



## **2021 Load Impact Evaluation of San Diego Gas and Electric's Voluntary Residential Critical Peak Pricing (CPP) and Time-of- Use (TOU) Rates**

**CALMAC Study ID SDG0336**

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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 2021, 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. The 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. Starting June 1, 2022, the CPP event window will coincide with the RA window of 4 to 9 p.m. period. In 2021, SDG&E did not call any CPP events. Therefore, the ex-post analysis does not contain CPP load impact evaluations.

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.

TOU enrollment rose from 8,800 customers in October 2020 to 12,698 in September 2021. Per-customer seasonal load impacts were 0.17 kWh/h in summer and 0.07 kWh/h



in winter. Seasonal load impacts were larger for Inland customers on a per-customer basis. Combining results across months and considering the effect of TOU on average *daily* usage, CA Energy Consulting finds that TOU customers *decreased* their energy consumption by an annual average of approximately 0.46 kWh/h.

Similarly, we evaluated the TOU load impacts for CPP customers. Enrollment in CPP grew from 13,167 in October 2020 to approximately 21,640 in September 2021. CPP customers reduced peak hour usage during the summer months but were varied during the winter months. The Inland residential CPP customers show a slight *increase* in peak period usage, whereas their TOU counterparts show a dramatic *decrease* in usage. The Coastal customers have more comparable load impacts throughout each season. The overall daily effect for CPP customers was an average annual *increase* of 0.13 kWh/h per-customer.

Among grandfathered customers, average enrollment in winter was 373 customers while average summer enrollment was 371 customers. Grandfathered customers exhibited a per-customer load *decreases* of 0.08 kWh/h for the winter season and a 0.18 kWh/h per-customer *increase* for the summer season during the TOU peak period. The overall effect of *daily* usage is an average annual *increase* of 1.99 kWh/h per customer.

## **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 2021. 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. Starting in 2022, the CPP event window will coincide with the RA window, such that ex-ante results beginning in 2022 will report load impacts over the 4 to 9 p.m. period. SDG&E did not call any CPP events in 2021.

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 TOU peak load impacts – TOU (TOU-DR)**

Table ES.1 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 2020). The winter months are indicated by light blue shading. Enrollment continued throughout the analysis period, with the numbers of enrolled customers rising from 8,800 in October 2020 to 12,698 in September 2021.<sup>1</sup> The estimated seasonal load impacts were largest during the summer months.

**Table ES.1: TOU Peak Load Impacts for TOU Customers – Average Weekday by Month**

Month	Climate Zone	Enrolled	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)	
Oct-20	All	8,800	12.12	1.29	1.38	0.15	73
Nov-20	All	9,102	10.92	0.75	1.20	0.08	61
Dec-20	All	9,380	13.09	0.80	1.40	0.09	58
Jan-21	All	9,577	11.79	0.81	1.23	0.09	58
Feb-21	All	9,838	10.25	0.83	1.04	0.08	59
Mar-21	All	10,140	6.74	0.02	0.66	0.00	58
Apr-21	All	10,316	4.50	-0.01	0.44	0.00	65
May-21	All	11,220	4.49	0.90	0.40	0.08	66
Jun-21	All	11,739	7.75	1.68	0.66	0.14	70
Jul-21	All	11,991	12.78	1.74	1.07	0.15	74
Aug-21	All	12,357	15.82	1.80	1.28	0.15	75
Sep-21	All	12,698	15.33	1.80	1.21	0.14	72

Table ES.2 shows peak load impact results by season and climate zone. Both the Inland and the Coastal climate zone exhibit higher reference loads during the summer than during winter, with Inland reference loads higher than Coastal reference loads during both periods. Customers in both climate zones decrease load during peak periods in the summer for an overall average load impact of 0.17 kwh/h. Inland customers have a larger load impact than Coastal customers in both summer and winter.

<sup>1</sup> 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 441 winter and 357 summer 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.2: TOU Peak Load Impacts for TOU 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	6,154	5.57	0.49	0.90	0.08	72
	Inland	5,363	7.43	1.46	1.39	0.27	74
	<b>All</b>	<b>11,517</b>	<b>13.00</b>	<b>1.95</b>	<b>1.13</b>	<b>0.17</b>	<b>73</b>
Winter	Coastal	4,991	4.16	-0.01	0.83	0.00	61
	Inland	4,948	4.78	0.70	0.97	0.14	61
	<b>All</b>	<b>9,939</b>	<b>8.94</b>	<b>0.69</b>	<b>0.90</b>	<b>0.07</b>	<b>61</b>

Combining results across months and considering the effect of TOU on average *daily* usage, CA Energy Consulting finds that TOU customers *decreased* their energy consumption by an annual average of approximately 0.46 kWh/h.

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

TOU-DR-P customers experience TOU prices on all weekdays that are not residential CPP event days. CA Energy Consulting examined the average usage changes on non-event days for this customer group, similar to TOU-only customers. Table ES.3 shows average monthly load and load impacts for summer (October 2020, and June through September 2021) and winter (November 2020 through May 2021) weekdays. Enrollment in CPP grew from 13,167 in October 2020 to approximately 21,640 in September 2021. Peak load impacts were around 0.04 kWh/h per customer during the summer months but near zero during the winter, except for April and March.

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

Month	Climate Zone	Enrolled	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)	
Oct-20	All	13,167	13.42	0.46	1.02	0.04	73
Nov-20	All	13,567	12.40	-0.05	0.91	0.00	62
Dec-20	All	14,251	15.15	-0.03	1.06	0.00	58
Jan-21	All	15,159	14.71	-0.05	0.97	0.00	58
Feb-21	All	16,004	13.66	-0.07	0.85	0.00	59
Mar-21	All	17,154	13.37	0.53	0.78	0.03	58
Apr-21	All	18,188	12.01	0.54	0.66	0.03	65
May-21	All	19,142	10.83	-0.13	0.57	-0.01	66
Jun-21	All	19,540	13.71	0.69	0.70	0.04	70
Jul-21	All	20,411	18.72	0.75	0.92	0.04	75
Aug-21	All	21,385	21.89	0.81	1.02	0.04	76
Sep-21	All	21,640	20.48	0.77	0.95	0.04	73

Table ES.4 summarizes TOU load impact results for residential CPP customers by season and climate zone. The two climate zones exhibited opposite signed load impacts, with the Inland climate zone increasing usage during the peak period in both seasons and Coastal customers decreasing usage in both seasons. Load impacts for the Coastal climate zone are lower in winter than in summer. Both Coastal and Inland customers have reduced reference loads during the winter relative to the summer. On average, CPP customers *increased* their load by 0.13 kWh/h per-customer per day over the course of the study period.

**Table ES.4: TOU Peak Load Impacts for 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	11,564	9.72	0.78	0.84	0.07	73
	Inland	7,664	7.85	-0.14	1.02	-0.02	74
	<b>All</b>	<b>19,229</b>	<b>17.57</b>	<b>0.64</b>	<b>0.91</b>	<b>0.03</b>	<b>73</b>
Winter	Coastal	9,965	7.97	0.15	0.80	0.02	61
	Inland	6,245	5.21	-0.03	0.83	-0.01	61
	<b>All</b>	<b>16,209</b>	<b>13.18</b>	<b>0.12</b>	<b>0.81</b>	<b>0.01</b>	<b>61</b>

### ES.3.3 TOU peak load impacts – Grandfathered (GTOU-DR-P)

Table ES.5 summarizes TOU peak-period load impact results for grandfathered customers by season and climate zone. The grandfathered summer TOU on-peak period is 11 a.m. to 6 p.m. on non-holiday weekdays. The grandfathered winter TOU on-peak period is 5 p.m. to 8 p.m. on non-holiday weekdays. Monthly results are identical within each season because level load impacts were estimated by season. Load impacts are also the same in each climate zone because results were not estimated separately by climate zone. In the summer period, grandfathered customers exhibited an *increase* in usage during peak hours. During the winter period, customers experienced a small decrease in usage during peak hours. The overall effect of *daily* usage is an average annual *increase* of about 1.99 kWh/h per customer.

**Table ES.5: 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	177	-0.26	-0.03	-1.47	-0.18	77
	Inland	193	-0.23	-0.03	-1.21	-0.18	80
	<b>All</b>	<b>371</b>	<b>-0.49</b>	<b>-0.07</b>	<b>-1.33</b>	<b>-0.18</b>	<b>78</b>
Winter	Coastal	177	0.24	0.01	1.38	0.08	60
	Inland	196	0.26	0.02	1.30	0.08	61
	<b>All</b>	<b>373</b>	<b>0.50</b>	<b>0.03</b>	<b>1.34</b>	<b>0.08</b>	<b>61</b>

## **ES.4 Ex-Ante Load Impacts**

Since no residential CPP events took place in 2021, the ex-ante analysis for CPP events applies CPP event load impacts from PY2020 to reference loads calculated using PY2021 customer load data. 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.

In the past, an issue in producing the ex-ante load impact forecasts for CPP has been 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 were summarized across the RA window as required. Starting June 1, 2022, the CPP event window will coincide with the RA window, such that ex-ante results beginning in 2022 will report load impacts over the 4 to 9 p.m. period. This means that the ex-post load impacts, which occurred between 2 and 6 p.m., were shifted forward to span the updated event window beginning in 2022.

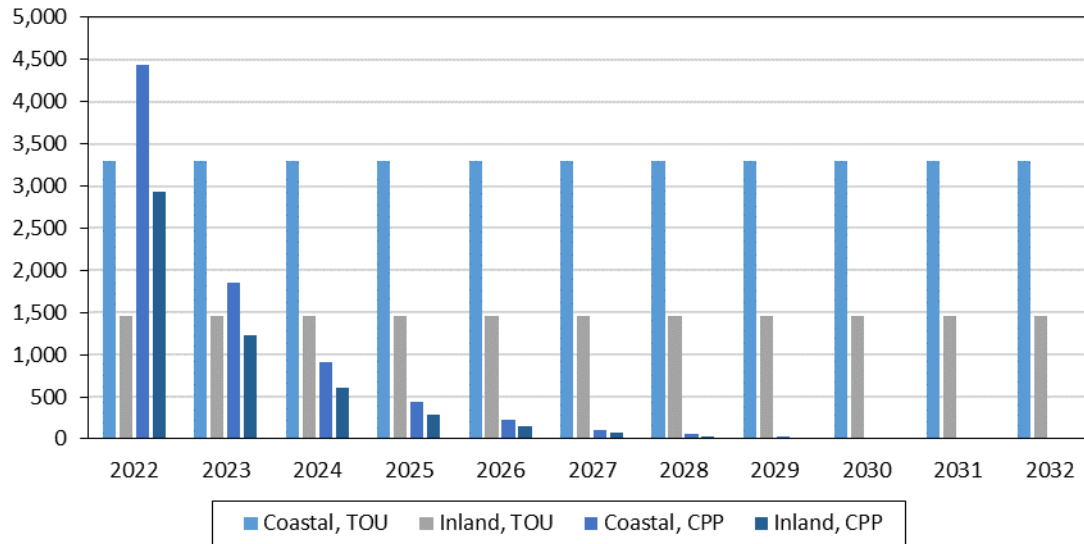
For the TOU rate and the TOU portion of the CPP rate, hourly percentage load impacts from the ex-post analysis are applied to weather-sensitive reference loads that were developed as described above. Level load impacts from ex-post are used for NEM customers.

### **ES.4.1 Enrollment forecast**

Figure ES.1 shows SDG&E's enrollment forecasts for the TOU and CPP rates. Enrollment for TOU is anticipated to be flat after 2021. Enrollment is expected to be greater in the Coastal climate zone than in the Inland for both rates, mirroring the current population distribution across these regions. Enrollment for grandfathered customers (GDRTODPH)

is assumed to remain constant at 367 customers until the grandfathering term expires on July 31, 2022.

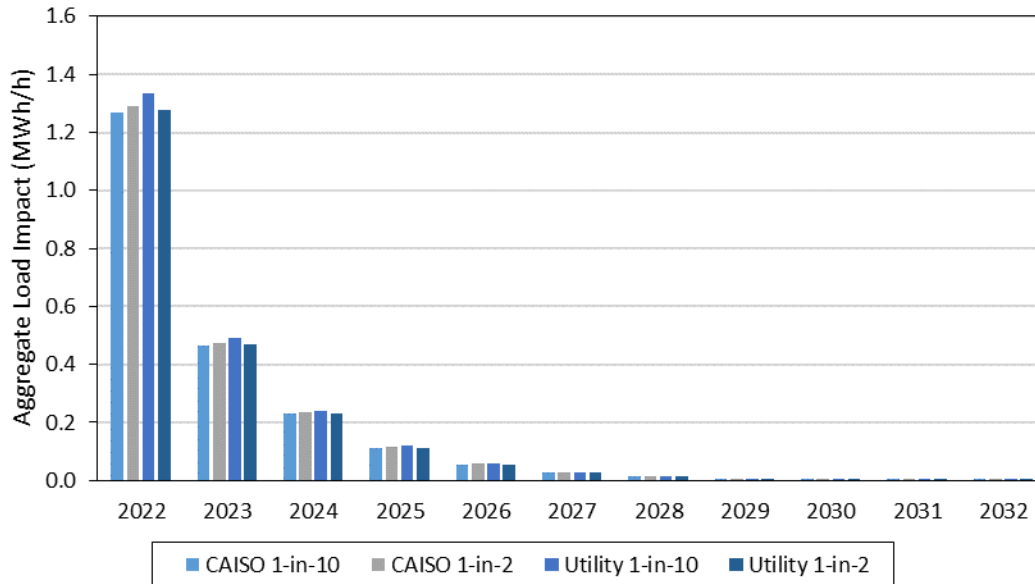
**Figure ES.1: Enrollments in TOU and CPP Rates**



#### ES.4.2 Ex-Ante load impacts – Residential CPP

Figure ES.2 illustrates the decline in forecasted aggregate CPP load impacts over the forecast period, as customers migrate to Community Choice Aggregator programs. 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 decrease from 1.28 MWh/h in 2022 to 0 MWh/h in 2032.

**Figure ES.2: Aggregate CPP Load Impacts (MWh/h), by Year and Weather Scenario  
(August Peak Day, RA Window)**



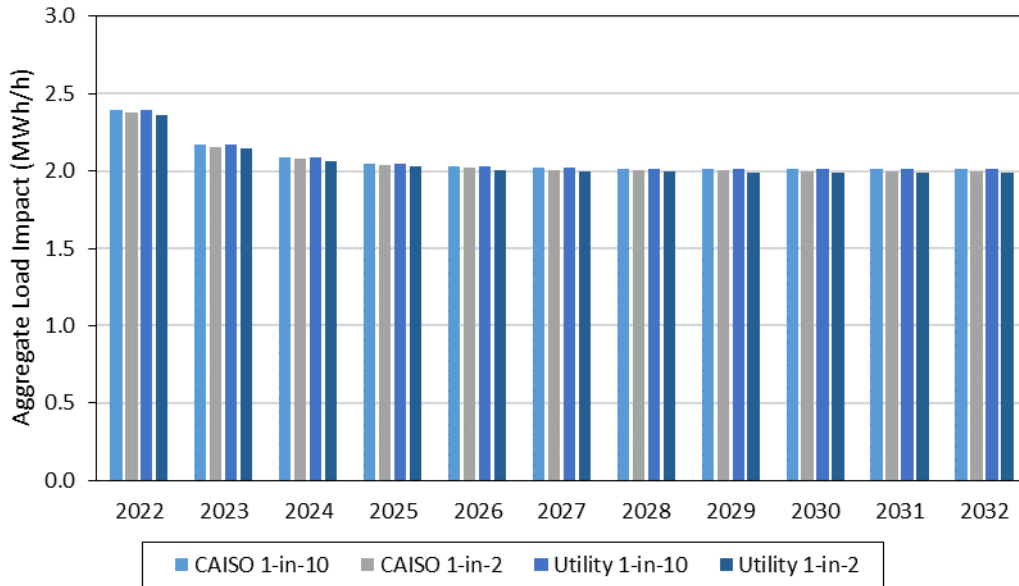
The ex-ante CPP load impact forecast for grandfathered customers is assumed to remain constant at -0.046 MWh/h during the RA window for each weather scenario and year up to the grandfathered term expiration on July 31, 2022.

### ES.4.3 Ex-Ante load impacts – Residential TOU

Aggregate peak load impacts for TOU customers are forecast to remain constant after 2022, 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. By 2025, most CPP customers will have migrated to Community Choice Aggregator programs, so the aggregate load impacts will be driven primarily by TOU-only customers. Values for each of the weather scenarios are nearly identical.



**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 ex-ante forecast daily load impact for grandfathered customers is assumed to remain constant at -6.8 MWh/hr. 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 2021. 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).<sup>2</sup> 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.<sup>3</sup> 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. Starting June 1, 2022, the CPP event window will coincide with the RA window of 4 p.m. to 9 p.m.

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.

Net Energy Metered (NEM) customers constitute a significant proportion of residential TOU customers, as shown in the Table 1.1 below. 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. The average NEM share of enrollment during the study period was 65% for TOU customers and 21% for TOU + CPP customers.

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<sup>2</sup> Results are also reported for a subset of CPP customers who also participated in the Technology Deployment (TD) program.

<sup>3</sup> CPP ex-post load impacts would have been estimated for *all* customers enrolled in CPP (TOU-DR-P) during the 2021 program year, had any events been called. TOU load ex-post load impacts are estimated for only customers who enrolled in either SPP rate during the October 2020 to September 2021 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, by Rate**

Date	TOU			TOU + CPP		
	Regular Enrollments	NEM Enrollments	Total Enrollments	Regular Enrollments	NEM Enrollments	Total Enrollments
Oct-20	3,193	5,607	8,800	10,676	2,491	13,167
Nov-20	3,254	5,848	9,102	10,910	2,657	13,567
Dec-20	3,290	6,090	9,380	11,387	2,864	14,251
Jan-21	3,269	6,308	9,577	12,063	3,096	15,159
Feb-21	3,260	6,578	9,838	12,699	3,305	16,004
Mar-21	3,338	6,802	10,140	13,615	3,539	17,154
Apr-21	3,313	7,003	10,316	14,296	3,892	18,188
May-21	4,025	7,195	11,220	14,970	4,172	19,142
Jun-21	4,227	7,512	11,739	15,127	4,413	19,540
Jul-21	4,368	7,623	11,991	15,999	4,412	20,411
Aug-21	4,578	7,779	12,357	16,804	4,581	21,385
Sep-21	4,854	7,844	12,698	17,221	4,419	21,640

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 Residential Opt-In TOU pilot, and in 2018 its Residential Default TOU pilot which was considered phase 1 of the full TOU rollout which began in March of 2019. SDG&E defaulted more than 800,000 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; and Section 4 contains the TOU ex-post load impact results. Section 5 describes the methods used to develop the CPP and TOU ex-ante load impacts. Section 6 contains the TOU and CPP ex-ante load impact results. Section 7 provides a series of comparisons of ex-post and ex-ante results. Section 8 provides recommendations.

## 2. Description of SPP Rates

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. No residential CPP events were called in 2021.

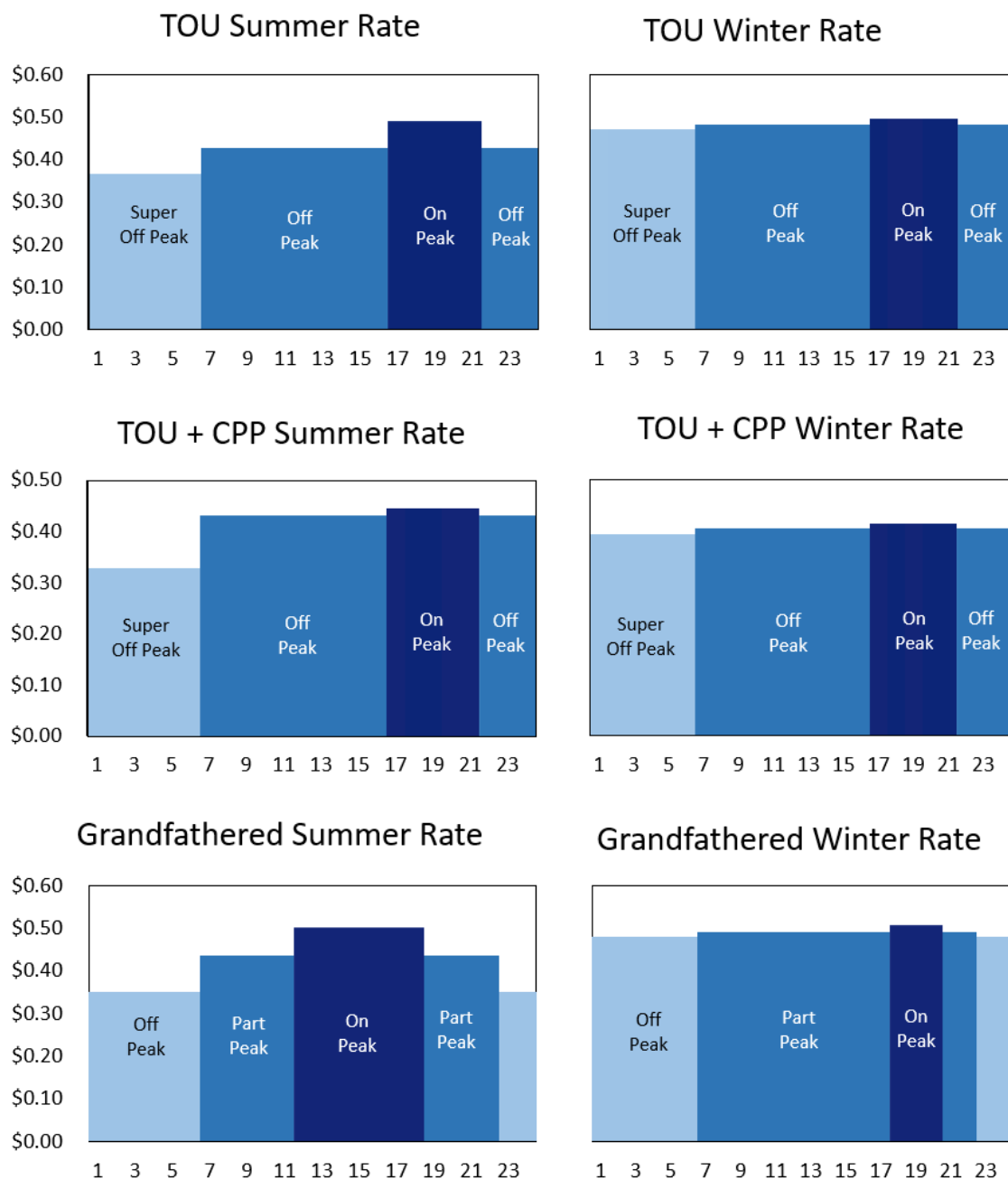
The total TOU rate charges as of September 30, 2021, for TOU (TOU-DR) customers are \$0.490, \$0.428, and \$0.368 per kWh for the summer on-peak, off-peak, and super-peak periods respectively. Thus, the peak to super-off-peak price ratio is 1.33 to one. Summer TOU charges for CPP (TOU-DR-P) customers are somewhat lower, at \$0.445, \$0.428, and \$0.328 per kWh, implying a peak to off-peak price ratio of 1.35 to one. Summer prices for Grandfathered CPP (GTOU-DR-P) customers are \$0.503, \$0.435, and \$0.352 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.<sup>4</sup>

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.

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<sup>4</sup> 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. Since

no residential CPP events were called in 2021, this section does not include a description of the methodology for estimating CPP event load impacts.<sup>5</sup>

### **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 2019 through September 2021;
- *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. Third, fixed-effects panel regression models are estimated, which produce difference-in-differences estimates of average TOU period load impacts.

#### **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 matched control group customers were drawn from an eligible population of SDG&E residential customers.

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 2019 through September 2020). Only incremental customers

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<sup>5</sup> For a full description of the ex-post methodology for determining CPP load impacts, see the PY2020 report.

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.<sup>6</sup> The incremental customers were matched based on two pairs of hourly loads for each season – one for all weekdays, and one for a subset of the hottest (or coldest) weekdays. Matching for the *winter* season used data for November 2019 through May 2020, while matching for the *summer* season used data for October 2019 and June through September of 2020.

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.<sup>7</sup> The PY2017 pre-treatment analysis periods cover October 2015 through September 2016. The post-treatment analysis period for these customers, however, covers October 2020 through September 2021.<sup>8</sup> 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. For the TOU analysis, the relevant customer characteristics include the average hourly usage on weekdays and hot/cold days for the summer/winter match (48 variables).<sup>9</sup> 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

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<sup>6</sup> The seasons defined for matching are summer (June through October) and winter (November through May). Therefore, incremental customers for the summer analysis are those that enrolled after October 1, 2020, while incremental customers for the winter analysis are those that enrolled after November 1, 2020. Customers must also be on a non-TOU rate (*e.g.*, DR) for the 85% of the pre-treatment period to be a valid incremental customer.

<sup>7</sup> 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.

<sup>8</sup> 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.

<sup>9</sup> Hot/cold days are among the highest/lowest 20<sup>th</sup> percentile in terms of CDD or HDD temperature values. Hot/cold days are selected separately by climate zone.

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 their solar PV system are included.<sup>10</sup> Second, NEM treatment customers must be matched to NEM control customers that have comparable solar photovoltaic generation capacity sizes.<sup>11</sup> 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 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.<sup>12</sup>

### 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.

The regression used to estimate average weekday TOU load impacts were estimated separately for the TOU-DR, TOU-DR-P, and GTOU-DR-P customers. The load impacts were also estimated separately for NEM customers within each rate and estimated separately by climate zone within each rate.

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<sup>10</sup> 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.

<sup>11</sup> 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).

<sup>12</sup> 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.



### 3.2.3 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.<sup>13</sup> 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  $\beta_1$ ). 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 customer groups (*e.g.*, climate zone, NEM). The customer-level fixed-effects models are of the following form:<sup>14</sup>

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

The variables and coefficients in the equation are described in Table 3.1. Incremental customers are used to estimate the TOU load impacts in each regression. Results are then scaled to the program level of enrollments.

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<sup>13</sup> 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.*,  $PctLI_{Season} = LI_{Season} / (Obs_{Season} + LI_{Season})$ ). The season-specific percentage load impacts are then used to calculate monthly average weekday or system peak day reference loads (*i.e.*,  $Ref_{Daytype} = Obs_{Daytype} / (1 - PctLI_{Season})$ ) and level load impacts (*i.e.*,  $LI_{Daytype} = Ref_{Daytype} \times PctLI_{Season}$ ). This method was used for each season for TOU-DR, GTOU-DR-P, and NEM customers.

<sup>14</sup> 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.

**Table 3.1: 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 $c$ <sup>15</sup>
$Post_{c,d}$	Variable indicating that date $d$ is in the post-enrollment period for customer $c$
$ACSDA\_Evt_{c,d}$	Variable indicating that date $d$ is an <i>AC Saver Day-Ahead (TD)</i> event day (1= event, 0 if not) for customer $c$
$ACSDO\_Evt_{c,d}$	Variable indicating that date $d$ is an <i>AC Saver Day-Of (Summer Saver)</i> event day (1=event, 0 if not) for customer $c$
$\beta_0$	Estimated constant coefficient
$\beta_1$	Estimate of TOU load impact
$\beta_{2,Cust}$ and $\beta_{3,date}$	Estimated customer and date fixed effects
$\beta_4$	Estimate of average event-day load impact
$\beta_5$ and $\beta_6$	Estimated average <i>TD</i> and <i>SS</i> 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

### 3.2.4 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 10<sup>th</sup>, 30<sup>th</sup>, 70<sup>th</sup>, and 90<sup>th</sup> percentile scenarios are generated from these distributions.

<sup>15</sup> For CPP customers, the *Evt* variable indicates that a day is a CPP event day.

To develop the uncertainty-adjusted load impacts associated with the 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 peak-hour TOU load impact is directly estimated). The associated standard errors are used to develop the uncertainty-adjusted load impacts in the same manner described above.

### **3.2.5 Validity assessment**

Because a control-group approach is being employed, the validity assessment focuses on comparisons of treatment and control-group loads for 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. 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.

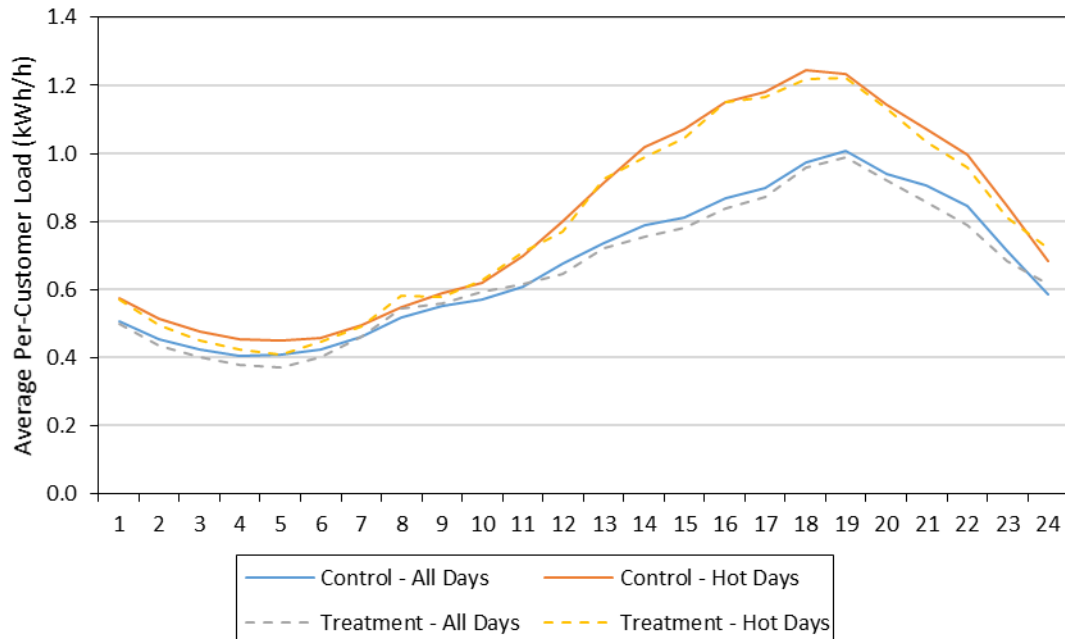
### ***4.1 TOU control group matching results for TOU customers***

Figures 4.1 and 4.2 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 -2.6 percent, while the mean absolute percentage error (MAPE) is 4.0 percent. In the winter months, the MPE is -0.8 percent and the MAPE is 2.5 percent.<sup>16</sup>

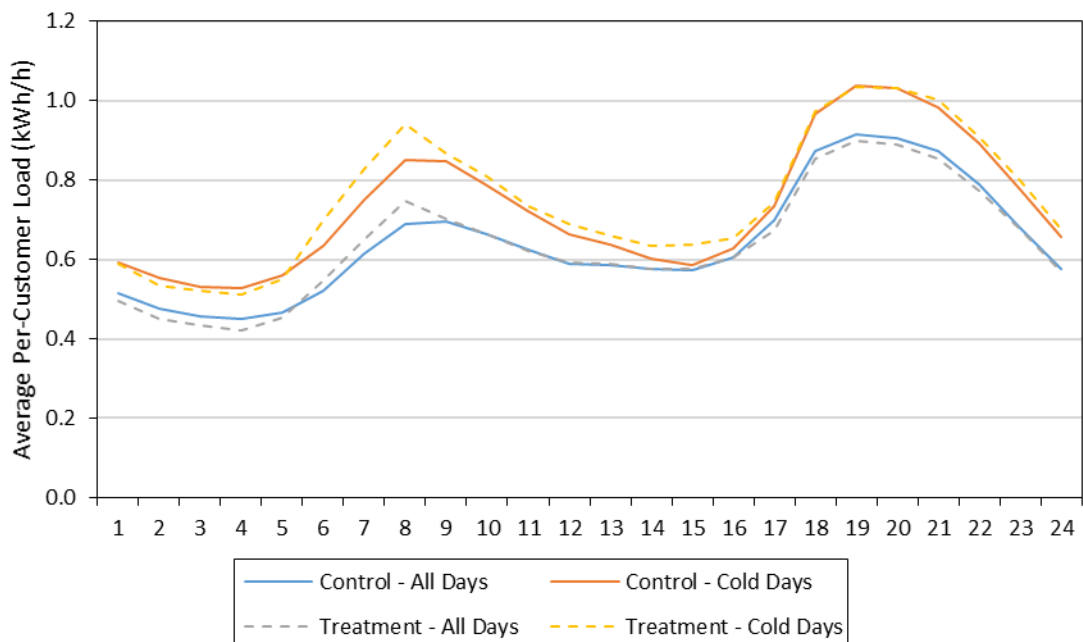
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<sup>16</sup> The MPE and MAPE statistics for the TOU matches are calculated over the two 24-hour load profiles, all days and hot/cold days.

**Figure 4.1: Non-NEM TOU and Matched Control Group Load Profiles – Summer**



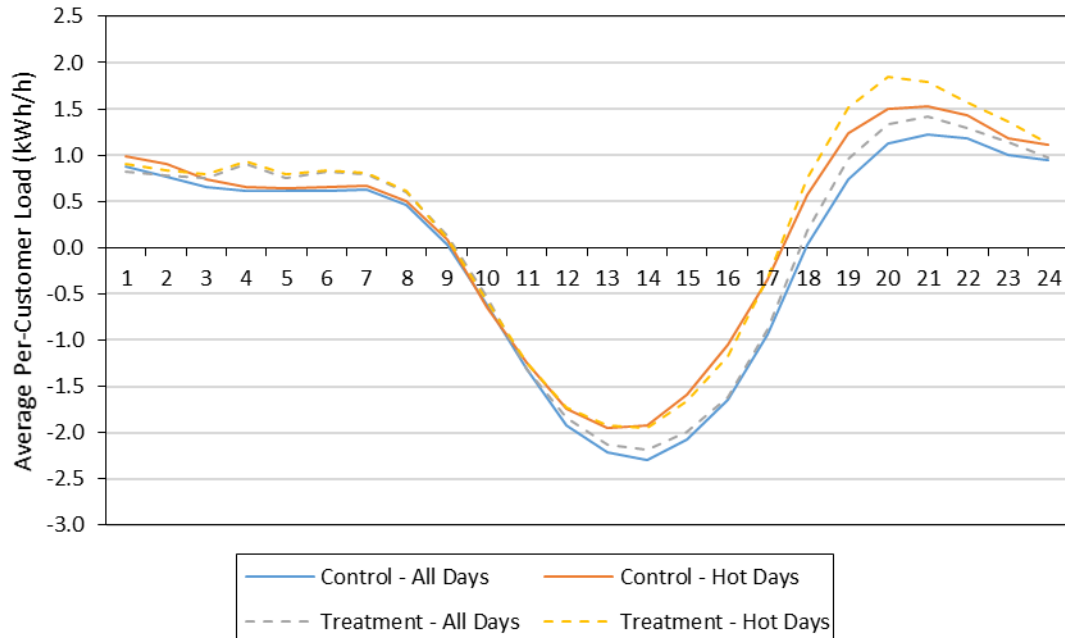
**Figure 4.2: Non-NEM TOU and Matched Control Group Load Profiles – Winter**



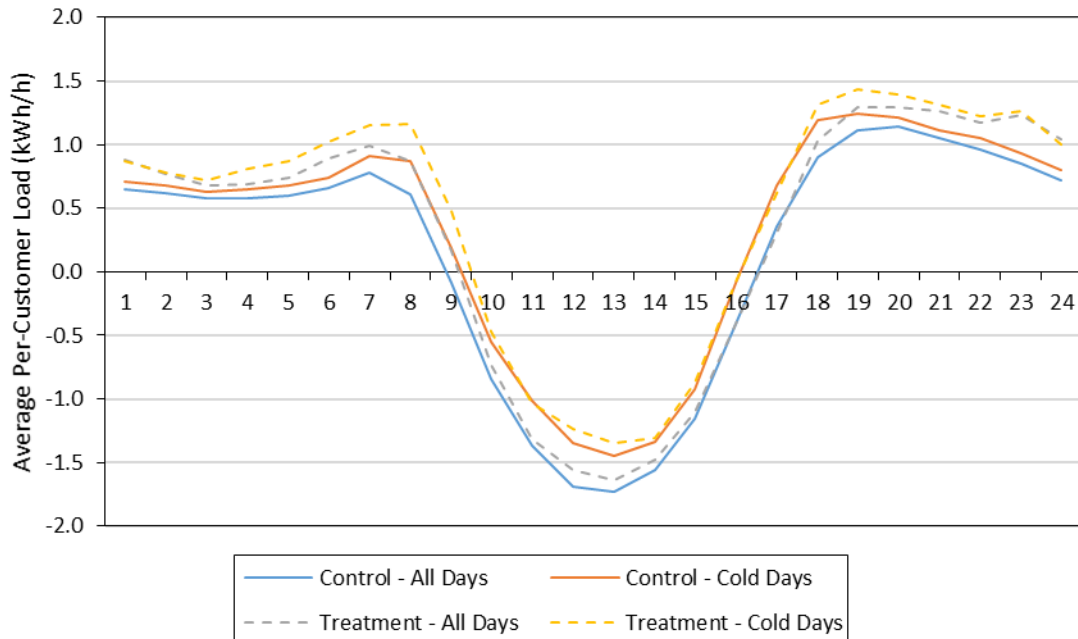
Figures 4.3 and 4.4 illustrate the quality of the matches for the TOU (TOU-DR) NEM customers, which were matched separately from Non-NEM customers. The figures show the average TOU and matched control-group customer load profiles for the summer and winter months, respectively. Two pairs of loads are shown, one for all days, and one for the hottest (or coldest) days. In the summer months, the mean error (ME) of the TOU

profile compared to the control-group profile is 0.11 kWh/h, while the mean absolute error (MAE) is 0.12 kWh/h. In the winter months, the ME is 0.16 kWh/h and the MAE is 0.16 kWh/h.

**Figure 4.3: NEM TOU and Matched Control Group Load Profiles - Summer**



**Figure 4.4: NEM TOU and Matched Control Group Load Profiles - Winter**



## 4.2 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 4.1 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 2020). The winter months are indicated by light blue shading. Enrollment continued throughout the period, with the numbers of enrolled customers rising from 8,800 in October 2020 to 12,698 in September 2021.<sup>17</sup> 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. The per-customer load impacts are higher during the summer months at approximately 0.15 kWh/h. The lowest load impact occurs during March and April, when there is virtually no load impact.

**Table 4.1: TOU Peak Load Impacts for TOU Customers – Average Weekday by Month**

Month	Climate Zone	Enrolled	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)	
Oct-20	All	8,800	12.12	1.29	1.38	0.15	73
Nov-20	All	9,102	10.92	0.75	1.20	0.08	61
Dec-20	All	9,380	13.09	0.80	1.40	0.09	58
Jan-21	All	9,577	11.79	0.81	1.23	0.09	58
Feb-21	All	9,838	10.25	0.83	1.04	0.08	59
Mar-21	All	10,140	6.74	0.02	0.66	0.00	58
Apr-21	All	10,316	4.50	-0.01	0.44	0.00	65
May-21	All	11,220	4.49	0.90	0.40	0.08	66
Jun-21	All	11,739	7.75	1.68	0.66	0.14	70
Jul-21	All	11,991	12.78	1.74	1.07	0.15	74
Aug-21	All	12,357	15.82	1.80	1.28	0.15	75
Sep-21	All	12,698	15.33	1.80	1.21	0.14	72

Table 4.2 shows results by season and climate zone. Both the Inland and the Coastal climate zone exhibit higher reference loads during the summer than during winter, with

<sup>17</sup> 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 206 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 37 NEM TOU customers are included in the regressions. The aggregate TOU load impacts are then scaled to total enrollments.

Inland reference loads higher than Coastal reference loads during both periods. While customers in both climate zones decrease load during peak periods in the summer for an overall average load impact of 0.17 kwh/h, Inland customers have a larger load impact than Coastal customers in both summer and winter.

**Table 4.2: TOU Peak Load Impacts for TOU 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	6,154	5.57	0.49	0.90	0.08	72
	Inland	5,363	7.43	1.46	1.39	0.27	74
	<b>All</b>	<b>11,517</b>	<b>13.00</b>	<b>1.95</b>	<b>1.13</b>	<b>0.17</b>	<b>73</b>
Winter	Coastal	4,991	4.16	-0.01	0.83	0.00	61
	Inland	4,948	4.78	0.70	0.97	0.14	61
	<b>All</b>	<b>9,939</b>	<b>8.94</b>	<b>0.69</b>	<b>0.90</b>	<b>0.07</b>	<b>61</b>

Table 4.3 shows the effect of TOU on average *daily* usage by month. TOU customers decreased their daily energy consumption in all months except for March and April.

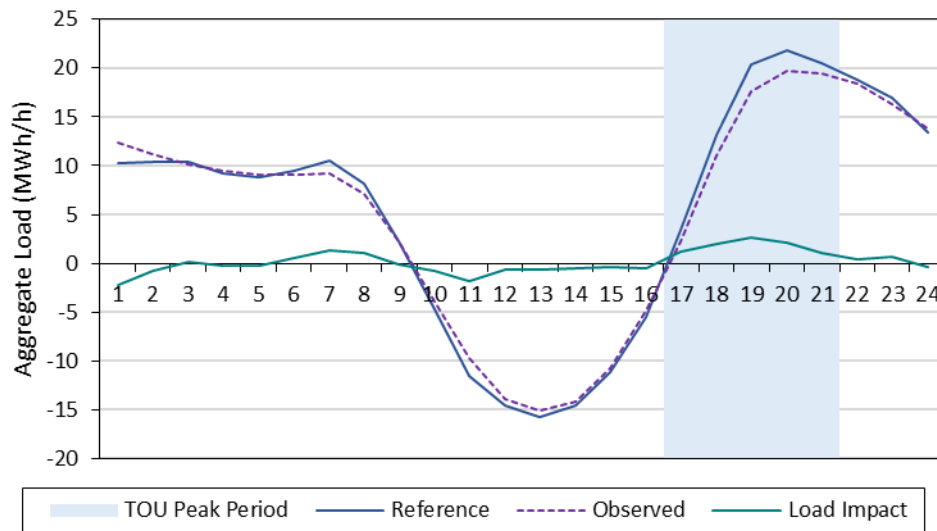
**Table 4.3: TOU Average Daily Load Impacts for TOU Customers, by Month**

Month	Climate Zone	Enrolled	Aggregate		Per-Customer	
			Daily Ref. Load (MWh/h)	Daily Load Impact (MWh/h)	Daily Ref. Load (kWh/h)	Daily Load Impact (kWh/h)
Oct-20	All	8,800	96.73	3.13	10.99	0.36
Nov-20	All	9,102	77.90	7.11	8.56	0.78
Dec-20	All	9,380	134.49	7.51	14.34	0.80
Jan-21	All	9,577	111.13	7.71	11.60	0.80
Feb-21	All	9,838	60.15	7.97	6.11	0.81
Mar-21	All	10,140	24.83	-0.28	2.45	-0.03
Apr-21	All	10,316	-12.58	-0.49	-1.22	-0.05
May-21	All	11,220	-15.23	8.60	-1.36	0.77
Jun-21	All	11,739	16.82	4.57	1.43	0.39
Jul-21	All	11,991	85.70	4.12	7.15	0.34
Aug-21	All	12,357	129.84	4.01	10.51	0.32
Sep-21	All	12,698	114.11	4.20	8.99	0.33

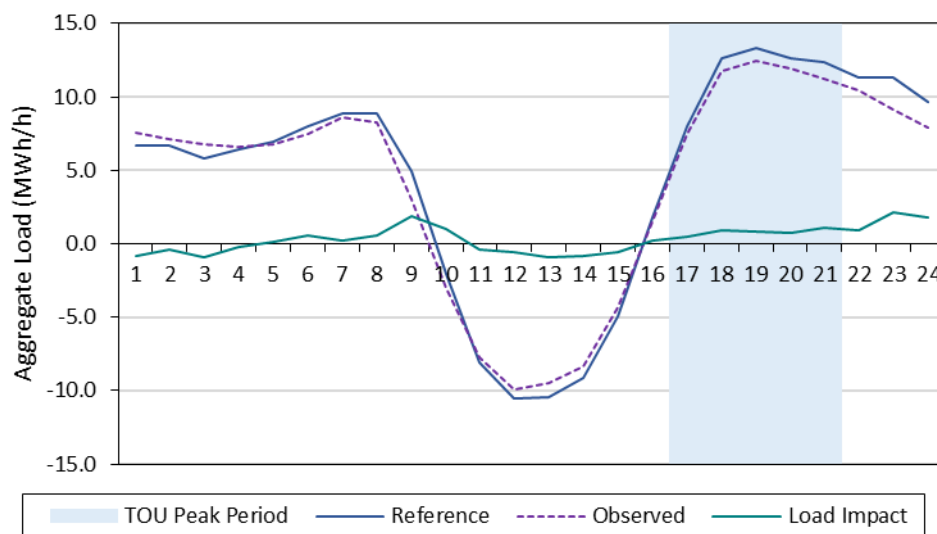
Figure 4.5 shows aggregate (NEM and Non-NEM combined) hourly observed and estimated reference loads, along with hourly estimated TOU load impacts for the TOU-

only customers for the average weekday in August. Figure 4.6 shows the same information for the average weekday in January. The hourly TOU load impacts in August illustrate a reduction in usage during the peak hours. There is not much evidence of load shifting to super off-peak hours as reference and observed loads during those hours are nearly identical, except in hour one. The TOU load impacts during the winter are positive and statistically significant for hours ending 18 through 21 only, and as in August, there is a slight increase in usage during the middle of the day.

**Figure 4.5: Aggregate Hourly Loads and TOU Load Impacts (MWh/h) – TOU Customers  
(Average Weekday, August 2021)**



**Figure 4.6: Aggregate Hourly Loads and TOU Load Impacts (MWh/h) – TOU Customers  
(Average Weekday, January 2021)**

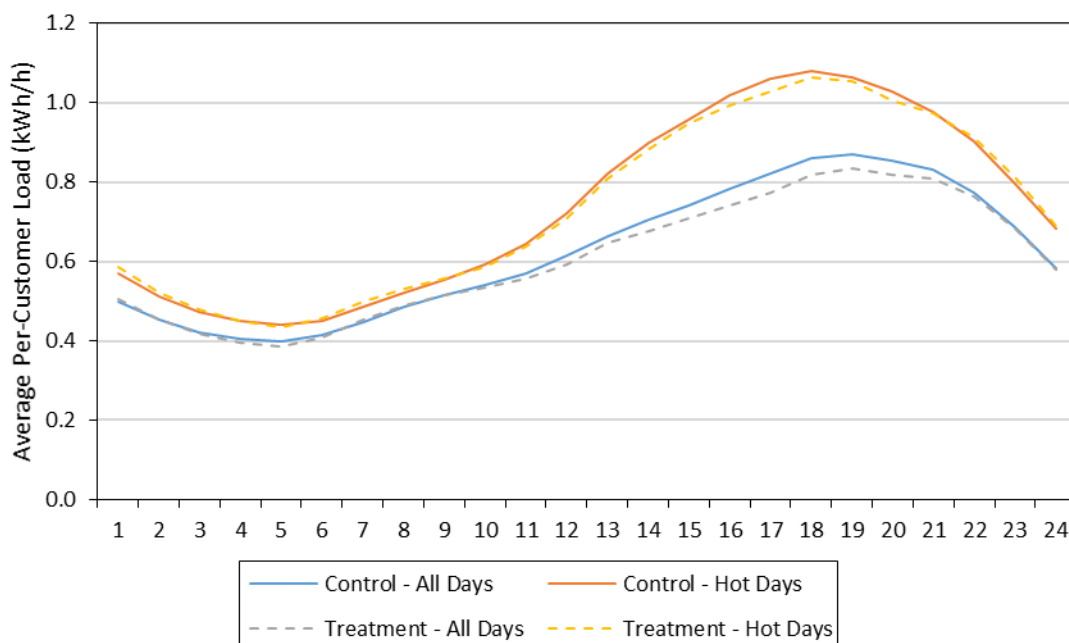




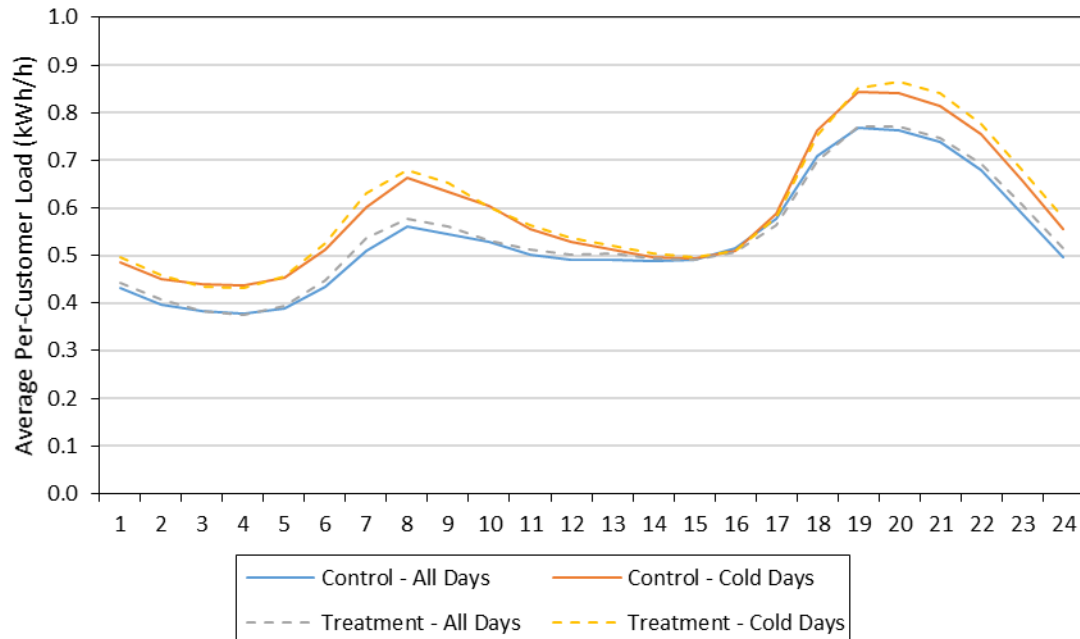
### 4.3 TOU control group matching results for CPP customers

Figures 4.7 and 4.8 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 -2.2 percent, while the mean absolute percentage error (MAPE) is 2.5 percent. In the winter months, the MPE is 1.5 percent and the MAPE is 1.9 percent.

**Figure 4.7: Non-NEM CPP and Matched Control Group Load Profiles – Summer**

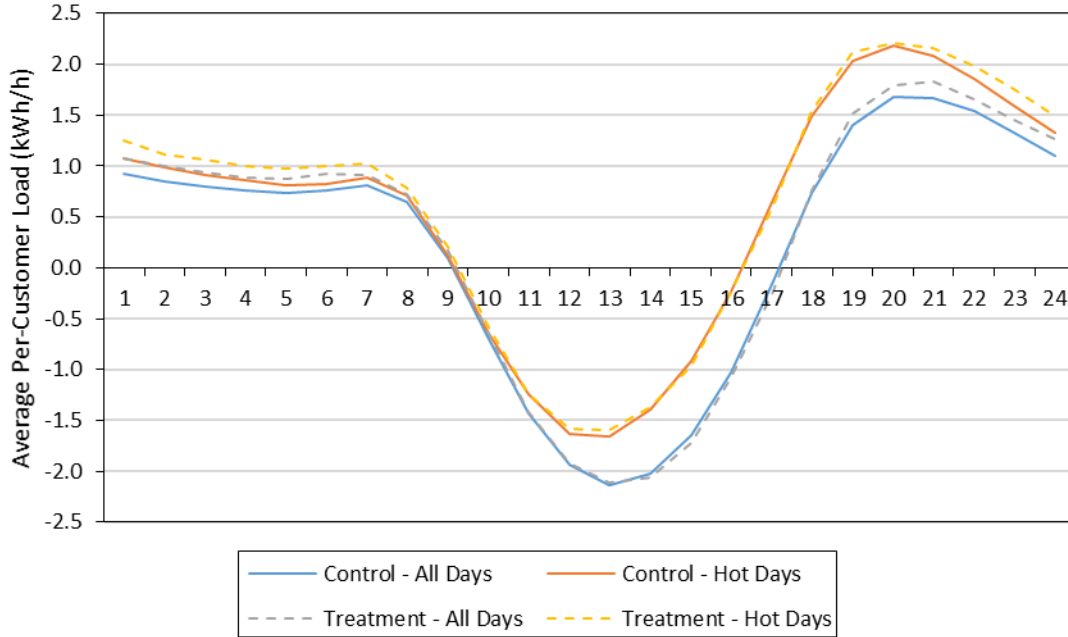


**Figure 4.8: Non-NEM CPP and Matched Control Group Load Profiles – Winter**

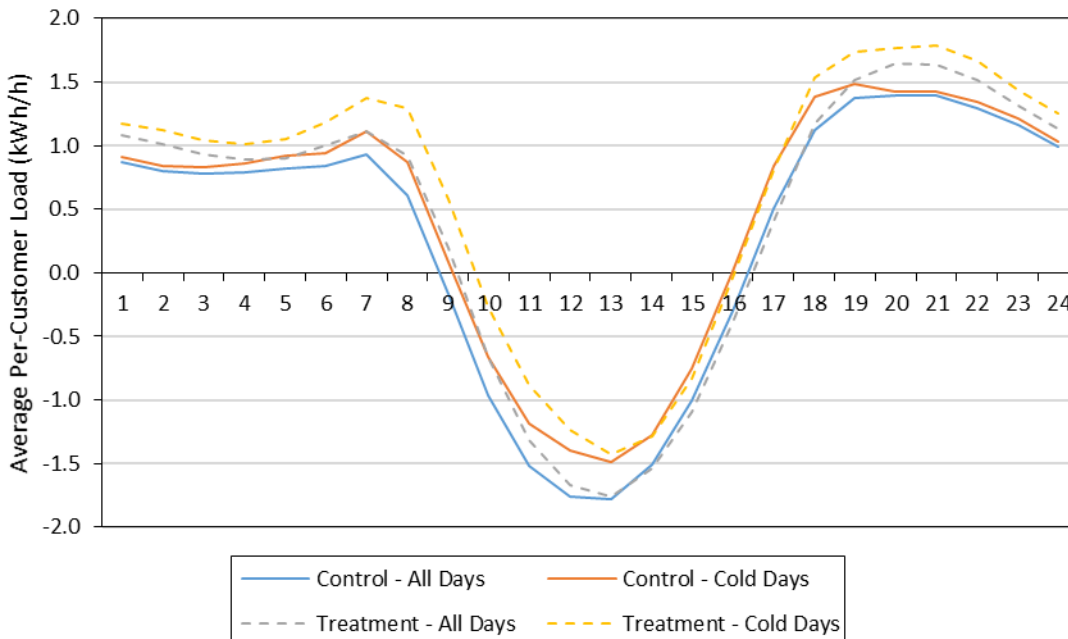


Figures 4.9 and 4.10 illustrate the quality of the matches for the NEM residential CPP (TOU-DR-P) customers in the context of measuring TOU peak load impacts on non-event days. The figures show the average CPP and matched control-group customer load profiles for the summer and winter months, respectively. 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 0.07 kWh/h, while the mean absolute error (MAE) is 0.10 kWh/h. In the winter months, the ME is 0.14 kWh/h and the MAE is 0.16 kWh/h.

**Figure 4.9: NEM CPP and Matched Control Group Load Profiles – Summer**



**Figure 4.10: NEM CPP and Matched Control Group Load Profiles – Winter**



#### **4.4 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 4.4 summarizes

peak-period loads and load impacts for the average summer (October 2020, and June through September 2021) and winter (November 2020 through May 2021) weekdays, by month. Reported enrollment in CPP grew from 13,167 in October 2020 to 21,640 in September 2021.<sup>18</sup> Peak load impacts varied across months, with estimated load reductions in all summer months, and load increases in all winter months except for March and April. Peak load impacts were consistently 0.04 kWh/h per-customer during the summer months and close to zero during the winter months, apart from March and April.

**Table 4.4: TOU Peak Load Impacts for CPP Customers – Average Weekday by Month**

Month	Climate Zone	Enrolled	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)	
Oct-20	All	13,167	13.42	0.46	1.02	0.04	73
Nov-20	All	13,567	12.40	-0.05	0.91	0.00	62
Dec-20	All	14,251	15.15	-0.03	1.06	0.00	58
Jan-21	All	15,159	14.71	-0.05	0.97	0.00	58
Feb-21	All	16,004	13.66	-0.07	0.85	0.00	59
Mar-21	All	17,154	13.37	0.53	0.78	0.03	58
Apr-21	All	18,188	12.01	0.54	0.66	0.03	65
May-21	All	19,142	10.83	-0.13	0.57	-0.01	66
Jun-21	All	19,540	13.71	0.69	0.70	0.04	70
Jul-21	All	20,411	18.72	0.75	0.92	0.04	75
Aug-21	All	21,385	21.89	0.81	1.02	0.04	76
Sep-21	All	21,640	20.48	0.77	0.95	0.04	73

Table 4.5 summarizes results by season and climate zone. The two climate zones display opposite signs of load impacts, with the Inland climate zone *increasing* usage during both periods. Load impacts for the Coastal climate zone decreases between summer and winter.

<sup>18</sup> 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 1,033 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 4.5: TOU Peak Load Impacts for 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	11,564	9.72	0.78	0.84	0.07	73
	Inland	7,664	7.85	-0.14	1.02	-0.02	74
	<b>All</b>	<b>19,229</b>	<b>17.57</b>	<b>0.64</b>	<b>0.91</b>	<b>0.03</b>	<b>73</b>
Winter	Coastal	9,965	7.97	0.15	0.80	0.02	61
	Inland	6,245	5.21	-0.03	0.83	-0.01	61
	<b>All</b>	<b>16,209</b>	<b>13.18</b>	<b>0.12</b>	<b>0.81</b>	<b>0.01</b>	<b>61</b>

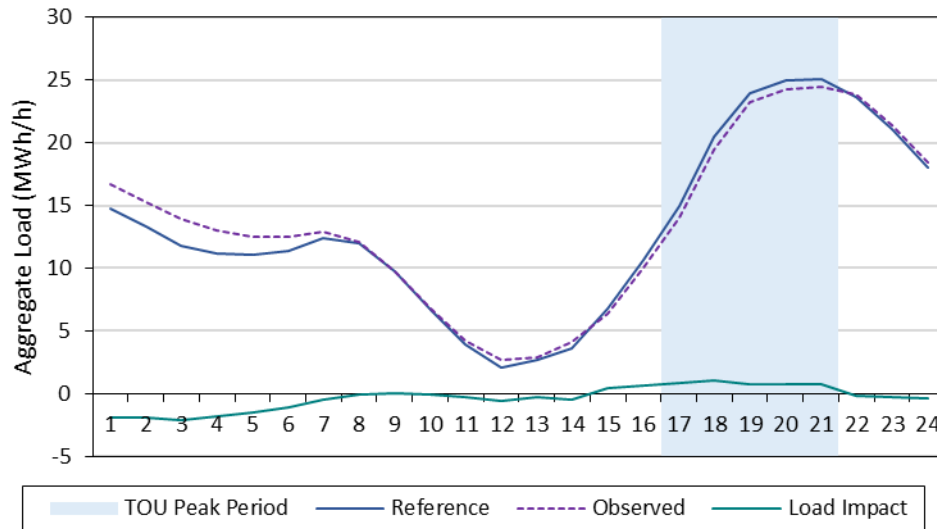
Table 4.6 shows the effect of TOU on average daily usage by month. CPP customers *increased* their average daily usage during all summer months and *decreased* their usage in all winter months. There is an overall annual load impact of approximately 0.13 kwh/h relative to the reference load.

**Table 4.6: TOU Average Daily Load Impacts for CPP Customers, by Month**

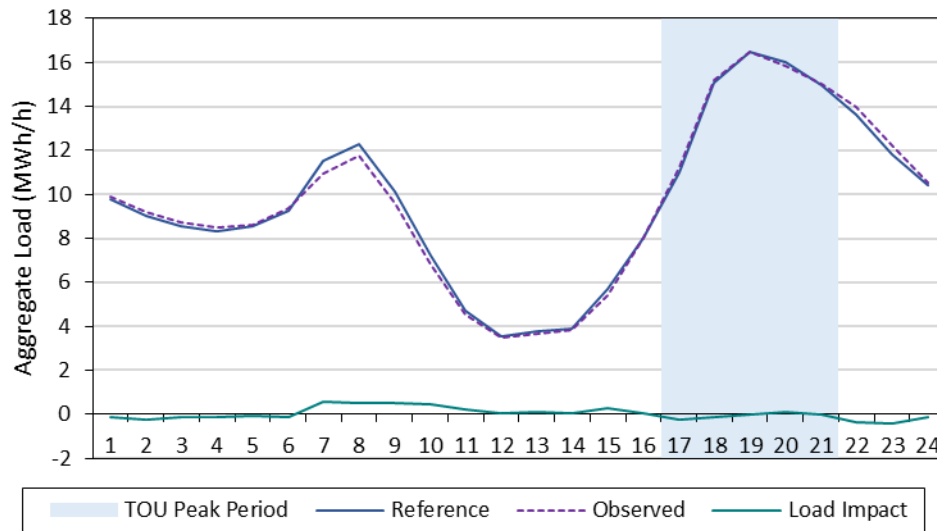
Month	Climate Zone	Enrolled	Aggregate		Per-Customer		Ave. Daily Temp.
			Daily Ref. Load (MWh/h)	Daily Load Impact (MWh/h)	Daily Ref. Load (kWh/h)	Daily Load Impact (kWh/h)	
Oct-20	All	13,167	195.52	-5.05	14.85	-0.38	69
Nov-20	All	13,567	183.95	0.55	13.56	0.04	60
Dec-20	All	14,251	236.50	0.76	16.60	0.05	56
Jan-21	All	15,159	233.59	0.74	15.41	0.05	55
Feb-21	All	16,004	206.80	0.71	12.92	0.04	56
Mar-21	All	17,154	209.09	3.08	12.19	0.18	55
Apr-21	All	18,188	180.61	2.65	9.93	0.15	61
May-21	All	19,142	169.33	0.36	8.85	0.02	63
Jun-21	All	19,540	192.93	-7.16	9.87	-0.37	67
Jul-21	All	20,411	270.77	-8.06	13.27	-0.39	72
Aug-21	All	21,385	316.35	-8.61	14.79	-0.40	72
Sep-21	All	21,640	290.94	-8.20	13.44	-0.38	70

Figure 4.11 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 4.12 shows the same information for the average weekday in January. The average weekday in August loads illustrates a slight 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 4.11: Aggregate Hourly Loads and TOU Load Impacts (MWh/h) – CPP Customers**  
**(Average Weekday, August 2021)**



**Figure 4.12: Aggregate Hourly Loads and TOU Load Impacts (MWh/h) – CPP Customers**  
**(Average Weekday, January 2021)**

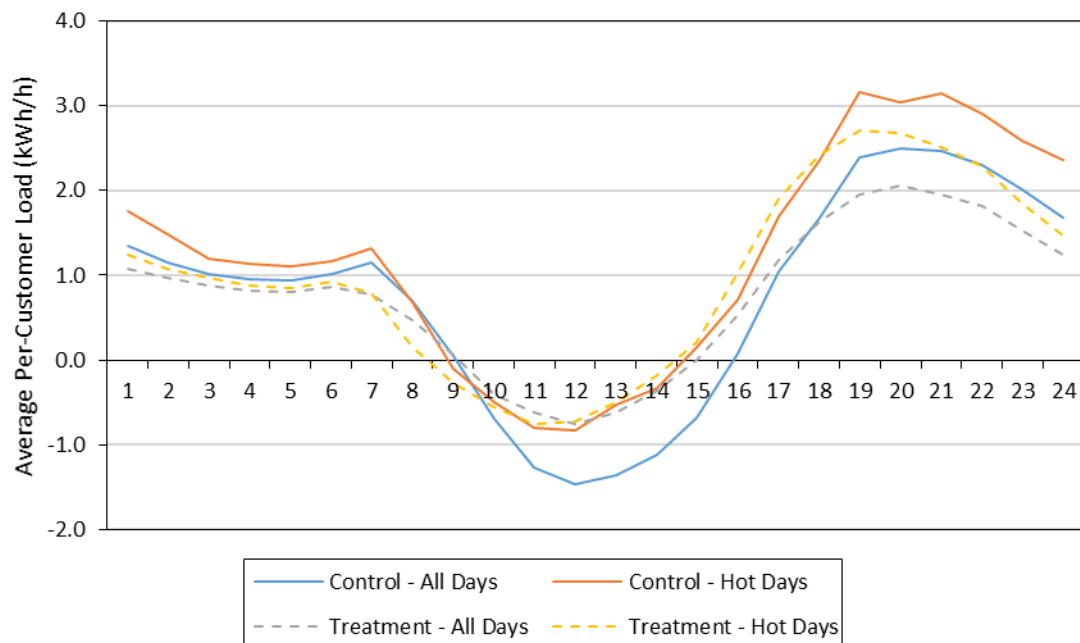


#### **4.5 TOU control group matching results for Grandfathered customers**

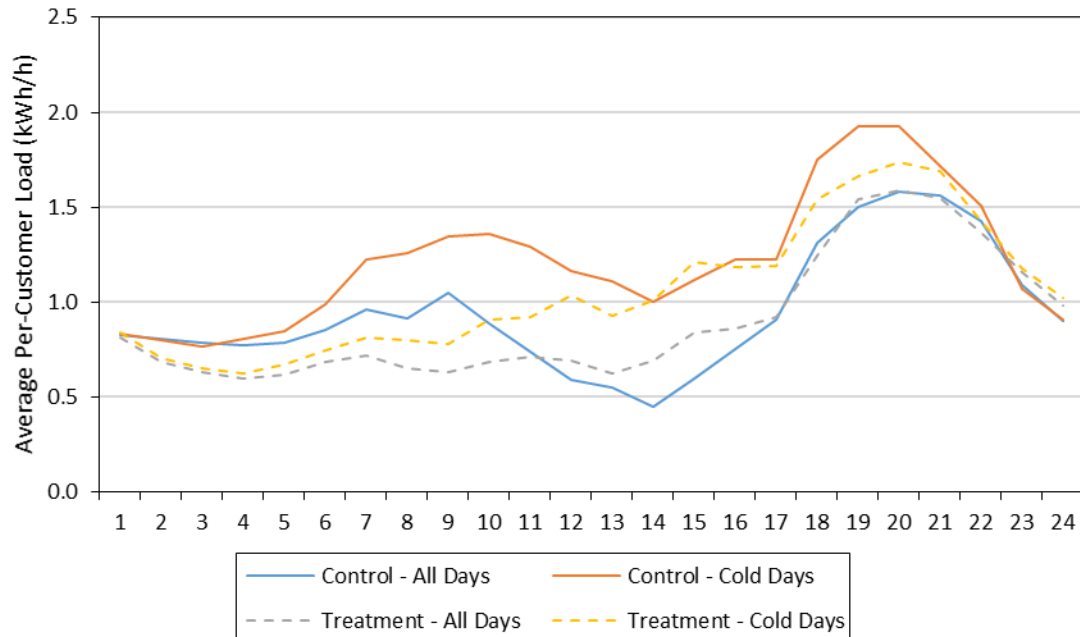
Figures 4.13 and 4.14 illustrate the quality of the matches for the grandfathered CPP (GTOU-DR-P) customers in the context of measuring TOU peak load impacts on non-

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 -0.002 kWh/h, while the mean absolute error (MAE) is 0.372 kWh/h. In the winter months, the ME is -0.05 kWh/h and the MAE is 0.13 kWh/h. In order to qualify as an eligible control customer for the grandfathered analysis, customers must have remained on the same rate, and not changed the size of their PV system, since 2015. The limited number of eligible control customers can result in lower quality matches relative to the non-grandfathered analysis.

**Figure 4.13: Grandfathered CPP and Matched Control Group Load Profiles – Summer**



**Figure 4.14: Grandfathered CPP and Matched Control Group Load Profiles – Winter**



## 4.6 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 4.7 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 PY2017 incremental customers who have remained on the grandfathered TOU rate and have not had structural changes to their Net Energy Metering setups. Monthly enrollment numbers and reference loads are drawn from the October 2020 through September 2021 period. The winter months are indicated by light blue shading. Customer enrollments hover around 370 throughout.<sup>19</sup> The per-customer load impacts remain constant by season because of the methodology implemented, resulting in per-customer load *decreases* of 0.08 kWh/h for the winter season and a 0.18 kWh/h per-customer *increase* for the summer season. Positive reference loads during the winter and negative reference loads during the summer occur because the grandfathered TOU peak-period in the summer

<sup>19</sup> 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 five incremental grandfathered customers were included in the regression analysis for the summer period and nine were used during the winter period. 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 PY2021 period.



occurs during the middle of the day, while the TOU peak-period in the winter occurs during the evening, after the sun has set.

**Table 4.7: 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-20	All	371	-0.30	-0.07	-0.81	-0.18	80
Nov-20	All	375	0.60	0.03	1.59	0.08	60
Dec-20	All	372	0.68	0.03	1.84	0.08	58
Jan-21	All	373	0.63	0.03	1.69	0.08	57
Feb-21	All	377	0.58	0.03	1.53	0.08	58
Mar-21	All	375	0.44	0.03	1.18	0.08	58
Apr-21	All	372	0.32	0.03	0.87	0.08	65
May-21	All	369	0.24	0.03	0.66	0.08	67
Jun-21	All	378	-0.77	-0.07	-2.03	-0.18	74
Jul-21	All	369	-0.53	-0.07	-1.43	-0.18	79
Aug-21	All	368	-0.43	-0.07	-1.17	-0.18	80
Sep-21	All	368	-0.44	-0.07	-1.21	-0.18	78

Table 4.8 summarizes results by season and climate zone. Because of data limitations arising from a small number of treatment customers, TOU regressions by climate zone were not estimated. Instead, the analysis estimates TOU impacts across a combined group of customers, which gives rise to load impacts that are assumed to be equal between climate zones. These load impacts were applied to climate zone-specific reference loads.

**Table 4.8: 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	177	-0.26	-0.03	-1.47	-0.18	77
	Inland	193	-0.23	-0.03	-1.21	-0.18	80
	<b>All</b>	<b>371</b>	<b>-0.49</b>	<b>-0.07</b>	<b>-1.33</b>	<b>-0.18</b>	<b>78</b>
Winter	Coastal	177	0.24	0.01	1.38	0.08	60
	Inland	196	0.26	0.02	1.30	0.08	61
	<b>All</b>	<b>373</b>	<b>0.50</b>	<b>0.03</b>	<b>1.34</b>	<b>0.08</b>	<b>61</b>

Table 4.9 shows the TOU effect on average daily usage by month. Grandfathered customers *decreased* overall usage during winter months but *increased* overall usage

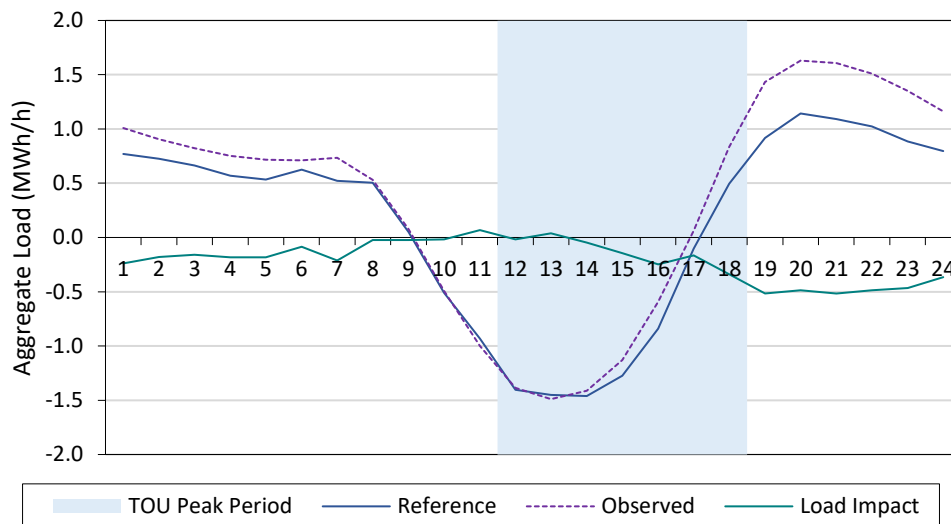
during summer months. The overall effect is an average annual *increase* of about 1.99 kWh/h per customer.

**Table 4.9: TOU Average *Daily* Load Impacts for Grandfathered Customers, *by Month***

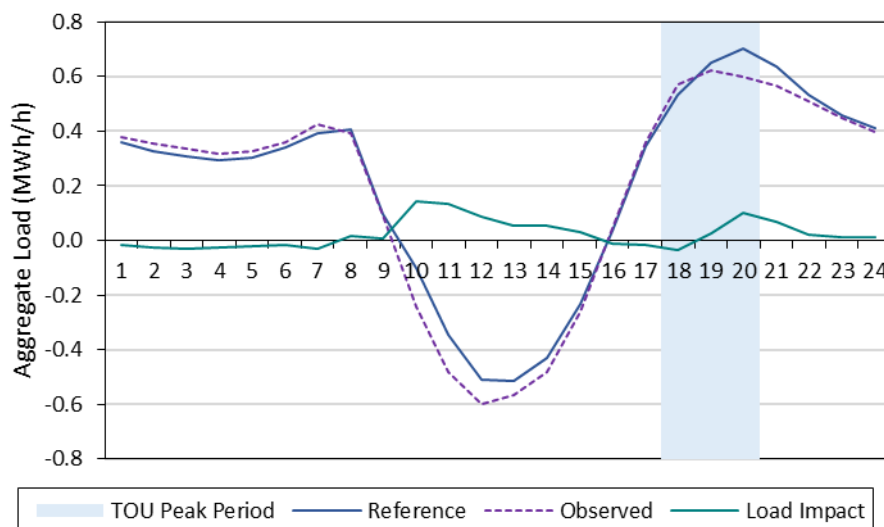
Month	Climate Zone	Enrolled	Aggregate		Per-Customer		Ave. Daily Temp.
			Daily Ref. Load (MWh/h)	Daily Load Impact (MWh/h)	Daily Ref. Load (kWh/h)	Daily Load Impact (kWh/h)	
Oct-20	All	371	1.74	-2.52	4.70	-6.79	69
Nov-20	All	375	3.56	0.53	9.50	1.42	59
Dec-20	All	372	6.33	0.53	17.02	1.42	55
Jan-21	All	373	5.01	0.53	13.42	1.42	55
Feb-21	All	377	2.50	0.54	6.63	1.42	56
Mar-21	All	375	0.91	0.53	2.43	1.42	54
Apr-21	All	372	-0.68	0.53	-1.84	1.42	61
May-21	All	369	-1.62	0.52	-4.40	1.42	63
Jun-21	All	378	-3.21	-2.57	-8.48	-6.79	67
Jul-21	All	369	0.04	-2.51	0.12	-6.79	72
Aug-21	All	368	1.67	-2.50	4.55	-6.79	73
Sep-21	All	368	0.95	-2.50	2.58	-6.79	70

Figure 4.15 and Figure 4.16 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. During the summer period, load impacts hover near zero during the initial peak hours, followed by an *increase* in usage during the later part of the TOU window. The winter load profile illustrates a reduced response throughout the middle of the day. The evening hours exhibit a decrease in usage during the short peak period.

**Figure 4.15: Aggregate Hourly Loads and TOU Load Impacts (MWh/h) – Grandfathered Customers (Average Weekday, August 2021)**



**Figure 4.16: Aggregate Hourly Loads and TOU Load Impacts (MWh/h) – Grandfathered Customers (Average Weekday, January 2021)**



## 5. 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. Since no CPP events took place in 2021, the ex-ante analysis for CPP

events applies CPP event load impacts from PY2020 to simulated reference loads using PY2021 customer load data.

## **5.1 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.

Although no CPP events occurred in 2021, SDG&E called nine CPP events in 2020. Lacking more recent event load impacts, this study uses load impacts from the nine events from the prior year as a basis for PY2021 ex-ante forecasts. The percentage load impact calculated in PY2020 is used for the average weekday event to simulate the ex-ante CPP load impact and is applied by climate zone, NEM status, and enrollment in ACSDA. CPP load impacts for different weather scenarios are developed by applying the estimated percentage ex-post load impact from PY2020 to weather-sensitive reference loads simulated in PY2021.

Portfolio-level load impacts are reported for instances when a CPP event is called on the same day as an 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. Therefore, dually enrolled customers are removed from the reference load and load impacts for portfolio-level estimates. The proportion of AC Saver Day-Ahead (ACSDA) and Day-Of (ACSDO) customers is assumed to be equivalent to ex-post enrollment numbers and is held constant throughout the ex-ante forecast.

CPP events, prior to 2022, were called during the program hours of 2 p.m. to 6 p.m. year-round. In 2022, the CPP event window will be shifted to overlap precisely with the RA window of 4 p.m. to 9 p.m. To apply load impacts that correspond to the updated CPP event hours, we first categorize each hour of the day with respect to the old and updated CPP event hours. **Error! Reference source not found.** summarizes our categorization of each hour, with the “Previous Event Window” column representing the current event hours and the “Ex-ante Event Window” column representing the new CPP event window starting in June 2022.<sup>20</sup> The PY2020 ex-post reference loads and load impacts are averaged over these periods to obtain percentage load impacts, which are then applied to PY2021 ex-ante reference loads during the corresponding categorized period to calculate the ex-ante load impacts.<sup>21</sup> For example, the PY2020 ex-post percentage load impact for the hour before the previous event window (HE 14) is applied to the PY2021 ex-ante reference load for the hour before the ex-ante event window (HE 16).

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<sup>20</sup> PY2020 ex-ante percentage load impacts are applied to PY2021 reference loads on an hourly basis for the period before SDG&E changes the event window; specifically, January 2022 through May 2022.

<sup>21</sup> For NEM customers, this shift uses level load impacts rather than percentages.

**Figure 5.1: Ex-Ante Event Window Shift**

Hour	Previous Event Window	Ex-Ante Event Window
1	Beginning of Event Day	Beginning of Event Day
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14	Pre-event hour	Pre-event hour
15	Beginning of Event	
16	Middle of Event	Beginning of Event
17	End of Event	
18	Post-event hour	Middle of Event
19	Remainder of Event Day	
20		End of Event
21		Post-event hour
22		Remainder of Event Day
23		
24		

Beginning in 2022, ACSDA event hours will be from 6 p.m. to 9 p.m. (instead of 5 p.m. to 9 p.m.). The first hour of the ACSDA event (HE 18) is one hour later than the first hour of the CPP event (HE 17). As a result, the first hour of CPP load impacts for customers on ACSDA (shown as “TD” in the protocol tables) are adjusted to account for the first CPP event hour not also being an ACSDA event hour. (In the ex-post analysis, the event windows are equivalent for CPP and ACSDA.) The adjustment assumes that CPP customers on ACSDA still respond to the higher CPP prices during the first CPP event hour, but not by the same amount had their thermostats been setback as part of the ACSDA event. Specifically, we derate the first hour percentage load impact for CPP customers on ACSDA by 70%.<sup>22</sup> The remainder of the CPP event draws on load impacts from ACSDA customers.

<sup>22</sup> The amount of deration applied to percentage load impacts was determined by comparing CPP percentage load impacts of customers on ACSDA with customers not enrolled on ACSDA. The proportional

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 within each rate is assumed to remain constant throughout the forecast period. Non-NEM and NEM results are customer weighted to produce program TOU and CPP outcomes.

## 5.2 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. Customers are first sorted as weather sensitive or not.<sup>23</sup> 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);<sup>24</sup>
- Data for all months were included, rather than estimating separate models by month or season; and

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difference in percentage load impacts of 70% is used for non-NEM customers while the proportional difference in level load impacts of 52% is used for NEM customers.

<sup>23</sup> 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.

<sup>24</sup> 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:  $HDH60 = \max(0, 60 - \text{Temperature in } ^\circ\text{F})$ .

- 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).<sup>25</sup> For NEM customers, reference loads are calculated 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.<sup>26</sup>

### **5.3 Enrollment Forecast**

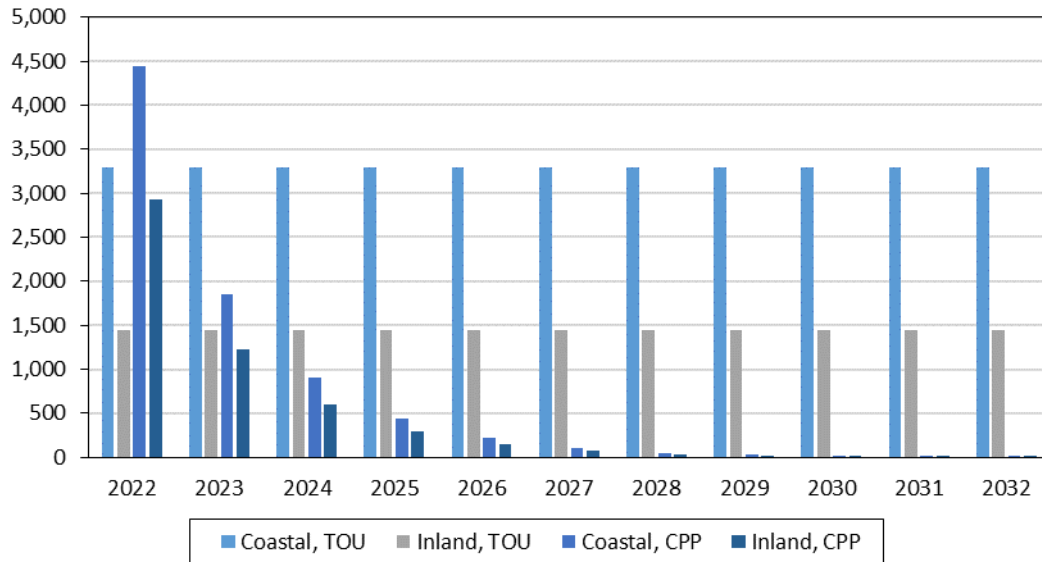
Figure 5.2 shows SDG&E’s enrollment forecasts for the TOU and CPP rates. Enrollment is anticipated to be essentially flat for TOU. While enrollment in CPP is forecasted to decline as customers migrate to Community Choice Aggregator programs, enrollment on the TOU-only rate in the Coastal climate zone is expected to be about twice as high as the Inland climate zone. Notably, as enrollment of CPP customers decline, the proportion of NEM customers on the SPP rates increases since the TOU-only rate has a higher NEM penetration rate (64.0% vs 20.4%). Enrollment for grandfathered customers (GTOU-DR-P) is assumed to remain constant at 367 customers until the grandfathering term expires on July 31, 2022.

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<sup>25</sup> 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 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.

<sup>26</sup> 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 may 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.

**Figure 5.2: Enrollments in TOU and CPP Rates**



## 6. 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.

### 6.1 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 6.1 illustrates the aggregate reference load, event-day load, and estimated load impact for an August peak day in 2023 for the SDG&E 1-in-2 weather scenario. The average event-period load impact is 0.59 MWh/h, or 7 percent of the reference load.<sup>27</sup>

<sup>27</sup> Reporting load impacts using percentages may be deceptive, because NEM customers may have reference loads so close to zero during certain hours that any load impact will appear to be a very large percentage of the reference load. As the reference load approaches zero, the percentage load impact will approach infinity.



**Figure 6.1: Aggregate Hourly Loads and CPP Load Impacts (MWh/h) –  
(August 2023 SDG&E 1-in-2 Peak Day)**

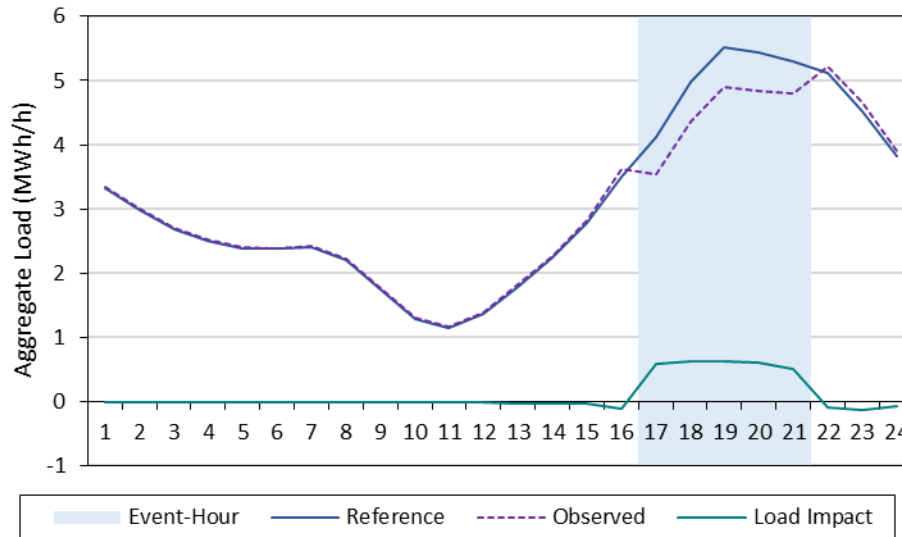


Figure 6.2 shows the monthly pattern of aggregate average ex-ante load impacts (RA window) in 2023 for the SDG&E 1-in-2 peak day. Load impacts are greatest in the summer months, reaching a maximum in September. The difference in load impacts between months also indicates the seasonal pattern in customer reference loads.

**Figure 6.2: Aggregate CPP Load Impacts (MWh/h), by Month –  
(2023 SDG&E 1-in-2 Peak Day, RA Window)**

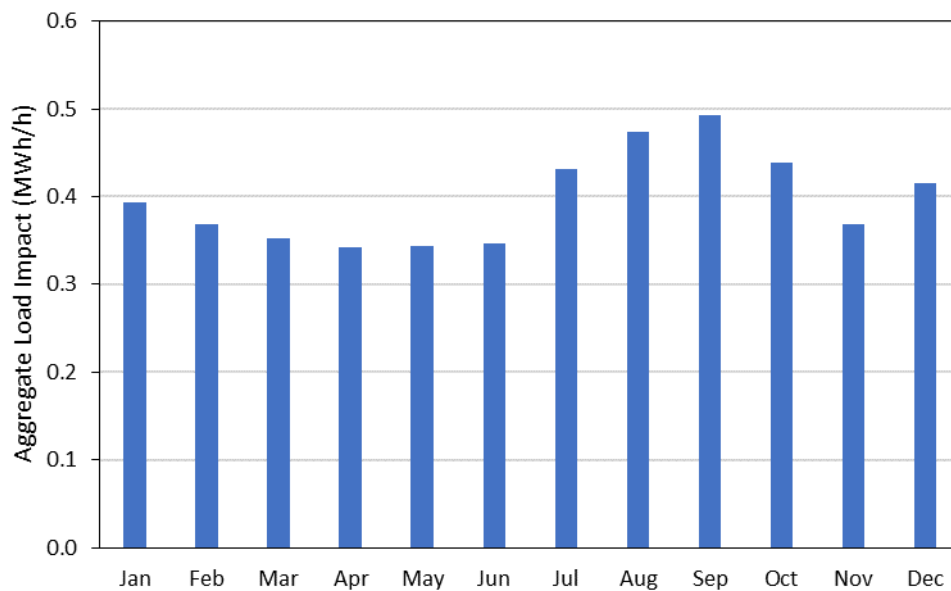
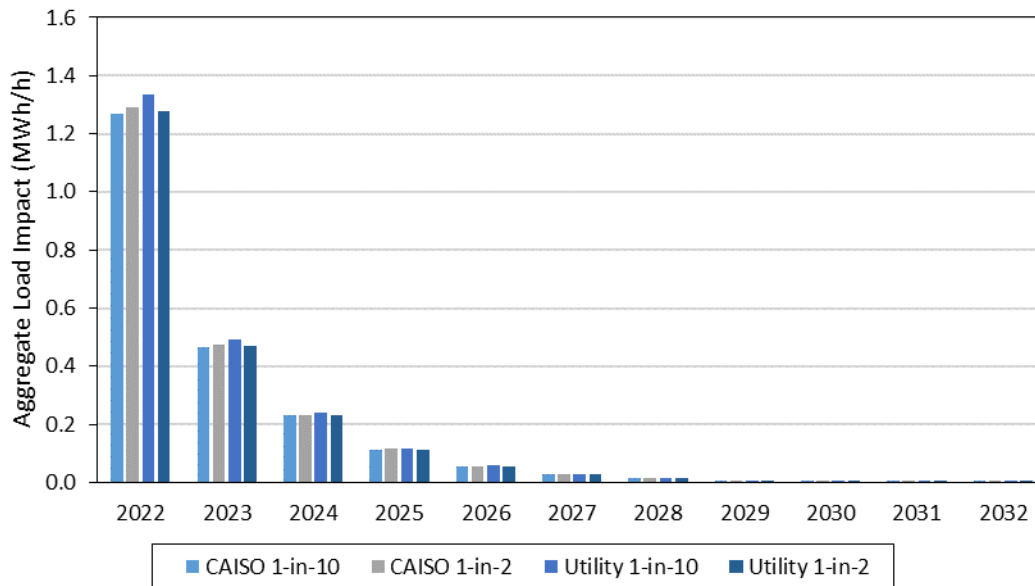


Figure 6.3 illustrates a substantial decrease in aggregate load impact over time as enrollment decreases. The differences are relatively minor between the aggregate ex-ante load impacts for the alternative weather scenarios over the forecast period. In each year, the Utility 1-in-10 scenario corresponds with the largest load impacts. Note that the weather data used to obtain these results indicate higher temperatures in CAISO 1-in-2 year types than CAISO 1-in-10 for the August System Peak day, which gives rise to lower estimated load impacts for CAISO 1-in-10.

**Figure 6.3: Aggregate CPP Load Impacts (MWh/h), by Year and Weather Scenario – (August Peak Day, RA Window)**



## 6.2 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 6.4 shows aggregate loads and load impacts for TOU and CPP customers, in 2023 for an August SDG&E 1-in-2 average weekday. The average peak load impact is 2.15 MWh/h.

**Figure 6.4: Aggregate Hourly Loads and TOU Load Impacts (MWh/h) – TOU-DR and TOU-DR-P Customers, (August 2023 SDG&E 1-in-2 Average Weekday)**

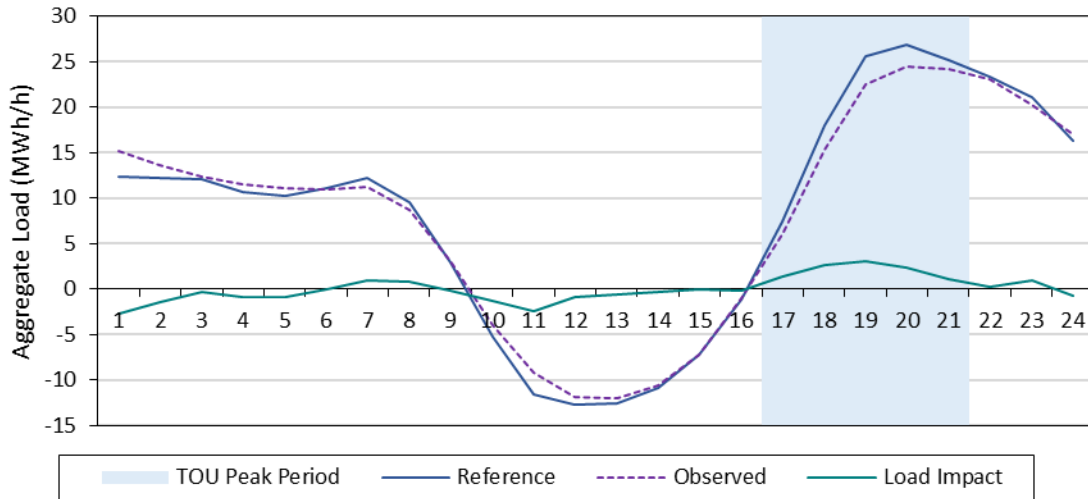
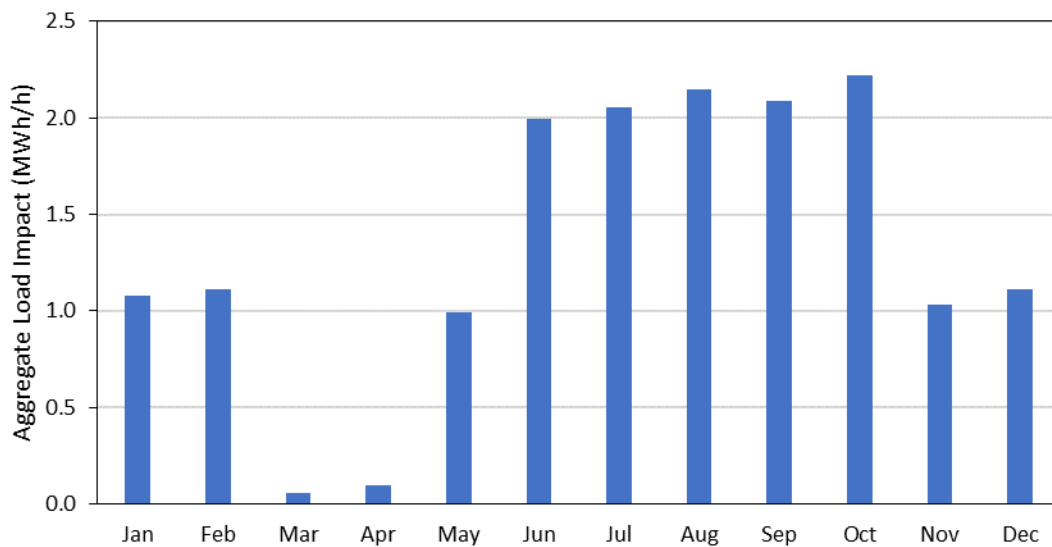


Figure 6.5 shows the monthly distributions of the peak-period TOU load impacts (TOU peak period aligns with the RA window) for TOU and CPP customers. Load impacts are smallest in the spring months, March and April.<sup>28</sup> Higher peak load impacts are expected to occur during the summer months based on the higher peak-hour prices, relative to the standard non-TOU rate prices, of the summer rate schedule.

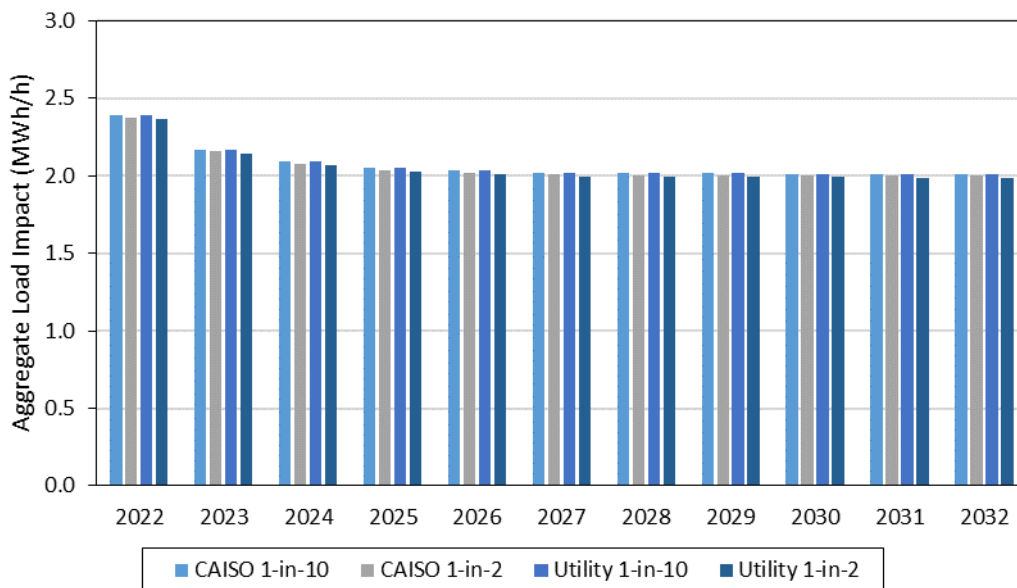
**Figure 6.5: Aggregate TOU Load Impacts (MWh/h) by Month – TOU-DR and TOU-DR-P Customers, (2023 SDG&E 1-in-2 Average Weekday, RA Window)**



<sup>28</sup> March and April are estimated separately because the TOU period during these months incorporates midday off-peak hours that differ from all other months.

Figure 6.6 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 residential CPP customers are forecasted to de-enroll as they transition to Community Choice Aggregator programs. The relatively level forecast reflects the enrollment forecast for TOU-DR customers remaining constant between 2022 and 2032, whereas any decay in aggregate load impact is due to decreasing enrollments of TOU-DR-P customers.

**Figure 6.6: Aggregate TOU Load Impacts (MWh/h) – TOU-DR and TOU-DR-P Customers, by Year and Weather Scenario (Average August Weekday, RA Window)**



### 6.3 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 367 customers. Figure 6.7 shows monthly aggregate CPP loads and load impacts for grandfathered customers, in 2022 for an SDG&E 1-in-2 average weekday. Results end in July of 2022 because the grandfathered rate is set to end thereafter. The CPP load impact remains constant for all months, but the event window shifts in June of 2022. As a result, the CPP load impact prior to June 2022 appears lower, because the event window does not align with the RA window, as reported. Load impacts also do not vary by weather scenario because the grandfathered customers are not weather sensitive.<sup>29</sup> It is assumed that grandfathered customers will have an

<sup>29</sup> 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

aggregate CPP load impact of 0.059 MWh/h during the event window. Since the event window only covers part of the RA window in the first five months of the year, the load impact during the RA window is only 0.023 MWh/h during those months.

**Figure 6.7: Aggregate CPP Load Impacts (MWh/h) by Month– Grandfathered Customers, (2022 SDG&E 1-in-2 Peak Day, RA Window)**

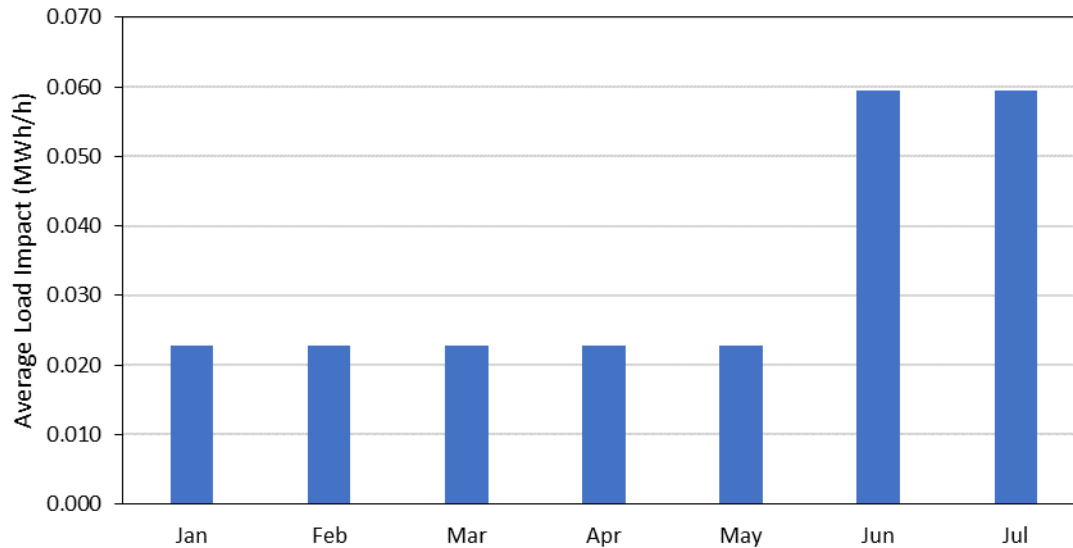
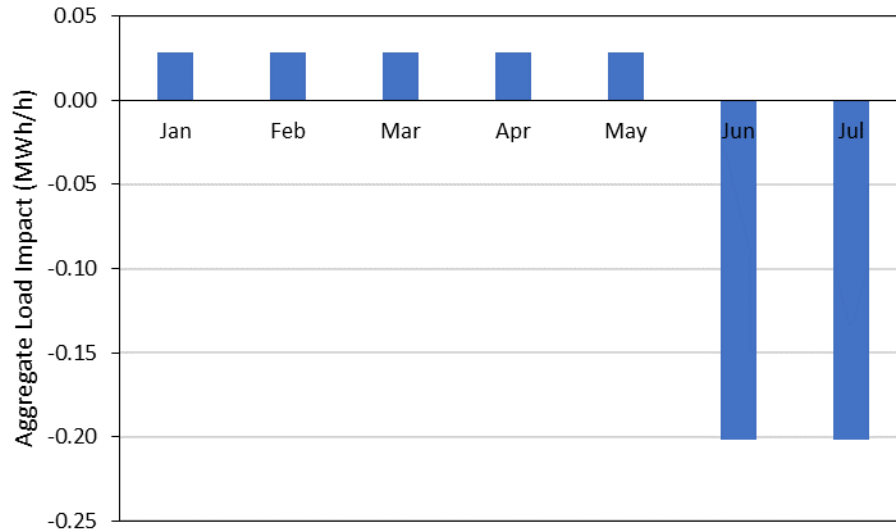


Figure 6.8 shows the monthly distributions of the RA window TOU load impacts for grandfathered customers. Load impacts are slightly positive in all winter months. Forecasted load *increases* occur during the summer period RA window. The RA window does not overlap with the summer TOU peak period for grandfathered customers. Similar to the CPP load impact forecast for grandfathered customers, the TOU load impact does not vary by weather scenario. The monthly load impacts are forecasted to remain constant within each season until the grandfathering term expires on July 31, 2022.

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between events for the NEM customers lead to unexpected *a priori* results (*i.e.*, higher temperatures leading to smaller CPP load impacts).

**Figure 6.8: Aggregate TOU Load Impacts (MWh/h) by Month – Grandfathered Customers, (2022 SDG&E 1-in-2 Average Weekday, RA Window)**



## 7. 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.
- Previous CPP ex-post and ex-ante load impacts.

In the above list, “current study” refers to this report, which is based on findings from the 2021 program year; and “previous study” refers to the report that was developed following the 2020 program year.

### 7.1 Residential CPP

No CPP events were called in 2021; therefore, comparisons with the current study’s ex-post do not exist. This section only includes comparisons for the previous versus current study ex-ante CPP load impacts.

#### 7.1.1 Previous versus current ex-ante

In this sub-section, the ex-ante forecast prepared following PY2020 (the “previous study”) are compared to the ex-ante forecast contained in this study (the “current study”). Table 7.1 reports the average event-hour load impacts for the August 2021 system peak day under utility-specific 1-in-2 weather conditions. The PY2020 results are provided during the RA window (HE 17-21) and the event window (HE 15-18). In the current study, the CPP event window is the same as the resource adequacy window. The per-customer load impact of 0.14 kWh/h and 0.15 kWh/h for the previous and current study event window, respectively, are similar by design. However, since the RA window

did not overlap with the event window in the previous study, the current study's RA window results are associated with higher load impacts, compared to the RA window results from PY2020. NEM customers tend to have larger RA reference loads, on average, than non-NEM customers. Therefore, the higher NEM penetration rate in 2022 results in slightly higher per-customer reference loads during the RA window. Enrollments also increased in the current study, resulting in an increased aggregate load impact.

**Table 7.1 Comparison of PY2020 Ex-Ante 2021 Forecast and Current Ex-Ante 2022 Forecast Load Impacts, CPP Event**

Result	<i>Ex-ante for 2022 System Peak Day PY2020 Study (RA Window)</i>	<i>Ex-ante for 2022 System Peak Day PY2020 Study (Event Window)</i>	<i>Ex-ante for 2022 System Peak Day PY2021 Study (RA &amp; Evt Window)</i>
# Enrolled	6,521	6,521	9,308
Reference (MWh/h)	8.08	5.83	12.09
Load Impact (MWh/h)	0.42	0.94	1.40
Per-customer reference (kWh/h)	1.24	0.89	1.31
Per-customer load impact (kWh/h)	0.06	0.14	0.15
% Load Impact	5%	16%	12%
Temperature	84.3	84.3	82.9
% NEM	17.7%	17.7%	20.8%

## **7.2 Residential TOU**

### **7.2.1 Previous versus current ex-post**

Table 7.2 shows the average reference loads and load impacts for the average August and January weekday 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 and aggregate load impacts. Per-customer load impacts increased in both the summer and winter periods of the current study. Notably, a 0.06 kWh/h per customer decrease in ex-post TOU load impact occurred between 2019 and 2020. In 2021, a 0.06 kWh/h increase in per-customer load impact occurred. The dip in 2020 may be attributable to COVID-19, since residential customers were more likely to be working at home, and more likely to be using AC during peak hours on hot summer days. In this sense, a per-customer load impact of 0.08 kWh/h during summer months may constitute a return to normalcy. The summer per-customer reference also moved closer to pre-COVID-19 levels, from 1.23 kWh/h in 2020 to 1.12 kWh/h in 2021.

**Table 7.2 Comparison of PY2020 Ex-Post and PY2021 Ex-Post TOU Load Impacts**

Season	Result	<i>Ex-post for 2020 Avg. Weekday PY2020 Study</i>	<i>Ex-post for 2021 Avg. Weekday PY2021 Study</i>
<b>Summer (August)</b>	# Enrolled	24,951	33,742
	Reference (MWh/h)	30.63	37.71
	Load Impact (MWh/h)	0.52	2.60
	Per-customer reference (kWh/h)	1.23	1.12
	Per-customer load impact (kWh/h)	0.02	0.08
	% Load Impact	1.7%	6.9%
	Temperature	76.9	75.5
	% NEM	33.7%	36.6%
<b>Winter (January)</b>	# Enrolled	20,360	24,736
	Reference (MWh/h)	19.22	26.50
	Load Impact (MWh/h)	0.47	0.76
	Per-customer reference (kWh/h)	0.94	1.07
	Per-customer load impact (kWh/h)	0.02	0.03
	% Load Impact	2.4%	2.9%
	Temperature	58.2	57.7
	% NEM	33.5%	31.0%

### 7.2.2 Previous versus current ex-ante

In this sub-section, the ex-ante forecast prepared following PY2020 (the “previous study”) are compared to the ex-ante forecast contained in this study (the “current study”). Table 7.3 reports the average RA-window load impacts for the August and January 2022 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 and load impacts in the present analysis are slightly larger compared to the previous study. In the previous study, we estimated that COVID-19 resulted in increased residential customer usage. The ex-ante reference loads were therefore adjusted towards pre-COVID-19 levels over time. In the current study, we assume that the effect of COVID-19 on reference loads is complete, so no adjustments to reference loads were made. The higher per-customer reference loads in the current study reflects that the COVID-19 assumption in the previous study resulted in lower reference loads than what occurred.



**Table 7.3 Comparison of PY2020 Ex-Ante 2022 Forecast and PY2021 Ex-Ante 2022 Forecast TOU Load Impacts**

Season	Result	<i>Ex-ante for 2022 Avg. Weekday PY2020 Study</i>	<i>Ex-ante for 2022 Avg. Weekday PY2021 Study</i>
<b>Summer (August)</b>	# Enrolled	17,908	21,570
	Reference (MWh/h)	18.84	26.03
	Load Impact (MWh/h)	1.35	2.36
	Per-customer reference (kWh/h)	1.05	1.21
	Per-customer load impact (kWh/h)	0.08	0.11
	% Load Impact	7.2%	9.1%
	Temperature	77.5	76.1
	% NEM	41.8%	43.8%
<b>Winter (January)</b>	# Enrolled	17,908	21,570
	Reference (MWh/h)	18.86	22.92
	Load Impact (MWh/h)	1.27	1.04
	Per-customer reference (kWh/h)	1.05	1.06
	Per-customer load impact (kWh/h)	0.07	0.05
	% Load Impact	6.7%	4.5%
	Temperature	59.2	61.1
	% NEM	41.8%	43.8%

### 7.2.3 Previous ex-ante versus current ex-post

Table 7.4 provides a comparison of the ex-ante forecast of 2021 TOU load impacts prepared in the previous study and the PY2021 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 PY2020 forecast, resulting in smaller aggregate reference loads. Per-customer load impacts were almost exactly the same for the month of January. The discrepancy between PY2020 ex-ante and PY2021 ex-post per customer TOU load impacts are likely attributable to COVID-19, as the ex-post impacts in the PY2020 study were muted as customers worked from home.

**Table 7.4 Comparison of PY2020 Ex-Ante 2021 Forecast and PY2021 Ex-Post  
TOU Load Impacts**

Season	Result	<i>Ex-ante for 2021 Avg. Weekday PY2020 Study</i>	<i>Ex-post for 2021 Avg. Weekday PY2021 Study</i>
<b>Summer (August)</b>	# Enrolled	26,691	33,742
	Reference (MWh/h)	29.56	37.71
	Load Impact (MWh/h)	1.02	2.60
	Per-customer reference (kWh/h)	1.11	1.12
	Per-customer load impact (kWh/h)	0.04	0.08
	% Load Impact	3.5%	6.9%
	Temperature	77.4	75.5
	% NEM	33.6%	36.6%
<b>Winter (January)</b>	# Enrolled	26,489	24,736
	Reference (MWh/h)	31.05	26.50
	Load Impact (MWh/h)	0.81	0.76
	Per-customer reference (kWh/h)	1.17	1.07
	Per-customer load impact (kWh/h)	0.03	0.03
	% Load Impact	2.6%	2.9%
	Temperature	59.2	57.7
	% NEM	33.4%	31.0%

#### **7.2.4 Current ex-post versus current ex-ante**

Table 7.5 compares the PY2021 ex-post TOU load impacts for the August average weekday with the corresponding ex-ante forecast for 2021 (of the utility-specific 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 Summer enrollments are forecast to have a sharp decrease, while the per customer load impact is expected to increase slightly. This is due to the shift in composition of customers towards TOU-DR, which have been estimated to have a larger TOU load impact, as TOU-DR-P customers migrate to the Community Choice Aggregator program. Note that per-customer reference loads increase as the composition of NEM customers increases. This is because NEM customers have larger loads during peak hours, at which time solar generation has largely ended for the day. Because the ex-ante load impacts are based on temperature scenarios that are larger than those in the ex-post analysis, higher ex-ante TOU load impacts might also be driven by higher expected temperatures in the ex-ante period.

**Table 7.5: Comparison of Current Ex-Post and Ex-Ante TOU Load Impacts**

Season	Result	<i>Ex-post for 2021 Avg. Weekday from PY2021 Study</i>	<i>Ex-ante for 2022 Avg. Weekday from PY2021 Study</i>
<b>Summer (August)</b>	# Enrolled	33,742	21,570
	Reference (MWh/h)	37.71	26.03
	Load Impact (MWh/h)	2.60	2.36
	Per-customer reference (kWh/h)	1.12	1.21
	Per-customer load impact (kWh/h)	0.08	0.11
	% Load Impact	6.9%	9.1%
	Temperature	75.5	76.12
	% NEM	36.6%	43.8%
<b>Winter (January)</b>	# Enrolled	24,736	21,570
	Reference (MWh/h)	26.50	22.92
	Load Impact (MWh/h)	0.76	1.04
	Per-customer reference (kWh/h)	1.07	1.06
	Per-customer load impact (kWh/h)	0.03	0.05
	% Load Impact	2.9%	4.5%
	Temperature	57.7	61.09
	% NEM	31.0%	43.8%

### **7.3 Grandfathered Customers – Residential CPP**

No CPP events were called in 2021; therefore, comparisons with the current study's ex-post do not exist. This section only includes comparisons for the previous versus current study ex-ante CPP load impacts.

#### **7.3.1 Previous versus current ex-ante**

Table 7.6 reports the average event-hour load impacts for the July 2021 system peak day under utility-specific 1-in-2 weather conditions. The PY2020 results are provided during the RA window (HE 17-21) and the event window (HE 15-18). The CPP event window is the same as the resource adequacy window in the current study. The reference load for the event window of the previous study is approximately zero, because the CPP event window partially covered a period of time during which solar generation occurred. The reference load during the RA window was positive, in both the previous and current studies. The per-customer load impacts are the same, by design, as the PY2020 ex-post level load impacts were applied to the ex-ante reference loads in both cases. Grandfathered enrollments declined in the current forecast.

**Table 7.6 Comparison of PY2020 Ex-Ante 2021 Forecast and Current Ex-Ante 2022  
Forecast Load Impacts, CPP Event**

<b>Result</b>	<b><i>Ex-ante for 2022 System Peak Day PY2020 Study (RA Window)</i></b>	<b><i>Ex-ante for 2022 System Peak Day PY2020 Study (Event Window)</i></b>	<b><i>Ex-ante for 2022 System Peak Day PY2021 Study (RA &amp; Evt Window)</i></b>
# Enrolled	477	477	367
Reference (MWh/h)	0.78	0.00	0.69
Load Impact (MWh/h)	0.02	0.13	0.02
Per-customer reference (kWh/h)	1.63	0.00	1.89
Per-customer load impact (kWh/h)	0.05	0.28	0.05
Temperature	80.7	86.4	81.1

## **7.4 Grandfathered Customers – Residential TOU**

### **7.4.1 Previous versus current ex-post**

Table 7.7 shows the average reference loads and load impacts for the average August and January weekday during the current and previous program years, averaged over the RA window. The RA window does not overlap with the summer peak period for grandfathered customers. Enrollment numbers decreased for both seasons, but the reference loads only decreased for summer customers, indicating that some larger customers left the program. In both years, grandfathered customers increased usage during the summer peak period. Customers reduced usage during the 2021 winter peak period, in comparison to increased usage during the 2020 winter peak period.

**Table 7.7 Comparison of PY2020 Ex-Post and PY2021 Ex-Post TOU Load Impacts – for Grandfathered Customers**

Season	Result	<i>Ex-post for 2020 Avg. Weekday PY2020 Study</i>	<i>Ex-post for 2021 Avg. Weekday PY2021 Study</i>
<b>Summer (August)</b>	# Enrolled	472	368
	Reference (MWh/h)	0.68	0.35
	Load Impact (MWh/h)	-0.15	-0.20
	Per-customer reference (kWh/h)	1.44	0.96
	Per-customer load impact (kWh/h)	-0.32	-0.55
	Temperature	78.1	76.4
<b>Winter (January)</b>	# Enrolled	441	373
	Reference (MWh/h)	0.52	0.57
	Load Impact (MWh/h)	-0.07	0.03
	Per-customer reference (kWh/h)	1.17	1.54
	Per-customer load impact (kWh/h)	-0.15	0.08
	Temperature	58.0	57.4

#### **7.4.2 Previous versus current ex-ante**

Table 7.8 reports the average RA-window load impacts for the July and January 2022 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 a decrease in enrollment, which is associated with a decrease in aggregate reference loads. Per-customer reference loads and load impacts in the present analysis are lower for the summer period and slightly smaller for the winter period compared to the previous study. In the previous study, we estimated that COVID-19 resulted in increased residential customer usage. The ex-ante reference loads were therefore adjusted towards pre-COVID-19 levels over time. In the current study, we assume that the effect of COVID-19 on reference loads is complete so no adjustments to reference loads were made.

**Table 7.8 Comparison of PY2020 Ex-Ante 2022 Forecast and PY2021 Ex-Ante 2022 Forecast TOU Load Impacts for Grandfathered Customers**

Season	Result	<i>Ex-ante for 2022 Avg. Weekday PY2020 Study</i>	<i>Ex-ante for 2022 Avg. Weekday PY2021 Study</i>
<b>Summer (July)</b>	# Enrolled	477	367
	Reference (MWh/h)	0.60	0.44
	Load Impact (MWh/h)	0.03	-0.20
	Per-customer reference (kWh/h)	1.26	1.19
	Per-customer load impact (kWh/h)	0.07	-0.55
	Temperature	76.2	74.72
<b>Winter (January)</b>	# Enrolled	477	367
	Reference (MWh/h)	0.52	0.50
	Load Impact (MWh/h)	-0.11	0.03
	Per-customer reference (kWh/h)	1.09	1.35
	Per-customer load impact (kWh/h)	-0.24	0.08
	Temperature	59.0	61.75

### 7.4.3 Previous ex-ante versus current ex-post

Table 7.9 provides a comparison of the ex-ante forecast of 2021 TOU load impacts prepared in the previous study and the PY2021 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. Enrollments decreased for both seasons. Per-customer reference loads and per-customer load impacts were lower than predicted in the summer but higher than predicted in the winter.

**Table 7.9 Comparison of PY2020 Ex-Ante 2021 Forecast and PY2021 Ex-Post  
TOU Load Impacts for Grandfathered Customers**

<b>Season</b>	<b>Result</b>	<i><b>Ex-ante for 2021 Avg. Weekday PY2020 Study</b></i>	<i><b>Ex-post for 2021 Avg. Weekday PY2021 Study</b></i>
<b>Summer (August)</b>	# Enrolled	477	368
	Reference (MWh/h)	0.82	0.35
	Load Impact (MWh/h)	-0.05	-0.20
	Per-customer reference (kWh/h)	1.73	0.96
	Per-customer load impact (kWh/h)	-0.10	-0.55
	Temperature	78.0	76.4
<b>Winter (January)</b>	# Enrolled	477	373
	Reference (MWh/h)	0.58	0.57
	Load Impact (MWh/h)	-0.05	0.03
	Per-customer reference (kWh/h)	1.22	1.54
	Per-customer load impact (kWh/h)	-0.11	0.08
	Temperature	59.0	57.4

#### **7.4.4 Current ex-post versus current ex-ante**

Table 7.10 compares the grandfathered customers' PY2020 ex-post TOU load impacts for the July average weekday with the corresponding ex-ante forecast for 2022 of the utility-specific 1-in-2 July average weekday produced in this study. Note that July 2022 is used instead of August since the grandfathered program is slated to end on July 31, 2022. The grandfathered customers' TOU load impacts are presented for all grandfathered customers and are averaged over the RA window. Enrollment numbers decrease slightly, and per-customer load impacts remain the same by design.

**Table 7.10: Comparison of Current Ex-Post and Ex-Ante TOU Load Impacts for Grandfathered Customers**

Season	Result	<i>Ex-post for 2021 Avg. Weekday PY2021 Study</i>	<i>Ex-ante for 2022 Avg. Weekday PY2021 Study</i>
<b>Summer (July)</b>	# Enrolled	369	367
	Reference (MWh/h)	0.25	0.44
	Load Impact (MWh/h)	-0.20	-0.20
	Per-customer reference (kWh/h)	0.67	1.19
	Per-customer load impact (kWh/h)	-0.55	-0.55
	Temperature	75.5	74.7
<b>Winter (January)</b>	# Enrolled	373	367
	Reference (MWh/h)	0.57	0.50
	Load Impact (MWh/h)	0.03	0.03
	Per-customer reference (kWh/h)	1.54	1.35
	Per-customer load impact (kWh/h)	0.08	0.08
	Temperature	57.4	61.8

## 8. Recommendations

In 2021, SDG&E didn't call any events. Calling events will improve the understanding of customer response to the program.

The treatment group among CPP customers will begin rapidly decreasing in enrollment as customers migrate to Community Choice Aggregator programs. As a result, finding valid incremental treatment customers will become more difficult in future years. The reduction of incremental customers limits the experimental leverage of estimating TOU load impacts for future program years.



## 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 removes load impacts that appear during the middles of the day, which is assumed to be caused by changes to solar generation and not a response to TOU pricing. 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 1 kWh/h.

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

