is 4 p.m. to 9 p.m. on non-holiday weekdays, with morning and evening off-peak periods before and after, and an overnight super-off-peak period. The super-off-peak hours are longer for weekend and holidays as well as during the months of March and April. Nine residential CPP events were called in 2020, on 8/17, 8/18, 8/19, 8/20, 9/5, 9/6, 9/7, 9/30, and 10/1. Three of the CPP events were called on weekends or holidays (9/5, 9/6, and 9/7).

The total TOU rate charges for TOU (TOU-DR) customers are \$0.483, \$0.428, and \$0.373 per kWh for the summer on-peak, off-peak, and super-peak periods respectively. Thus, the peak to super-off-peak price ratio is 1.30 to one. Summer TOU charges for CPP (TOU-DR-P) customers are somewhat lower, at \$0.440, \$0.428, and \$0.336 per kWh, implying a peak to off-peak price ratio of 1.31 to one. Summer prices for Grandfathered CPP (GTOU-DR-P) customers are \$0.489, \$0.430, and \$0.357 for summer on-peak, semi-peak, and off-peak periods, respectively. In addition, a CPP event-period adder of \$1.16 per kWh applies on event days for both CPP and Grandfathered CPP customers. Figure 2.1 illustrates the hourly TOU rates for each TOU period, rate, and season.⁷

CPP participants are generally notified of events by 3 p.m. on the business day prior to the event, and several notification options are available, including email and text. For the first full season following their enrollment, CPP participants are eligible for *bill protection*, which guarantees that their bill will be no larger than what it would have been under their otherwise applicable tariff.

⁷ The super-off-peak period includes 10 a.m. to 2 p.m. in March and April for non-Grandfathered customers, which is not represented by the winter rates in Figure 2.1.

Figure 2.1: Rate Time-of-Use Periods and Prices



3. *Ex-Post* Evaluation Methodology

The primary objectives of the *ex-post* impact evaluation were described in Section 1. This section describes the data and specific methods that were used in the study.

3.1 Data

An analysis that addresses each of the load impact objectives listed in Section 1 requires the following types of data:

- *Customer* information for the residential TOU and CPP enrollees and potential control group customers (*e.g.*, location indicator for matching to climate zone, CARE status, PV size);
- Billing-based *interval load data* (*i.e.*, hourly loads for each TOU and CPP enrollee, and potential control group customers), for October 2018 through September 2020;
- *Weather data* (*i.e.*, hourly temperatures and other variables for the relevant time period, for both climate zones—coastal and inland);
- *Program event data* (*i.e.*, dates and hours of CPP events, and event triggers).

3.2 Analysis Methods

The evaluation approach used in this study includes implementing a difference-in-differences regression analysis using data for TOU and CPP participants and matched control group customers. The analysis involves three steps. First, CA Energy Consulting requests hourly load data for the TOU and CPP enrollees, and potential control group customers, for the current year and the previous year (pre-enrollment year for new enrollees). Second, matched control group customers are selected for the TOU and CPP enrollees, as described below. Third, fixed-effects panel regression models are estimated, which produce difference-in-differences estimates of event-day load impacts (for CPP), and average TOU period load impacts (for both TOU and for CPP non-event days).

3.2.1 Evaluation design and control group matching

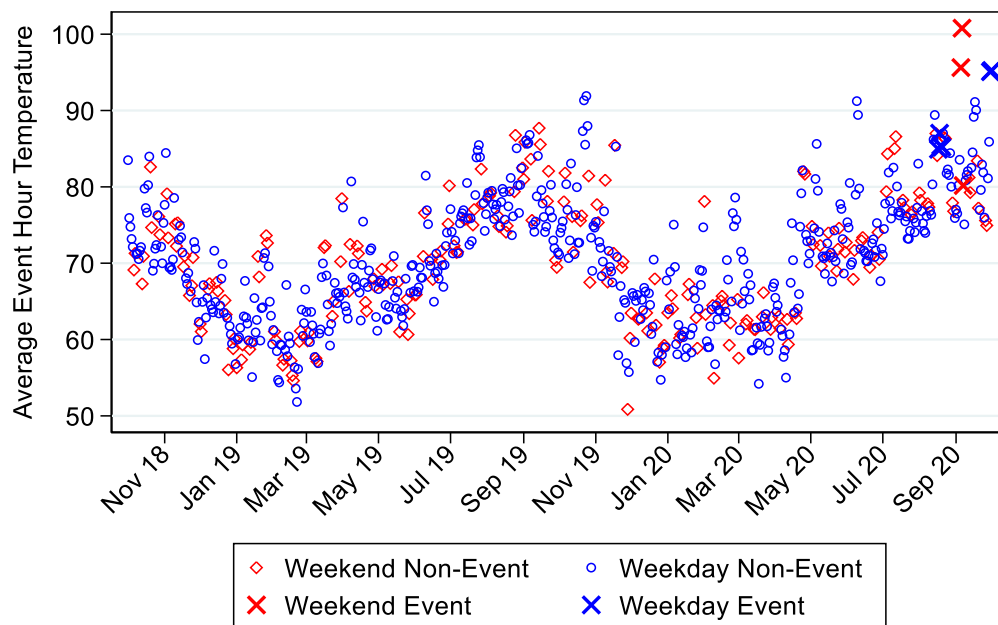
The difference-in-differences evaluation is a quasi-experimental approach that compares the usage of treatment and matched control group customers on relevant days or time periods, adjusted by their usage differences on pre-treatment or non-event days. The control groups were selected by matching each treatment customer to one of a sample of eligible non-treatment customers in relevant population segments (*e.g.*, climate zone, NEM, and CARE status), based on the closest match of load profiles. The initial samples of eligible control group customers were developed as seven-to-one samples by segment from the eligible population of SDG&E residential customers.

The matching process differed for customers on the two rates. Since the CPP (TOU-DR-P) customers experienced TOU rates on all non-event days, and the CPP rate on event days, those customers are treated as CPP customers when evaluating CPP load impacts, and as TOU customers when evaluating TOU impacts.

For analyzing CPP impacts, the CPP customers were matched to potential control group customers using loads on selected event-like non-event days (*e.g.*, days with

temperatures most like those on the event days). Figure 3.1 displays the average event-hour temperature for all weekday and weekends between October 2018 and November 2020. Red diamond markers indicate weekend non-event days while blue circles indicate weekday non-event days. The red and blue X markers represent weekend and weekday event days, respectively. The event days in 2020 were among the hottest days during 2020. With enough non-event hot days to choose from in 2020, the selected set of event-like non-event weekdays was 5/6, 6/9, 8/13, 8/24, 8/25, 9/4, 9/16, 9/17, 9/18, and 9/28. The non-event weekend days were 7/4, 7/5, 7/11, 7/12, 8/1, 8/15, 8/22, 8/23, 9/12, and 9/19.

Figure 3.1: Average Event-Hour Temperatures



For analyzing TOU impacts, for both CPP and TOU customers, only incremental treatment customers were used in the analysis and matched based on loads in the pre-treatment period (October 2018 through September 2019). Only incremental customers are used in the TOU load impact study because these customers have enough pre-treatment data to provide a quality difference-in-difference analysis. The matching and regression analysis are separated by season, thus allowing different threshold dates that define incremental customers.⁸ Specifically, incremental customers for the winter analysis are those that enrolled after June 1, 2019 while incremental customers for the summer analysis are those that enrolled after October 1, 2019. The incremental TOU customers were matched based on two pairs of hourly loads for each season – one for

⁸ The seasons defined for matching are summer (June through October) and winter (November through May).

all weekdays, and one for a subset of the hottest (or coldest) weekdays. Matching for the *winter* season used data for November 2018 through May 2019, while that for the *summer* season used data for October 2018 and June through September of 2019.

The grandfathered rate prevents new customers from joining the rate from a standard tiered rate (*e.g.*, DR). As a result, all Grandfathered customers are already treated (*i.e.*, either on the Grandfathered or TOU rate) during the pre-treatment matching periods mentioned above. To estimate TOU load impacts for these customers, TOU load impacts are estimated using PY2017 incremental customers that are now Grandfathered customers.⁹ The PY2017 pre-treatment analysis periods cover October 2015 through September 2016. The post-treatment analysis period for these customers, however, covers October 2019 through September 2020.¹⁰ Current Grandfathered customers that enrolled in either TOU-DR or TOU-DR-P after May 1, 2016 are incremental customers for the grandfathered winter analysis and those that enrolled after September 1, 2016 are incremental customers for the grandfathered summer analysis.

Matching was based on Euclidean distance minimization between treatment and potential control group customer loads. This approach minimizes the difference between a standardized usage metric of the treatment and potential control group customers as shown in the equation below.

$$Distance_{T,C} = \sqrt{(T_1 - C_1)^2 + (T_2 - C_2)^2 \dots + (T_n - C_n)^2}$$

In this equation, the *T* variables represent treatment customer characteristics and the *C* variables represent the corresponding eligible control group customer characteristics. As described, separate matches and therefore sets of variables are used for the CPP and TOU analyses. For matching in the CPP analysis, the customer characteristics include the average hourly usage on event-like non-event weekdays (24 variables). For the TOU analysis, the customer characteristics include the average hourly usage on weekdays and hot/cold days for the summer/winter match (48 variables).¹¹ Treatment and potential control customers are also segmented by climate zone and CARE status. Each enrolled customer is compared to each potential control group customer within their segment, using the distance measure. When the minimum distance statistic is found, the potential control group customer associated with that value is selected as the match for that TOU customer. Potential control group customers were matched with replacement (*i.e.*, matched to multiple enrolled customers).

NEM customers are matched similarly, with three major distinctions. First, only customers that are NEM for the entire analysis period and have not made changes to

⁹ PY2017 incremental customer are used to estimate grandfathered load impacts because it was the last year that any Grandfathered customers switched from a standard tiered rate to a TOU rate.

¹⁰ The gap in data between the pre- and post-treatment period requires that incremental customers exist for the entire period. Otherwise, the method is equivalent to the other difference-in-difference analyses.

¹¹ Hot/cold days are among the highest/lowest 20th percentile in terms of CDD or HDD temperature values. Hot/cold days are selected separately by climate zone.

their solar PV system are included.¹² Second, NEM treatment customers must be matched to NEM control customers that have comparable solar photovoltaic generation capacity sizes.¹³ Third, customers with large changes in net profiles between periods are not used in the analysis because the differences are more likely caused by unobserved structural changes to a customer's solar PV system. The methodology and thresholds used for identifying NEM customers with large changes in usage and subsequently removed from the analysis is explained in more detail in Appendix C. Each of these requirements helps prevent estimating load impacts (TOU or residential CPP) that are confounded by differences in solar generation capacity between periods and/or between the treatment and control groups, as opposed to only a behavioral response to TOU rates or CPP events.¹⁴

3.2.2 Fixed-effects panel regression models

The formal *ex-post* load impact estimates are based on *fixed-effects* panel regression models. These models are appropriate in situations like the current study, in which observed data are available for both multiple individual customers (cross-section) and multiple days, or time periods (time-series). The advantages of estimating such models include: 1) accounting for the effect of relevant factors on the variation in usage across customers and days, 2) accounting for the effects of weather conditions on usage, and 3) the availability of standard errors around the estimated load impact coefficients, thus allowing construction of *confidence intervals*.

Two versions of fixed-effects models were estimated. The first version was used to estimate residential CPP event-day hourly load impacts (estimated separately for TOU-DR-P and GTOU-DR-P customers). Weekend CPP events were estimated separately from weekday events, as load usage may vary between weekdays and weekend days. The second version was used to estimate average weekday TOU load impacts (estimated separately for the TOU-DR, TOU-DR-P, and GTOU-DR-P customers). In addition to estimating each load impact type separately by rate, the load impacts were estimated separately for NEM customers within each rate.

¹² With a matched control group, it is essential to create a counterfactual that mimics any changes a treatment customer faces. It becomes increasingly unlikely to find a suitable match for customers that become NEM during the analysis period or change their solar PV characteristics because the best practice would be to search for a control customer that made comparable changes at parallel points in time. Additionally, including controls in a regression for these changes is limited by the amount of overlap between the change and becoming a TOU customer. Essentially, it is more difficult to statistically disentangle effects the closer they occur to each other.

¹³ NEM customers are segmented only by solar PV size, rounded to the next integer level (capacity sizes greater than 12 kW are a separate segment).

¹⁴ For example, a high premise usage treatment customer with a larger solar generation system may be matched to a lower premise usage control customer with a smaller solar generation system based on similar net load profiles. If conditions are met so that solar generation is larger in the post-period, then any analysis based on net load profiles will exhibit that the treatment customer reduced their usage, relative to their own pre-treatment usage as well as relative to the control customer's usage.

In the first model, which addresses the objective of estimating hourly *ex-post* load impacts at the program level, a set of twenty-four separate fixed-effects models were estimated, one for each hour of the day. These models allow customer-specific constant terms, but estimate the same coefficient, effectively representing an average load impact across the included treatment customers, for variables that do not vary across customers (*e.g.*, the occurrence of an event day).

3.2.3 *Ex-post* models for estimating CPP load impacts

The load impact estimation model for CPP accounts for customer-specific and date-specific fixed effects (which include weather and day-type factors) and effectively estimates the CPP load impact as the difference between CPP and control-group customer loads on event days, controlling for the aforementioned fixed effects. This can be described as a difference-in-differences estimate (the difference between treatment and control group usage on event days, adjusted for differences on non-event days). The primary customer-level fixed-effects regression model used in the analysis is shown below, where the equation is estimated separately for each of the 24 hours. This model produces load impact estimates for each hour of every event:

$$kWh_{c,d} = \beta_0 + \sum_{Evs(i)} (\beta_{1,i} \times CPP_{c,d} \times Evt_{i,d}) + \beta_2 \times CPP_{c,d} + \sum_{Evs(i)} (\beta_{3,i} \times TD_{c,d} \times Evt_{i,d}) + \sum_{Cust} (\beta_{4,Cust} \times C_c) + \sum_{date} (\beta_{5,date} \times D_{date,d}) + \beta_6 \times SS_Evt_{c,d} + \epsilon_{c,d}$$

The variables and coefficients in the equation are described in Table 3.1. Results are scaled to enrollment numbers because a portion of residential CPP customers are removed from the analysis based upon load quality and NEM customer restrictions (see Appendix C).

Table 3.1: Description of Variables Used in the CPP Analysis Regressions

Symbol	Description
$kWh_{c,d}$	Load in a particular hour for customer c on date d
$CPP_{c,d}$	Variable indicating whether customer c is only a <i>CPP</i> customer (<i>i.e.</i> , not also dually enrolled in <i>TD</i>) on date d (1 = yes, 0 if not)
$Evt_{i,d}$	Variable indicating that date d is the i^{th} event day (1= i^{th} event, 0 if not)
$TD_{c,d}$	Variable indicating whether customer c is a dually enrolled <i>CPP</i> and <i>TD</i> customer on date d (1 = yes, 0 if not)
$SS_Evt_{c,d}$	Variable indicating that date d is a <i>Summer Saver</i> event day (1=event, 0 if not) for customer c
β_0	Estimated constant coefficient
$\beta_{1,d}$	Estimated load impact for event d for <i>CPP</i> only customers
β_2	Estimated non-event day response for incremental <i>CPP</i> customers
$\beta_{3,d}$	Estimated load impact for event d for dually enrolled <i>CPP</i> and <i>TD</i> customers
$\beta_{4,Cust}$ and $\beta_{5,date}$	Customer and date fixed effects
β_6	Estimated average <i>Summer Saver</i> load impact
C_c	Variable indicating that the observation is for customer c
$D_{date,d}$	Date indicator variable (1 = date d equals date day)
$\epsilon_{c,d}$	Error term

3.2.4 Ex-post models for estimating TOU load impacts

To obtain TOU load impacts (for TOU-DR, TOU-DR-P, and GTOU-DR-P customers), a distinct model is estimated for each required result. For example, to obtain the average TOU load impacts on August non-holiday weekdays, a model is estimated that includes only days of that day type.¹⁵ In this case, the model is simplified to include customer and date fixed effects, plus a variable to estimate the load impact (*i.e.*, the coefficient θ_1). The model is estimated separately by rate (*e.g.*, TOU-DR, TOU-DR-P, GTOU-DR-P), hour, month, day-type (*i.e.*, average weekday versus peak month day), and applicable

¹⁵ In cases where insufficient numbers of observations were available, the approach was modified by combining day-types into seasons that correspond to TOU periods (*i.e.*, summer is June through October, winter is November through February and May, and a separate core winter season for March and April). Specifically, observations were combined for all season-specific weekdays to estimate a constant season percentage load impact (*i.e.*, $PctLL_{Season} = LL_{Season} / (Obs_{Season} + LL_{Season})$). The season-specific percentage load impacts are then used to calculate monthly average weekday or system peak day reference loads (*i.e.*, $Ref_{Daytype} = Obs_{Daytype} / (1 - PctLL_{Season})$) and level load impacts (*i.e.*, $LL_{Daytype} = Ref_{Daytype} * PctLL_{Season}$). This method was used for each season for TOU-DR, GTOU-DR-P, and NEM customers.

customer groups (*e.g.*, climate zone, NEM). The customer-level fixed-effects models are of the following form:¹⁶

$$kW_{c,d} = \beta_0 + \beta_1 \times (TOU_c \times Post_{c,d}) + \sum_{Cust} (\beta_{2,Cust} \times C_c) + \sum_{dates} (\beta_{3,dates} \times D_{dates}) + \beta_4 \times Evt_{c,d} + \beta_5 \times SS_Evt_{c,d} + \beta_6 \times TD_Evt_{c,d} + \epsilon_{c,d}$$

The variables and coefficients in the equation are described in Table 3.2. Incremental customers are used to estimate the TOU load impacts in each regression. Results are then scaled to the program level of enrollments.

Table 3.2: Description of Variables Used in the TOU Analysis Regressions

Symbol	Description
$kW_{c,d}$	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 ¹⁷
$Post_{c,d}$	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 a Summer Saver 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
$\epsilon_{c,d}$	Error term

¹⁶ Note that the customer and date fixed effects remove the need for us to include stand-alone TOU_c and $Post_{c,d}$ variables. The former is perfectly collinear with the customer's fixed effect and the latter is perfectly collinear with a combination of date fixed effects.

¹⁷ For CPP customers, the Evt variable indicates that a day is a CPP event day.

3.2.5 Calculating uncertainty-adjusted load impacts

The Load Impact Protocols require the estimation of uncertainty-adjusted load impacts. In the case of *ex-post* load impacts, the coefficients that represent the estimated load impacts in the fixed-effects regressions are not estimated with certainty, but with a range of uncertainty indicated by the variance of the estimates. Therefore, the uncertainty-adjusted load impacts are based on the variances associated with the estimated load impact coefficients (*e.g.*, the event-day or treatment-period coefficients in the twenty-four hourly regressions).

The uncertainty-adjusted scenarios are then simulated under the assumption that each hour's load impact is normally distributed with the mean equal to the sum of the estimated load impacts and the standard deviation equal to the square root of the sum of the variances of the errors around the estimates of the load impacts. Results for the 10th, 30th, 70th, and 90th percentile scenarios are generated from these distributions.

To develop the uncertainty-adjusted load impacts associated with the *average* CPP event hour or by TOU pricing period (*i.e.*, the bottom rows in the tables produced by the *ex-post* table generator), additional sets of regression models are estimated in which the load impact variable is constrained to be the same across the applicable hours (*e.g.*, an average event-hour CPP load impact is directly estimated). The associated standard errors are used to develop the uncertainty-adjusted load impacts in the same manner described above.

3.2.6 Validity assessment

Because a control-group approach is being employed, the validity assessment focuses on comparisons of treatment and control-group loads for selected event-like non-event days (for CPP) or pre-treatment loads (TOU). Statistics such as the mean absolute percentage error (MAPE) and mean percent error (MPE), which provide formal estimates of the percent differences between treatment and control group loads, are also reported. The MAPE offers a measure of accuracy while MPE offers a measure of bias.

4. CPP *Ex-Post* Load Impact Study Findings

This section documents the findings from the *ex-post* load impact evaluation analysis of the CPP portion of the TOU-DR-P and GTOU-DR-P rates. For CPP, the primary load impact results include average estimated event-hour load impacts (*i.e.*, the average of the hourly load impacts estimated for the four-hour event window from 2 p.m. to 6 p.m.), in aggregate and per-customer, for each event day. Results of the analysis of the TOU portion of each rate (*i.e.*, peak load impacts on non-event days) are presented in Section 5, along with results for the TOU-DR rate.

Results for all hours are also illustrated in figures. Detailed results for each hour in electronic form may be found in Protocol table generators provided along with this report. As described in Section 3, all of the above results were estimated using fixed-

effects regression analysis of hourly data for treatment and matched control group customers.

4.1 Control group matching results

Figure 4.1 illustrates the quality of the matches for the Non-NEM residential CPP (TOU-DR-P) customers in the context of estimating load impacts on the CPP event day. The figure shows the average CPP and matched control-group customer load profiles for the selected event-like non-event days. Across all 24 hours, the mean percentage error (MPE) of the CPP profile compared to the control-group profile is 1.5 percent, while the mean absolute percentage error (MAPE) is 1.8 percent. For the CPP event window (2 p.m. to 6:00 p.m.), the MPE is -0.7 percent while the MAPE is 0.8 percent.

Figure 4.1: CPP and Matched Control Group Load Profiles – Average Event-Like Day

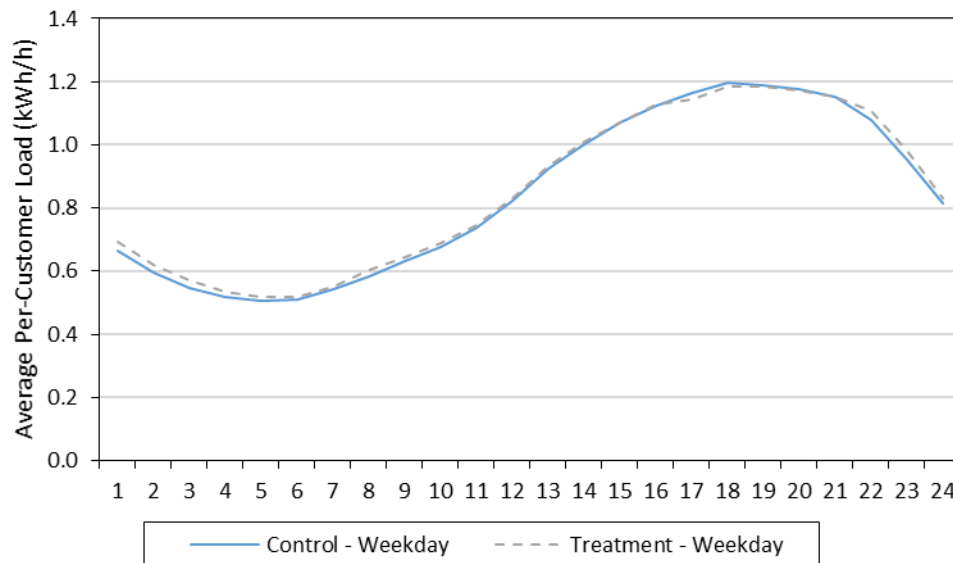


Figure 4.2 similarly illustrates the match quality for NEM residential CPP customers, as NEM customers were matched separately from Non-NEM customers. Across all 24 hours, the mean error (ME) of the CPP profile compared to the control-group profile is 0.04 kWh/h, while the mean absolute error (MAE) is 0.05 kWh/h. For the CPP event window (2 p.m. to 6:00 p.m.), the ME is 0.00 kWh/h while the MAE is 0.03 kWh/h.¹⁸

¹⁸ The ME and MAE statistics are used in lieu of MPE and MAPE because NEM customers can have loads near zero which disproportionately distort percentage values.

Figure 4.2: NEM CPP and Matched Control Group Load Profiles – Average Event-Like Day

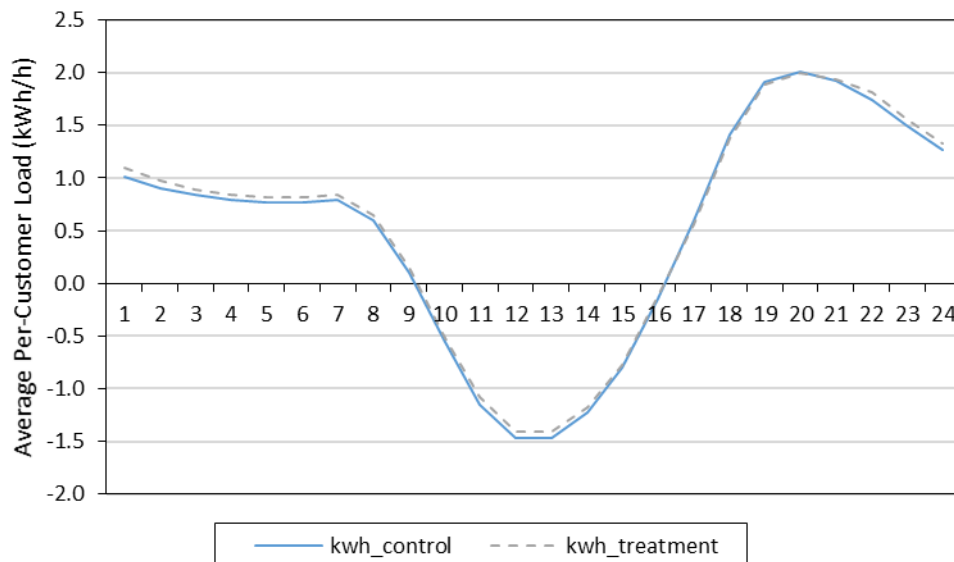
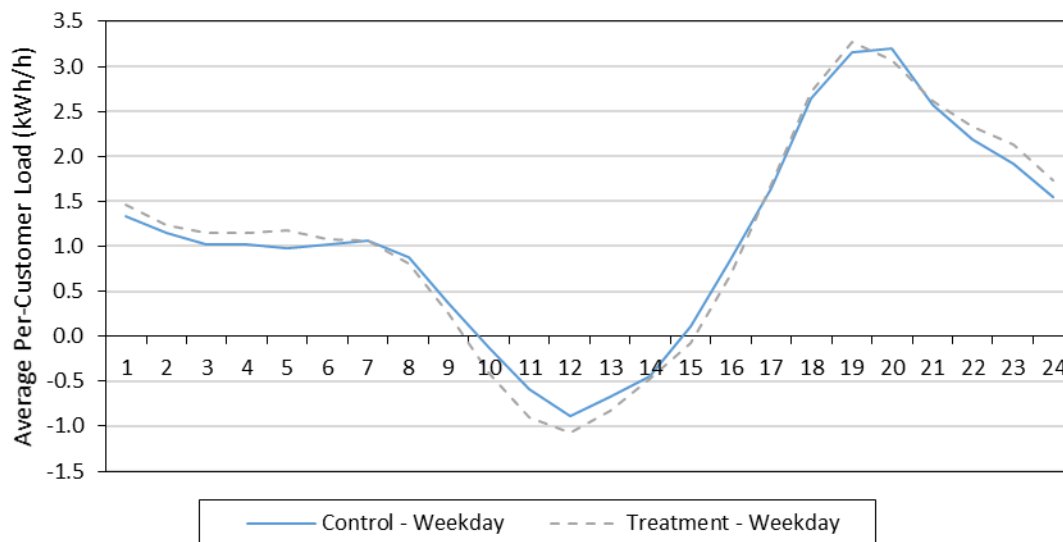


Figure 4.3 similarly illustrates the match quality for grandfathered CPP customers (GTOU-DR-P). Across all 24 hours, the mean error (ME) of the CPP profile compared to the control-group profile is 0.00 kWh/h, while the mean absolute error (MAE) is 0.13 kWh/h. For the CPP event window (2 p.m. to 6:00 p.m.), the ME is -0.06 kWh/h while the MAE is 0.12 kWh/h.¹⁹

Figure 4.3: Grandfathered CPP and Matched Control Group Load Profile – Average Event-Like Day



¹⁹ The ME and MAE statistics are used in lieu of MPE and MAPE because NEM customers can have loads near zero which disproportionately distort percentage values.

4.2 CPP load impacts

This section summarizes average event-hour reference loads²⁰ and load impacts, at an aggregate and per-customer basis, for the nine 2020 CPP events called on Aug 17, Aug 18, Aug 19, Aug 20, Sep 5, Sep 6, Sep 7, Sep 30, and Oct 1. Each event had an event-window of 2 p.m. to 6 p.m. (HE 15-18). This section contains only the results for CPP customers; CPP load impacts for Grandfathered CPP customers are reported in Section 4.3.

Table 4.1 summarizes reference load and CPP load impact results for all CPP customers, by climate zone.²¹ The first three columns show the climate zone, event date, and numbers of enrolled customers. The next two columns show aggregate estimated reference loads and load impacts for the average event hour, in MWh/h. The next two columns show the same variables for the average customer, in units of kWh/h. The last two columns show the load impacts as a percentage of the reference loads and the average temperature during the event window. Rows highlighted in blue signify weekend event days. All results are statistically significant at the 10% level.

²⁰ Reference loads represent estimates of the counter-factual loads that would have prevailed on an event day if the event had not been called. Mechanically, the *reference* loads are constructed by adding the estimated load impacts (developed in the difference-in-differences regression analysis) to the *observed* load of the treatment customers on the relevant event day. Alternatively, if percentage load impacts are estimated, then the *reference* loads are calculated by dividing the *observed* load by one minus the percentage load impact.

²¹ Technology Deployment customers are included in these results.

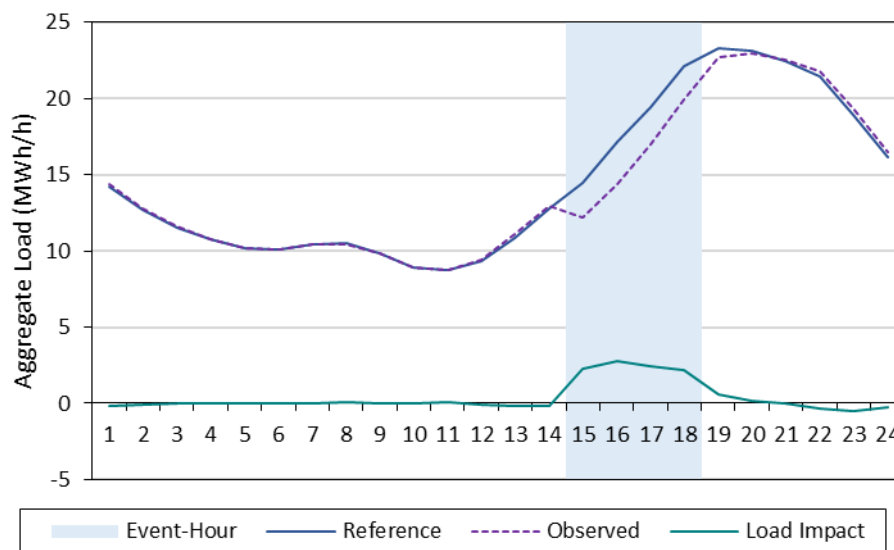
Table 4.1: Average CPP Event-Hour Load Impacts

Climate Zone	Date	Enrolled	Aggregate		Per-Customer		% Load Impact	Ave. Event Temp.
			Ref. Load (MWh/h)	Load Impact (MWh/h)	Ref. Load (kWh/h)	Load Impact (kWh/h)		
Coastal	Aug 17, 2020	9,316	8.45	1.14	0.91	0.12	14%	85
	Aug 18, 2020	9,333	9.60	1.05	1.03	0.11	11%	83
	Aug 19, 2020	9,349	9.39	1.26	1.00	0.13	13%	84
	Aug 20, 2020	9,363	9.67	1.18	1.03	0.13	12%	84
	Sep 5, 2020	9,485	12.29	1.54	1.30	0.16	13%	93
	Sep 6, 2020	9,503	15.20	1.73	1.60	0.18	11%	100
	Sep 7, 2020	9,489	9.10	0.66	0.96	0.07	7%	78
	Sep 30, 2020	9,481	10.33	1.48	1.09	0.16	14%	93
	Oct 1, 2020	9,481	10.63	1.17	1.12	0.12	11%	93
	Typical Weekday Event	9,387	9.67	1.21	1.03	0.13	13%	87
	Typical Weekend Event	9,492	12.20	1.31	1.28	0.14	11%	90
Inland	Aug 17, 2020	5,974	8.91	1.56	1.49	0.26	17%	90
	Aug 18, 2020	5,989	9.77	1.34	1.63	0.22	14%	89
	Aug 19, 2020	6,000	9.33	1.34	1.56	0.22	14%	89
	Aug 20, 2020	5,999	9.06	1.24	1.51	0.21	14%	89
	Sep 5, 2020	6,042	13.03	1.48	2.16	0.25	11%	101
	Sep 6, 2020	6,074	13.88	1.74	2.28	0.29	13%	104
	Sep 7, 2020	6,047	8.95	1.12	1.48	0.18	12%	83
	Sep 30, 2020	6,011	10.24	1.41	1.70	0.23	14%	97
	Oct 1, 2020	6,008	9.75	1.21	1.62	0.20	12%	96
	Typical Weekday Event	5,997	9.51	1.35	1.59	0.23	14%	92
	Typical Weekend Event	6,054	11.95	1.44	1.97	0.24	12%	96
All	Aug 17, 2020	15,290	17.46	2.71	1.14	0.18	16%	87
	Aug 18, 2020	15,322	19.47	2.40	1.27	0.16	12%	86
	Aug 19, 2020	15,349	18.82	2.61	1.23	0.17	14%	86
	Aug 20, 2020	15,362	18.84	2.43	1.23	0.16	13%	86
	Sep 5, 2020	15,527	25.52	3.05	1.64	0.20	12%	97
	Sep 6, 2020	15,577	29.22	3.47	1.88	0.22	12%	101
	Sep 7, 2020	15,536	18.11	1.75	1.17	0.11	10%	80
	Sep 30, 2020	15,492	20.70	2.90	1.34	0.19	14%	95
	Oct 1, 2020	15,489	20.50	2.41	1.32	0.16	12%	95
	Typical Weekday Event	15,384	19.28	2.57	1.25	0.17	13%	89
	Typical Weekend Event	15,547	24.28	2.75	1.56	0.18	11%	93

Program enrollment was 15,290 customers for the first event, skewed somewhat toward the Coastal climate zone.²² On a weekday Typical Event Day (*i.e.*, the average event), the per-customer reference load during event hours for all customers was 1.25 kWh/h. Per-customer load impacts averaged 0.13 kWh/h for customers in the Coastal climate zone, representing 13 percent of their reference load, and 0.23 kW, or 14 percent, for the Inland climate zone. Average event-window temperatures were somewhat cooler in the Coastal zone, at 87 degrees, than the 92-degree temperature for the Inland zone. Both customer groups, inland and coastal, respond similarly in percentage terms to the average weekday event. The sixth event-day, Sep 6, was a weekend day and had the hottest event-window temperature as well as the largest per-customer load impact.

Figure 4.4 shows aggregate hourly loads and load impacts for the average weekday event. The largest hourly load impact was 2.68 MWh/h in hour-ending 16 (3 to 4 p.m.).

**Figure 4.4: Aggregate CPP Hourly Loads and Load Impacts
– Average Weekday Event**



4.3 Grandfathered CPP load impacts

This section summarizes average event-hour reference loads and load impacts, at an aggregate and per-customer basis, for the nine 2020 CPP events for the Grandfathered CPP customers. Table 4.2 summarizes reference load and CPP load impact results for Grandfathered CPP customers, by climate zone. Program enrollment remained fairly constant between events. The average per-customer load impact is larger for customers in the inland climate zone. Percentage load impacts are not presented because all

²² These enrollment numbers differ from the number of customers that were used in the regression models, for whom all required data were available (*e.g.*, all selected event-like days, as well as the event day). The number of CPP customers used in the regressions was 13,614. The CPP load impacts are scaled up to total program enrollments.

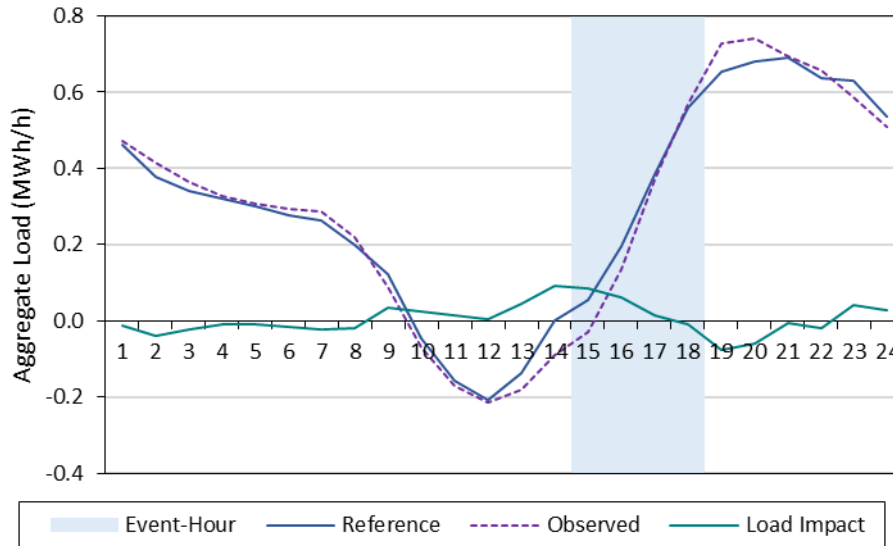
grandfathered customers are NEM customers that can have near zero reference loads, resulting in misleading percentage load impacts. Customers in the coastal climate exhibited an *increase* in usage on an average weekday event whereas customers in the inland climate exhibited an average *decrease*. For the average weekday event, the per-customer level load impact of non-grandfathered customers is larger than grandfathered CPP customers.

Table 4.2: Average Grandfathered CPP Event-Hour Load Impacts

Climate Zone	Date	Enrolled	Aggregate		Per-Customer		Ave. Event Temp.
			Ref. Load (MWh/h)	Load Impact (MWh/h)	Ref. Load (kWh/h)	Load Impact (kWh/h)	
Coastal	Aug 17, 2020	110	0.00	0.00	0.01	-0.03	84
	Aug 18, 2020	110	0.03	0.01	0.27	0.09	83
	Aug 19, 2020	110	0.02	0.00	0.19	-0.03	84
	Aug 20, 2020	110	0.03	0.01	0.26	0.08	84
	Sep 5, 2020	110	0.09	0.02	0.81	0.14	93
	Sep 6, 2020	110	0.16	-0.01	1.48	-0.10	100
	Sep 7, 2020	110	-0.02	-0.10	-0.20	-0.91	78
	Sep 30, 2020	110	0.01	-0.05	0.11	-0.42	92
	Oct 1, 2020	110	0.05	-0.03	0.43	-0.26	93
	Typical Weekday Event	110	0.05	-0.01	0.44	-0.10	88
	Typical Weekend Event	110	0.08	-0.03	0.70	-0.29	90
Inland	Aug 17, 2020	140	0.12	0.03	0.86	0.20	91
	Aug 18, 2020	140	0.21	0.06	1.50	0.40	88
	Aug 19, 2020	140	0.17	0.05	1.23	0.33	89
	Aug 20, 2020	140	0.15	0.03	1.06	0.20	89
	Sep 5, 2020	139	0.30	-0.05	2.13	-0.35	102
	Sep 6, 2020	139	0.30	-0.07	2.18	-0.47	103
	Sep 7, 2020	139	0.22	0.04	1.60	0.27	82
	Sep 30, 2020	140	0.22	0.00	1.54	0.02	99
	Oct 1, 2020	140	0.20	0.01	1.46	0.08	97
	Typical Weekday Event	140	0.23	0.03	1.64	0.21	93
	Typical Weekend Event	139	0.27	-0.03	1.97	-0.18	96
All	Aug 17, 2020	250	0.15	0.05	0.59	0.20	88
	Aug 18, 2020	250	0.27	0.09	1.08	0.38	86
	Aug 19, 2020	250	0.21	0.06	0.83	0.22	87
	Aug 20, 2020	250	0.19	0.05	0.75	0.18	87
	Sep 5, 2020	249	0.35	-0.08	1.39	-0.31	98
	Sep 6, 2020	249	0.45	-0.10	1.81	-0.39	102
	Sep 7, 2020	249	0.25	-0.01	1.02	-0.04	81
	Sep 30, 2020	250	0.25	-0.02	1.00	-0.10	96
	Oct 1, 2020	250	0.28	0.01	1.11	0.03	95
	Typical Weekday Event	250	0.30	0.04	1.20	0.15	91
	Typical Weekend Event	249	0.35	-0.06	1.41	-0.25	94

Figure 4.5 shows aggregate hourly loads and load impacts for the average weekday event for Grandfathered CPP customers. The largest hourly load impact was 0.12 MWh/h in hour-ending 14 and 15 (2 to 3 p.m.).

**Figure 4.5 Aggregate Grandfathered CPP Hourly Loads and Load Impacts
– Average Weekday Event**



4.4 Technology Deployment load impacts

This section compares the CPP load impact estimates for customers that were dually enrolled in CPP and the Technology Deployment (“TD”) program during 2020. Customers dually enrolled in TD and CPP experienced the same CPP events and event-window (Aug 17, Aug 18, Aug 19, Aug 20, Sep 5, Sep 6, Sep 7, Sep 30, and Oct 1; 2 p.m. to 6 p.m.). Note that there were no Grandfathered customers on TD included in the analysis.

Table 4.3 summarizes reference loads and load impacts for customers by enrollment status during the event-hour window, bifurcating results for customers enrolled solely in CPP (“CPP Only”) and customers dually enrolled in CPP and TD (“Dually Enrolled CPP+TD”). The number of dually enrolled customers by the last event date was 390 (which is about 2.5% of all CPP customers). On average, customers dually enrolled in TD have larger reference loads and load impacts. For example, the average weekday event reference load and load impact for dually enrolled customers was 1.72 kWh/h and 0.21 kWh/h, respectively. While the average weekday event reference load and load impact for non-dually enrolled customers was 1.22 kWh/h and 0.16 kWh/h, respectively. The load impact percentage of dually enrolled customers is more than or equal to double that of non-dually enrolled customers for the last three events.

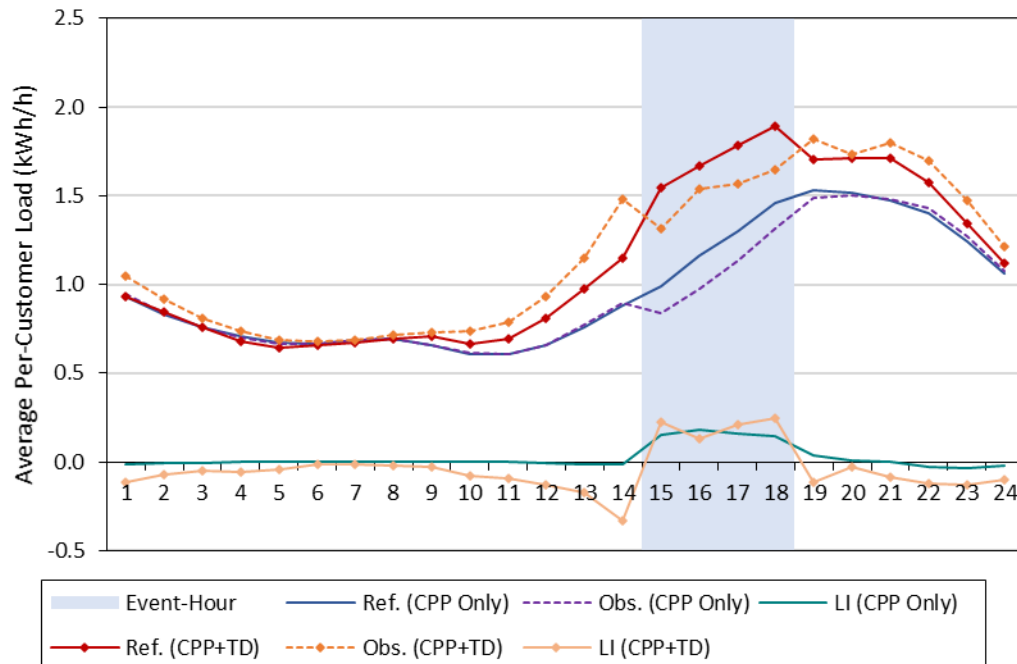
The event with the lowest average event-hour temperature, September 7th, saw the highest load impact of 23 percent for dually enrolled customers. Interestingly, non-dually enrolled customers saw the lowest load impact on this same day.

**Table 4.3: Comparison of Average CPP Event-Hour Load Impacts
for TD and CPP Enrollment Type**

Enrollment Type	Date	Enrolled	Aggregate		Per-Customer		% Load Impact	Ave. Event Temp.
			Ref. Load (MWh/h)	Load Impact (MWh/h)	Ref. Load (kWh/h)	Load Impact (kWh/h)		
CPP Only	Aug 17, 2020	14,900	16.58	2.57	1.11	0.17	16%	87
	Aug 18, 2020	14,933	18.55	2.36	1.24	0.16	13%	86
	Aug 19, 2020	14,960	17.87	2.50	1.19	0.17	14%	86
	Aug 20, 2020	14,973	17.88	2.33	1.19	0.16	13%	86
	Sep 5, 2020	15,130	24.02	3.04	1.59	0.20	13%	97
	Sep 6, 2020	15,180	27.54	3.42	1.81	0.23	12%	101
	Sep 7, 2020	15,139	16.97	1.32	1.12	0.09	8%	80
	Sep 30, 2020	15,102	19.62	2.61	1.30	0.17	13%	95
	Oct 1, 2020	15,099	19.46	2.17	1.29	0.14	11%	95
	Typical Weekday Event	14,995	18.32	2.43	1.22	0.16	13%	89
	Typical Weekend Event	15,150	22.83	2.59	1.51	0.17	11%	93
CPP + TD	Aug 17, 2020	390	0.61	0.07	1.55	0.17	11%	87
	Aug 18, 2020	389	0.66	0.03	1.68	0.08	5%	86
	Aug 19, 2020	389	0.65	0.06	1.67	0.15	9%	86
	Aug 20, 2020	389	0.66	0.05	1.69	0.14	8%	86
	Sep 5, 2020	397	0.83	0.03	2.10	0.07	4%	97
	Sep 6, 2020	397	0.96	0.07	2.42	0.17	7%	101
	Sep 7, 2020	397	0.65	0.15	1.63	0.37	23%	80
	Sep 30, 2020	390	0.74	0.15	1.91	0.38	20%	95
	Oct 1, 2020	390	0.72	0.12	1.85	0.32	17%	95
	Typical Weekday Event	390	0.67	0.08	1.72	0.21	12%	89
	Typical Weekend Event	397	0.81	0.08	2.05	0.20	10%	93

Figure 4.6 shows average per-customer hourly loads and load impacts for customers dually enrolled and not dually-enrolled in CPP and TD for the 2020 average weekday event. The shaded hours indicate the event-hours (2 to 6 p.m.). The observed load of dually enrolled customers ("Obs. (CPP+TD)") illustrates that TD customers have pre-cooling in the hours before the event begins and a snapback effect in the hours after the event, whereas non-dually enrolled customers do not have this pattern surrounding the event hours. The largest hourly TD load impact was 0.25 kWh/h in the last SCTD event-hour (5 to 6 p.m.).

**Figure 4.6: CPP+TD Hourly Loads and Load Impacts for Dually Enrolled Customers
– Average Weekday Event**



5. TOU *Ex-Post* Load Impact Study Findings

This section presents the match quality and estimates of monthly peak TOU load impacts for the TOU (TOU-DR), CPP (TOU-DR-P), and grandfathered (GTOU-DR-P) customers.

5.1 TOU control group matching results for TOU customers

Figures 5.1 and 5.2 illustrate the quality of the matches for the TOU (TOU-DR) Non-NEM customers. The figures show the average TOU and matched control-group customer load profiles for the summer and winter months, respectively. Two pairs of loads are shown, one for all days, and one for the hottest (or coldest) days. In the summer months, the mean percentage error (MPE) of the TOU profile compared to the control-group profile is -0.8 percent, while the mean absolute percentage error (MAPE) is 1.7 percent. In the winter months, the MPE is 3.5 percent and the MAPE is 3.5 percent.²³

²³ The MPE and MAPE statistics for the TOU matches are calculated over the two 24-hour load profiles, all days and hot/cold days.

Figure 5.1: Non-NEM TOU and Matched Control Group Load Profiles – Summer

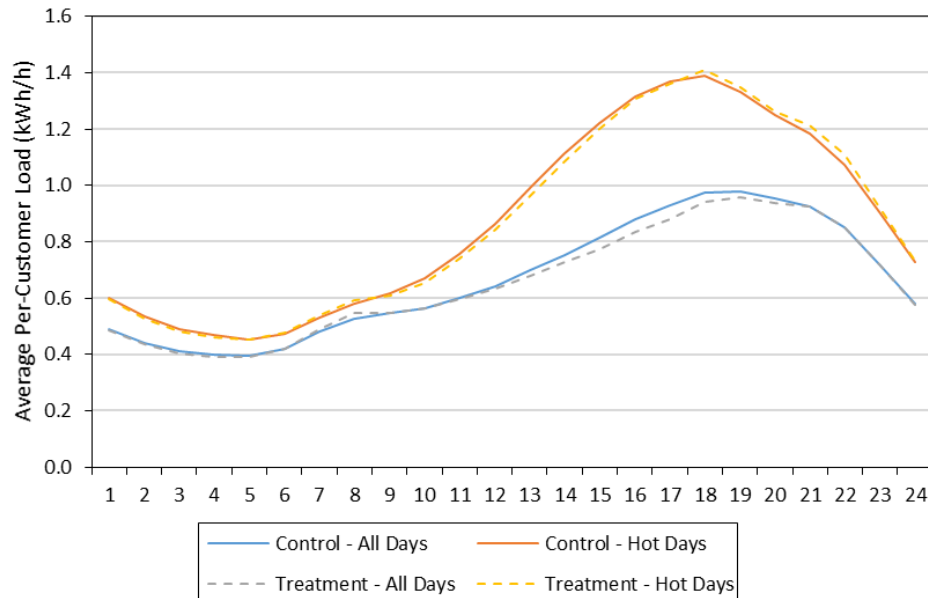
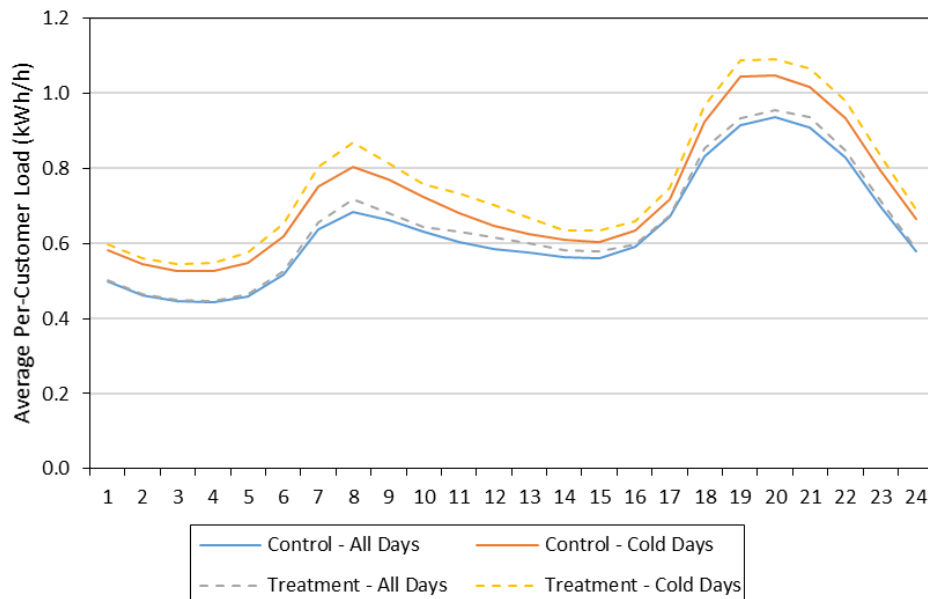


Figure 5.2: Non-NEM TOU and Matched Control Group Load Profiles – Winter



Figures 5.3 and 5.4 illustrate the quality of the matches for the TOU (TOU-DR) NEM customers, which were matched separately from Non-NEM customers. The figures show the average TOU and matched control-group customer load profiles for the summer and winter months, respectively. Two pairs of loads are shown, one for all days, and one for the hottest (or coldest) days. In the summer months, the mean percentage error (ME) of the TOU profile compared to the control-group profile is 0.06 kWh/h, while the mean absolute error (MAE) is 0.09 kWh/h. In the winter months, the ME is 0.16 kWh/h and the MAE is 0.16 kWh/h.

Figure 5.3: NEM TOU and Matched Control Group Load Profiles - Summer

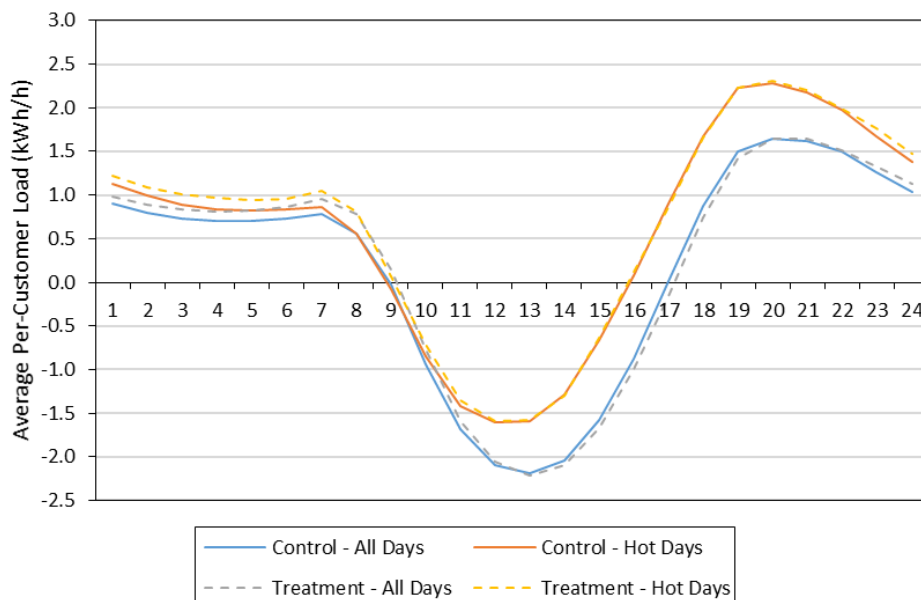
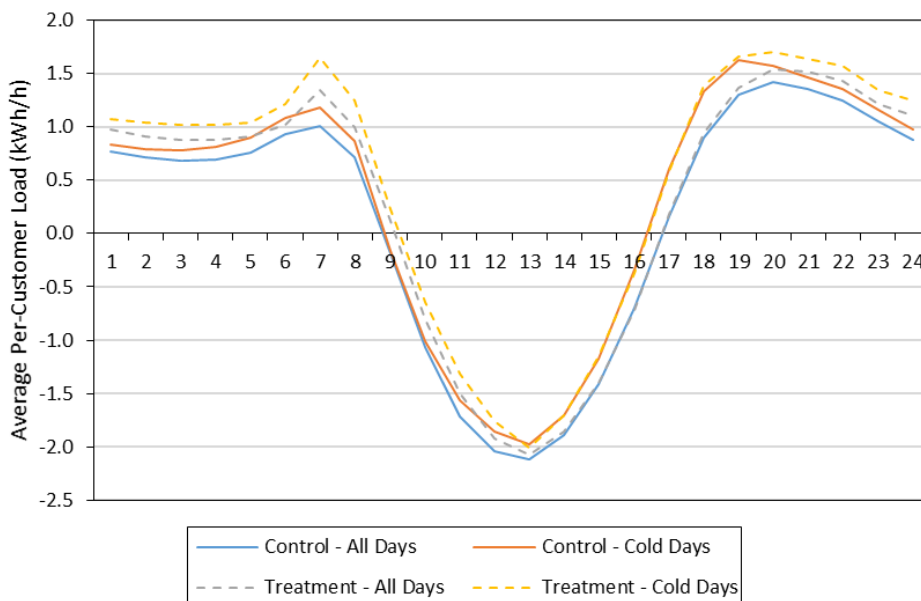


Figure 5.4: NEM TOU and Matched Control Group Load Profiles - Winter



5.2 Ex-post TOU load impacts for TOU customers

This sub-section shows *ex-post* TOU load impact results for those customers enrolled in the TOU (TOU-DR) rate. Table 5.1 summarizes the average reference loads and TOU load impacts for the TOU peak period (*i.e.*, 4 p.m. to 9 p.m.), for the average weekday *by month*, on an aggregate and per-customer basis. The months are shown starting with

the first month included in the analysis (October 2019). The winter months are indicated by light blue shading. Enrollment continued throughout the period, with the numbers of enrolled customers rising from 6,274 in October 2019 to 9,980 in September 2020.²⁴ The estimation methodology for TOU non-NEM customers included applying seasonal (March and April as a separate season) percentage load impacts to monthly reference loads. The seasonal level load impacts are similarly used for NEM customers. During the summer months, the per-customer load impacts are largest and remain constant at 0.06 kWh/h, though this impact varies in percentage terms with respect to the reference load from 3.9 percent in September to 9.1 percent in June. Usage during peak hours *increased* during winter months.

Table 5.1: TOU Peak Load Impacts for TOU Customers – Average Weekday by Month

Month	Climate Zone	Enrolled	Aggregate		Per-Customer		% Peak Load Impact	Ave. Peak Temp.
			Peak Ref. Load (MWh/h)	Peak Load Impact (MWh/h)	Peak Ref. Load (kWh/h)	Peak Load Impact (kWh/h)		
Oct-19	All	6,274	5.48	0.37	0.87	0.06	6.7%	72
Nov-19	All	6,641	6.56	-0.04	0.99	-0.01	-0.6%	62
Dec-19	All	7,056	8.38	-0.03	1.19	0.00	-0.4%	57
Jan-20	All	7,561	7.52	-0.04	0.99	-0.01	-0.5%	58
Feb-20	All	7,960	6.77	-0.04	0.85	-0.01	-0.7%	60
Mar-20	All	8,227	5.07	-0.13	0.62	-0.02	-2.5%	60
Apr-20	All	8,387	4.69	-0.13	0.56	-0.02	-2.7%	64
May-20	All	8,516	4.46	-0.04	0.52	0.00	-0.9%	70
Jun-20	All	8,664	5.50	0.50	0.63	0.06	9.1%	72
Jul-20	All	8,963	7.63	0.52	0.85	0.06	6.8%	74
Aug-20	All	9,418	13.60	0.54	1.44	0.06	4.0%	78
Sep-20	All	9,980	14.46	0.56	1.45	0.06	3.9%	78

Table 5.2 shows results by season and climate zone. The inland climate saw a larger decrease in energy consumption than the coastal climate during summer but saw an increase in the winter.

²⁴ The enrollment numbers in the tables differ from the number of customers used in the regression models, which is a subset of customers that have all the required data for conducting the *ex-post* load impact analysis. Specifically, there were 1,015 incremental customers on the TOU-DR rate with quality load data that were used in estimating the TOU load impacts. Many NEM customers could not be used in the analysis because they changed their NEM status at some point during the two-year study period. Specifically, only 155 NEM TOU customers are included in the regressions. The aggregate TOU load impacts are then scaled to total enrollments.

Table 5.2: TOU Peak Load Impacts for TOU Customers – Average Weekday by Season & Climate Zone

Season	Climate Zone	Enrolled (Average)	Aggregate		Per-Customer		% Peak Load Impact	Ave. Peak Temp.
			Peak Ref. Load (MWh/h)	Peak Load Impact (MWh/h)	Peak Ref. Load (kWh/h)	Peak Load Impact (kWh/h)		
Summer	Coastal	4,362	4.02	0.20	0.92	0.05	5.0%	74
	Inland	4,298	5.28	0.28	1.23	0.07	5.4%	76
	All	8,660	9.30	0.49	1.07	0.06	5.2%	75
Winter	Coastal	3,883	3.16	0.07	0.81	0.02	2.3%	62
	Inland	3,881	3.08	-0.10	0.79	-0.03	-3.4%	61
	All	7,764	6.24	-0.03	0.80	0.00	-0.5%	62

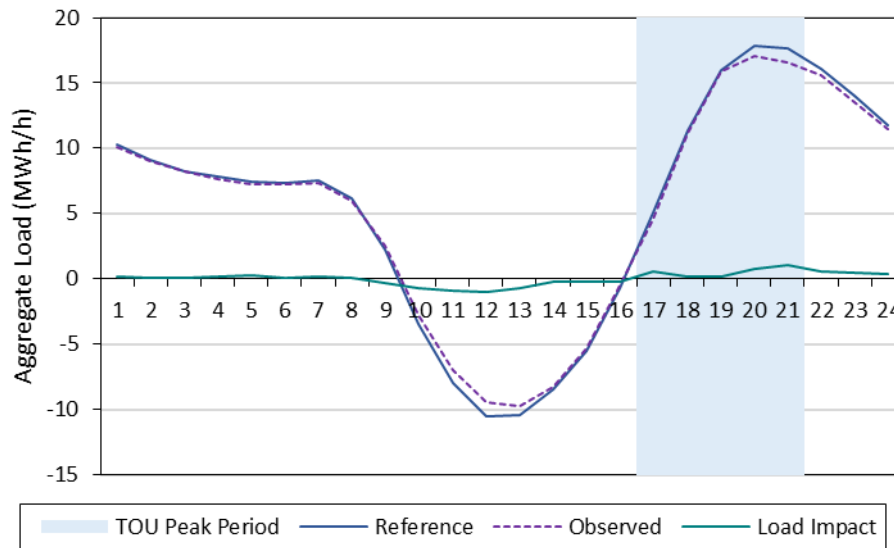
Table 5.3 shows the effect of TOU on average *daily* usage by month. TOU customers decreased their energy consumption in each of the summer months as well as March, April and May; however, they increased daily usage during the remaining winter months. The overall change was an average annual *increase* of about 3 percent. The Covid-19 pandemic also impacted average per-customer reference loads during certain months of the PY2020 period. For example, non-NEM customers increased usage 11 percent during peak hours in months March through September relative to the same period in PY2019.

Table 5.3: TOU Average Daily Load Impacts for TOU Customers, by Month

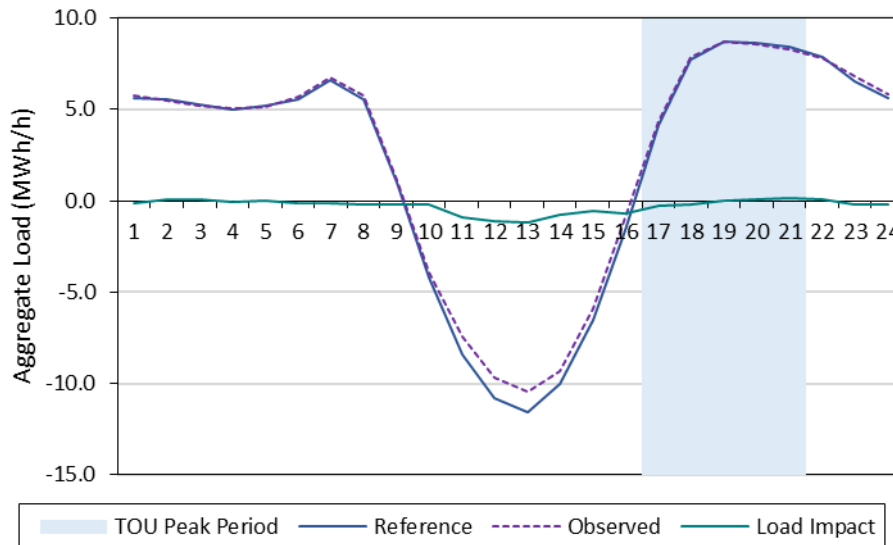
Month	Climate Zone	Enrolled	Aggregate		Per-Customer		Ave. Daily Temp.
			Daily Ref. Load (MWh/h)	Daily Load Impact (MWh/h)	Daily Ref. Load (kWh/h)	Daily Load Impact (kWh/h)	
Oct-19	All	6,274	14.72	1.36	2.35	0.22	67
Nov-19	All	6,641	40.55	-5.93	6.11	-0.89	60
Dec-19	All	7,056	79.77	-6.39	11.31	-0.91	55
Jan-20	All	7,561	49.80	-6.78	6.59	-0.90	55
Feb-20	All	7,960	14.96	-7.09	1.88	-0.89	56
Mar-20	All	8,227	39.76	6.59	4.83	0.80	57
Apr-20	All	8,387	25.91	6.61	3.09	0.79	61
May-20	All	8,516	-19.80	-7.50	-2.32	-0.88	66
Jun-20	All	8,664	19.55	1.61	2.26	0.19	68
Jul-20	All	8,963	38.74	1.39	4.32	0.16	70
Aug-20	All	9,418	129.03	0.82	13.70	0.09	74
Sep-20	All	9,980	131.05	1.10	13.13	0.11	73

Figure 5.5 shows aggregate (NEM and Non-NEM combined) hourly observed and estimated reference loads, along with hourly estimated TOU load impacts for the TOU-only customers for the average weekday in August. Figure 5.6 shows the same information for the average weekday in January. The hourly TOU load impacts in August illustrate a slight reduction in load during the end of peak hours, with a slight increase in usage during off-peak hours in the middle of the day, possibly attributable to “pre-cooling.” There isn’t much evidence of load shifting to super off-peak hours as reference and observed loads during those hours are nearly identical. The TOU load impacts during the winter are not statistically different from zero, and as in August, there is a slight increase in usage during the middle of the day.

**Figure 5.5: Aggregate Hourly Loads and TOU Load Impacts (MWh/h) – TOU Customers
(Average Weekday, August 2020)**



**Figure 5.6: Aggregate Hourly Loads and TOU Load Impacts (MWh/h) – TOU Customers
(Average Weekday, January 2020)**



5.3 TOU control group matching results for CPP customers

Figures 5.7 and 5.8 illustrate the quality of the matches for the Non-NEM residential CPP (TOU-DR-P) customers in the context of measuring TOU peak load impacts on non-event days. The figures show the average CPP and matched control-group customer load profiles for the summer and winter months, respectively. Two pairs of loads are shown, one for all weekdays, and one for the hottest (or coldest) days. In the summer months, the mean percentage error (MPE) of the TOU profile compared to the control-group profile is -3.0 percent, while the mean absolute percentage error (MAPE) is 3.2 percent. In the winter months, the MPE is -0.2 percent and the MAPE is 1.3 percent.

Figure 5.7: Non-NEM CPP and Matched Control Group Load Profiles – Summer

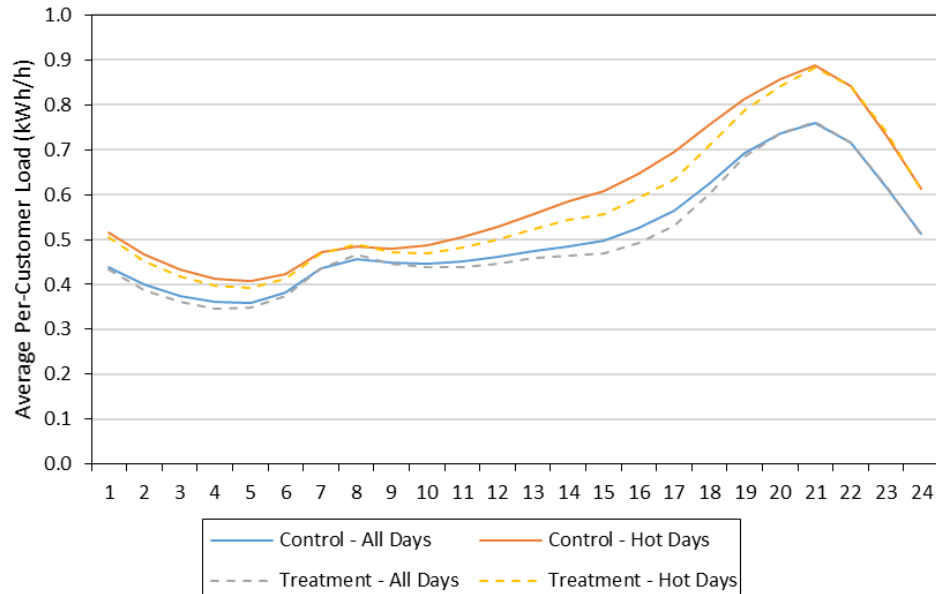
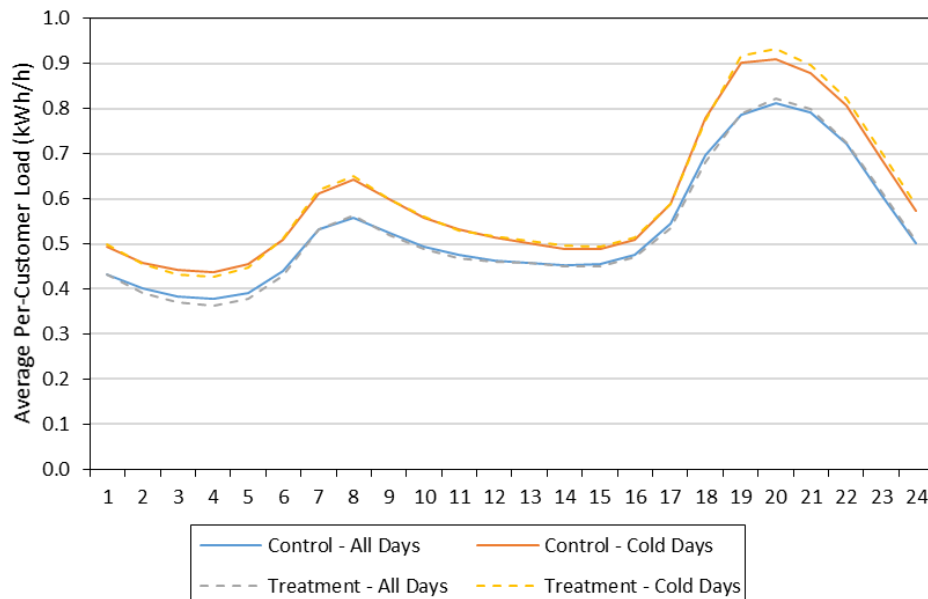


Figure 5.8: Non-NEM CPP and Matched Control Group Load Profiles – Winter



Figures 5.9 and 5.10 illustrate the quality of the matches for the NEM residential CPP (TOU-DR-P) customers in the context of measuring TOU peak load impacts on non-event days. The figures show the average CPP and matched control-group customer load profiles for the summer and winter months, respectively. Two pairs of loads are shown, one for all weekdays, and one for the hottest (or coldest) days. In the summer months, the mean error (ME) of the TOU profile compared to the control-group profile is 0.11 kWh/h, while the mean absolute error (MAE) is 0.16 kWh/h. In the winter months, the ME is 0.15 kWh/h and the MAE is 0.16 kWh/h.

Figure 5.9: NEM CPP and Matched Control Group Load Profiles – Summer

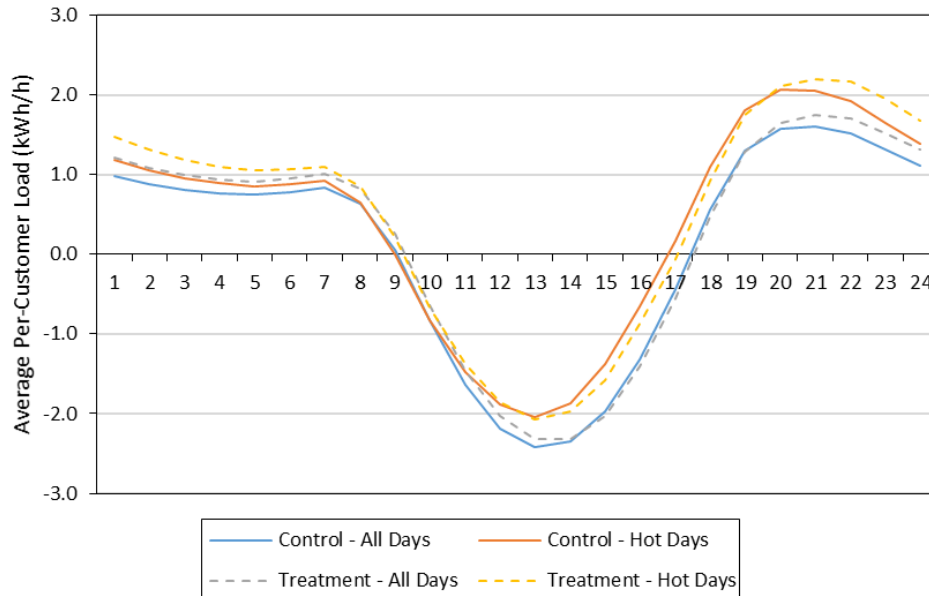
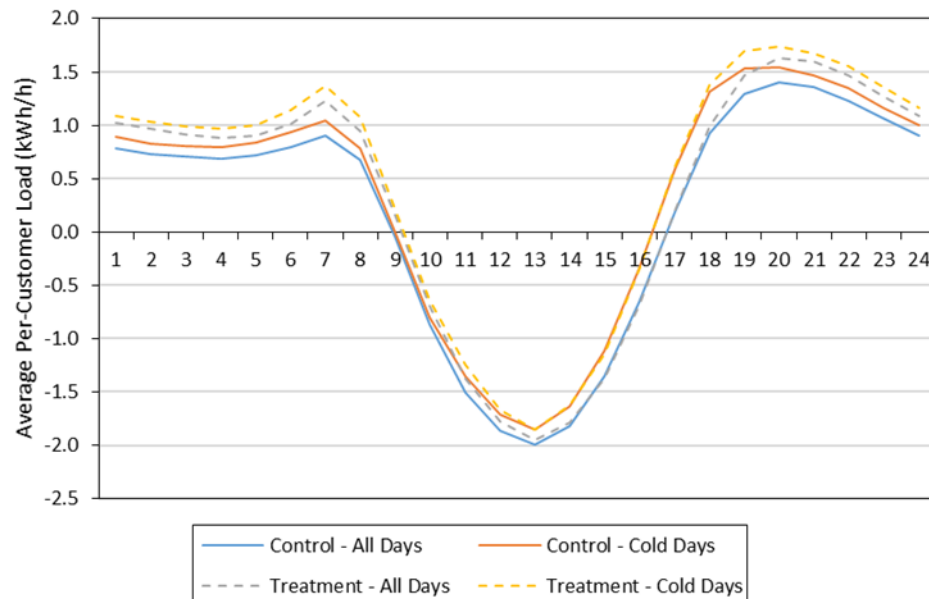


Figure 5.10: NEM CPP and Matched Control Group Load Profiles – Winter



5.4 Ex-post TOU load impacts for CPP customers

Since TOU-DR-P customers experience TOU prices on all weekdays that are not residential CPP event days, it is of interest to examine their usage changes on non-event days, similar to TOU customers. This sub-section reports *ex-post* TOU load impact results for those customers enrolled on the CPP (TOU-DR-P) rate. Table 5.4 summarizes peak-period loads and load impacts for the average summer (October 2019, and June through September 2020) and winter (November 2019 through May 2020) weekdays, by month.

Reported enrollment in CPP grew from 11,838 in October 2019 to 15,735 in September 2020.²⁵ Peak load impacts varied across months, with estimated load reductions in all months except for August. Peak load reductions ranged from 1.1 percent (in July) to 10.1 percent of the reference load (in October).

Table 5.4: TOU Peak Load Impacts for CPP Customers – Average Weekday by Month

Month	Climate Zone	Enrolled	Aggregate		Per-Customer		% Peak Load Impact	Ave. Peak Temp.
			Peak Ref. Load (MWh/h)	Peak Load Impact (MWh/h)	Peak Ref. Load (kWh/h)	Peak Load Impact (kWh/h)		
Oct-19	All	11,838	10.34	1.04	0.87	0.09	10.1%	72
Nov-19	All	12,071	10.40	0.33	0.86	0.03	3.2%	62
Dec-19	All	12,383	12.81	0.66	1.03	0.05	5.2%	58
Jan-20	All	12,799	11.70	0.51	0.91	0.04	4.3%	58
Feb-20	All	13,216	11.04	0.49	0.84	0.04	4.4%	60
Mar-20	All	13,611	10.33	0.17	0.76	0.01	1.7%	60
Apr-20	All	14,102	10.99	0.23	0.78	0.02	2.1%	64
May-20	All	14,412	11.69	0.79	0.81	0.05	6.8%	70
Jun-20	All	14,689	11.57	0.25	0.79	0.02	2.2%	72
Jul-20	All	15,075	13.54	0.14	0.90	0.01	1.1%	73
Aug-20	All	15,533	17.04	-0.02	1.10	0.00	-0.1%	76
Sep-20	All	15,735	17.22	0.22	1.09	0.01	1.3%	77

Table 5.5 summarizes results by season and climate zone. Summer load impacts are larger for the Coastal climate zone; while winter load impacts are larger for the inland climate zone.

²⁵ The number of CPP customers included in the regressions is substantially smaller than the number used for the same group of customers in the context of measuring CPP load impacts. This difference is due to the need to have data available for both the program year and the pre-treatment period, which served as the basis for control group matching, whereas load data for only the event day and event-like non-event days were required for measuring CPP load impacts. There were 3,067 incremental customers on the TOU-DR-P rate with quality load data that were used in the regressions for estimating the TOU load impact for CPP customers.

Table 5.5: TOU Peak Load Impacts for CPP Customers – Average Weekday by Season & Climate Zone

Season	Climate Zone	Enrolled (Average)	Aggregate		Per-Customer		% Peak Load Impact	Ave. Peak Temp.
			Peak Ref. Load (MWh/h)	Peak Load Impact (MWh/h)	Peak Ref. Load (kWh/h)	Peak Load Impact (kWh/h)		
Summer	Coastal	8,864	7.66	0.27	0.86	0.03	3.6%	73
	Inland	5,710	6.25	0.05	1.10	0.01	0.8%	76
	All	14,574	13.92	0.32	0.95	0.02	2.3%	74
Winter	Coastal	7,976	6.54	0.24	0.82	0.03	3.7%	63
	Inland	5,252	4.73	0.21	0.90	0.04	4.4%	62
	All	13,228	11.27	0.45	0.85	0.03	4.0%	62

Table 5.6 shows the effect of TOU on average daily usage by month. CPP customers *increased* their average daily usage during all summer months, with the exception of October, and *decreased* their usage in all winter months, with the exception of March and April. There is a net zero overall annual load impact. The Covid-19 pandemic also impacted average per-customer reference loads during certain months of the PY2020 period. For example, non-NEM customers increased usage 12 percent during peak hours in months March through September relative to the same period in PY2019.

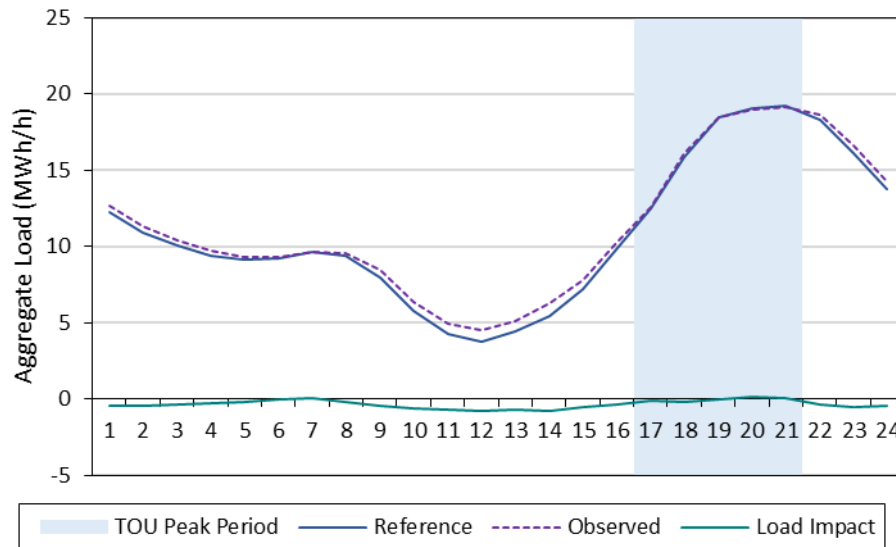
Table 5.6: TOU Average Daily Load Impacts for CPP Customers, by Month

Month	Climate Zone	Enrolled	Aggregate		Per-Customer		% Peak Load Impact	Ave. Daily Temp.
			Daily Ref. Load (MWh/h)	Daily Load Impact (MWh/h)	Daily Ref. Load (kWh/h)	Daily Load Impact (kWh/h)		
Oct-19	All	11,838	153.72	10.23	12.99	0.86	6.7%	67
Nov-19	All	12,071	159.09	1.33	13.18	0.11	0.8%	60
Dec-19	All	12,383	204.24	6.22	16.49	0.50	3.0%	55
Jan-20	All	12,799	184.43	4.65	14.41	0.36	2.5%	55
Feb-20	All	13,216	165.28	2.35	12.51	0.18	1.4%	57
Mar-20	All	13,611	167.67	-4.15	12.32	-0.30	-2.5%	57
Apr-20	All	14,102	173.98	-2.60	12.34	-0.18	-1.5%	61
May-20	All	14,412	169.54	2.06	11.76	0.14	1.2%	67
Jun-20	All	14,689	183.04	-2.35	12.46	-0.16	-1.3%	68
Jul-20	All	15,075	208.72	-4.12	13.85	-0.27	-2.0%	70
Aug-20	All	15,533	262.03	-8.36	16.87	-0.54	-3.2%	73
Sep-20	All	15,735	256.61	-5.02	16.31	-0.32	-2.0%	72

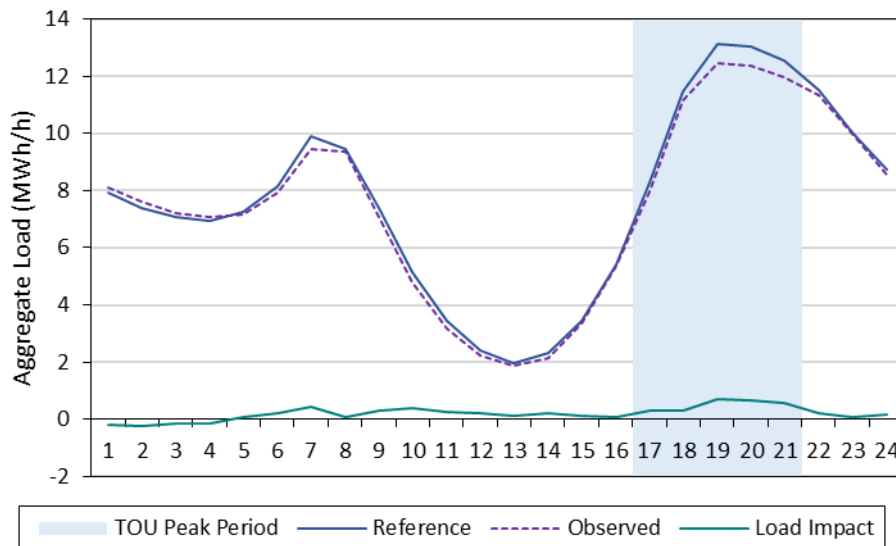
Figure 5.11 shows aggregate hourly observed and estimated reference loads, along with hourly estimated load impacts for the residential CPP customers for the average weekday in August. Figure 5.12 shows the same information for the average weekday in

January. The average weekday in August loads illustrates a load shift out of the peak period to the off-peak periods. The January average loads exhibit a reduction in usage during the peak period, and close to zero change during all other hours.

**Figure 5.11: Aggregate Hourly Loads and TOU Load Impacts (MWh/h) – CPP Customers
(Average Weekday, August 2020)**



**Figure 5.12: Aggregate Hourly Loads and TOU Load Impacts (MWh/h) – CPP Customers
(Average Weekday, January 2020)**



5.5 TOU control group matching results for Grandfathered customers

Figures 5.13 and 5.14 illustrate the quality of the matches for the grandfathered CPP (GTOU-DR-P) customers in the context of measuring TOU peak load impacts on non-event days. The figures show the average grandfathered CPP and matched control-group customer load profiles for the summer and winter months, respectively. Two pairs of loads are shown, one for all weekdays, and one for the hottest (or coldest) days. In the summer months, the mean error (ME) of the TOU profile compared to the control-group profile is 0.10 kWh/h, while the mean absolute error (MAE) is 0.11 kWh/h. In the winter months, the ME is 0.00 kWh/h and the MAE is 0.04 kWh/h.

Figure 5.13: Grandfathered CPP and Matched Control Group Load Profiles – Summer

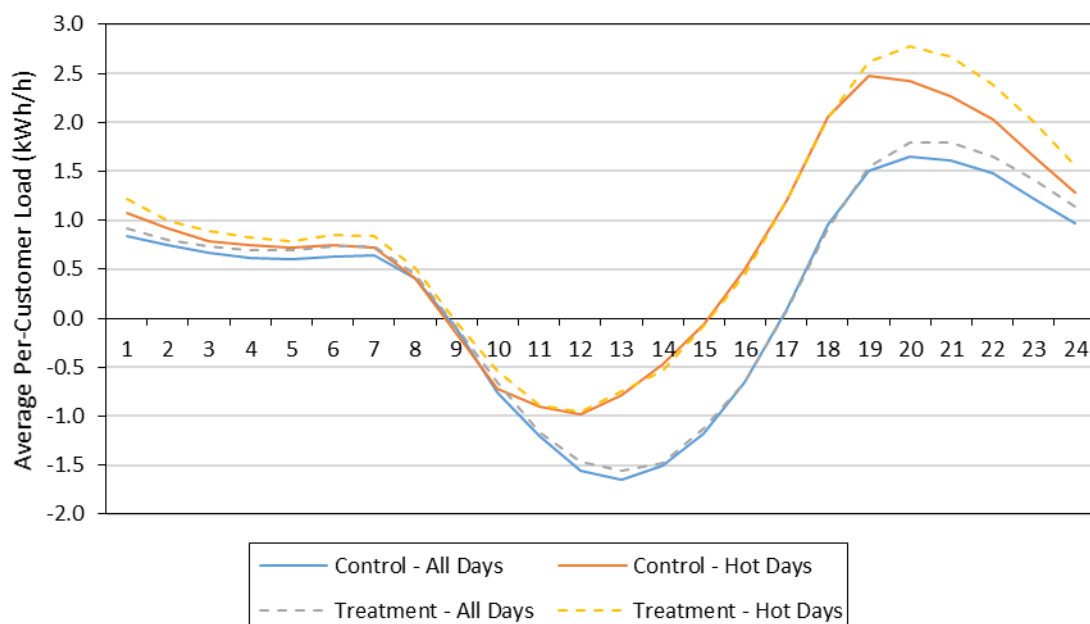
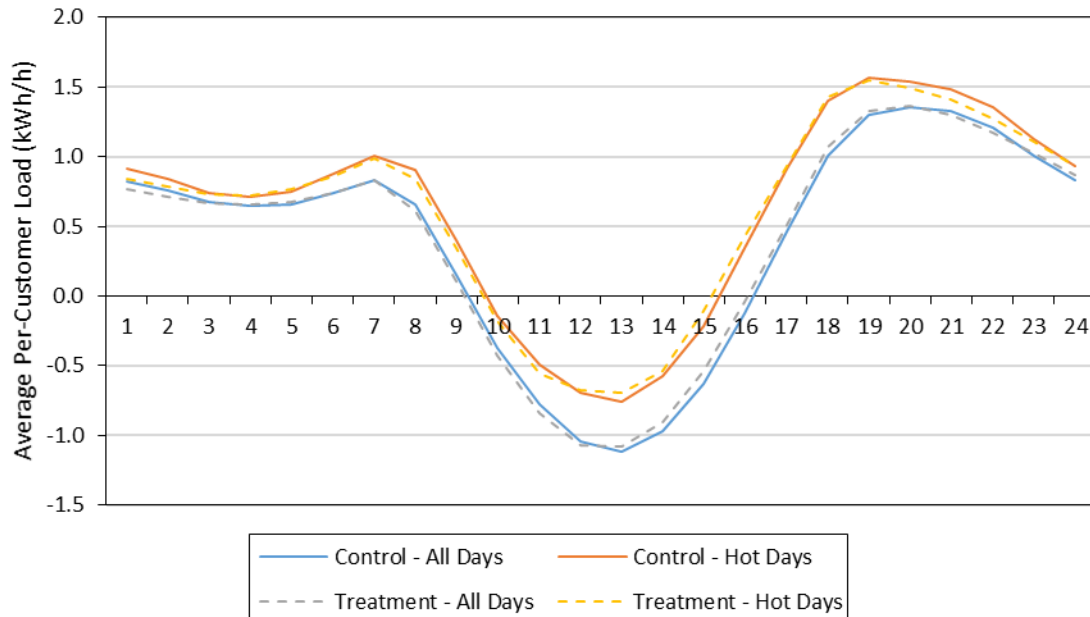


Figure 5.14: Grandfathered CPP and Matched Control Group Load Profiles – Winter



5.6 Ex-post TOU load impacts for Grandfathered customers

This sub-section shows *ex-post* TOU load impact results for Grandfathered customers (enrolled in GTOU-DR-P). Table 5.7 summarizes the average reference loads and TOU load impacts for the TOU peak period (*i.e.*, 11 a.m. to 6 p.m. during summer months, 5 to 8 p.m. during winter months), for the average weekday *by month*, on an aggregate and per-customer basis. The TOU load impacts are estimated using incremental customers that were matched using PY2016 data, since grandfathered customers have been treatment customers since that time. However, monthly enrollment numbers and reference loads are drawn from the October 2019 through September 2020 period. The winter months are indicated by light blue shading.²⁶ Enrollments gradually increase throughout the period.²⁷ The per-customer load impacts remain constant by season because of the methodology implemented, resulting in per-customer load *increases* of 0.11 kWh/h and 0.17 kWh/h for the summer and winter seasons, respectively. Positive reference loads during the winter and negative reference loads during the summer occur because of the different TOU peak-period, where the summer peak-period covers a more of the day when customers are generating more than they are using.

²⁶ The summer and season month definitions, however, differed during the PY2017 analysis. Specifically, May was categorized as a summer month, but is now included in the winter season period.

²⁷ The enrollment numbers in the tables differ from the number of customers used in the regression models, which is a subset of customers that have all the required data for conducting the *ex-post* load impact analysis. Specifically, only 27 incremental grandfathered customers were included in the regression analysis. These are customers who remained unchanged since the pretreatment period in 2016. The aggregate TOU load impacts are then scaled to total enrollments during the PY2020 period.

**Table 5.7: TOU Peak Load Impacts for Grandfathered Customers
– Average Weekday by Month**

Month	Climate Zone	Enrolled	Peak Ref. Load (MWh/h)	Peak Load Impact (MWh/h)	Peak Ref. Load (kWh/h)	Peak Load Impact (kWh/h)	Ave. Peak Temp.
Oct-19	All	429	-0.63	-0.05	-1.47	-0.11	78
Nov-19	All	431	0.55	-0.07	1.27	-0.17	61
Dec-19	All	432	0.64	-0.07	1.49	-0.17	57
Jan-20	All	441	0.57	-0.07	1.29	-0.17	58
Feb-20	All	445	0.53	-0.08	1.18	-0.17	60
Mar-20	All	450	0.39	-0.08	0.86	-0.17	60
Apr-20	All	453	0.36	-0.08	0.80	-0.17	65
May-20	All	455	0.36	-0.08	0.78	-0.17	71
Jun-20	All	459	-0.83	-0.05	-1.82	-0.11	75
Jul-20	All	462	-0.81	-0.05	-1.75	-0.11	78
Aug-20	All	472	-0.38	-0.05	-0.81	-0.11	82
Sep-20	All	477	-0.25	-0.05	-0.53	-0.11	84

Table 5.8 summarizes results by season and climate zone. Both climate zones *increased* usage during the summer period, whereas the Coastal climate zone *decreased* usage during the TOU peak-period load impacts during winter.²⁸

**Table 5.8: TOU Peak Load Impacts for Grandfathered Customers
– Average Weekday by Season & Climate Zone**

Season	Climate Zone	Enrolled (Average)	Aggregate		Per-Customer		Ave. Peak Temp.
			Peak Ref. Load (MWh/h)	Peak Load Impact (MWh/h)	Peak Ref. Load (kWh/h)	Peak Load Impact (kWh/h)	
Summer	Coastal	217	-0.35	-0.08	-1.62	-0.38	78
	Inland	243	-0.26	0.00	-1.09	-0.02	81
	All	460	-0.62	-0.05	-1.26	-0.11	80
Winter	Coastal	210	0.28	0.02	1.33	0.09	62
	Inland	234	0.22	-0.08	0.94	-0.35	61
	All	444	0.50	-0.08	1.09	-0.17	62

²⁸ The aggregate load impacts in separate climate zones do not sum to the impacts in the “all” climate zone category because the former load impacts were obtained from regressions that were estimated separately by climate zone, while the latter load impacts were obtained from regressions using all customers.

Table 5.9 shows the effect of TOU on average daily usage by month. Grandfathered customers *increased* overall usage during both summer and winter months. The overall effect is an average annual *increase* of about 3.25 kWh/h per customer.

Table 5.9: TOU Average *Daily* Load Impacts for Grandfathered Customers, *by Month*

Month	Climate Zone	Enrolled	Aggregate		Per-Customer		Ave. Daily Temp.
			Daily Ref. Load (MWh/h)	Daily Load Impact (MWh/h)	Daily Ref. Load (kWh/h)	Daily Load Impact (kWh/h)	
Oct-19	All	429	-0.41	-1.50	-0.96	-3.50	67
Nov-19	All	431	3.07	-1.32	7.12	-3.07	59
Dec-19	All	432	5.45	-1.33	12.62	-3.07	55
Jan-20	All	441	2.85	-1.35	6.45	-3.07	55
Feb-20	All	445	-0.22	-1.37	-0.49	-3.07	56
Mar-20	All	450	0.39	-1.38	0.87	-3.07	57
Apr-20	All	453	-0.91	-1.39	-2.00	-3.07	61
May-20	All	455	-3.18	-1.40	-6.98	-3.07	67
Jun-20	All	459	-1.32	-1.61	-2.88	-3.50	68
Jul-20	All	462	-0.30	-1.62	-0.64	-3.50	70
Aug-20	All	472	5.35	-1.65	11.33	-3.50	74
Sep-20	All	477	5.57	-1.67	11.68	-3.50	73

Figure 5.15 and Figure 5.16 show aggregate hourly observed and estimated reference loads, along with hourly estimated load impacts for the grandfathered customers for the average weekday in August and January, respectively. The TOU peak periods are represented by the hours with blue highlighting. The summer period appears to exhibit some load shifting from the TOU peak period of off-peak hours that correspond to the non-grandfathered TOU period (and the RA window). The winter load profile illustrates a larger response during the middle of the day, outside of the peak TOU period, and a load increase during peak hours.

Figure 5.15: Aggregate Hourly Loads and TOU Load Impacts (MWh/h) – Grandfathered Customers (Average Weekday, August 2020)

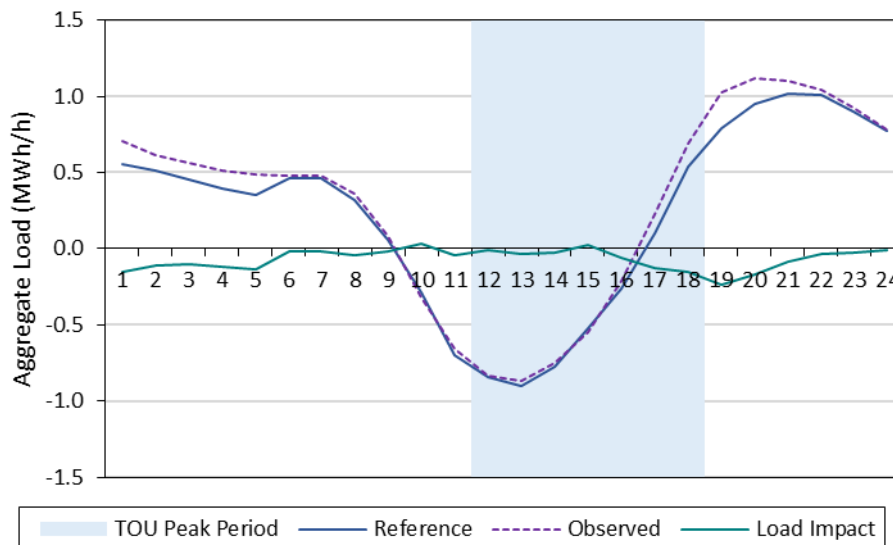
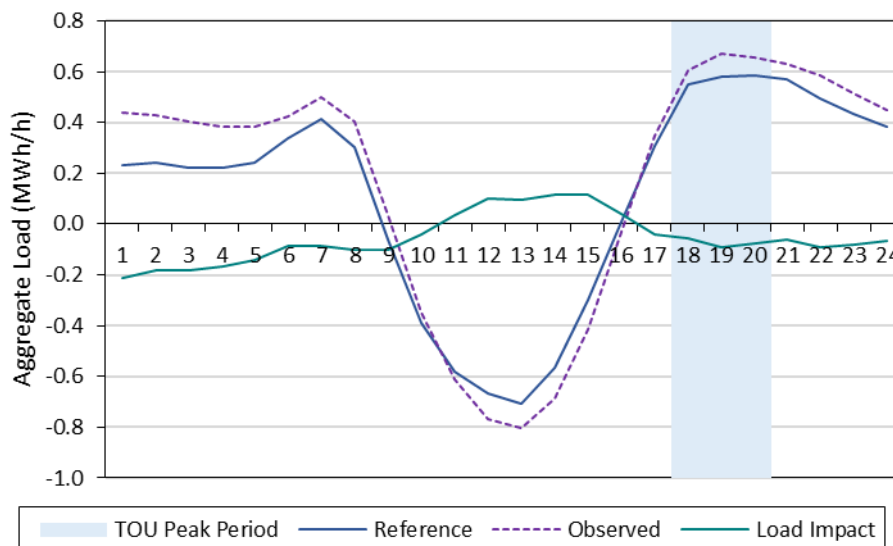


Figure 5.16: Aggregate Hourly Loads and TOU Load Impacts (MWh/h) – Grandfathered Customers (Average Weekday, January 2020)



6. *Ex-Ante* Evaluation Methodology

This section describes the methodology for developing *ex-ante* load impact forecasts for the CPP and TOU rates. *Ex-ante* load impacts represent forecasts of load impacts that are expected to occur when program events are called in future years (CPP), or in TOU peak periods (TOU), under standardized weather conditions. 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.

In PY2020, the COVID-19 pandemic influenced customer reference loads and load impacts. The following primary sections provide details regarding a standard *ex-ante* methodology while Section 6.4 provides additional methods and adjustments used to account for COVID-19 during the forecast period.

6.1 Per-customer load impacts

In cases where multiple events have been called in the historical period for event-based programs such as CPP, a relationship between the estimated event-day *ex-post* load impacts and the weather conditions is developed. That relationship is used to produce weather-sensitive *ex-ante* load impacts for the relevant weather scenarios. In 2020 SDG&E called nine residential CPP events, six of which were called on a weekday. Since the *ex-ante* analysis relies on weekday load impacts, this means there are six events on which to base the *ex-ante* forecasts. The percentage load impact is used for the average weekday event to simulate the *ex-ante* CPP load impact. CPP load impacts for different weather scenarios are developed by applying the estimated percentage load impact from the *ex-post* analysis to weather-sensitive reference loads.

Portfolio-level load impacts are reported for instances when a CPP event is called on the same day as a AC Saver Day-Ahead or Day-Of event. For such days, it is assumed that AC Saver Day-Ahead and Day-Of customers do not provide a load impact that can be attributable to CPP and therefore remove dually enrolled customers from the reference load and load impacts for portfolio-level estimates. The proportion of AC Saver Day-Ahead and Day-Of customers is assumed to be equivalent to *ex-post* enrollment numbers and is held constant throughout the *ex-ante* forecast.

An additional issue in producing the *ex-ante* load impact forecasts is that the Protocols call for estimating load impacts for the RA hours of 4 to 9 p.m., while the CPP events are called during the program hours of 2 p.m. to 6 p.m. year-round. Load impacts are simulated using the event hours that are indicated by the tariff, however the load impacts are summarized across the RA window, as required.

For TOU load impacts (TOU-DR and TOU-DR-P customers), percentage peak load impacts from the *ex-post* analysis (monthly values for CPP and seasonal values for TOU) are applied to weather-sensitive reference loads that are developed as described in the following sub-section.

NEM customer reference loads and load impacts are estimated separately from non-NEM customers. For both TOU and CPP load impacts, *ex-post* seasonal TOU load impacts and average CPP event-day 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 and CPP outcomes.

6.2 Per-customer reference loads

Weather-sensitive reference loads for the average customer in each of the two climate zones were developed through a regression analysis of hourly load data for weekday non-event days for the CPP and TOU customers.²⁹ Customers are first sorted as weather sensitive or not.³⁰ Regression models were estimated separately for each hour of the day, by weather sensitivity, using daily observations for weekdays, and a form similar to that of the *ex-post* load impact models. The primary differences between this analysis compared to the *ex-post* analysis are:

- The analysis included only the treatment customers;
- Weather variables were included (Mean17, CDH60, and HDH60)³¹;
- Data for all months were included, rather than estimating separate models by month or season; and
- Month-year indicator variables were added to account for monthly and yearly differences in usage patterns.

The resulting equations allow the simulation of “observed” (*i.e.*, post TOU load impacts) loads under the four different weather scenarios. Reference loads for the alternative scenarios were then obtained by adjusting the above observed loads by the relevant estimated percentage TOU load impacts from the *ex-post* analysis (seasonal values for TOU, and monthly values for CPP).³² For NEM customers, reference loads are calculated

²⁹ The most recent October through September period is used. In the current PY20 analysis, however, the COVID-19 pandemic influenced reference loads. Therefore, PY19 reference loads are used as a baseline and COVID-19 adjustments are incorporated over the forecast period. The COVID-19 assumptions and reference load adjustments are described below in Section 6.4.

³⁰ Customer-specific regressions are implemented to categorize customers as weather sensitive or not. Weather sensitive customers change usage in response to changes in the weather, while non-weather sensitive customers do not. Determining which customers are non-weather sensitive allows for a more parsimonious regression model by not including weather variables as explanatory variables for these customers. The following regression specification is used to determine whether a customer is weather sensitive:

$$Q_t = b^{Weather} \times Weather_t + \sum_{i=2}^5 (b_i^{DTYPE} \times DTYPE_{i,t}) + \sum_{i=7}^9 (b_i^{MONTH} \times MONTH_{i,t}) + \sum_{i=1}^{EVT} (b_i^{EVT} \times EVT_{i,t}) + e_t$$

, where Q_t represents the average customer usage during event hours on day t in the summer months of June through September. $DTYPE_{i,t}$ represents the day of week, while $MONTH_{i,t}$ represents each month. The $EVT_{i,t}$ variables control for any event days a customer faces (BIP, CPP, *etc.*). The variable of importance is $Weather_t$, which is defined as CDD55, CDD60, or CDD65, each as a separate regression. The regression is estimated for each customer and weather specification. A customer is identified as weather sensitive if the weather coefficient ($b^{Weather}$) is positive and statistically significant for any of the three separate weather specifications.

³¹ Mean17 is the average temperature in degrees Fahrenheit during the first 17 hours of the day. Cooling degree hours (CDH) for each hour of the day are defined as: $CDH60 = \max(0, \text{Temperature in } ^\circ\text{F} - 60)$. Likewise, heating degree hours (HDH) for each hour of the day are defined as: $HDH60 = \max(0, 60 - \text{Temperature in } ^\circ\text{F})$.

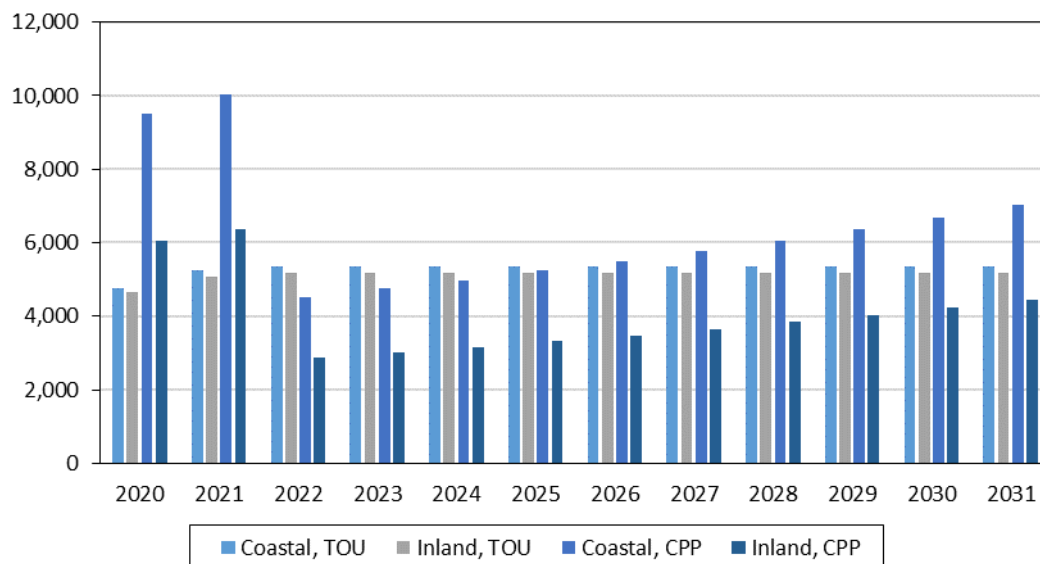
³² The adjustment takes the form of $\text{Reference} = \text{Observed} / (1 - \% \text{TOULoadImpact})$. CA Energy Consulting examined several alternative approaches to developing the weather-sensitive reference load, including the same type of regression analysis using load data for the matched control group customers. The

by adjusting observed loads by the relevant seasonal *ex-post* level load impacts. The process for obtaining simulated reference and observed loads is completed separately for each reporting category.³³

6.3 Enrollment Forecast

Figure 6.1 shows SDG&E's enrollment forecasts for the TOU and CPP rates. Enrollment is anticipated to be essentially flat for TOU. While enrollment in CPP is forecasted to increase in 2021 and then substantially decline in 2022 as customers migrate to the Community Choice Aggregator program. Enrollment on the TOU-only rate is expected to be somewhat greater in the Coastal climate zone than in the Inland. This enrollment by climate zone difference is larger among residential CPP customers. Enrollment for grandfathered customers (GTOU-DR-P) is assumed to remain constant at 477 customers until the grandfathering term expires on July 31, 2022.

Figure 6.1: Enrollments in TOU and CPP Rates



6.4 COVID-19 Adjustments to the Ex-Ante Forecast

Residential customers, on average, exhibited an increase in load as a response to the COVID-19 pandemic which began in March 2020. As a result, the methodology

resulting reference loads were not very sensitive to the data and approach used, although the selected approach produced more accurate loads during the swing months.

³³ The use of panel regressions limits results to only apply to the customer type included in the regressions, as opposed to customer-specific regressions for which sub-categories can be created by combining pieces from the individual regressions. Therefore, any sub-categorization of results needs to be processed separately to account for possible differences in weather sensitivity and load profiles. For example, customers dually enrolled in CPP and TD have larger loads. Therefore, separate panel regressions including only dually enrolled CPP and TD customers would be estimated to simulate reference and observed loads for these customers.

described above for estimating *ex-ante* reference loads and load impacts requires an adjustment to account for how COVID will affect customer usage over the forecast period. First, we estimate the effect COVID had on the average customer's hourly reference loads. Separate hourly COVID effects are estimated by rate (TOU-DR and TOU-DR-P, and grandfathered counterparts) and NEM status. Second, we adjust the magnitude of the COVID effect over time based on utility-provided assumptions regarding the expected evolution of the COVID effect during the forecast period. Consequently, the TOU load impacts are adjusted for non-NEM customers because they are calculated based upon the *ex-post* load impact percentage relative to the reference load. Third, TOU load impacts for NEM customers are adjusted based upon the difference between the PY20 and PY19 load impacts and the assumed transition of the COVID effect over time.³⁴

The following regression specification is estimated for each rate, by NEM status, and hour separately to capture the effect COVID had on consumption:

$$kWh_{c,d} = \beta_0 + \beta_1 \times COVID_d + \beta_2 \times CDD65_d + \beta_3 \times HDD65_d + \sum_m (\beta_{4,m} \times MONTH_{d,m}) + \sum_{Cust} (\beta_{5,Cust} \times C_c) + \epsilon_{c,d}$$

Table 6.1: Descriptions of Terms included in the COVID Regression Equation

Variable Name	Variable Description
$kWh_{c,d}$	Load in a particular hour for customer c on date d
The various b 's	the estimated parameters
$COVID_d$	an indicator variable for if day d is during the COVID-19 pandemic (<i>i.e.</i> , post March 2020)
$CDD65_d$	average cooling degree days ³⁵
$HDD65_d$	average heating degree days ³⁶
$MONTH_d$	a series of indicator variables for each month
C_c	Variable indicating that the observation is associated with customer c
$\epsilon_{c,d}$	the error term

Table 6.1 provides a description of the variables in the model. Customer non-holiday weekday load data covering the period October 2018 through September 2020 is used

³⁴ The DR-TOU load impacts for NEM customers are not based on percentages relative to the reference load. The *ex-ante* load impact, consequently, would not differ as a result of COVID-19 adjustments to reference loads. The assumption is made that differences between the PY20 and PY19 *ex-post* level load impacts for NEM customers is a result of COVID-19. The magnitude of the COVID effect on NEM *ex-ante* load impacts decreases over time based on the assumed timeline provided by SDG&E.

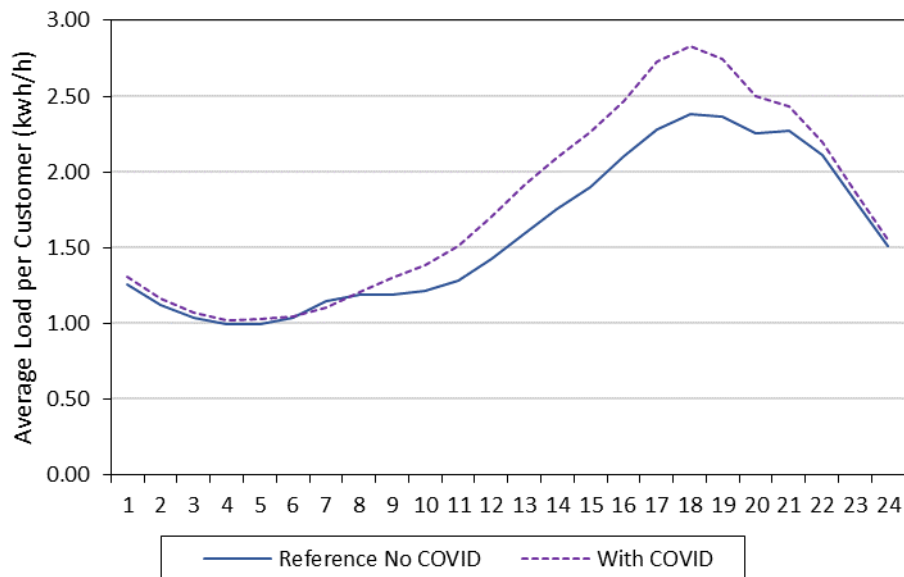
³⁵ Cooling degree days (CDD) are defined as $\text{MAX}[0, (\text{Max Temp} + \text{Min Temp}) / 2 - 60]$, where Max Temp is the daily maximum temperature in degrees Fahrenheit and Min Temp is the daily minimum temperature. Customer-specific CDD values are calculated using data from the most appropriate weather station.

³⁶ Heating degree days (HDD) are defined as $\text{MAX}[0, 60 - (\text{Max Temp} + \text{Min Temp}) / 2]$, 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.

to provide sufficient pre-COVID information.³⁷ Only embedded customers, *i.e.*, those that were on the TOU-DR or TOU-DR-P rate for the entire period, are included to prevent confounding the COVID effect with a TOU effect. The variable of importance, *COVID*, provides an estimate of each customer's load change in response to the pandemic. The estimated coefficient for *COVID*, β_1 , is used to adjust *ex-ante* reference loads for the various levels of COVID specified in the utility's forecasts.

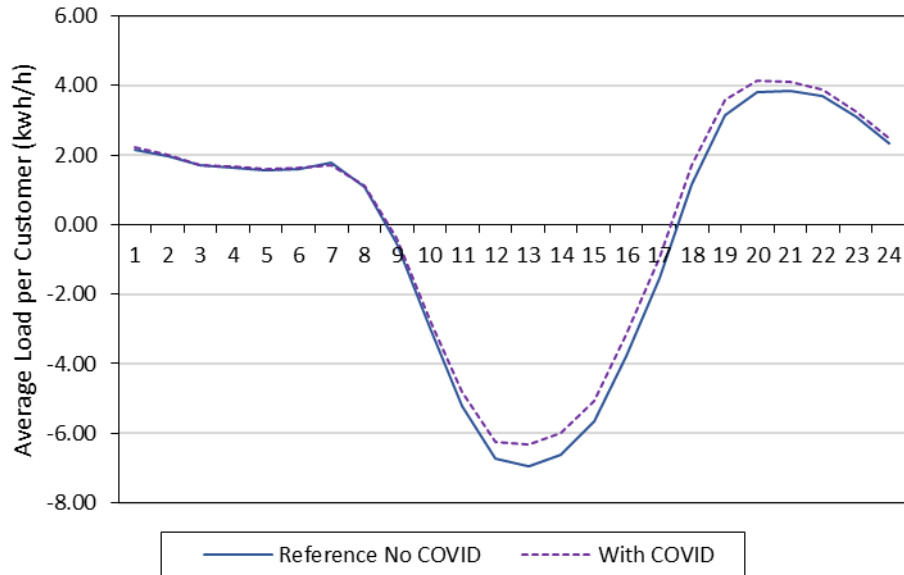
Figures 6.2 through 6.5 illustrate the average per-customer August *ex-ante* reference loads with and without COVID for each rate (TOU-DR and TOU-DR-P) and NEM status. The purple dashed line displays the adjusted reference loads assuming 100% of the COVID effect. In each case, energy consumption is greater during the day as a result of COVID, whereas energy consumption remains similar during super off-peak periods. For example, the average TOU-DR non-NEM customer increased usage by 2 percent during the morning hours (hour-ending 1-8), but increased usage by 13 percent during the remaining hours of the day.

Figure 6.2: Ex-Ante August Load with Covid-19 Adjustment, TOU-DR non-NEM Customers



³⁷ A greater period of data is required to not confound the COVID effect with usage that occurs during summer months. Therefore, it is important to have at least of full year of data before the pandemic began in March 2020. The maximum amount of data available is used for customers that had less than the full two-year period. Specific days that have an effect on customer usage are removed from the analysis (*e.g.*, program events, public safety power shutoffs, FLEX alert).

**Figure 6.3: Ex-Ante August Load with Covid-19 Adjustment,
TOU-DR NEM Customers**



**Figure 6.4: Ex-Ante Aggregate June Load with Covid-19 Adjustment,
TOU-DR-P non-NEM Customers**

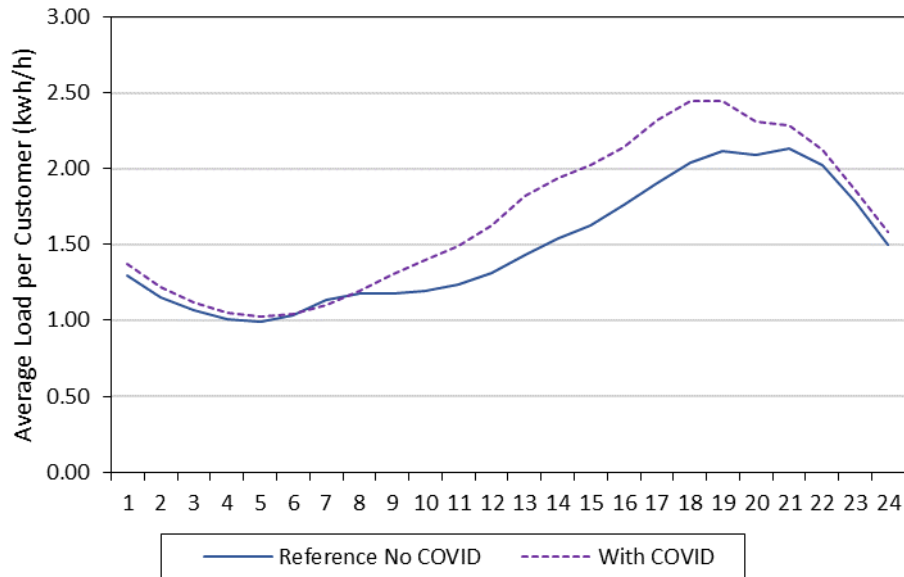
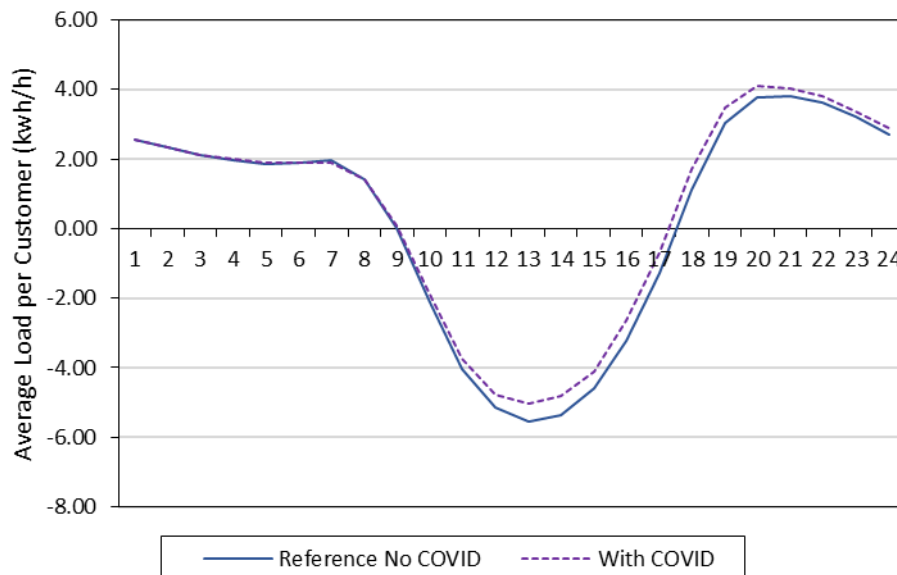
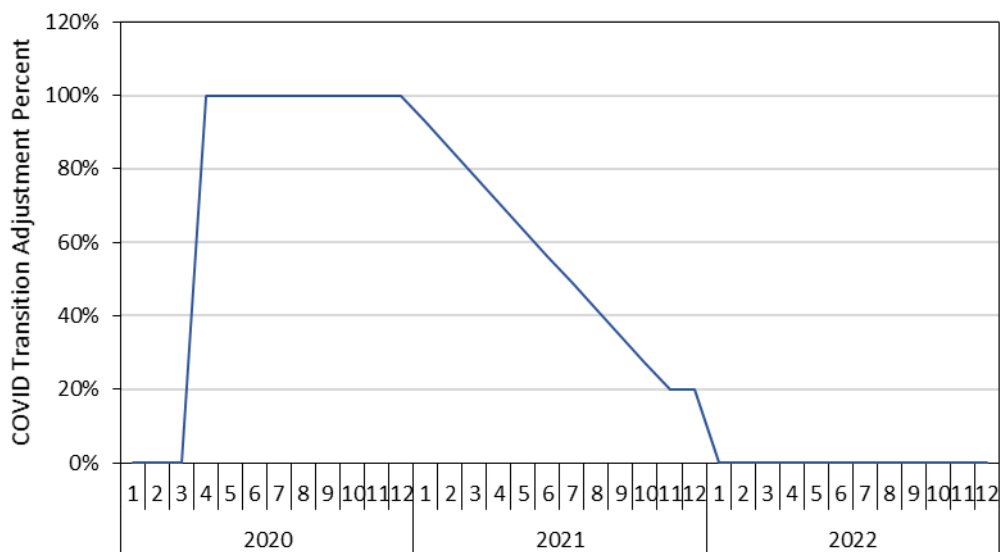


Figure 6.5: Ex-Ante Aggregate June Load with Covid-19 Adjustment, TOU-DR-P non-NEM Customers



SDG&E provided assumptions regarding how to adjust the magnitude of the COVID effect over time. The magnitude of the pandemic effect on customer usage lessens over time. Therefore, COVID-affected reference loads (and load impacts) will approach the non-COVID reference load according to the COVID transition assumptions. Figure 6.6 illustrates the monthly COVID transition assumption, with the effect assumed to be zero percent starting in 2022. The percentage assumptions are applied to the magnitude of the COVID effect in its respective period. For example, a 0.1 kW COVID related usage decrease is reduced to 0.05 kW when 50 percent of the COVID effect is assumed. The COVID effects are estimated and applied at the rate by NEM status level.

Figure 6.6: COVID-19 Transition Path Assumption



7. *Ex-Ante* Load Impact Study Findings

This section presents the *Ex-ante* TOU load impacts for rates TOU-DR and TOU-DR-P, along with grandfathered counterparts.

7.1 *Ex-Ante* load impacts – Residential CPP

This subsection summarizes the *ex-ante* load impact forecasts for future CPP event days, for customers anticipated to be enrolled in CPP. Figure 7.1 illustrates the aggregate reference load, event-day load, and estimated load impact for an August peak day in 2022 for the SDG&E 1-in-2 weather scenario. The average event-period percentage load impact is 16 percent.

**Figure 7.1: Aggregate Hourly Loads and CPP Load Impacts (MWh/h) –
(August 2022 SDG&E 1-in-2 Peak Day)**

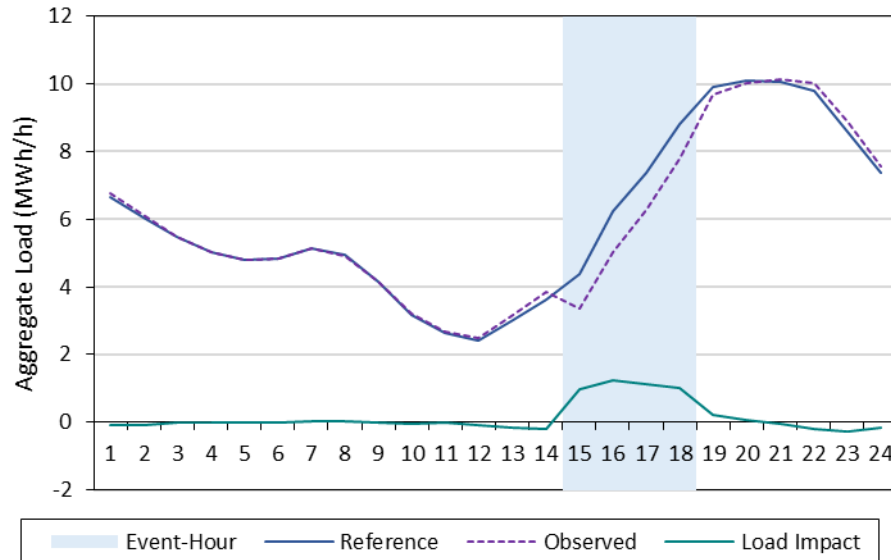


Figure 7.2 shows the monthly pattern of aggregate average *ex-ante* load impacts (RA window) in 2022 for the SDG&E 1-in-2 peak day. Load impacts are greatest in the summer months, reaching a maximum in August. The difference in load impacts between months also indicates the seasonal pattern in customer reference loads.

**Figure 7.2: Aggregate CPP Load Impacts (MWh/h), by Month –
(2022 SDG&E 1-in-2 Peak Day, RA Window)**

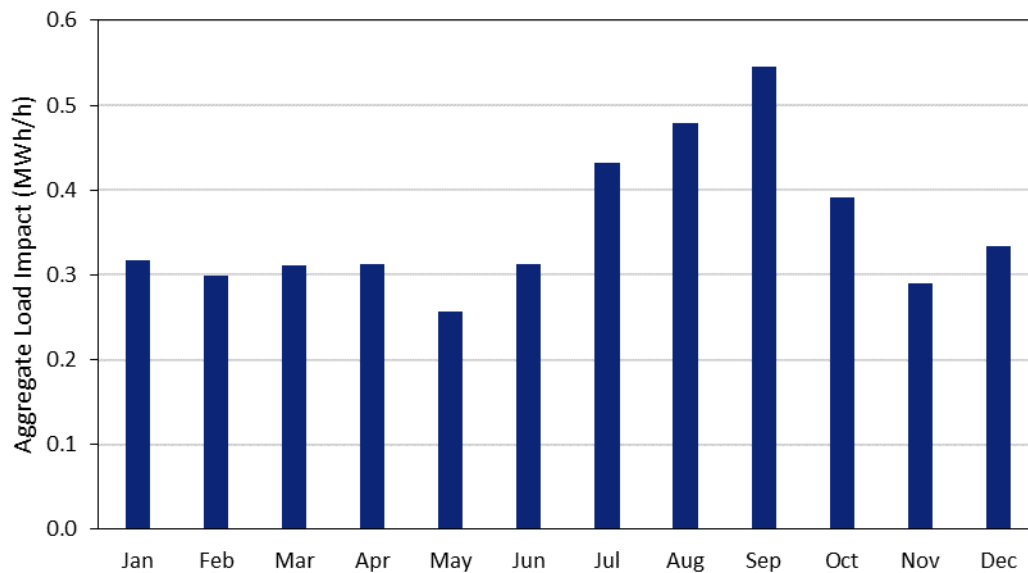
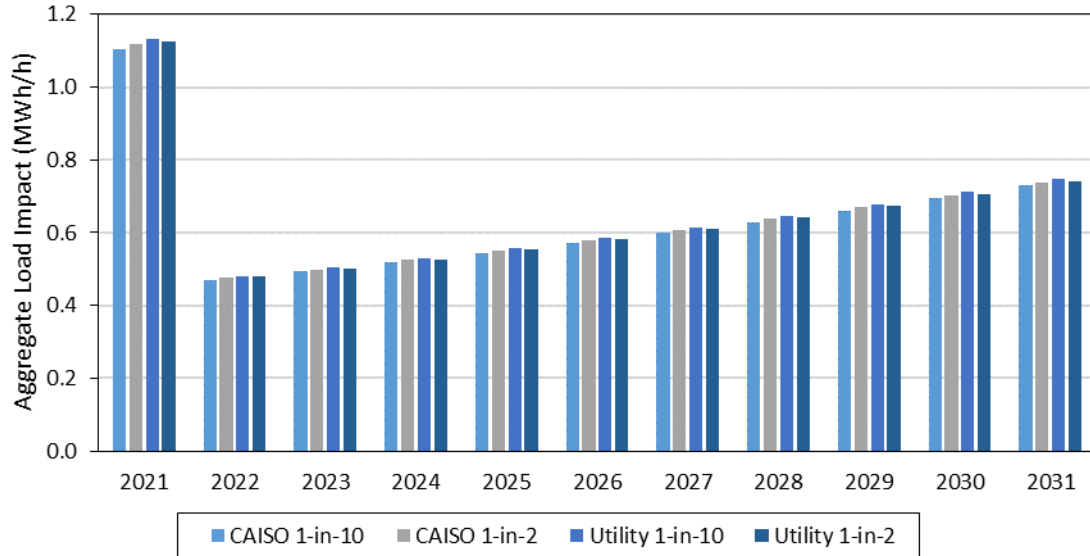


Figure 7.3 illustrates a substantial decrease of load impacts in 2022 because of the enrollment changes. Afterwards, there is a steady growth in forecasted CPP load impacts. The differences are relatively minor between the aggregate *ex-ante* load impacts for the alternative weather scenarios over the forecast period. In each year, the Utility 1-in-10 scenario corresponds with the largest load impacts.

Figure 7.3: Aggregate CPP Load Impacts (MWh/h), by Year and Weather Scenario – (August Peak Day, RA Window)



7.2 Ex-Ante load impacts – Residential TOU

This subsection summarizes the *ex-ante* TOU peak load impact forecasts for customers anticipated to be enrolled in both the TOU and CPP rates (TOU-DR and TOU-DR-P). Figure 7.4 shows aggregate loads and load impacts for TOU and CPP customers, in 2022 for an August SDG&E 1-in-2 average weekday. The average peak load impact is 1.35 MWh/h.

Figure 7.4: Aggregate Hourly Loads and TOU Load Impacts (MWh/h) – TOU-DR and TOU-DR-P Customers, (August 2022 SDG&E 1-in-2 Average Weekday)

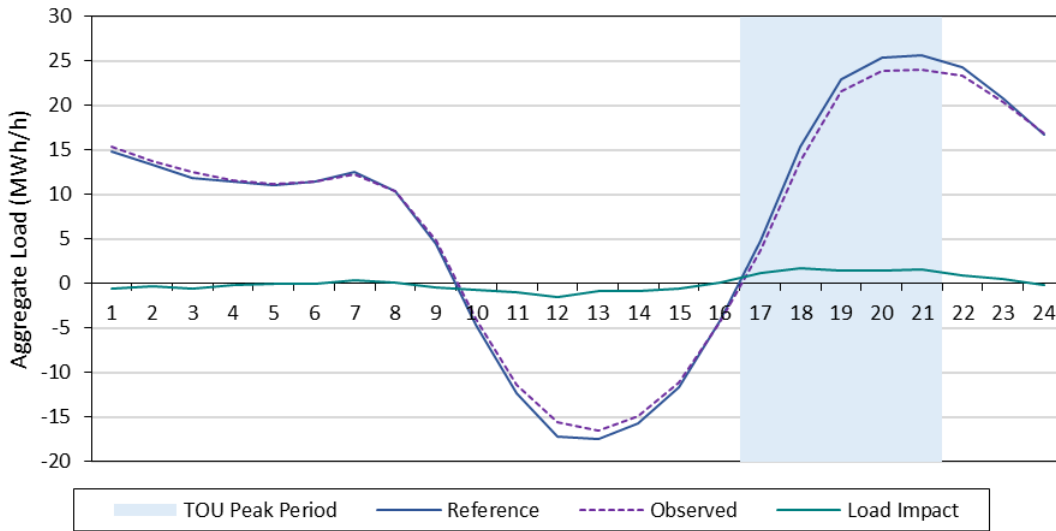


Figure 7.5 shows the monthly distributions of the peak-period TOU load impacts (TOU peak period aligns with the RA window) for TOU and CPP customers. Load impacts are greatest in the summer months, June through October. Results for the winter months are smaller, with the lowest impacts in May and November. Higher peak load impacts are expected to occur during the summer months based on the higher peak-hour prices, relative to the standard non-TOU rate prices, of the summer rate schedule.

Figure 7.5: Aggregate TOU Load Impacts (MWh/h) by Month – TOU-DR and TOU-DR-P Customers, (2022 SDG&E 1-in-2 Average Weekday, RA Window)

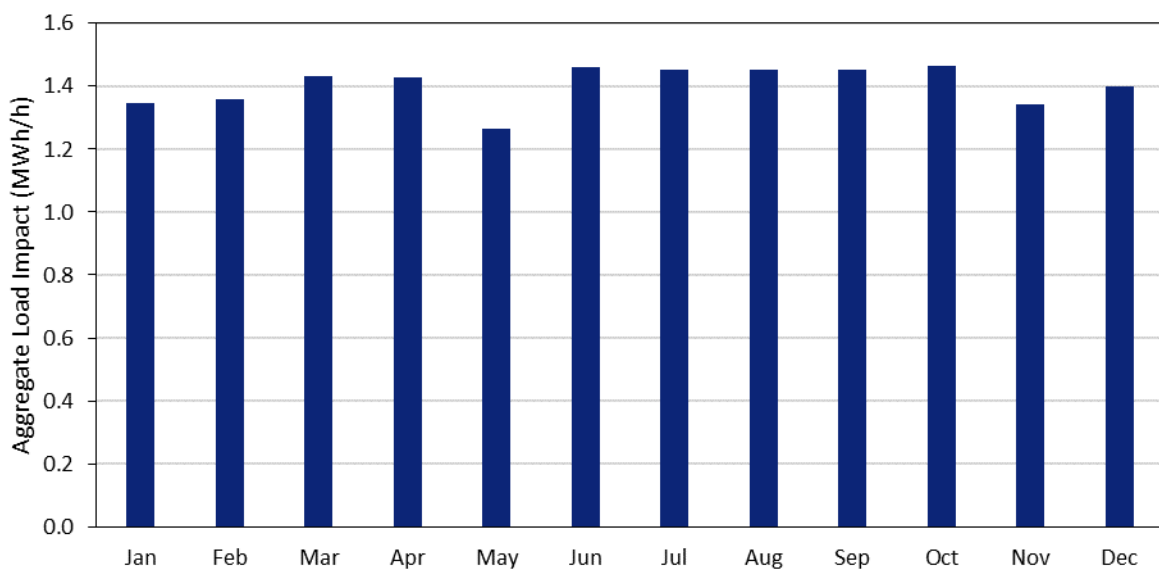
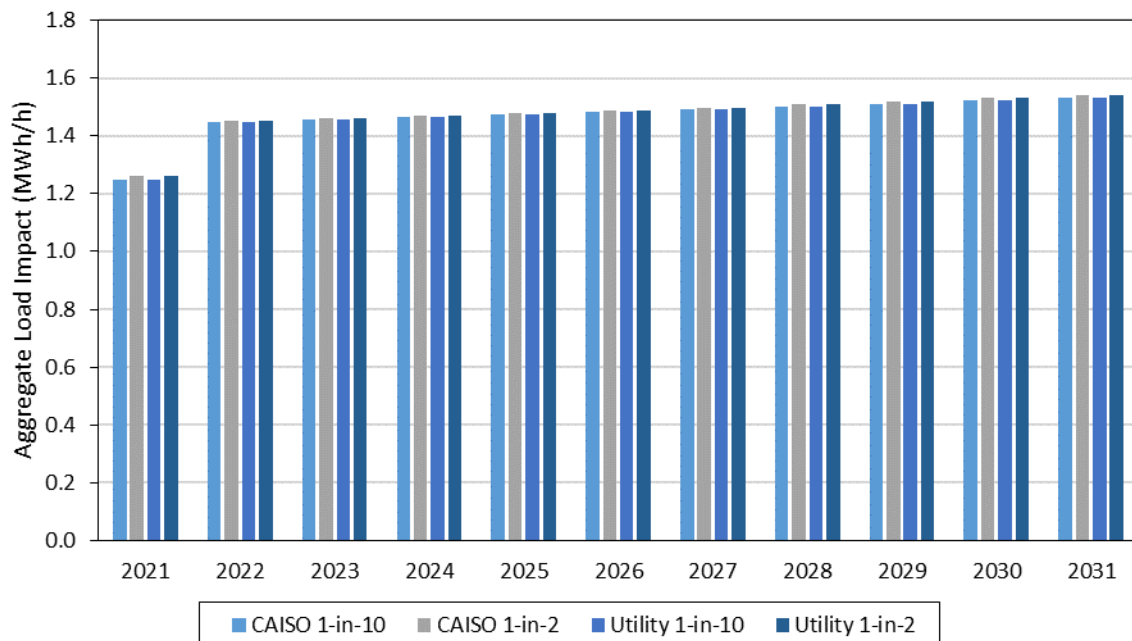


Figure 7.6 shows the aggregate average August weekday TOU load impacts over the forecast period, differentiated by weather scenario. The load impacts are largest, just slightly, for the CAISO and Utility 1-in-10 scenarios, which have equivalent temperatures for the average August weekday. (TOU load impacts are largest for the Utility 1-in-10 scenarios on monthly peak days.) In 2022, a substantial number of customers who are currently on the residential CPP rate will leave for the Consumer Choice Aggregator program. Since the *ex-post* load impact for this subset of customers is negative over the peak period, and since this subset of customers is nearly twice as large as the TOU-DR customer group, the exodus of customers from the residential CPP group in 2022 actually causes the aggregate peak load impact to *increase*, even though there are fewer customers on the program.³⁸ Following that change in customer mix, aggregate load impact increases in proportion to customer growth for the remainder of the *ex-ante* period.

Figure 7.6: Aggregate TOU Load Impacts (MWh/h) – TOU-DR and TOU-DR-P Customers, by Year and Weather Scenario (Average August Weekday, RA Window)



7.3 Ex-Ante load impacts – Residential Grandfathered CPP

This subsection summarizes the *ex-ante* TOU and CPP load impact forecasts for grandfathered customers enrolled in GTOU-DR-P. The enrollment forecast is assumed to remain constant at 477 customers, though some attrition may occur. Figure 7.7 shows monthly aggregate CPP loads and load impacts for grandfathered customers, in 2021 for

³⁸ Since the forecast after 2021 draws upon results from PY2019 for NEM customers, rather than on the *negative* load impacts obtained in PY2020, TOU-DR-P customers contribute an increase in aggregate load impacts for years 2022 and beyond.

an August SDG&E 1-in-2 average weekday. The CPP load impact remains constant for all months because level load impacts from the *ex-post* analysis are applied to the number of customers within the program. Consequently, the load impacts also do not vary by weather scenario.³⁹ It is assumed that grandfathered customers will have a CPP load impact of 0.018 MWh/h during the RA window. In other words, they are expected to decrease usage slightly during event hours.

Figure 7.7: Aggregate CPP Load Impacts (MWh/h) by Month– Grandfathered Customers, (2021 SDG&E 1-in-2 Peak Day, RA Window)

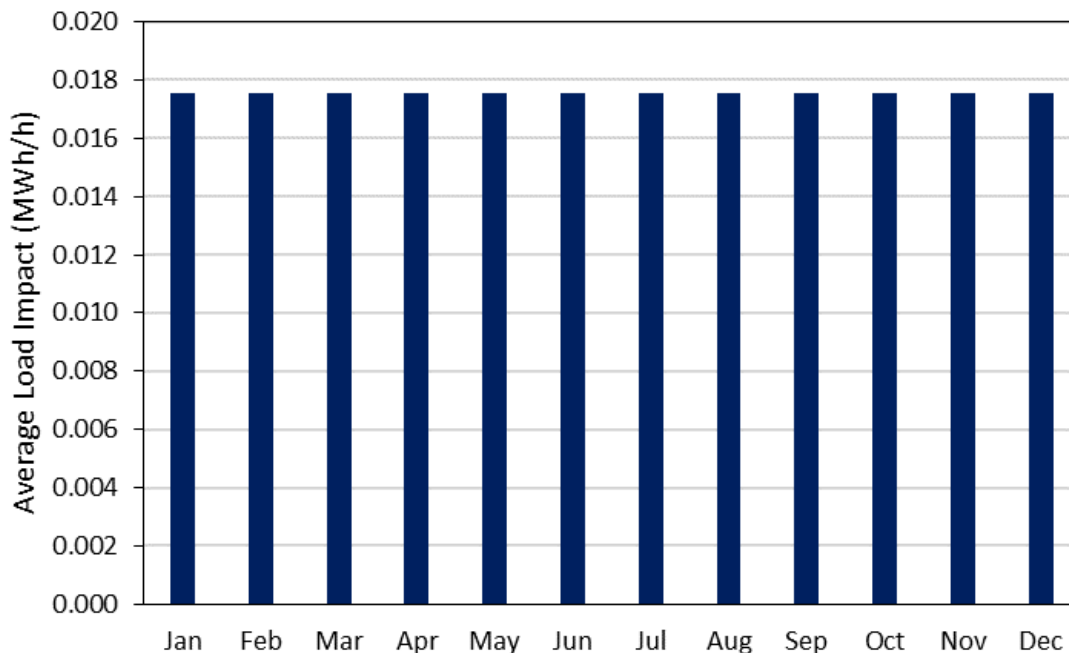
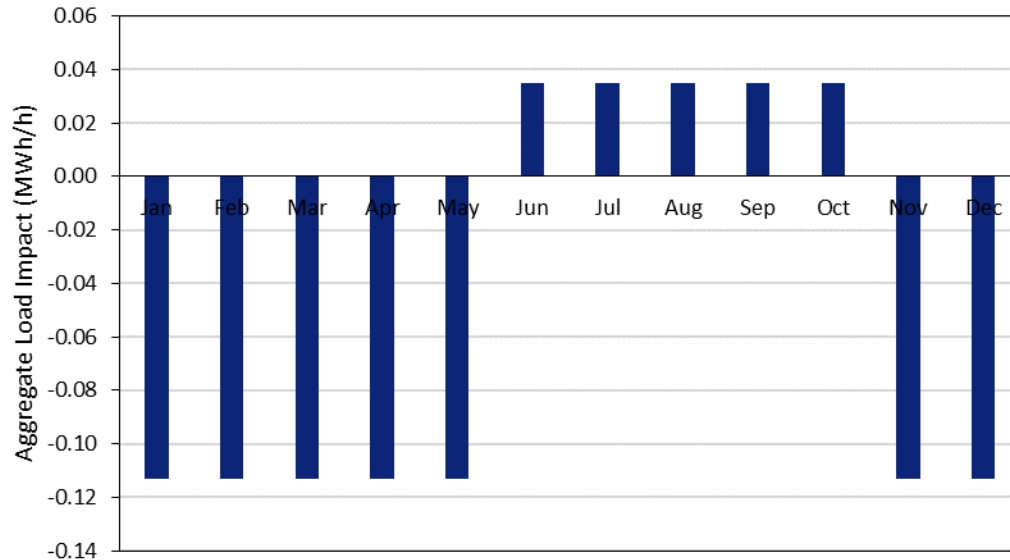


Figure 7.8 shows the monthly distributions of the RA window TOU load impacts for grandfathered customers. Load impacts are negative in all winter months, meaning that grandfathered customers increased usage during the RA window. This is partly attributed to the misalignment of grandfathered peak periods and the RA window. Similar to the CPP load impact forecast for grandfathered customers, the TOU load impact does not vary by weather scenario. However, the results do vary by year, as load impacts from PY2019 were used starting in 2022, when SDG&E predicts an end to the Covid-19 effect on residential load. Starting in 2022, the monthly load impacts are forecasted to remain constant until the grandfathering term expires on July 31, 2022.

³⁹ CA Energy Consulting investigated the weather sensitivity of load impacts but determined that constant level load impacts provided a more accurate representation of forecast demand response for grandfathered customers. This is due to a combination of the number of events and idiosyncratic patterns between events for the NEM customers lead to unexpected *a priori* results (*i.e.*, higher temperatures leading to smaller CPP load impacts).

Figure 7.8: Aggregate TOU Load Impacts (MWh/h) by Month – Grandfathered Customers, (2022 SDG&E 1-in-2 Average Weekday, RA Window)



8. Comparisons of Results

This section presents several comparisons of load impacts for SDG&E:

- *Ex-post* load impacts from the current and previous studies;
- *Ex-ante* load impacts from the current and previous studies;
- Previous *ex-ante* and current *ex-post* load impacts; and
- Current *ex-post* and *ex-ante* load impacts.

In the above list, “current study” refers to this report, which is based on findings from the 2020 program year; and “previous study” refers to the report that was developed following the 2019 program year.

8.1 Residential CPP

8.1.1 Previous versus current *ex-post*

Table 8.1 shows the average event-hour reference loads and CPP load impacts for the average weekday event during the current and previous program years, using PY2018 as the previous year comparison since there were no residential CPP events called in PY2019. The event hours were 2 p.m. to 6 p.m. in both the PY2018 and PY2020 studies. The aggregate enrollments more than doubled in the current program since PY2018, which also increased reference loads and CPP load impacts. The per-customer reference load and load impact in the PY2018 study is larger. The percentage load impact is slightly larger in the previous study at 16 percent versus 13 percent in the PY2020 study. A likely explanation for the slight decrease in load impact is the Covid-19 pandemic, during which residential customers were more likely to work from home during event hours.

Table 8.1 Comparison of PY2018 *Ex-Post* and Current 2020 *Ex-Post* Load Impacts, Residential CPP Weekday Event

Result	<i>Ex-post for 2018 Event Day from PY2018 Study</i>	<i>Ex-post for 2020 Event Day from PY2020 Study</i>
# Enrolled	6,796	15,384
Reference (MWh/h)	9.14	19.28
Load Impact (MWh/h)	1.45	2.57
Per-customer reference (kWh/h)	1.35	1.25
Per-customer load impact (kWh/h)	0.21	0.17
% Load Impact	16%	13%
Temperature	91.0	89.3

8.1.2 Previous versus current *ex-ante*

In this sub-section, the *ex-ante* forecast prepared following PY2019 (the “previous study”) are compared to the *ex-ante* forecast contained in this study (the “current study”). Table 8.2 reports the average event-hour load impacts for the August 2021 system peak day under utility-specific 1-in-2 weather conditions. While per-customer reference loads are higher in the current study, the current study *ex-ante* forecast has slightly lower percentage load impacts, resulting from different *ex-post* load impacts in PY2019 and PY2020, as well as higher temperature forecasts in PY2019. Aggregate reference loads and load impacts are smaller in the PY2019 *ex-ante* analysis due to a change in the enrollment forecast. The per-customer reference load is higher in the current study because of increased usage due to Covid-19. The effect of Covid-19 is assumed to be zero starting in 2022.

Table 8.2 Comparison of PY2019 *Ex-Ante* 2021 Forecast and Current *Ex-Ante* 2021 Forecast Load Impacts, CPP Event

Result	<i>Ex-ante for 2021 System Peak Day from PY2019 Study</i>	<i>Ex-ante for 2021 System Peak Day from PY2020 Study</i>
# Enrolled	15,777	16,375
Reference (MWh/h)	14.88	16.54
Load Impact (MWh/h)	2.70	2.57
Per-customer reference (kWh/h)	0.94	1.01
Per-customer load impact (kWh/h)	0.17	0.16
% Load Impact	18%	16%
Temperature	90.4	89.9

8.1.3 Previous *ex-ante* versus current *ex-post*

Table 8.3 provides a comparison of the *ex-ante* forecast of 2020 load impacts prepared following PY2019 and the PY2020 load impacts estimated as part of this study, averaged over the CPP event-window. The *ex-ante* forecast shown in the table represents the August peak day during a utility-specific 1-in-2 weather year. The *ex-post* load impacts are based on the 2020 average CPP event day. The increase in aggregate reference loads is due to an increase in enrollment and Covid-19, since residential customers may be more likely to be at home during event hours. The percentage load impact is lower in the current *ex-post* study, which may be explained by a Covid-19 influence, as residential customers working from home may decide to run air conditioning and other electronics through event hours to stay comfortable during the work day.

Table 8.3 Comparison of PY2019 *Ex-Ante* 2020 Forecast and Current *Ex-Post* Load Impacts, Residential CPP Event

Result	<i>Ex-ante for 2020 System Peak Day from PY2019 Study</i>	<i>Ex-post for 2020 Event Day from PY2020 Study</i>
# Enrolled	14,990	15,384
Reference (MWh/h)	14.14	19.28
Load Impact (MWh/h)	2.56	2.57
Per-customer reference (kWh/h)	0.94	1.25
Per-customer load impact (kWh/h)	0.17	0.17
% Load Impact	18%	13%
Temperature	90.4	89.3

8.1.4 Current *ex-post* versus current *ex-ante*

Table 8.4 compares the CPP *ex-post* load impacts for the average weekday event against the *ex-ante* load impacts for 2021 (of the SDG&E 1-in-2 August peak day), from this study. The *ex-post* and first set of *ex-ante* load impacts are averaged over the CPP event hours (HE 15-18) while the second set of *ex-ante* load impacts are summarized over the RA window (HE 17-21). The per-customer load impact percentages are differ during the event window because 2021 per-customer reference loads for both NEM and Non-NEM customers are estimated to be lower as the Covid-19 effect diminishes, but for NEM customers, the level load impact remains the same. The lower reference load, coupled with the same level load impact for NEM customers, drives this differential. The RA window includes non-event hours-ending 19 through 21, which reduces the percentage load impacts. Aggregate reference loads and load impacts decline in *ex-ante* despite increased enrollments. This is a result of lower per-customer reference loads in 2021 because the effect of Covid-19 is diminished. The load impacts are the same in aggregate between the *ex-post* and *ex-ante* analyses, and slightly different on a per-customer basis as a result of differing reference loads. Per-customer reference loads

decrease in *ex-ante* over the event window despite higher temperatures. The *ex-ante* per-customer reference loads are larger during the RA window because the average load profile displays rising hourly loads during event and RA window.

Table 8.4: Comparison of Current *Ex-Post* and *Ex-Ante* Load Impacts, Residential CPP Event

Result	<i>Ex-post</i> for 2020 (Event Window)	<i>Ex-ante</i> for 2021 Peak Day (Event Window)	<i>Ex-ante</i> for 2021 Peak Day (RA Window)
# Enrolled	15,384	16,375	16,375
Reference (MWh/h)	19.28	16.54	21.83
Load Impact (MWh/h)	2.57	2.57	1.13
Per-customer reference (kWh/h)	1.25	1.01	1.33
Per-customer load impact (kWh/h)	0.17	0.16	0.07
% Load Impact	13%	16%	5%
Temperature	89.3	89.9	84.3

Table 8.5 compares the key components of the two analyses. As the table describes, the three largest sources of differences between the *ex-post* and *ex-ante* load impacts are the effect of Covid-19, the enrollment level, and the summary over the RA window for *ex-ante* versus the actual event hours for the *ex-post* impacts.

Table 8.5: Ex-Post versus Ex-Ante Factors, CPP Event

Factor	Ex-Post	Ex-Ante	Expected Impact
Weather	89.3 degrees Fahrenheit during HE 15-18.	89.9 degrees Fahrenheit during HE 17-21 of a utility-specific 1-in-2 August peak day.	Warmer <i>ex-ante</i> weather increases the reference load and load impact.
Event window	HE 15-18 for the average weekday event.	RA Window: HE 17-21. Event Window: HE 15-18.	The RA window covers HE 19-21 which are not event hours, resulting in a lower load impact over the RA window.
% of resource dispatched	The entire program was dispatched on each of the days that comprise the average weekday event.	Assume all customers are called.	None. The <i>ex-ante</i> method assumes that all enrolled customers are dispatched.
Enrollment	15,384 customers enrolled.	16,375 customers.	The increase in <i>ex-ante</i> enrollments increases the total load impact proportionately relative to <i>ex-post</i> .
Methodology	Climate-zone-specific regressions using a matched control-group and difference-in-differences analysis on event and event-like non-event days.	Treatment only customer regressions to estimate observed loads using PY2019 data.	No effect to percentage load impacts. The <i>ex-post</i> percentage load impacts are applied to reference loads of the various scenarios in the <i>ex-ante</i> study.
Covid-19	Reference loads and load impacts recorded during pandemic.	Estimated pandemic effect assumed to diminish until zero effect beginning in 2022.	Lower per-customer reference loads in the <i>ex-ante</i> study as the effect of Covid is diminished.

8.2 Residential TOU

8.2.1 Previous versus current *ex-post*

Table 8.6 shows the average reference loads and load impacts for the average August and January weekday day during the current and previous program years, averaged over the RA window, which corresponds to the TOU peak period. Enrollment numbers have increased resulting in higher aggregate reference loads. Percentage load impacts declined both in the summer and winter periods of the current study, possibly because more residential customers were working from home, with less opportunity or desire to curtail load during peak periods.

Table 8.6 Comparison of PY2019 *Ex-Post* and PY2020 *Ex-Post* TOU Load Impacts

Winter (January)	Result	<i>Ex-post for 2019 Avg. Weekday from PY2019 Study</i>	<i>Ex-post for 2020 Avg. Weekday from PY2020 Study</i>
Summer (August)	# Enrolled	19,694	24,951
	Reference (MWh/h)	19.82	30.63
	Load Impact (MWh/h)	1.61	0.52
	Per-customer reference (kWh/h)	1.01	1.23
	Per-customer load impact (kWh/h)	0.08	0.02
	% Load Impact	8.1%	1.7%
	Temperature	76.5	76.9
Winter (January)	# Enrolled	11,419	20,360
	Reference (MWh/h)	12.64	19.22
	Load Impact (MWh/h)	0.81	0.47
	Per-customer reference (kWh/h)	1.11	0.94
	Per-customer load impact (kWh/h)	0.07	0.02
	% Load Impact	6.4%	2.4%
	Temperature	55.4	58.2

8.2.2 Previous versus current *ex-ante*

In this sub-section, the *ex-ante* forecast prepared following PY2019 (the “previous study”) are compared to the *ex-ante* forecast contained in this study (the “current study”). Table 8.7 reports the average RA-window load impacts for the August and January 2021 average weekday under utility-specific 1-in-2 weather conditions. The TOU RA window and peak-period remains the same in both forecasts. The current study forecasts an increase in enrollment, which is associated with an increase in aggregate reference loads. Per-customer reference loads are also expected to grow slightly compared to the previous study, even as per customer load impacts decline. The load impacts from each study rely on *ex-post* load impact results, which were lower on a percentage basis in the current study than the previous study because the months of interest occur under the Covid-19 pandemic.

Table 8.7 Comparison of PY2019 *Ex-Ante* 2021 Forecast and PY2020 *Ex-Ante* 2021 Forecast TOU Load Impacts

Season	Result	<i>Ex-ante for 2021 Avg. Weekday from PY2019 Study</i>	<i>Ex-ante for 2021 Avg. Weekday from PY2020 Study</i>
Summer (August)	# Enrolled	22,666	26,691
	Reference (MWh/h)	23.75	29.56
	Load Impact (MWh/h)	1.86	1.02
	Per-customer reference (kWh/h)	1.05	1.11
	Per-customer load impact (kWh/h)	0.08	0.04
	% Load Impact	7.9%	3.5%
	Temperature	77.3	77.4
Winter (January)	# Enrolled	21,879	26,489
	Reference (MWh/h)	21.67	31.05
	Load Impact (MWh/h)	1.32	0.81
	Per-customer reference (kWh/h)	0.99	1.17
	Per-customer load impact (kWh/h)	0.06	0.03
	% Load Impact	6.1%	2.6%
	Temperature	59.2	59.2

8.2.3 Previous *ex-ante* versus current *ex-post*

Table 8.8 provides a comparison of the *ex-ante* forecast of 2020 TOU load impacts prepared in the previous study and the PY2020 *ex-post* TOU load impacts estimated as part of this study. The *ex-ante* forecast shown in the table represents the August and January average weekday during a utility-specific 1-in-2 weather year. The *ex-post* load impacts are based on August and January weekdays. Increased enrollments lead to larger aggregate reference loads in the summer period. However, the enrollments for January were smaller than the PY2019 forecast, resulting in smaller aggregate reference loads. Per-customer load impacts were smaller than forecasted because of the Covid-19 pandemic, which affected residential usage during peak hours.

Table 8.8 Comparison of PY2019 *Ex-Ante* 2020 Forecast and PY2020 *Ex-Post* TOU Load Impacts

Season	Result	<i>Ex-ante for 2020 Avg. Weekday from PY2019 Study</i>	<i>Ex-post for 2020 Avg. Weekday from PY2020 Study</i>
Summer (August)	# Enrolled	21,879	24,951
	Reference (MWh/h)	22.95	30.63
	Load Impact (MWh/h)	1.82	0.52
	Per-customer reference (kWh/h)	1.05	1.23
	Per-customer load impact (kWh/h)	0.08	0.02
	% Load Impact	7.9%	1.7%
	Temperature	77.3	76.9
Winter (January)	# Enrolled	21,879	20,360
	Reference (MWh/h)	21.67	19.22
	Load Impact (MWh/h)	1.32	0.47
	Per-customer reference (kWh/h)	0.99	0.94
	Per-customer load impact (kWh/h)	0.06	0.02
	% Load Impact	6.1%	2.4%
	Temperature	59.2	58.2

8.2.4 Current *ex-post* versus current *ex-ante*

Table 8.9 compares the PY2020 *ex-post* TOU load impacts for the August average weekday with the corresponding *ex-ante* forecast for 2020 (of the SDG&E 1-in-2 August average weekday) produced in this study. The TOU load impacts are presented for all TOU customers and are averaged over the RA window, which perfectly overlaps with the TOU peak period. The *ex-ante* per-customer reference loads are smaller during the summer period because of the diminished effect of Covid-19. The *ex-post* winter period, however, has a smaller per-customer reference load in *ex-post* because January customer usage was not yet affected by the pandemic. The *ex-ante* load impacts are based upon *ex-post* percentage load impacts for each TOU period. Differences in percentage load impacts between *ex-post* and *ex-ante* are largely a result of the Covid-19 pandemic, which affected results and assumptions both in the *ex-post* period and in the *ex-ante* period. As in the CPP reconciliations table in Section 8.1.4, the lower reference load in 2021, in combination with the equivalent level load impact for NEM customers, drives the differential between *ex-post* and *ex-ante* percentage load impacts. Furthermore, the August 2020 *ex-post* results draw from data obtained in the midst of the pandemic, whereas the August 2021 *ex-ante* results assume a diminished pandemic effect.

Table 8.9: Comparison of Current *Ex-Post* and *Ex-Ante* TOU Load Impacts

Season	Result	<i>Ex-post for 2020 Avg. Weekday from PY2020 Study</i>	<i>Ex-ante for 2021 Avg. Weekday from PY2020 Study</i>
Summer (August)	# Enrolled	24,951	26,691
	Reference (MWh/h)	30.63	29.56
	Load Impact (MWh/h)	0.52	1.02
	Per-customer reference (kWh/h)	1.23	1.11
	Per-customer load impact (kWh/h)	0.02	0.04
	% Load Impact	1.7%	3.5%
	Temperature	76.9	77.4
Winter (January)	# Enrolled	20,360	26,489
	Reference (MWh/h)	19.22	31.05
	Load Impact (MWh/h)	0.47	0.81
	Per-customer reference (kWh/h)	0.94	1.17
	Per-customer load impact (kWh/h)	0.02	0.03
	% Load Impact	2.4%	2.6%
	Temperature	58.2	59.2

8.3 Grandfathered Customers

This section compares the *ex-post* with *ex-ante* load impacts for grandfathered customers.

8.3.1 Current *ex-post* versus current *ex-ante*, CPP load impacts

Table 8.10 compares the grandfathered customers' CPP *ex-post* load impacts for the average weekday event against the *ex-ante* load impacts for 2021 (of the SDG&E 1-in-2 August peak day), from this study. The *ex-post* and first set of *ex-ante* load impacts are averaged over the CPP event hours (HE 15-18) while the second set of *ex-ante* load impacts are summarized over the RA window (HE 17-21). Since the *ex-ante* CPP load impacts are built on the 2020 *ex-post* values, the per-customer load impact nearly identical during the event window. Any differences between *ex-post* and *ex-ante* stem from changes in the number of customers between climate zones because this is the only source of differentiation in the load impact estimates. The RA window includes non-event hours ending 19 through 21, which reduces the level load impacts. Aggregate reference loads and load impacts decline, and program enrollment faces some attrition.

Table 8.10: Comparison of Current *Ex-Post* and *Ex-Ante* Load Impacts, CPP Event for Grandfathered Customers

Result	<i>Ex-post</i> for 2020 (Event Window)	<i>Ex-ante</i> for 2021 Peak Day (Event Window)	<i>Ex-ante</i> for 2021 Peak Day (RA Window)
# Enrolled	250	236	236
Reference (MWh/h)	0.30	0.21	0.62
Load Impact (MWh/h)	0.04	0.02	-0.05
Per-customer reference (kWh/h)	1.20	0.89	2.62
Per-customer load impact (kWh/h)	0.15	0.07	-0.20
Temperature	91.0	91.9	86.0

8.3.2 Current *ex-post* versus current *ex-ante*, TOU load impacts

Table 8.11 compares the grandfathered customers' PY2020 *ex-post* TOU load impacts for the August average weekday with the corresponding *ex-ante* forecast for 2021 (of the SDG&E 1-in-2 August average weekday) produced in this study. The grandfathered customers' TOU load impacts are presented for all grandfathered customers and are averaged over the RA window, which perfectly overlaps with the TOU peak period. Similar to the CPP load impacts for grandfathered customers, any differences between *ex-post* and *ex-ante* load impacts stem from changes in the number of customers within climate zones. Enrollment numbers increase slightly, but *ex-ante* aggregate reference loads are forecasted to be smaller, as the effect of Covid-19 on residential load declines throughout 2021.

Table 8.11: Comparison of Current *Ex-Post* and *Ex-Ante* TOU Load Impacts for Grandfathered Customers

Season	Result	<i>Ex-post</i> for 2020 Avg. Weekday from PY2020 Study	<i>Ex-ante</i> for 2021 Avg. Weekday from PY2020 Study
Summer (August)	# Enrolled	472	477
	Reference (MWh/h)	0.68	0.82
	Load Impact (MWh/h)	-0.15	-0.05
	Per-customer reference (kWh/h)	1.44	1.73
	Per-customer load impact (kWh/h)	-0.32	-0.10
	Temperature	78.1	78.0
Winter (January)	# Enrolled	441	477
	Reference (MWh/h)	0.52	0.58
	Load Impact (MWh/h)	-0.07	-0.05
	Per-customer reference (kWh/h)	1.17	1.22
	Per-customer load impact (kWh/h)	-0.15	-0.11
	Temperature	58.0	59.0

9. Recommendations

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.

Appendices

The following Appendices are Excel files that can produce the tables required by the Protocols.

Appendix A Residential TOU and CPP *Ex-Post* Load Impact Tables

Appendix B Residential TOU and CPP *Ex-Ante* Load Impact Tables

Appendix C NEM Customer Restrictions

NEM customers may introduce bias into the load impact results if changes occur to their solar PV generation that is not accounted for. CA Energy Consulting attempts to reduce this by 1) including only NEM customers that are NEM for the entire analysis period, 2) matching NEM customers to other NEM customer with similar size solar PV generation, and 3) removing customers that have large changes in usage between periods. To identify what constitutes a large change in usage and its possible effect on load impact estimates, a difference-in-difference of raw load profiles was calculated for different threshold restrictions (for each rate and season). Customers that have average usage (HE 12-18) differences, in absolute value, between periods below the threshold meet the requirement and are kept in the analysis. Figure C.2 illustrates the difference-in-differences load profile based upon raw averages from TOU customer load profiles that meet specific thresholds over the summer period. The line corresponding to a threshold of 4 indicates that customers with a change in usage between periods less than 4 kWh/h are kept in the analysis. The figure illustrates that as the threshold becomes smaller, the raw difference-in-difference does not exhibit great changes in the load impact that appears more influenced by the TOU rate than by solar generation. A result that is different from previous years because more data is available that identifies when customers make changes to their solar PV system, which is used to screen customers from the analysis. Nevertheless, for the purposes of this analysis, CA Energy Consulting removed customers that have a change in usage, in absolute value, greater than or equal to 2 kWh/h.

Figure C.1: Summer Period Difference-in-Difference for TOU Customers (TOU-DR)

