



2024 Load Impact Evaluation of Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates for San Diego Gas & Electric

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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 program year ("PY") 2024. The rates consist of TOU-DR, a traditional non-event TOU rate, TOU-DR-P, a TOU rate with an event-based CPP component, and EV-TOU-5-P, an electric vehicle TOU rate with an event-based CPP component. The TOU analysis evaluates the TOU price response of TOU-DR and TOU-DR-P customers, while the CPP analysis evaluates the CPP price response of TOU-DR-P and EV-TOU-5-P customers.¹ TOU-DR and TOU-DR-P rates became active in February 2015 while EV-TOU-5-P became active in December 2023.

The TOU periods for the two rates included in the TOU analysis (TOU-DR and TOU-DR-P) are centered around an on-peak period from 4 to 9 p.m., which is surrounded by morning and evening off-peak periods, and an overnight super-off-peak period. The super-off-peak hours are longer during weekends and holidays. During the months of March and April, additional super off-peak hours are carved into the off-peak period between 10 a.m. and 2 p.m.

Residential CPP events may be called during the event window from 4 to 9 p.m. on any day of the week throughout the year. The CPP event window coincides with the resource adequacy window in all months except March, April, and May, when the RA window is 5 to 10 p.m. In PY 2024, SDG&E called three CPP events on September 5th, 6th, and 9th.

The ex-post load impact evaluations for the TOU and CPP analyses apply difference-in-differences analysis methods that compare hourly usage of treatment customers and a quasi-experimental matched control group during the post treatment period or event days and adjusts for usage differences on pre-treatment or non-event days. Control group customers are selected by matching each treatment customer to a sample of eligible non-treatment customers in relevant population segments (e.g., climate zone, Net Energy Metered ("NEM"), rate class), based on the closest match of load profiles. The protocol tables contain separate results for NEM and Non-NEM customers that are based on customer-weighted average weather conditions, along with combined results of all customers regardless of NEM status.

In PY 2024, the CPP ex-post analysis indicates that, on average, CPP customers in the Coastal climate zone reduced their usage by 0.17 kWh/hour and customers in the Inland climate zone reduced their usage by 0.19 kWh/hour during the 4 to 9 p.m. event window. CPP enrollment on September 9th was 7,338 customers, with 66 percent of the customers residing in the Coastal climate zone.² The aggregate event hour reference load was largest during the September 9th event day at 16.35 MWh/hour, with a load impact of 1.03 MWh/hour. On September 5th and 6th, the aggregate reference loads were 15.94 and 14.13 MWh/hour, respectively, with corresponding load impacts of 1.45 and 1.38 MWh/hour.

Separating the CPP analysis out by TOU-DR-P and EV-TOU-5-P reveals that on average, TOU-DR-P customers reduced their usage by 0.18 kWh/hour and EV-TOU-5-P reduced their

¹ EV-TOU-5 customers that are enrolled in CPP, EV-TOU-5-P, are included in the CPP analysis. TOU load impacts of EV-TOU-5 and EV-TOU-5-P customers are evaluated in a separate report.

² There are minor differences in number of customers enrolled across event days, with September 5th and 6th having 7,322 and 7,324 enrolled, respectively.

usage by 0.17 kWh/hour during the CPP event window.³ On September 9th, the aggregate event hour reference load for TOU-DR-P was 14.34 MWh/hour, with a load impact of 0.93 MWh/hour, while for EV-TOU-5-P, the aggregate event hour reference load was 2.02 MWh/hour with a load impact of 0.10 MWh/hour. On September 5th and 6th, the aggregate reference loads for TOU-DR-P were 14.05 and 12.51 MWh/hour with corresponding load impacts of 1.32 and 1.26 MWh/hour, respectively. For EV-TOU-5-P, the reference loads were 1.89 and 1.62 MWh/hour with load impacts of 0.13 and 0.13 MWh/hour on September 5th and 6th, respectively.

TOU customer⁴ enrollment rose from 30,137 to 31,278 customers between October 2023 and September 2024. Per-customer peak-period load impacts were 0.05 kWh/hour in summer and 0.01 kWh/hour in winter. Overall, TOU customers increased their energy consumption by an annual average of 0.67 kWh/customer/day, which is based on combining the TOU customer results across months and considering the effect of TOU on average *daily* usage.

Enrollment in CPP, excluding EV-TOU-5-P,⁵ declined from 10,179 to 6,729 customers between October 2023 and September 2024. The main cause of de-enrollment in CPP is customers enrolling in community choice aggregators (“CCAs”) in April 2024, which results in customers being shifted from a TOU-DR-P rate to a TOU-DR rate because CCA customers are ineligible for TOU-DR-P.⁶ TOU load impacts are estimated for CPP customers by season. The results suggest that peak hour usage is reduced by 0.06 kWh/hour during the summer months and 0.04 kWh/hour during the winter months. The overall daily effect from TOU for CPP customers was an average annual increase of 0.38 kWh/customer/day.

³ While the enrollment numbers vary slightly from day to day, on September 9th, 699 customers were enrolled in EV-TOU-P while 6,639 were enrolled in TOU-DR-P.

⁴ For the purposes of this report, unless specified otherwise, *TOU customer* refers to customers who are on rate TOU-DR and does not include customers on rate TOU-DR-P.

⁵ EV-TOU-5-P customers are not included in the TOU analysis.

⁶ TOU-DR-P is a commodity rate. When a customer joins a CCA, the CCA becomes responsible for procuring the commodity portion of the customer’s rate.

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 program year ("PY") 2024. The TOU rate category consists of TOU-DR, a traditional non-event TOU rate, while CPP includes TOU-DR-P, a TOU rate with an event-based CPP component, and EV-TOU-5-P, an electric vehicle rate with an event-based CPP component. Both the TOU-DR and TOU-DR-P rates became active in February 2015 while EV-TOU-5-P became active December 2023.

ES.1 Resources Covered

The TOU periods for the two rates included in the TOU analysis (TOU-DR and TOU-DR-P) are centered around an on-peak period from 4 to 9 p.m., which is surrounded by morning and evening off-peak periods, and an overnight super-off-peak period. The super-off-peak hours are longer during weekends and holidays. During the months of March and April, additional super off-peak hours are carved into the off-peak period between 10 a.m. and 2 p.m. Residential CPP events may be called during the event window from 4 to 9 p.m. on any day of the week throughout the year. The CPP event window coincides with the resource adequacy window in all months except March, April, and May, when the RA window is 5 to 10 p.m. In PY 2024, SDG&E called three CPP events on September 5th, 6th, and 9th.

ES.2 Evaluation Methodologies

The ex-post load impact evaluations for the TOU and CPP rates apply difference-in-differences analysis methods that compare hourly usage of treatment customers and a quasi-experimental matched control group during the post treatment time period or event days and adjusts for usage differences on pre-treatment or non-event days. Control group customers are selected by matching each treatment customer to a sample of eligible non-treatment customers in relevant population segments (e.g., climate zone, NEM, rate class, weather station), based on the closest match of load profiles. For the CPP analysis, EV-TOU-5-P is included in the model; however, it is not part of the TOU analysis.

ES.3 Ex-Post Load Impacts

ES.3.1 Ex-Post CPP Event Load Impacts (TOU-DR-P & EV-TOU-5-P)

Table ES.1 summarizes average event-hour reference loads and load impacts for residential CPP customers during an average weekday event.⁷ Results are shown by EV-TOU-5-P, TOU-DR-P, and an aggregate rate as well as by Coastal and Inland climate zones. The first three columns show the rate, climate zone, and the number of enrolled customers. The next two columns show aggregate estimated reference loads and load impacts for the average event hour, in MWh/hour. Note that here, and throughout the report, a positive load impact denotes a decrease in energy consumption. The next two columns show the average event hour results for the average customer, in kWh/hour. The last column shows the average temperature during the event window. Load impacts for events are not reported in percentage terms due to the large share of

⁷ CPP residential customers are those that voluntarily enrolled on rate TOU-DR-P.

NEM customers in the sample.⁸ An asterisk included next to a load impact indicates that the result is statistically significant at the 10 percent level (or lower). All results in table ES.1 have load impacts which are statistically significant at the 10 percent level.

Table ES.1: Residential CPP Event-Hour Load Impacts – Average Weekday Event⁹

Rate	Climate Zone	Enrolled	Aggregate		Per-Customer		Avg. Event Temp.
			Ref. Load (MWh/hr)	Load Impact (MWh/hr)	Ref. Load (kWh/hr)	Load Impact (kWh/hr)	
All	Coastal	4,852	9.93	0.81*	2.05	0.17*	84
	Inland	2,476	5.53	0.47*	2.23	0.19*	90
	All	7,328	15.47	1.29*	2.11	0.18*	86
TOU-DR-P	Coastal	4,281	8.39	0.72*	1.96	0.17*	84
	Inland	2,357	5.24	0.45*	2.22	0.19*	90
	All	6,638	13.63	1.17*	2.05	0.18*	86
EV-TOU-5-P	Coastal	571	1.55	0.09*	2.71	0.16*	83
	Inland	118	0.29	0.02*	2.47	0.20*	89
	All	690	1.84	0.12*	2.67	0.17*	84

Program enrollment during the CPP event was 7,328 customers, of which approximately 10% were on an EV-TOU-5 rate. Looking at climate zone, about 66 percent of customers were located in the Coastal climate zone.¹⁰ There is variation between the rates, with 64% of TOU-DR-P customers being located in the Coastal climate zone, while for EV-TOU-5-P the share of customers residing in the Coastal climate zone are 83%. The aggregate reference load was 15.47 MWh/hour, and the load impact was 1.29 MWh/hour. Per-customer load impacts averaged 0.17 kWh/hour for customers in the Coastal climate zone and 0.19 kWh/hour for customers in the Inland climate zone. Separating the CPP analysis out by TOU-DR-P and EV-TOU-5-P¹¹ reveals that on average, TOU-DR-P customers reduced their usage by 0.18 kWh/hour and EV-TOU-5-P reduced their usage by 0.17 kWh/hour. Average temperatures during the event were cooler in the Coastal zone, at 84 degrees, compared to 90 degrees for the Inland zone.

⁸ Since NEM customers experience reference loads that become negative during daylight hours, the load impact divided by the reference load increases dramatically as the reference load approaches zero. Throughout the report, only level load impacts are displayed when NEM customers are included in the data being presented.

⁹ Adding TOU-DR-P and EV-TOU-5-P enrollments differ slightly from the total enrollments, due to rounding of enrollments for a typical event day. The combined aggregate reference loads and load impacts for TOU-DR-P and EV-TOU-5-P are slightly different from the sum of aggregate reference loads and load impacts as the combined result is estimated separately.

¹⁰ These enrollment numbers differ from the number of customers that were included in the regression models. In order to be included in the regression models, customers needed to have a sufficient load history that included all selected event-like days as well as the event day, along with other characteristics needed for the models.

¹¹ While the numbers vary slightly from day to day, on September 9th EV-TOU-P represented 699 enrolled customers while TOU-DR-P represents 6,639.

ES.3.2 Ex-Post TOU Load Impacts – TOU Customers (TOU-DR)

Table ES.2 summarizes the average reference loads and load impacts on an aggregate and per-customer basis for customers on the TOU-DR rate during the TOU peak period (4 to 9 p.m.) for the average weekday in each month. The months are shown starting with the first month included in the analysis (October 2023). The winter months are indicated by light blue shading. TOU enrollments increased throughout the analysis period, with the numbers of enrolled customers rising from 30,137 in October 2023 to 31,278 in September 2024.¹² The estimated seasonal load impacts were largest during the summer months, with the highest load impact occurring during August. An asterisk next to a load impact indicates that the result is statistically significant at the 10 percent level. All the summer months plus March and April are statistically significant at the 10 percent level.

Table ES.2: TOU Peak Load Impacts for TOU Customers – Average Weekday by Month

Month	Climate Zone	Enrolled	Aggregate		Per-Customer		Avg. Peak Temp.
			Peak Ref. Load (MWh/hr)	Peak Load Impact (MWh/hr)	Peak Ref. Load (kWh/hr)	Peak Load Impact (kWh/hr)	
Oct-23	All	30,137	23.40	0.84*	0.78	0.03*	70
Nov-23	All	30,072	24.79	-0.46	0.82	-0.02	63
Dec-23	All	30,059	28.94	0.06	0.96	0.00	59
Jan-24	All	30,071	28.21	0.27	0.94	0.01	57
Feb-24	All	30,096	25.89	0.24	0.86	0.01	57
Mar-24	All	29,989	16.18	1.15*	0.54	0.04*	59
Apr-24	All	32,305	12.83	1.27*	0.40	0.04*	62
May-24	All	32,219	9.06	-0.38	0.28	-0.01	63
Jun-24	All	32,045	15.61	0.87*	0.49	0.03*	67
Jul-24	All	31,921	30.55	1.95*	0.96	0.06*	73
Aug-24	All	31,858	36.17	2.26*	1.14	0.07*	75
Sep-24	All	31,278	27.07	1.63*	0.87	0.05*	69

Table ES.3 summarizes the results by season and climate zone. Both climate zones exhibit higher reference loads during the summer months. Inland reference loads are higher than Coastal reference loads during both periods. Overall, TOU customers decrease loads during the peak period by 0.05 kWh/customer/hour on average during summer and 0.01 kWh/customer/hour during the winter. Inland customers have slightly higher load impacts compared to Coastal

¹² The enrollment numbers shown differ from the number of customers used in the regression models. Treatment customers used for the TOU analysis are customers that switched from a non-TOU rate to TOU-DR during PY2024. Customer must also have sufficient load data history during both the pre-treatment period (PY2023) and the post-treatment period (PY2024). Specifically, there were 249 incremental TOU-DR customers with quality load data and sufficient history that were used in estimating the TOU load impacts for the winter model and 205 customers for the summer model. The aggregate TOU load impacts are obtained by scaling the per-customer load impacts for incremental customers to total TOU-DR enrollments.

customers during both seasons. The summer results are statistically significant at the 10 percent level.

**Table ES.3: TOU Peak Load Impacts for TOU Customers –
Average Weekday by Season & Climate Zone**

Season	Climate Zone	Enrolled (Average)	Aggregate		Per-Customer		Avg. Peak Temp.
			Peak Ref. Load (MWh/hr)	Peak Load Impact (MWh/hr)	Peak Ref. Load (kWh/hr)	Peak Load Impact (kWh/hr)	
Summer	Coastal	17,156	12.21	0.69*	0.71	0.04*	70
	Inland	14,292	14.32	0.80*	1.00	0.06*	72
	All	31,448	26.53	1.49*	0.84	0.05*	71
Winter	Coastal	16,171	10.67	0.14	0.66	0.01	61
	Inland	14,516	10.17	0.17	0.70	0.01	60
	All	30,687	20.84	0.31	0.68	0.01	60

Overall, TOU customers increased their energy consumption by an annual average of approximately 0.67 kWh/customer/day, representing an 11% increase. This is based on combining the TOU results across months and considering the effect of TOU on average *daily* usage.

ES.3.3 Ex-Post TOU Load Impacts – CPP Customers (TOU-DR-P)

CPP customers experience TOU prices on all days that are not residential CPP event days. Table ES.4 summarizes the average reference loads and load impacts on an aggregate and per-customer basis for customers on the TOU-DR-P rate during the TOU peak period (4 to 9 p.m.) for the average weekday in each month. Enrollment in CPP declined from 10,179 in October 2023 to approximately 6,729 in September 2024. The estimated seasonal load impacts were largest during the summer months. Declining enrollments lead to aggregate load impacts during summer that are only slightly higher than the load impacts during some of the winter months. An asterisk next to a load impact indicates that the result is statistically significant at the 10 percent level. The load impacts are not statistically significant in October.

**Table ES.4: TOU Peak Load Impacts for Residential CPP Customers –
Average Weekday by Month**

Month	Climate Zone	Enrolled	Aggregate		Per-Customer		Avg. Peak Temp.
			Peak Ref. Load (MWh/hr)	Peak Load Impact (MWh/hr)	Peak Ref. Load (kWh/hr)	Peak Load Impact (kWh/hr)	
Oct-23	All	10,179	8.42	0.37	0.83	0.04	72
Nov-23	All	9,939	8.24	0.27*	0.83	0.03*	64
Dec-23	All	9,733	9.32	0.47*	0.96	0.05*	60
Jan-24	All	9,585	8.60	0.57*	0.90	0.06*	57
Feb-24	All	9,395	7.85	0.55*	0.84	0.06*	58
Mar-24	All	9,273	5.61	0.21*	0.60	0.02*	61
Apr-24	All	9,088	4.83	0.22*	0.53	0.02*	64
May-24	All	6,980	3.51	0.18*	0.50	0.03*	65
Jun-24	All	6,911	4.95	0.30*	0.72	0.04*	70
Jul-24	All	6,831	8.06	0.54*	1.18	0.08*	75
Aug-24	All	6,795	9.04	0.58*	1.33	0.09*	77
Sep-24	All	6,729	6.60	0.46*	0.98	0.07*	71

On average, CPP customers increased their load by 0.38 kWh/day per-customer per day over the course of the study period.

Table ES.5 summarizes the results for CPP customers by season and climate zone. Both climate zones exhibit higher reference loads during the summer months, with higher reference loads for Inland customers. Overall, CPP customer decrease loads during the peak period by 0.06 kWh/customer/hour on average during summer and 0.04 kWh/customer/hour during the winter. Inland customers have lower load impacts compared to Coastal customers during both seasons. All results except coastal during the summer are statistically significant at the 10 percent level.

Table ES.5: TOU Peak Load Impacts for Residential CPP Customers – Average Weekday by Season & Climate Zone

Season	Climate Zone	Enrolled (Average)	Aggregate		Per-Customer		Avg. Peak Temp.
			Peak Ref. Load (MWh/hr)	Peak Load Impact (MWh/hr)	Peak Ref. Load (kWh/hr)	Peak Load Impact (kWh/hr)	
Summer	Coastal	4,929	4.59	0.27	0.93	0.05	72
	Inland	2,560	2.84	0.18*	1.11	0.07*	75
	All	7,489	7.43	0.45*	0.99	0.06*	73
Winter	Coastal	6,474	4.78	0.24*	0.74	0.04*	61
	Inland	2,667	2.07	0.11*	0.78	0.04*	60
	All	9,142	6.85	0.35*	0.75	0.04*	61

ES.4 Ex-Ante Load Impacts

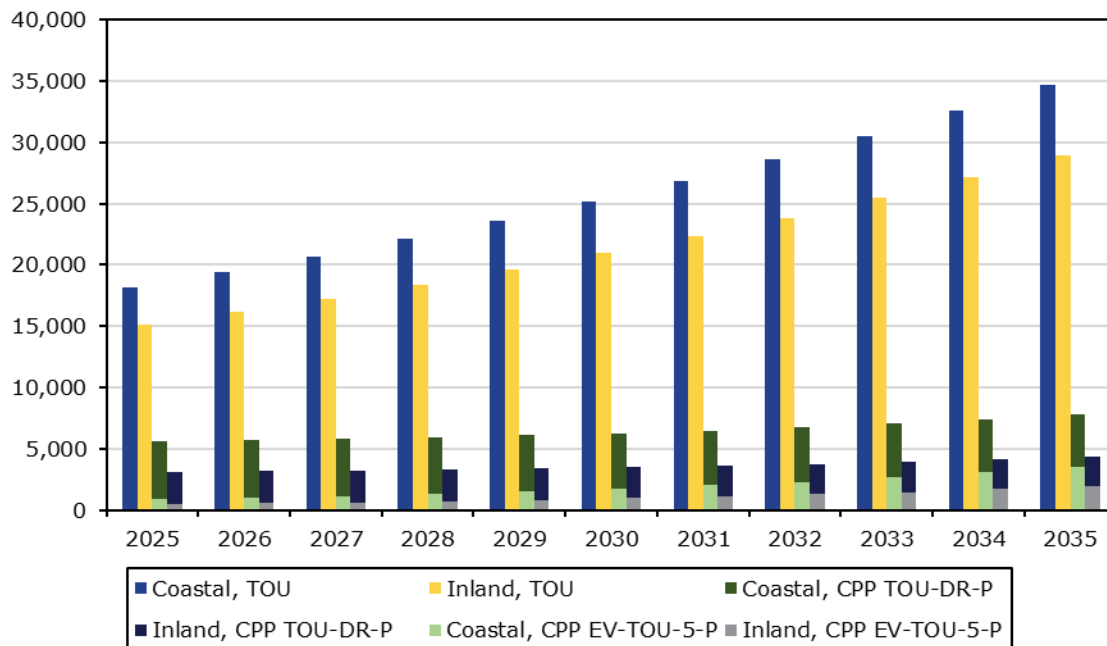
The ex-ante analysis for CPP events applies the PY2024 ex-post CPP event load impacts to reference loads calculated using PY2024 customer load data. Load impacts for different weather scenarios are developed by applying the estimated load impact from the ex-post analysis to weather-sensitive reference loads. The reference loads are estimated by obtaining weather-specific coefficients using regression models like those used in the ex-post analysis and applying the coefficients to two alternative weather scenarios. Since June 1, 2022, the CPP event window coincides with the RA window (4 to 9 p.m.).

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 are developed as described above. Level load impacts from ex-post are used for NEM customers to avoid issues with percentage load impacts for these 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 begin increasing after 2025. Enrollment is expected to be greater in the Coastal climate zone than in the Inland climate zone for both TOU and CPP customers, however the differences are more pronounced for CPP customers. This mirrors the fact that the rates have different enrollment ratios in the two climate zones. For CPP the EV-TOU-5 rate becomes a larger share of total enrollment year-to-year, starting at 15% of total CPP enrollment in 2025 and by 2035 it encompasses 41% of total enrollment.

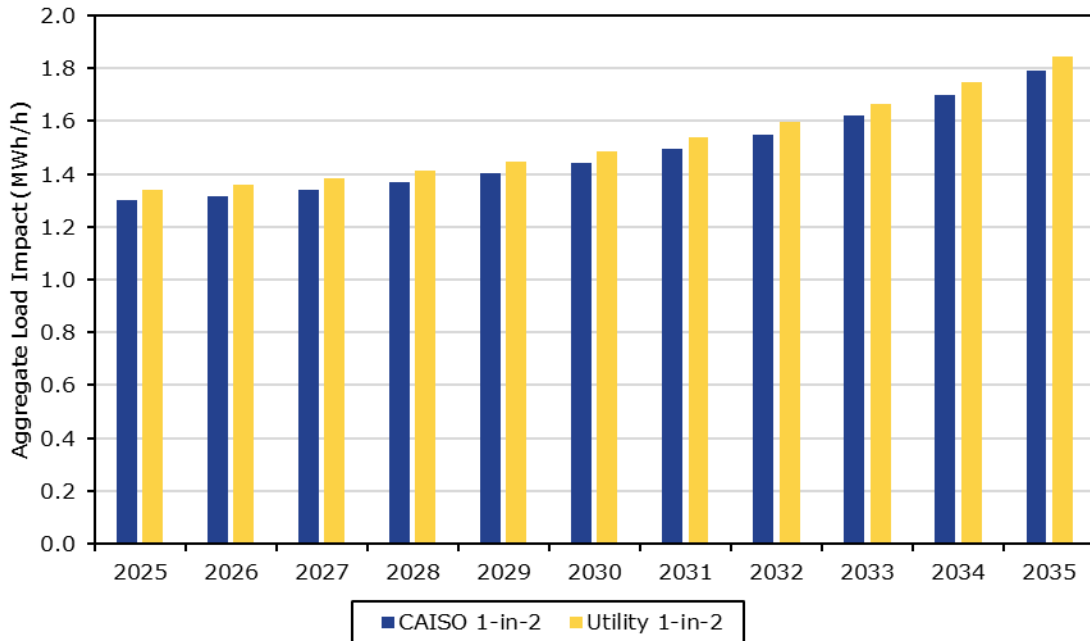
Figure ES.1: Enrollments in TOU and CPP Rates



ES.4.2 Ex-Ante CPP Event Load Impacts

Figure ES.2 illustrates the increase in forecasted aggregate CPP load impacts for the RA window over the forecast period for each weather scenario. Aggregate load impacts are forecasted to increase over time, commensurate with an increase in enrollments. The figure also shows relatively minor differences between the aggregate ex-ante load impacts by weather scenario. Load impacts under the SDG&E 1-in-2 weather scenario are forecast to increase from 1.34 MWh/hour in 2025 to 1.84 MWh/hour in 2035.

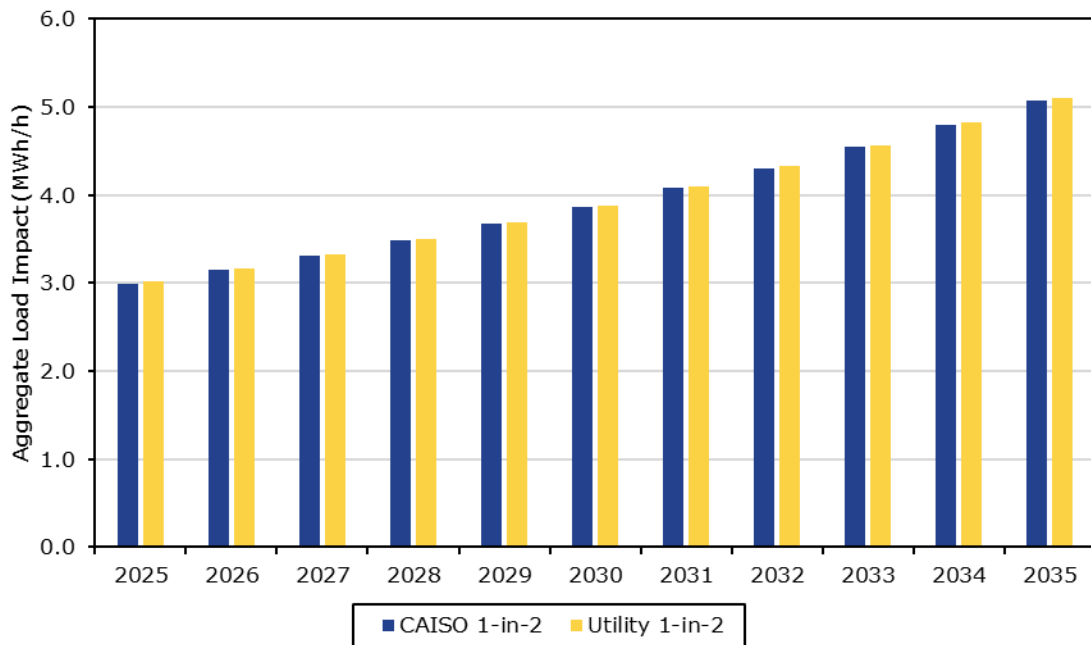
Figure ES.2: Aggregate CPP Load Impacts (MWh/hour), by Year and Weather Scenario (August System Worst Day, RA Window)



ES.4.3 Ex-Ante TOU Load Impacts

Aggregate load impacts for TOU customers during the average peak hour are forecast to increase after 2025, commensurate with increasing enrollments. Figure ES.3 shows differences in the aggregate peak TOU load impact forecasts for customers enrolled in the TOU-DR and TOU-DR-P customers over the entire period for the average August weekday weather scenarios. Values for each of the weather scenarios are nearly identical. Load impacts under the SDG&E 1-in-2 weather scenario are forecast to increase from 3.02 MWh/hour in 2025 to 5.10 MWh/hour in 2035.

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



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 the 2024 program year ("PY"). The rates consist of TOU-DR, a traditional non-event TOU rate, TOU-DR-P, a TOU rate with an event-based CPP component, and EV-TOU-5-P, an electric vehicle rate with an event-based CPP component. The TOU analysis evaluates the TOU price response of TOU-DR and TOU-DR-P customers, while the CPP analysis evaluates the CPP price response of TOU-DR-P and EV-TOU-5-P customers.¹³ TOU-DR and TOU-DR-P rates became active in February 2015 while EV-TOU-5-P became active in December 2023. TOU load impacts are estimated for customers enrolled in TOU-DR-P and TOU-DR, since the TOU-DR-P customers experience TOU rates on days that are not CPP event days, while CPP load impacts are estimated for residential TOU-DR-P and EV-TOU-5-P customers.¹⁴ The evaluation also develops ex-ante load impacts for the TOU and CPP analyses. The evaluations conform to the Load Impact Protocols adopted by the CPUC in D.08-04-050 as well as subsequent updates, including those adopted in D.24-12-003.

The TOU periods for the two rates included in the TOU analysis (TOU-DR and TOU-DR-P) are centered around an on-peak period from 4 to 9 p.m., which is surrounded by morning and evening off-peak periods, and an overnight super-off-peak period. The super-off-peak hours are longer during weekends and holidays. During the months of March and April, additional super off-peak hours are carved into the off-peak period between 10 a.m. and 2 p.m. Residential CPP events may be called during the event window from 4 to 9 p.m. on any day of the week throughout the year.

Table 1.1 provides monthly enrollments for each rate by net energy metered ("NEM") status. NEM customers constitute a significant proportion of residential TOU customers.¹⁵ Some CPP customers transitioned to a community choice aggregator ("CCA") in April 2024. CCA customers cannot be enrolled in the CPP program and thus were migrated from a TOU-DR-P rate to TOU-DR rate because of their CCA enrollment.¹⁶ This explains the pattern of declining CPP customer enrollment and increasing TOU customer enrollment during PY2024.¹⁷ Results for NEM customers are provided separately from Non-NEM customers in the protocol table generators associated with this report, in addition to all customers being presented together. The average NEM share of enrollment during the study period was 45 percent for customers included in the TOU analysis and 28 percent for customers included in the CPP analysis.

¹³ EV-TOU-5 customers that are enrolled in CPP, EV-TOU-5-P, are included in the CPP analysis. TOU load impacts of EV-TOU-5 and EV-TOU-5-P customers are evaluated in a separate report.

¹⁴ TOU ex-post load impacts are estimated only for customers who enrolled in TOU-DR-P or TOU-DR rates during PY2024 (October 2023 to September 2024), also referred to as incremental TOU customers. The estimated TOU load impacts of incremental customers are applied to all customers on TOU-DR and TOU-DR-P rates.

¹⁵ For the purposes of this report, unless specified otherwise, *TOU customer* refers to customers who are on rate TOU-DR and does not include customers on rate TOU-DR-P.

¹⁶ TOU-DR-P is a commodity rate. When a customer joins a CCA, the CCA becomes responsible for procuring the commodity portion of the customer's rate.

¹⁷ Customers who are both TOU-DR and TOU-DR-P in a given month are counted as enrolled in both rates. Therefore, counting customers that switched rates in April 2024 causes increased enrollments in TOU before enrollments decline in CPP.

Table 1.1: Customer Enrollments by Rate and NEM Status

Date	TOU-DR			TOU-DR-P			EV-TOU-5-P		
	Non-NEM	NEM	Total	Non-NEM	NEM	Total	Non-NEM	NEM	Total
Oct-2023	15,350	14,787	30,137	7,177	3,002	10,179	0	0	0
Nov-2023	15,066	15,006	30,072	7,096	2,843	9,939	0	0	0
Dec-2023	14,866	15,193	30,059	7,065	2,713	9,778	30	37	67
Jan-2024	14,738	15,333	30,071	7,113	2,631	9,744	99	73	172
Feb-2024	14,650	15,446	30,096	7,127	2,507	9,634	147	101	248
Mar-2024	14,466	15,523	29,989	7,149	2,425	9,574	194	119	313
Apr-2024	16,760	15,545	32,305	7,115	2,339	9,454	229	146	375
May-2024	16,644	15,574	32,218	5,131	2,303	7,434	296	166	462
Jun-2024	16,463	15,581	32,044	5,162	2,261	7,423	342	189	531
Jul-2024	16,332	15,588	31,920	5,192	2,224	7,416	395	205	600
Aug-2024	16,237	15,620	31,857	5,261	2,208	7,469	449	231	680
Sep-2024	15,644	15,633	31,277	5,304	2,170	7,474	503	252	755

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

2. DESCRIPTION OF CPP RATES

The TOU periods for the three rates are centered around an on-peak period from 4 to 9 p.m., which is surrounded by morning and evening off-peak periods, and an overnight super-off-peak period. The super-off-peak hours are longer during weekends and holidays. During the months of March and April, additional super off-peak hours are carved into the off-peak period between 10 a.m. and 2 p.m.

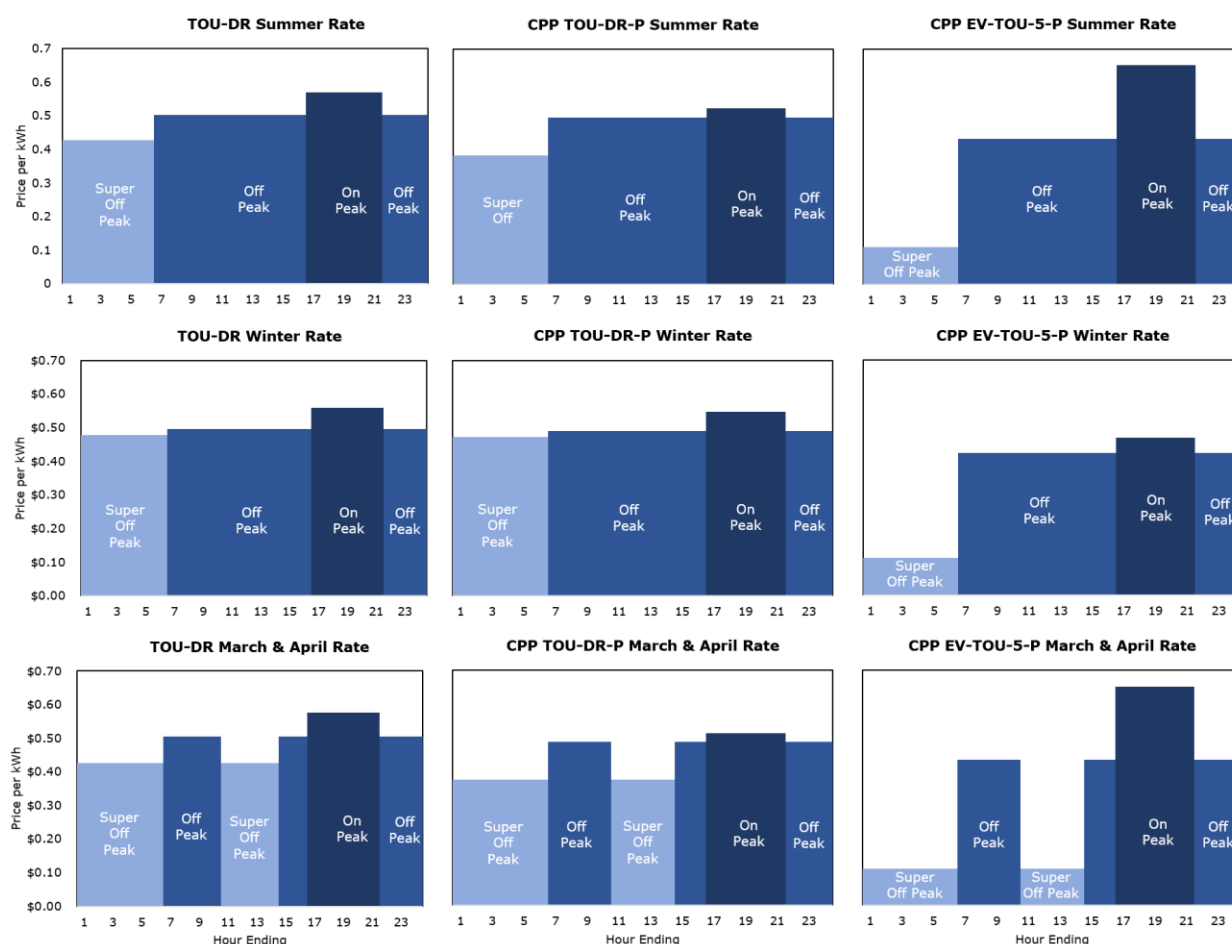
The total TOU rate charges as of February 1, 2025, for TOU-DR customers during summer months (June 1st through October 31st) are \$0.576, \$0.505, and \$0.427 per kWh for the on-peak, off-peak, and super-peak periods, respectively.^{18, 19} Thus, the peak to super-off-peak price

¹⁸ See Schedule TOU-DR, TOU-DR-P, EV-TOU-5-P for current rates and Residential Time-of-Use periods at <https://www.sdge.com/total-electric-rates>.

¹⁹ Customers with CARE status are charged lower rates across all hours but have a similar peak-to-off peak ratio to Non-CARE customers, providing a similar incentive to reduce usage during peak hours. As the proportion of CARE customers is less than 24 percent of all customers included in the analysis, the rates shown in Figure 2.1 only reflect prices charged to Non-CARE customers.

ratio is 1.35-to-1. Summer TOU charges for TOU-DR-P customers are somewhat lower, at \$0.512, \$0.487, and \$0.375 per kWh, implying a peak to super-off-peak price ratio of 1.37-to-1. In addition, a CPP event-period adder of \$1.16 per kWh applies during event hours on CPP event days for these customers, implying a peak to off-peak price ratio of 4.46-to-1. For EV-TOU-5-P customers, the summer rates are \$0.652, \$0.433, and \$0.110 for the on-peak, off-peak, and super-peak periods, respectively, meaning the peak to super-off-peak price ratio is 5.92-to-1. With the CPP event-price adder of \$1.16 per kWh the peak to super-off-peak ratio increases to 16.47-to-1. Figure 2.1 illustrates the hourly TOU rates for each TOU period, rate, and season.²⁰ Rates differ by season for each TOU period, but the periods remain the same (with the exception of the super off-peak period in March and April).

Figure 2.1: Time-of-Use Periods and Prices by Rate²¹



Residential CPP events may be called during the event window from 4 to 9 p.m. on any day of the week throughout the year. CPP participants are generally notified of events by 3 p.m. on the day prior to the event, and several notification options are available, including email and text.

²⁰ The weekend and non-holiday weekday time-of-use periods and prices are not included in Figure 2.1. The same prices apply to weekends and non-holiday weekdays, but the time periods differ somewhat. For weekends and non-holiday weekdays, the super-off-peak hours extend until 2 p.m. in both winter and summer.

²¹ See Schedule TOU-DR and TOU-DR-P for current rates and Residential Time-of-Use periods: Residential TOU-DR and TOU-DR-P for TOU periods at <https://www.sdge.com/total-electric-rates>.

CPP participants are eligible for bill protection for the first full season following their enrollment, which guarantees that their bill will be no larger than what it would have been under their otherwise applicable tariff. During PY 2024, SDG&E called three CPP events: September 5th, 6th, and 9th.

3. EX-POST EVALUATION METHODOLOGY

The primary objectives of the ex-post load impact evaluation were described in Section 1. This section describes the data and methods that are used to produce the ex-post load impact estimates for this study.

3.1 Data

To address each of the load impact objectives listed in Section 1, the following data is required:

- *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 2022 through September 2024;
- *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, notification status of customers in 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. Using hourly load data for TOU and CPP enrollees and potential control group customers for the current year and the previous year (pre-enrollment year for new enrollees), matched control group customers are selected for the TOU and CPP enrollees based on average customer load profiles. For the TOU evaluation, matching is performed on average load profiles during the pre-enrollment period. For the CPP evaluation, matching is based on event-like, non-event days in PY2024. Following matching, fixed-effects panel regression models are estimated on treatment and matched control customers, which produce difference-in-differences estimates of event day load impacts (for CPP), and average TOU period load impacts (for both TOU and for TOU-DR-P non-event days).

3.2.1 Evaluation Design and Control Group Matching

Difference-in-differences is a quasi-experimental approach that compares the usage of treatment and matched control group customers during the post treatment period, or event days, and adjusts for usage differences during the pre-treatment period, or non-event days. The control groups are 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, rate class,²² weather station), based on the closest match of load profiles. The matched control group customers are drawn from an eligible population of SDG&E residential customers. For analyzing the TOU impacts, the eligible population consists of customers that were retained as control customers for the default TOU pilot program. These are customers that are not on a TOU rate for the entire two-year period between October 2022 and September 2024. For analyzing the CPP impacts, the eligible population of potential control customers uses the same potential controls as the TOU analysis as well as customers on rates TOU-DR or EV-TOU-5 during all CPP event days.

The matching process differs for customers on the two non-EV rates, TOU-DR and TOU-DR-P. Since the TOU-DR-P customers experience TOU rates on all non-event days, and the CPP rate on event days, those customers are treated as CPP customers when evaluating CPP load impacts and as TOU customers when evaluating TOU impacts. As a result, TOU load impacts are provided for both the TOU customers (TOU-DR) and CPP customers (TOU-DR-P). EV-TOU-5-P customers are excluded from the TOU impacts analysis.

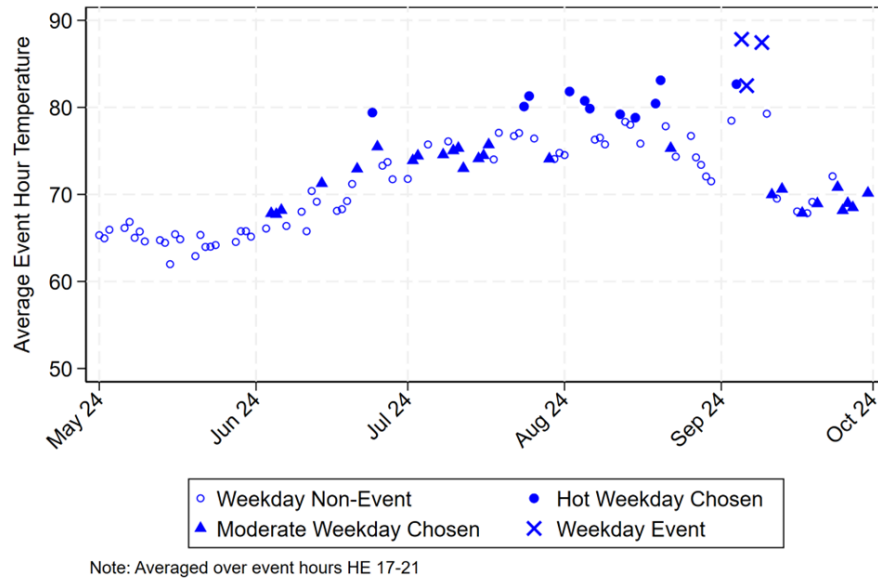
For the CPP load impacts analysis, CPP customers (TOU-DR-P and EV-TOU-5-P) are matched to potential control group customers using loads on selected event-like non-event days (*i.e.*, days with temperatures that are closest to event day temperatures) as well as moderate weather non-event days.²³ Figure 3.1 displays the average event-hour temperature for all weekdays between May and September 2024. The blue X marker represents the three PY2024 weekday events: September 5th, 6th, and 9th. Blue circles indicate weekday non-event days. The event day in 2024 was among the hottest weekdays during 2024. The filled in blue circles represent weekday event-like non-event days and the filled blue triangles represent moderate weather days that were chosen for matching.²⁴

²² The rate class indicates similar rates when ignoring the CPP component. Specifically, TOU-DR-P customers are matched to customers on rates TOU-DR or DR while EV-TOU-5-P customers are matched to customers on rate EV-TOU-5.

²³ Non-event days with moderate temperatures were included along with non-event days with hot “event-like” temperatures to account for customer weather sensitivity.

²⁴ The event-like days used in the 2024 CPP analysis are 6/24, 7/24, 7/25, 8/2, 8/5, 8/6, 8/12, 8/15, 8/19, 8/20, 9/4. The moderate weather days used in the 2024 CPP analysis are 6/4, 6/5, 6/7, 6/14, 6/21, 6/25, 7/2, 7/3, 7/8, 7/10, 7/11, 7/12, 7/15, 7/16, 7/17, 7/29, 8/22, 9/11, 9/13, 9/17, 9/20, 9/24, 9/25, 9/26, 9/27, 9/30.

Figure 3.1: Average Event-Hour Temperatures



For the TOU load impact analysis, which includes both TOU-DR-P and TOU-DR customers, only incremental treatment customers are included in the analysis. Incremental customers are customers that were on a non-TOU rate during PY2023 and switched to TOU-DR or TOU-DR-P at some point during PY2024. The matching is performed based on loads during the pre-treatment period (October 2022 through September 2023). To be included in the analysis, customers must have sufficient pre-treatment data history to provide a quality difference-in-difference analysis.²⁵ The matching and regression analysis are performed separately by season, thus allowing different threshold dates that define incremental customers. The incremental customers are 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. This ensures that customers are matched based on the sensitivity of their energy usage to weather conditions. Matching for the *winter* season uses data for November 2022 through May 2023, while matching for the *summer* season used data for October 2022 and June through September 2023.

Matching is based on Euclidean distance minimization between treatment and potential control group customer loads based on the metric 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 and C variables represent the value of the treatment and control customers' characteristics (e.g., average load during a given hour of the day). For the TOU analysis, the relevant customer characteristics include the average hourly usage over three time periods across all weekdays, average usage on weekdays with extreme temperatures (i.e., the hottest or coldest weekdays in summer or winter, respectively), and customer characteristics

²⁵ Customers must also be on a non-TOU rate (i.e., DR) throughout the pre-treatment period to be a valid incremental customer. Customers that switch from other TOU rates such as TOU-DR1, TOU-DR2, and TOU-ELEC are not eligible to be incremental customers.

that include CARE status and solar photovoltaic generation capacity size for NEM customers.²⁶ The hourly time period averages used for matching are 1 to 6 a.m., 10 a.m. to 2 p.m., and 4 to 9 p.m. Treatment and potential control customers are also segmented by climate zone and NEM status to ensure the treatment and control customer have the same value of these characteristics.

Each treatment customer in the analysis is matched with the control customer in their segment associated with the smallest value of the above distance measure. Potential control group customers are matched with replacement (i.e., may be matched with multiple treatment customers).

While NEM customers are matched similarly, there are additional considerations made for such customers. Only customers that are NEM for the entire analysis period and have not made changes to their solar PV system are included in the treatment or eligible control group.²⁷ Customers with large changes in net load 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 for identifying large changes in usage is explained in more detail in Appendix C. These requirements help 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 the behavioral response to the TOU or CPP rates that this evaluation seeks to estimate.²⁸

3.2.2 Fixed-Effects Panel Regression Models

The ex-post load impact estimates are based on fixed-effects panel regression models. These panel data models are appropriate when observed data are available for many individual customers (cross section) over a long time frame of days or months (time series). The advantages of estimating such models include: 1) accounting for the effect of relevant factors on the variation in usage across customers and days, 2) accounting for the effects of weather conditions on usage, and 3) the availability of standard errors around the estimated load impact coefficients, thus allowing construction of confidence intervals.

Two versions of fixed-effects models were estimated. The first version is used to estimate residential CPP event-day hourly load impacts. Weekend CPP event load impacts are estimated separately from weekday event impacts since load patterns may vary between weekdays and weekend days; however, there were no weekend events called in PY 2024. The CPP event load impacts are also estimated separately across rates, with EV-TOU-5-P CPP load impacts being estimated using both EV-TOU-5-P and TOU-DR-P customers and TOU-DR-P load impacts being estimated using just the TOU-DR-P customers. The second version is used to estimate TOU load

²⁶ Hot/cold days are among the highest/lowest 20th percentile in terms of CDD or HDD temperature values. Hot/cold days are selected separately by climate zone.

²⁷ Treatment or control customers with large changes in their PV system during the analysis period are not included in the regressions.

²⁸ For example, a high usage treatment customer with a large solar generation system may be matched to a low usage control customer with a small solar generation system based on similar net load profiles. If weather conditions during the post-treatment period cause increased solar generation relative to the pre-treatment period, then net load profiles comparisons in the pre- and post-treatment periods will measure the differences between solar installation sizes of the treatment and control customers, indicating a load reduction, rather than measuring load changes that are a result of a behavioral response to the TOU rate.

impacts, which include interaction terms to estimate potential differences in TOU load impacts between TOU-DR and TOU-DR-P customers.

3.2.3 Ex-Post Regression Model for Estimating CPP Load Impacts

The load impact estimation model for CPP estimates the CPP load impact as the difference between CPP and control-group customer loads on event days less the difference on non-event days. The following model is estimated for each hour of the day:

$$kWh_{c,d} = \beta_0 + \sum_{Evs(i)} (\beta_{1,i} \times NonDual_{c,d} \times Evt_{i,d}) + \sum_{Evs(i)} (\beta_{2,i} \times Dual_{c,d} \times Evt_{i,d}) + \sum_{Evs(i)} (\beta_{3,i} \times NonDual_Control_{c,d} \times Evt_{i,d}) + \sum_{Evs(i)} (\beta_{4,i} \times Dual_Control_{c,d} \times Evt_{i,d}) + \beta_5 \times CPP_{c,d} + \beta_6 \times CDD60_{c,d} + C_c + D_d + \varepsilon_{c,d}$$

The variables and coefficients in the equation are described in Table 3.1.

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

Symbol	Description
$kWh_{c,d}$	Load in a particular hour for customer c on date d
$NonDual_{c,d}$	Variable indicating whether customer c is a non-dual CPP customer on date d (1 = yes, 0 if not)
$Dual_{c,d}$	Variable indicating whether customer c is a dually enrolled CPP customer on date d (1 = yes, 0 if not)
$NonDual_Control_{c,d}$	Variable indicating whether customer c is a control customer matched to a CPP customer who is not dually enrolled, on date d (1 = yes, 0 if not)
$Dual_Control_{c,d}$	Variable indicating whether customer c is a control customer matched to a dually enrolled CPP customer, on date d (1 = yes, 0 if not)
$Evt_{i,d}$	Variable indicating that date d is the i^{th} event day (1= i^{th} event, 0 if not)
$CDD60_{c,d}$	Variable indicating the cooling degree days, base of 60 degrees Fahrenheit, for customer c on date d
C_c	Customer Fixed Effects
D_d	Date Fixed Effects
$\varepsilon_{c,d}$	Error term
β_0	Estimated constant coefficient
$\beta_{1,i}$	Estimated load impact for event i for non-dual CPP customers
$\beta_{2,i}$	Estimated load impact for event i for dually enrolled CPP customers
$\beta_{3,i}$	Estimated load impact for event i for control customers matched to non-dual CPP customers
$\beta_{4,i}$	Estimated load impact for event i for control customers matched to dually enrolled CPP customers
β_5	Estimated non-event day response for incremental CPP customers
β_6	Estimated coefficient for a $CDD60_{c,d}$ value.

The model includes date and customer fixed effects to account for factors that commonly affect all customers over time (e.g., weather conditions and day-type factors) and time-invariant customer characteristics (e.g., home size). The $\beta_{1,i}$ coefficients represent the estimated average load impacts for each hour of every event day for CPP customers who are not dually enrolled.

The $\beta_{2,i}$ coefficients separately estimate load impacts for customers dually enrolled in CPP and a dual group of interest. We apply this interacted model to produce separate estimates for customers dually enrolled in emergency load reduction program (“ELRP”). This model is also estimated for customers who receive notifications and customer who do not receive notifications.

Results are scaled to enrollment numbers because a portion of residential CPP customers are removed from the analysis based upon insufficient load quality and NEM customer restrictions (see Appendix C). To produce load impact estimates for specific customer segments (e.g., by climate zone, NEM), the model is estimated for the subset of customers in each segment.

3.2.4 Ex-Post Regression Model for Estimating TOU Load Impacts

The load impact estimation model for TOU estimates the TOU load impact as the difference between TOU and non-TOU (DR) control-group customer loads during the post-TOU enrollment period less the difference during the pre-enrollment period. The following model is estimated for each season²⁹ and hour of the day:

$$\begin{aligned} kWh_{c,d} = & \beta_0 + \beta_1 \times TOU_c \times Post_{c,d} + \beta_2 \times Post_{c,d} + \beta_3 \times TOU_c \times Post_{c,d} \times CPP_c \\ & + \beta_4 \times Weather_{c,d} + \beta_5 \times Weather_{c,d} \times NEM_c + \beta_6 \times Inland_c \times Weather_{c,d} \\ & + \beta_7 \times TOU_c \times Post_{c,d} \times Weather_{c,d} + C_c + D_d + \varepsilon_{c,d} \end{aligned}$$

The variables and coefficients in the equation are described in Table 3.2.

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

Symbol	Description
$kWh_{c,d}$	Load in a particular hour for customer c on date d
TOU_c	Variable indicating whether customer c is in TOU (1) or Control (0) customer
CPP_c	Variable indicating whether customer c is in CPP (1) or Control (0) customer
NEM_c	Variable indicating whether customer c is a NEM (1) customer or a non-NEM (0) customer
$Inland_c$	Variable indicating whether customer c is an Inland climate zone (1) customer or is a Coastal climate zone (0) customer
$Post_{c,d}$	Variable indicating that date d is in the post-enrollment period for customer c
$Weather_{c,d}$	Weather conditions on day d for customer c
C_c	Customer Fixed Effects
D_d	Date Fixed Effects
$\varepsilon_{c,d}$	Error term
β_0	Estimated constant coefficient
β_1	Estimated TOU load impact for all TOU customers

²⁹ The model is estimated for the three TOU seasons: summer, winter, and March through April. The summer season includes June, July, August, September, and October, while the winter season includes January, February, May, November, and December.

Symbol	Description
β_2	Estimated load impact for control customers during post-enrollment period
β_3	Estimated incremental TOU load impact for CPP customers
β_4	Estimated load impact of weather
β_5	Estimated load impact of NEM status interacted with weather
β_6	Estimated load impact of Inland climate zone interacted with weather
β_7	Estimated TOU load impact interacted with weather

The model is estimated for each TOU season. Interactions between the treatment effect and weather allow the load impact to vary based on weather conditions in a given month or on a given peak day within a month. The β_1 coefficient is the estimated average TOU load impact for each season and hour. The β_3 coefficient is the estimated incremental TOU load impact for CPP customers. The β_7 coefficient is the incremental load impact associated with a change in weather conditions. The estimated load impact for a given month is obtained by the following formula:

$$Load\ Impact_{month\ m} = \hat{\beta}_1 + \hat{\beta}_3 \times CPP_c + \hat{\beta}_7 \times \overline{Weather}_{month\ m}$$

The first term indicates the load impact for a customer that adopted a TOU rate (TOU-DR or TOU-DR-P), while the second term indicates the incremental load impact for TOU customers that are enrolled in CPP (TOU-DR-P). The third term multiplies the average weather conditions during month m by the estimated coefficient for the interaction term between the treatment effect and weather. The same formula is applied using weather conditions for each monthly system worst day to produce TOU load impacts for monthly system worst days.

The model includes date and customer fixed effects to account for factors that commonly affect all customers over time (e.g., day-type factors) and time-invariant customer characteristics (e.g., home size). Incremental customers along with their matched control group are used to estimate the TOU load impacts in each regression. Event days are removed from the dataset when estimating TOU load impacts. Results are then scaled to the program level of enrollments. To produce load impact estimates for specific customer segments (e.g., TOU vs. CPP rate, climate zone, NEM), the model is estimated for the subset of customers in each segment.

3.2.5 Calculating Uncertainty-Adjusted Load Impacts

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

The uncertainty-adjusted scenarios are then simulated under the assumption that each hour's load impact is normally distributed with the mean equal to the sum of the estimated load impacts and the standard deviation equal to the square root of the sum of the variances of the errors around the estimates of the load impacts. Results for the 5th and 95th percentile scenarios are generated from these distributions.

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.

3.2.6 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 analysis) or during event-like non-event days (CPP analysis). Statistics such as the mean absolute percentage error ("MAPE") and mean percent error ("MPE"), which provide formal estimates of the percent differences between treatment and control group loads, are also reported. The MAPE offers a measure of accuracy while MPE offers a measure of bias.

4. CPP EX-POST LOAD IMPACT STUDY FINDINGS

This section documents the findings from the ex-post load impact evaluation analysis of the CPP portion of the EV-TOU-5-P and TOU-DR-P rate. For CPP, the primary load impact results include average estimated event-hour load impacts (i.e., the average of the hourly load impacts estimated for the five-hour event window from 4 to 9 p.m.), in aggregate and per-customer, for each event day. Results of the analysis of the TOU portion of TOU-DR-P (i.e., peak load impacts on non-event days) are presented in Section 5, along with results for the TOU-DR rate.

Detailed results for each hour in electronic form may be found in Protocol table generators provided along with this report. As described in Section 3, the results were estimated using fixed-effects regression analysis of hourly data for treatment and matched control group customers.

4.1 Control Group Matching Results

Figure 4.1 illustrates match quality for non-NEM residential CPP (TOU-DR-P and EVTOU-5) customers. The figure shows the average CPP customer load profile compared to the load profile of matched control-group customers across the selected event-like non-event days. Eligible control group customers for this analysis include non-NEM customers on a DR or TOU-DR rate that reside in the same climate zone as the treatment customers. Across all 24 hours, both the mean percentage error (MPE) and mean absolute percentage error (MAPE) of the CPP profile compared to the control-group profile are 2.6 percent. For the CPP event window (4 to 9 p.m.), the MPE and MAPE are 1.0 percent.³⁰

³⁰ Across all 24 hours MPE and MAPE for TOU-DR-P and EV-TOU-5-P customers were 2.5% and 4.2%. The peak hour MPE and MAPE were 0.7% for TOU-DR-P customers and 4.2% for EV-TOU-5-P customers.

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

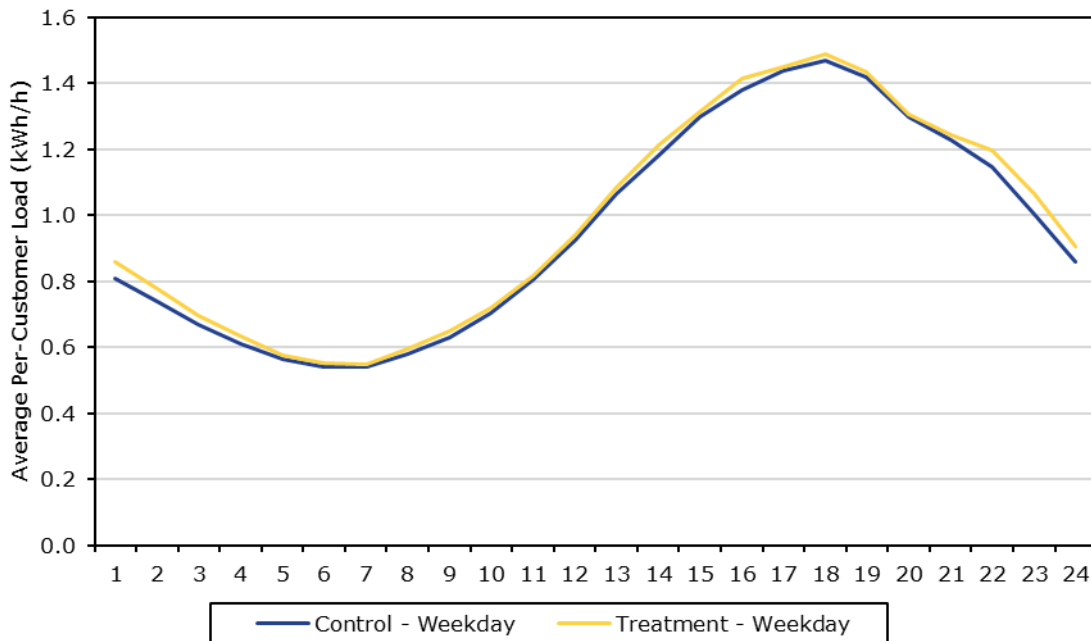
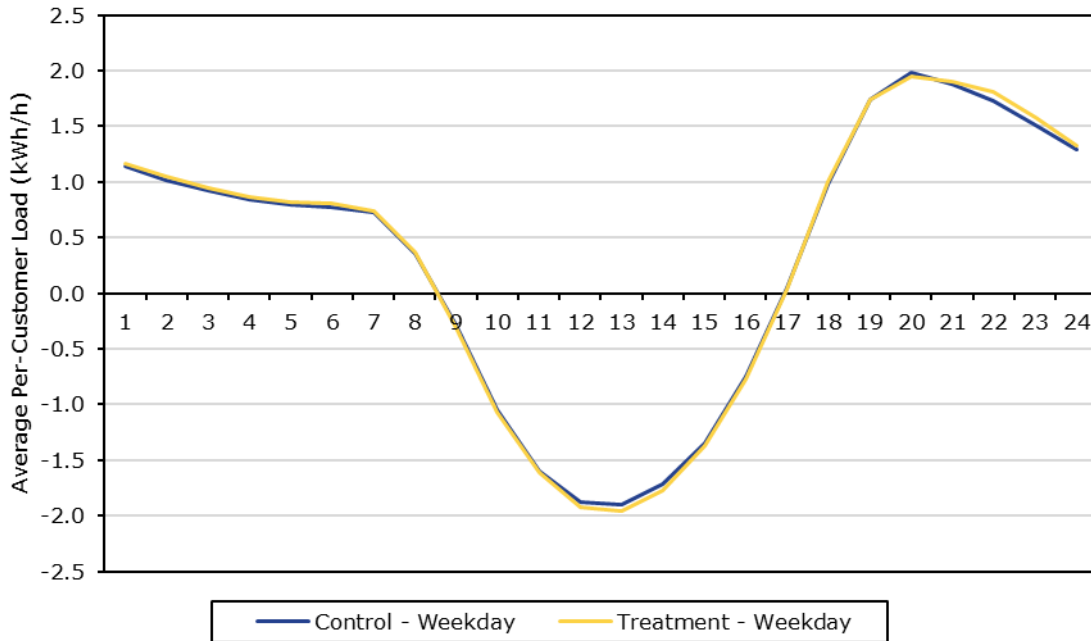


Figure 4.2 similarly illustrates the match quality for NEM residential CPP customers. Eligible control group customers for this analysis include non-NEM customers on a DR or TOU-DR rate that reside in the same climate zone as the treatment customers. Across all 24 hours, the mean error (ME) and mean absolute error (MAE) of the CPP profile compared to the control-group profile are 0.00 kWh/hour and 0.03 kWh/hour, respectively. For the CPP event window (4 to 9 p.m.), the ME and MAE are 0 kWh/hour and 0.02 kWh/hour.^{31,32}

³¹ The ME and MAE statistics are used in lieu of MPE and MAPE because NEM customers can have loads near zero which distorts percentage values so that large percentages can result from relatively small magnitude differences.

³² Across all 24 hours ME and MAE for TOU-DR-P were 0 kWh/hour and 0.03 kWh/hour. For EV-TOU-5-P across all 24 hours ME and MAE were 0.01 kWh/hour and 0.05 kWh/hour. The peak hour ME and MAE for TOU-DR-P customers were 0 kWh/hour and 0.02 kWh/hour and for EV-TOU-5-P customers were -0.04 kWh/hour and 0.06 kWh/hour.

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



4.2 CPP Load Impacts

This section summarizes average event-hour reference loads³³ and load impacts, at an aggregate and per-customer basis, for the 2024 CPP events called on September 5th, 6th, and 9th. The CPP event window is from 4 to 9 p.m. (HE 17-21).

Table 4.1 summarizes average event hour reference loads and CPP load impacts for all CPP customers, by climate zone.³⁴ The first two columns show the climate zone and number of enrolled customers. The next two columns show aggregate estimated reference loads and load impacts for the average event hour, in MWh/hour. The next two columns show the same variables for the average customer, in kWh/hour. The last column summarizes the average temperature during the event window. An asterisk is included next to load impacts that are statistically significant at the 10 percent level. All results are statistically significant at the 10 percent level.

³³ Reference loads represent estimates of the counter-factual loads that would have prevailed on an event day if the event had not been called. Mechanically, the reference loads are constructed by adding the estimated load impacts (developed in the difference-in-differences regression analysis) to the observed load of the treatment customers on the relevant event day. Alternatively, if percentage load impacts are estimated, then the reference loads are calculated by dividing the observed load by one minus the percentage load impact.

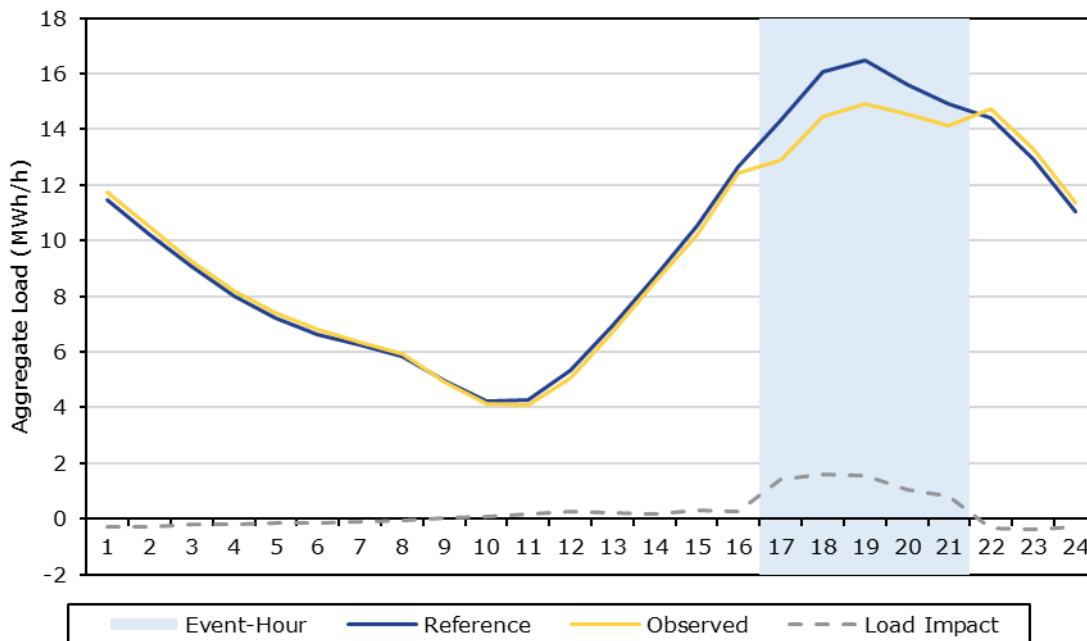
³⁴ Technology Deployment customers are included in these results.

Table 4.1: Average CPP Event-Hour Load Impacts

Rate	Climate Zone	Enrolled	Aggregate		Per-Customer		Avg. Event Temp.
			Ref. Load (MWh/hr)	Load Impact (MWh/hr)	Ref. Load (kWh/hr)	Load Impact (kWh/hr)	
All	Coastal	4,852	9.93	0.81*	2.05	0.17*	84
	Inland	2,476	5.53	0.47*	2.23	0.19*	90
	All	7,328	15.47	1.29*	2.11	0.18*	86

Program enrollment during the CPP event was 7,328 customers, of which 10% were on an EV-TOU-5 rate. About 66 percent of customers were located in the Coastal climate zone.³⁵ The aggregate reference load was 15.47 MWh/hour, and the load impact was 1.29 MWh/hour. Per-customer load impacts averaged 0.17 kWh/hour for customers in the Coastal climate zone and 0.19 kWh/hour for customers in the Inland climate zone. Average temperatures during the event were cooler in the Coastal zone, at 84 degrees, compared to 90 degrees for the Inland zone.

Figure 4.3 shows aggregate hourly loads and load impacts for the CPP events. The largest hourly load impact was 1.55 MWh/hour in hour-ending 18 (5 to 6 p.m.).

Figure 4.3: Aggregate CPP Hourly Loads and Load Impacts – Average Weekday Event

³⁵ These enrollment numbers differ from the number of customers that were included in the regression models. In order to be included in the regression models, customers needed to have a sufficient load history that included all selected event-like days as well as the event day, along with other characteristics needed for the models.

4.3 Comparison of CPP Load Impacts for TOU-DR-P and EV-TOU-5-P

This section compares the CPP load impact estimates between TOU-DR-P and EV-TOU-5-P customers who were enrolled during 2024 analysis period. Customers enrolled in TOU-DR-P and EV-TOU-5-P experience the same CPP events.

Table 4.2 summarizes reference loads and load impacts for customers enrolled in TOU-DR-P and customers enrolled in EV-TOU-5-P separately. An asterisk next to a load impact indicates that the result is statistically significant at the 10 percent level. All results are statistically significant at the 10 percent level. The number of EV-TOU-5-P customers for a typical event called in 2024 was 690,³⁶ about 10 percent of TOU-DR-P customers. On average, EV-TOU-5-P customers have larger reference loads and load impacts. The average per-customer reference load and load impact for EV-TOU-5-P customers were 2.67 kWh/hour and 0.17 kWh/hour, respectively. The average per-customer event reference load and load impact for TOU-DR-P enrolled customers were 2.05 kWh/hour and 0.18 kWh/hour, respectively.

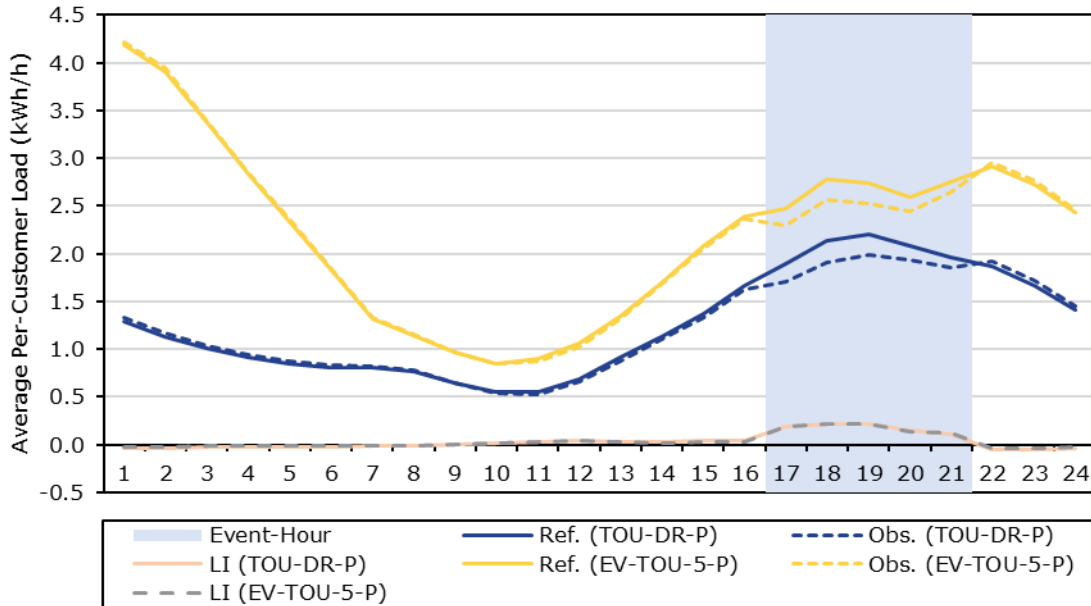
Table 4.2: Comparison of Average CPP Event-Hour Load Impacts for TOU-DR-P and EV-TOU-5 Customers

Rate	Climate Zone	Enrolled	Aggregate		Per-Customer		Avg. Event Temp.
			Ref. Load (MWh/hr)	Load Impact (MWh/hr)	Ref. Load (kWh/hr)	Load Impact (kWh/hr)	
TOU-DR-P	Coastal	4,281	8.39	0.72*	1.96	0.17*	84
	Inland	2,357	5.24	0.45*	2.22	0.19*	90
	All	6,638	13.63	1.17*	2.05	0.18*	86
EV-TOU-5-P	Coastal	571	1.55	0.09*	2.71	0.16*	83
	Inland	119	0.29	0.02*	2.47	0.20*	89
	All	690	1.84	0.12*	2.67	0.17*	84

Figure 4.4 shows average per-customer hourly loads and load impacts for TOU-DR-P customers and EV-TOU-5-P customer for a typical CPP event. The event hours from 4 to 9 p.m. are shaded. The observed loads of EV-TOU-5-P customers ("Obs. (EV-TOU-5-P)") illustrate that EV-TOU-5 customers are on average larger than TOU-DR-P customers. Both EV-TOU-5-P and TOU-DR-P customers show no discernable pre-cooling in the hours before the event begins and a limited snapback effect in the hours after the event. The largest hourly EV-TOU-5-P load impact was 0.2 kWh/customer/hour in the second and third hour of the event (5 to 6 p.m.).

³⁶ While the numbers vary slightly from day to day, on September 9th 699 customers were enrolled in EV-TOU-P while 6,639 customers were enrolled in TOU-DR-P.

Figure 4.4: CPP Hourly Loads and Load Impacts by Rate



4.4 Notification Status Load Impacts

This section compares the CPP load impact estimates for customers that were notified of an event to load impacts for customers that did not receive notifications. Customers who were not notified may not have known that a CPP event was occurring.

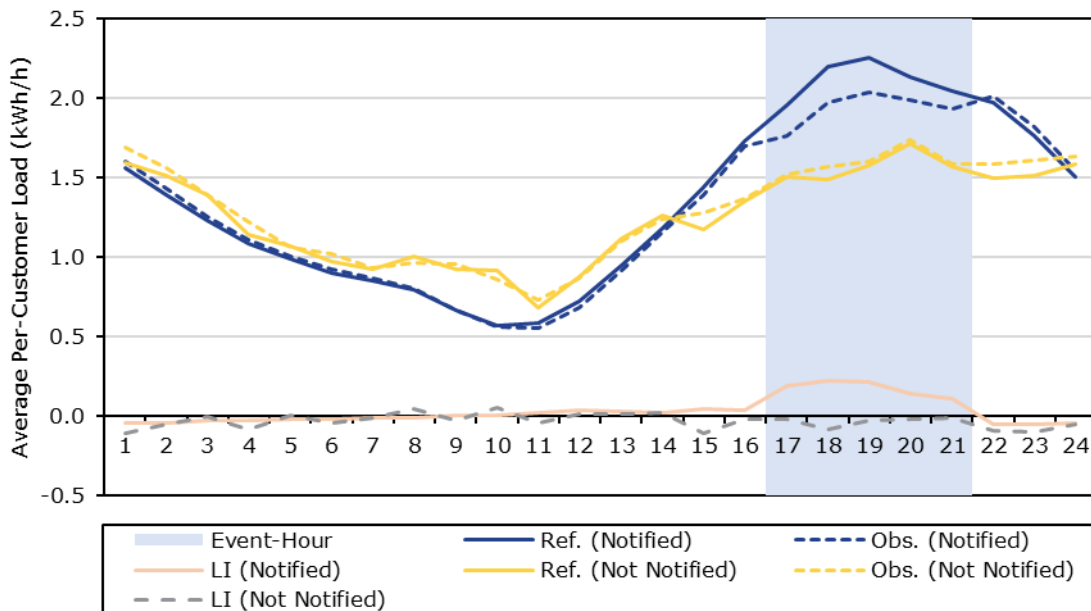
Table 4.3 summarizes reference loads and load impacts for customers that were notified of an event and those that did not receive notifications. The number of non-notified customers for the CPP events was ■■■ for September 5th, ■■■ for September 6th and 110 for September 9th (which is about 1.4 percent of CPP customers). Customers who were not notified had smaller average reference loads and load impacts that are not statistically significant, which is consistent with customers having a load response that is not distinguishable from zero. The average event reference load and load impact for non-notified customers was 1.57 kWh/hour and -0.03 kWh/hour, respectively. The average event reference load and load impact for notified customers was 2.12 kWh/hour and 0.18 kWh/hour, respectively. All the load impacts for notified customers are statistically significant at the 10 percent level.

Table 4.3: Comparison of Average CPP Event-Hour Load Impacts by Notification Status

Type	Date	Enrolled	Aggregate		Per-Customer		Avg. Event Temp.
			Ref. Load (MWh/hr)	Load Impact (MWh/hr)	Ref. Load (kWh/hr)	Load Impact (kWh/hr)	
Notified	Sep 5, 2024	7,218	15.77	1.44*	2.18	0.20*	88
	Sep 6, 2024	7,224	13.98	1.39*	1.94	0.19*	83
	Sep 9, 2024	7,228	16.17	1.04*	2.24	0.14*	87
	Typical Weekday Event	7,223	15.31	1.29*	2.12	0.18*	86
Non-Notified	Sep 5, 2024						
	Sep 6, 2024						
	Sep 9, 2024	110	0.18	-0.01	1.60	-0.06	87
	Typical Weekday Event	105	0.16	0.00	1.57	-0.03	85

Figure 4.5 shows average per-customer hourly loads and load impacts for CPP customers who were notified compared to customers who were not notified for a typical weekday CPP event. The event hours from 4 to 9 p.m. are shaded. Non-notified customers do not show evidence of a noticeable load impact during event hours, unlike the notified customers. No event hour with a load impact is statistically significant at the 10 percent. Notified customers have statistically significant load impacts during each event hour as well as statistically post-event snapback.

Figure 4.5: Hourly Loads and Load Impacts for Notified and Non-Notified (NN) Customers



5. TOU EX-POST LOAD IMPACT STUDY FINDINGS

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

5.1 TOU Control Group Matching Results for TOU Customers

Figure 5.1 and Figure 5.2 illustrate the match quality 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. Eligible control group customers for this analysis include non-NEM customers on a DR rate that reside in the same climate zone as the treatment customers. 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 over the 24-hour period is -0.9 percent, while the mean absolute percentage error (MAPE) is 2.4 percent. During the summer peak hours (4 p.m. to 9 p.m.) the MPE and MAPE is 0.5 percent. In the winter months, over the 24-hour period, the MPE is 1.8 percent and the MAPE is 3.1 percent. Over the winter peak hours, the MPE and MAPE is 3.4 percent.

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

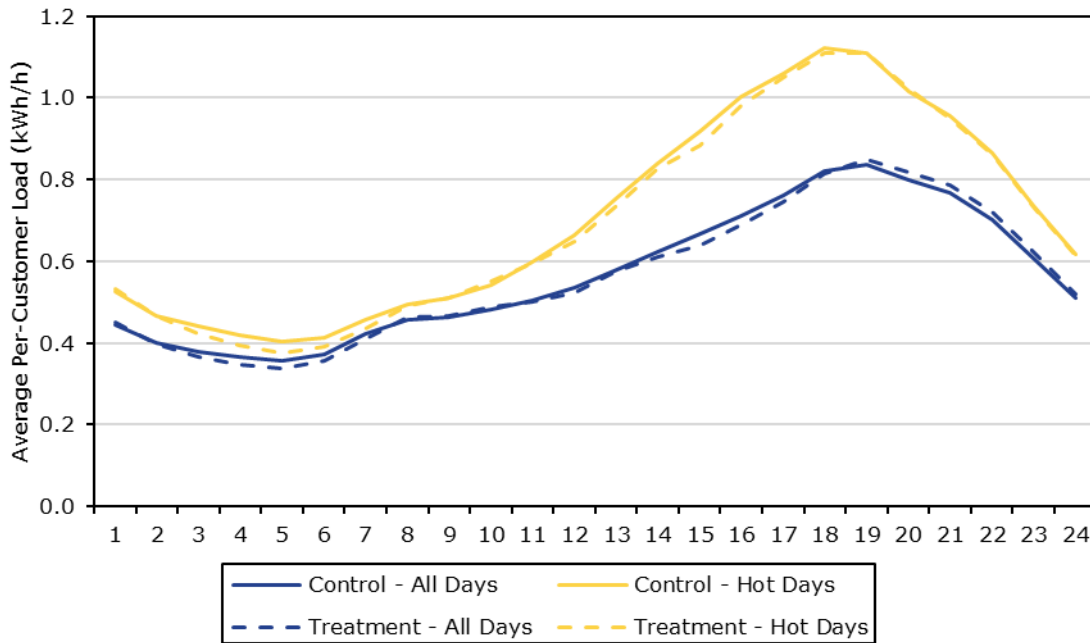


Figure 5.2: Non-NEM TOU and Matched Control Group Load Profiles – Winter

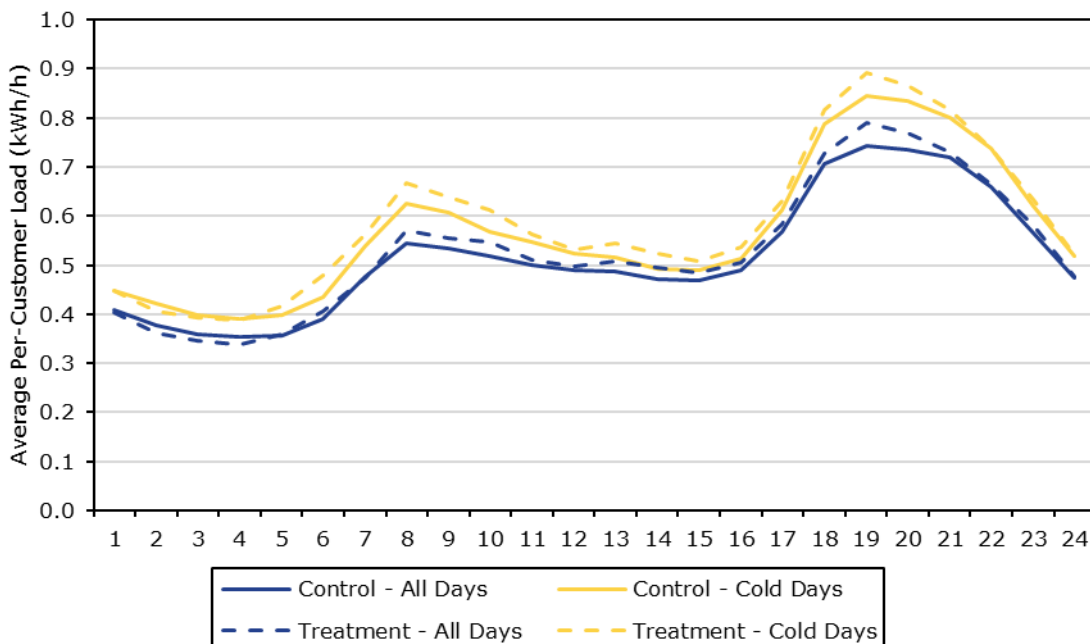


Figure 5.3 and Figure 5.4 illustrate the quality of the matches for the TOU (TOU-DR) NEM customers, similar to the above figures. Eligible control group customers for this analysis include NEM customers on a DR rate that reside in the same climate zone as the treatment customers. In the summer months, the mean error (ME) of the TOU profile compared to the control-group profile over the 24-hour period is 0.04 kWh/hour, while the mean absolute error (MAE) is 0.08

kWh/hour. Over the peak-hour period the ME is -0.05 kWh/hour and the MAE is 0.06 kWh/hour. In the winter months, over the 24-hour period, the ME is 0.02 kWh/hour and the MAE is 0.03 kWh/hour. Over the winter peak-hour period both ME is 0.00 kWh/hour and MAE is 0.01 kWh/hour.

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

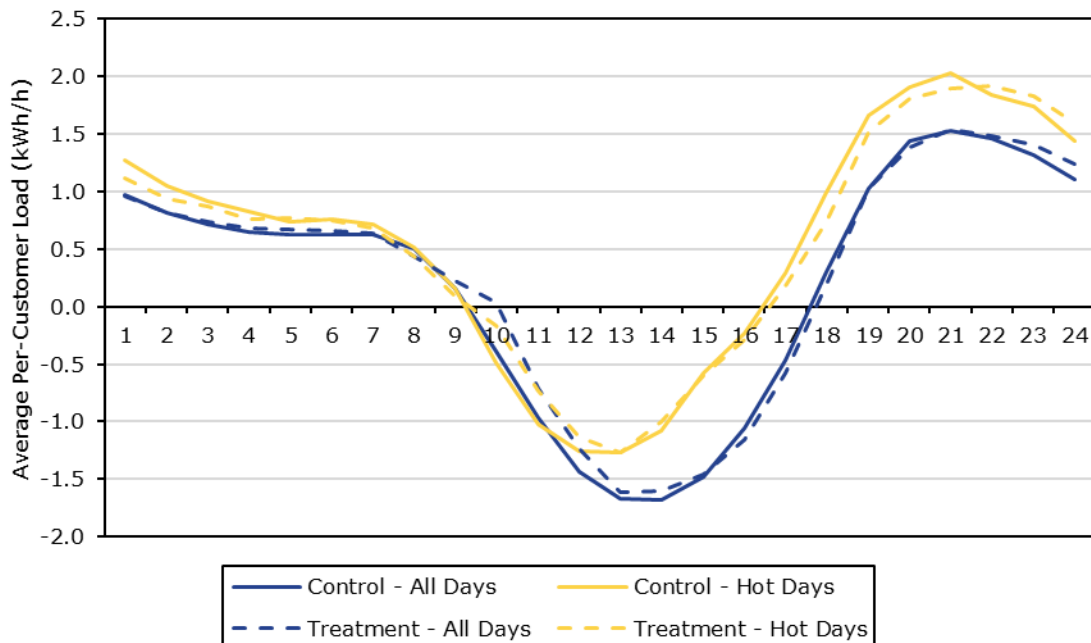
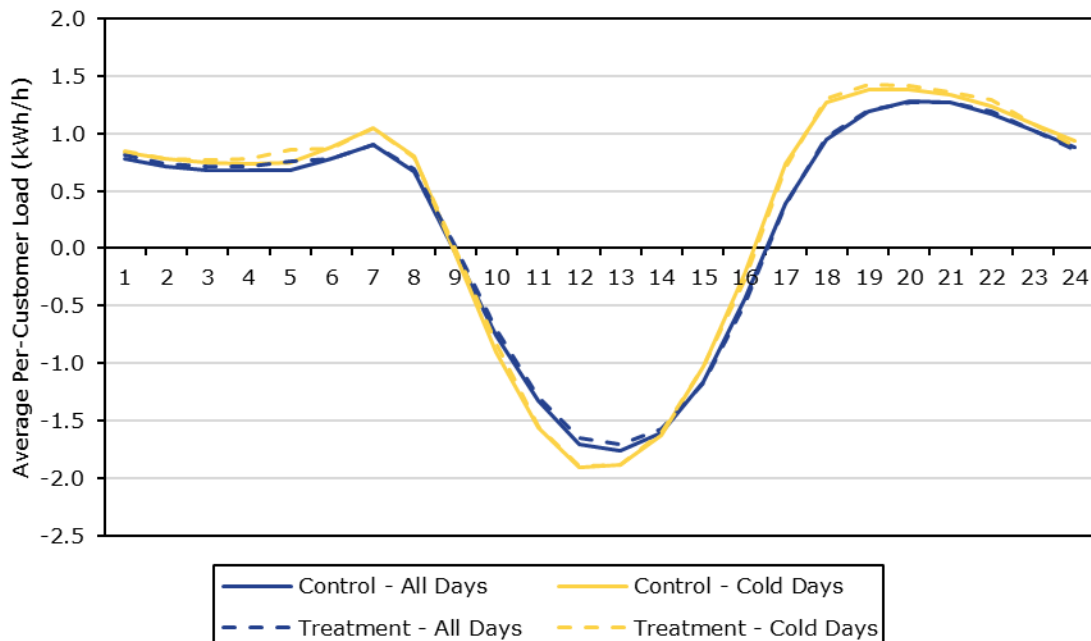


Figure 5.4: NEM TOU and Matched Control Group Load Profiles – Winter



5.2 Ex-Post TOU Load Impacts for TOU Customers

This sub-section shows ex-post TOU load impact results for those customers enrolled in the TOU (TOU-DR) rate. Table 5.1 summarizes the average reference loads and TOU load impacts for the TOU peak period (4 to 9 p.m.) for the average weekday *by month*, on an aggregate and per-customer basis. The months are shown chronologically starting with the first month included in the analysis (October 2023). The winter months are indicated by light blue shading. Enrollments increased throughout the period, with the number of enrolled customers increasing from 30,137 in October 2023 to 31,278 in September 2024.³⁷ As described in Section 3.2.4, the TOU methodology estimates load impacts using seasonal models that interact the estimated load impacts with weather conditions to produce monthly TOU load impacts based on differences in average monthly weather. The per-customer load impacts are higher during the summer months at approximately 0.05 kWh/hour compared to 0.01 kWh/hour during winter months. The lowest load impacts occur during May and November when peak usage increases by 0.01 and 0.02 kWh/customer/hour, respectively. An asterisk next to a load impact indicates that the result is statistically significant at the 10 percent level. All summer results are statistically significant as well as March and April.

³⁷ 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 244 incremental non-NEM customers who switched to the TOU-DR rate with quality load data sufficient for estimating the TOU load impacts. Many NEM customers could not be used in the analysis because of a change in NEM status or PV installation size during the two-year study period. Specifically, only 86 NEM TOU customers are included in the regressions. The aggregate TOU load impacts are then scaled to total enrollments.

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

Month	Climate Zone	Enrolled	Aggregate		Per-Customer		Avg. Peak Temp.
			Peak Ref. Load (MWh/hr)	Peak Load Impact (MWh/hr)	Peak Ref. Load (kWh/hr)	Peak Load Impact (kWh/hr)	
Oct-2023	All	30,137	23.40	0.84*	0.78	0.03*	70
Nov-2023	All	30,072	24.79	-0.46	0.82	-0.02	63
Dec-2023	All	30,059	28.94	0.06	0.96	0.00	59
Jan-2024	All	30,071	28.21	0.27	0.94	0.01	57
Feb-2024	All	30,096	25.89	0.24	0.86	0.01	57
Mar-2024	All	29,989	16.18	1.15*	0.54	0.04*	59
Apr-2024	All	32,305	12.83	1.27*	0.40	0.04*	62
May-2024	All	32,219	9.06	-0.38	0.28	-0.01	63
Jun-2024	All	32,045	15.61	0.87*	0.49	0.03*	67
Jul-2024	All	31,921	30.55	1.95*	0.96	0.06*	73
Aug-2024	All	31,858	36.17	2.26*	1.14	0.07*	75
Sep-2024	All	31,278	27.07	1.63*	0.87	0.05*	69

Table 5.2 shows results by season and climate zone. The Inland and Coastal climate zones exhibit higher reference loads during the summer than during winter. Inland reference loads are higher than Coastal reference loads during both periods. While customers in both climate zones decrease loads by 0.05 kWh/customer/hour on average during the peak period in summer months, Inland customers have a slightly higher load impact of 0.06 kWh/customer/hour. Inland customers also have a higher load impact during winter months. An asterisk next to a load impact indicates that the result is statistically significant at the 10 percent level. All summer results are statistically significant at the 10 percent level.

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

Season	Climate Zone	Enrolled (Average)	Aggregate		Per-Customer		Avg. Peak Temp.
			Peak Ref. Load (MWh/hr)	Peak Load Impact (MWh/hr)	Peak Ref. Load (kWh/hr)	Peak Load Impact (kWh/hr)	
Summer	Coastal	17,156	12.21	0.69*	0.71	0.04*	70
	Inland	14,292	14.32	0.80*	1.00	0.06*	72
	All	31,448	26.53	1.49*	0.84	0.05*	71
Winter	Coastal	16,171	10.67	0.14	0.66	0.01	61
	Inland	14,516	10.17	0.17	0.70	0.01	60
	All	30,687	20.84	0.31	0.68	0.01	60

Table 5.3 shows the effect of TOU on average *daily* usage by month. TOU customers increased their daily energy consumption in every month. An asterisk next to a load impact indicates that the result is statistically significant at the 10 percent level. Results in October, November, December, January, February, May, and June are statistically significant.

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

Month	Climate Zone	Enrolled	Aggregate		Per-Customer		Avg. Daily Temp.
			Daily Ref. Load (MWh/day)	Daily Load Impact (MWh/day)	Daily Ref. Load (kWh/day)	Daily Load Impact (kWh/day)	
Oct-2023	All	30,137	161.12	-21.23*	5.35	-0.70*	66
Nov-2023	All	30,072	195.61	-33.09*	6.50	-1.10*	61
Dec-2023	All	30,059	285.49	-27.32*	9.50	-0.91*	57
Jan-2024	All	30,071	286.02	-25.53*	9.51	-0.85*	55
Feb-2024	All	30,096	264.22	-25.70*	8.78	-0.85*	56
Mar-2024	All	29,989	77.78	-11.73	2.59	-0.39	57
Apr-2024	All	32,305	49.46	-9.06	1.53	-0.28	59
May-2024	All	32,219	7.77	-34.95*	0.24	-1.08*	61
Jun-2024	All	32,045	74.75	-23.34*	2.33	-0.73*	65
Jul-2024	All	31,921	270.85	-12.62	8.48	-0.40	70
Aug-2024	All	31,858	334.48	-9.34	10.50	-0.29	72
Sep-2024	All	31,278	233.18	-14.82	7.46	-0.47	67

Figure 5.5 shows aggregate (NEM and non-NEM combined) hourly observed and estimated reference loads and load impacts for the TOU-only customers for the average weekday in August. Figure 5.6 shows the same information for the average weekday in January. The hourly TOU load impacts in August illustrate a statistically significant reduction in usage during the peak hours. The TOU load impacts during the winter are statistically insignificant for the peak hours with the exception of load reductions in hour ending ("HE") 20. For both winter and summer there appears to be evidence of statistically significant load shifting to super off-peak hours as reference loads are below observed loads in HE 1 through HE 7.

Figure 5.5: Aggregate Hourly Loads and TOU Load Impacts(MWh/hour) – TOU Customers (Average Weekday, August 2024)

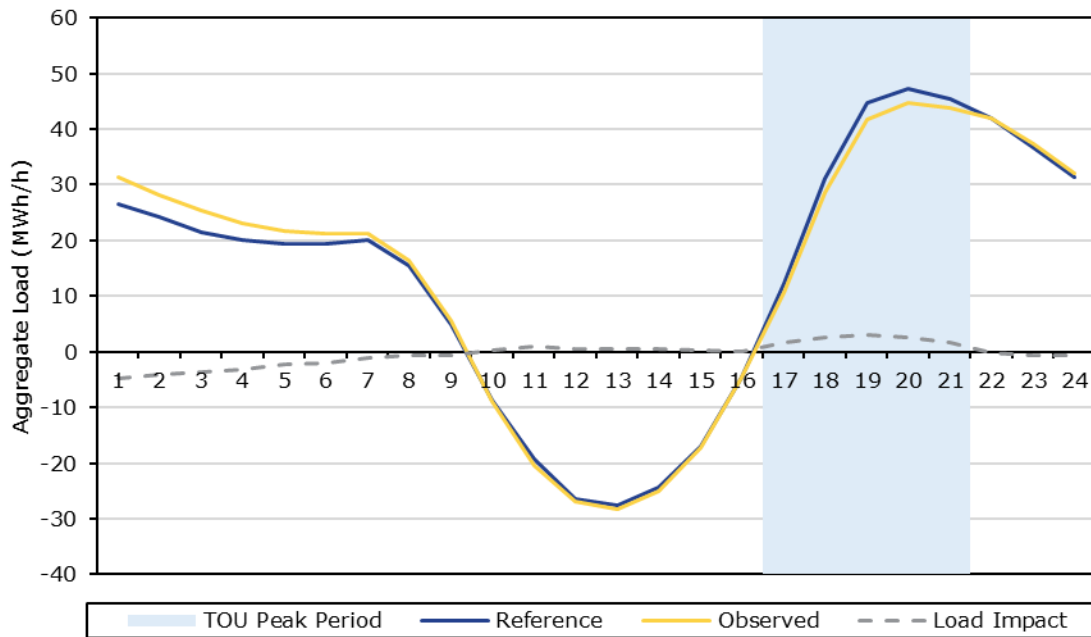
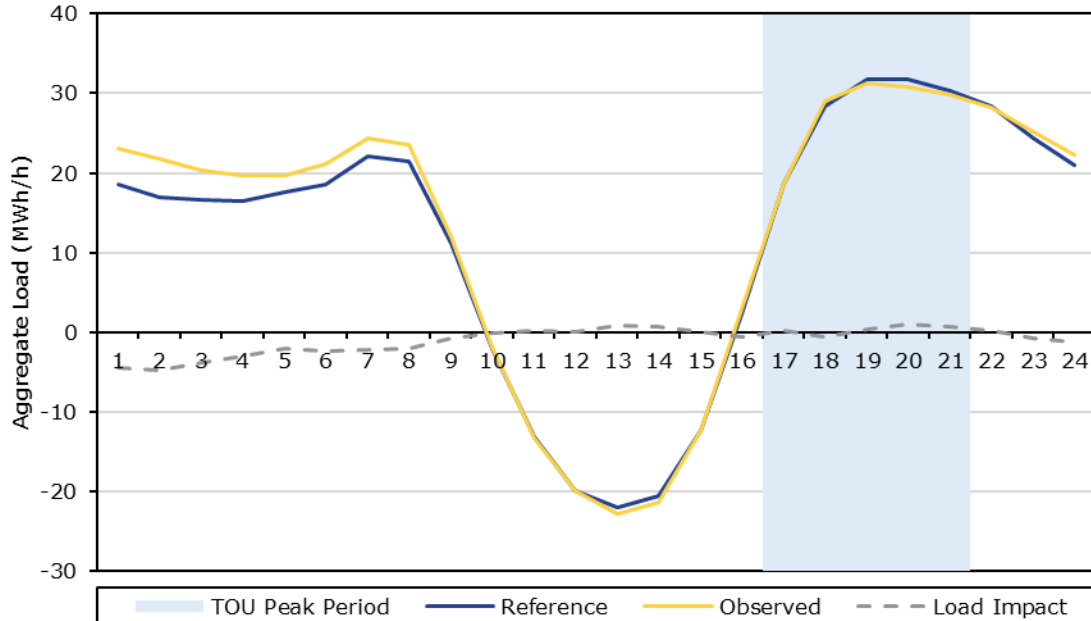


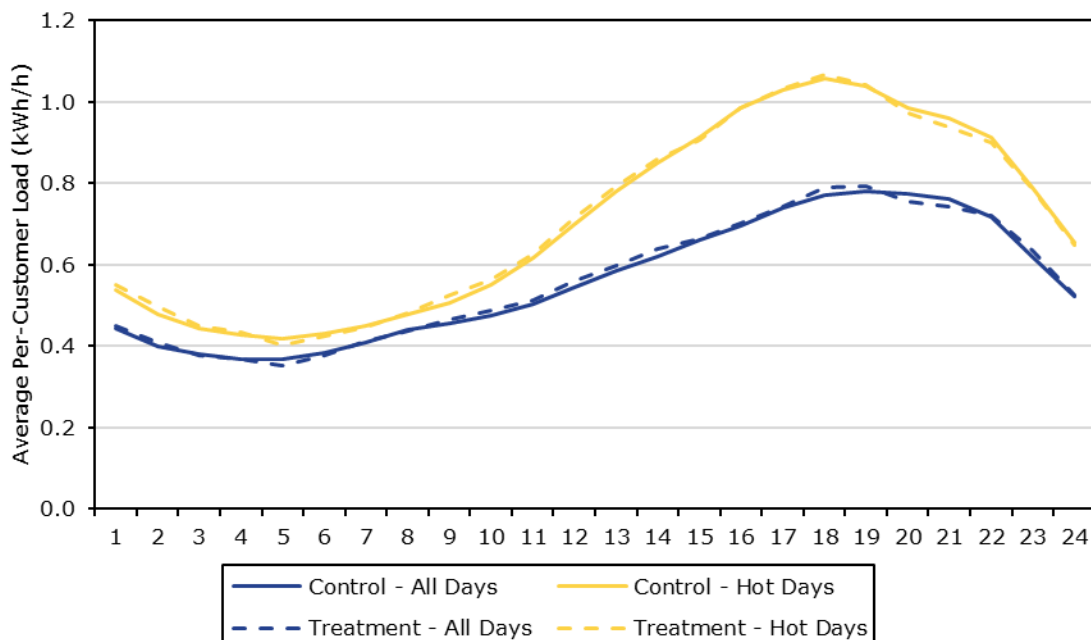
Figure 5.6: Aggregate Hourly Loads and TOU Load Impacts (MWh/hour) – TOU Customers (Average Weekday, January 2024)



5.3 TOU Control Group Matching Results for CPP Customers

Figure 5.7 and Figure 5.8 illustrate the match quality for the non-NEM residential CPP (TOU-DR-P) customers on non-event days³⁸. The figures show the average and matched control-group customer load profiles for the summer and winter months, respectively. Eligible control group customers for this analysis include non-NEM customers on a DR rate that reside in the same climate zone as the treatment customers. 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 over the 24-hour period is 0.66 percent, while the mean absolute percentage error (MAPE) is 1.6 percent. During the summer peak hours (4 p.m. to 9 p.m.) the MPE is 0.1 percent and the MAPE is 1.9 percent. In the winter months, over the 24-hour period, the MPE is 0.5 percent and the MAPE is 1.8 percent. Over the winter peak hours, the MPE is 1.7 percent and the MAPE is 2.0 percent.

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



³⁸ EV-TOU-5-P is not included in the TOU analysis.

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

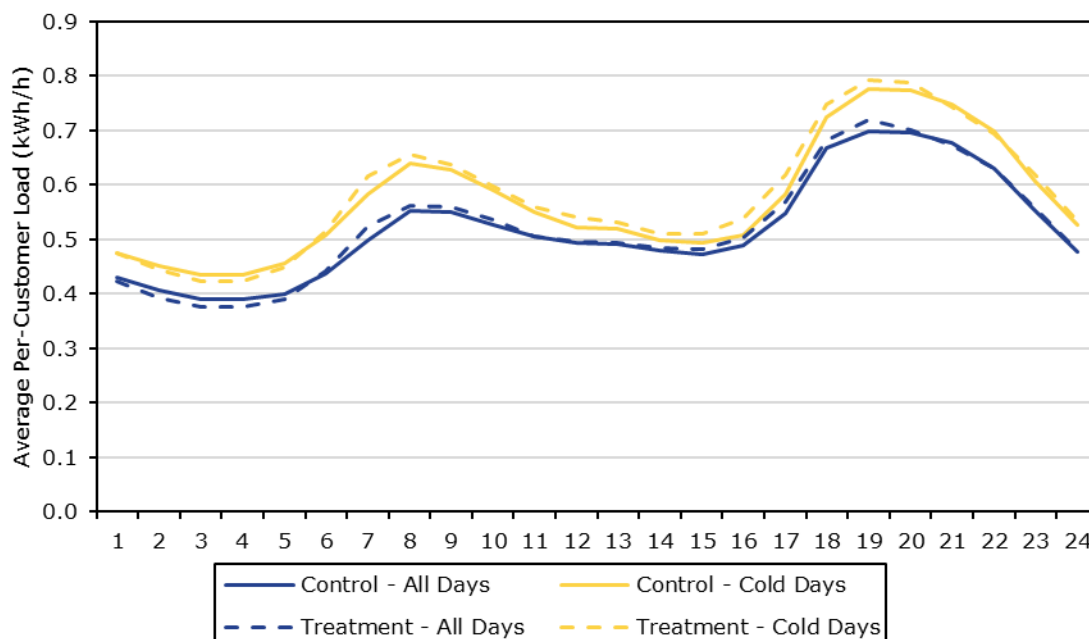


Figure 5.9 and Figure 5.10 illustrate the match quality for the NEM residential CPP (TOU-DR-P) customers on non-event days. The figures show the average CPP and matched control-group customer load profiles for the summer and winter months, respectively. Eligible control group customers for this analysis include NEM customers on a DR rate that reside in the same climate zone as the treatment customers. 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) and mean absolute error (MAE) of the TOU profile compared to the control-group profile over the 24-hour period is 0.17 kWh/hour. Over the peak-hour period the ME and MAE is 0.21 kWh/hour. In the winter months, over the 24-hour period the ME is 0.00 kWh/hour, and the MAE is 0.04 kWh/hour. Over the winter peak-hour period the ME is -0.01 kWh/hour, and the MAE is 0.04 kWh/hour.

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

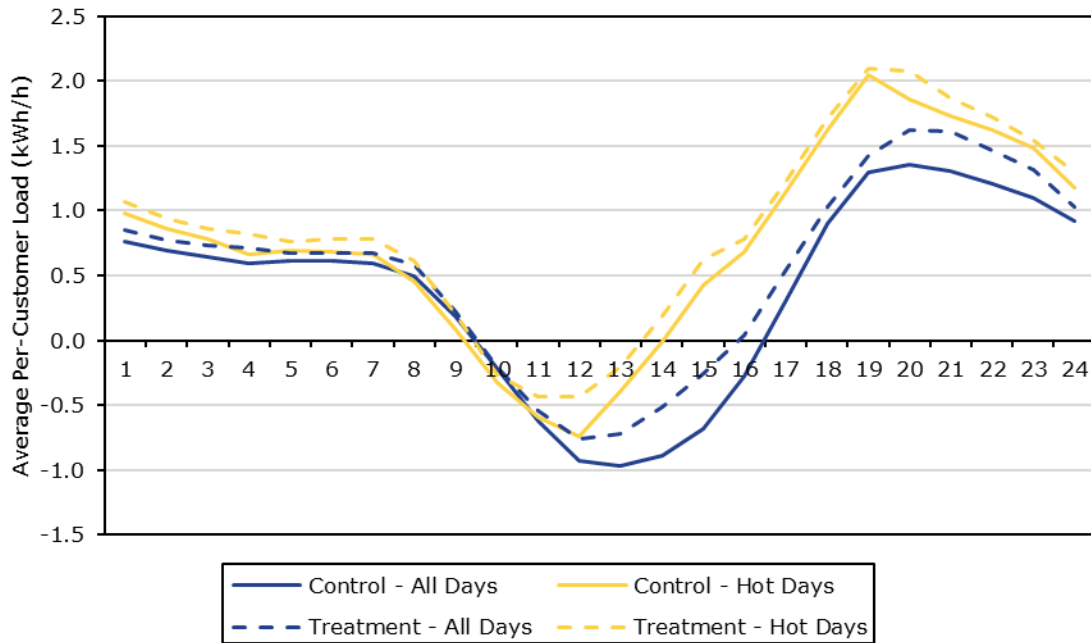
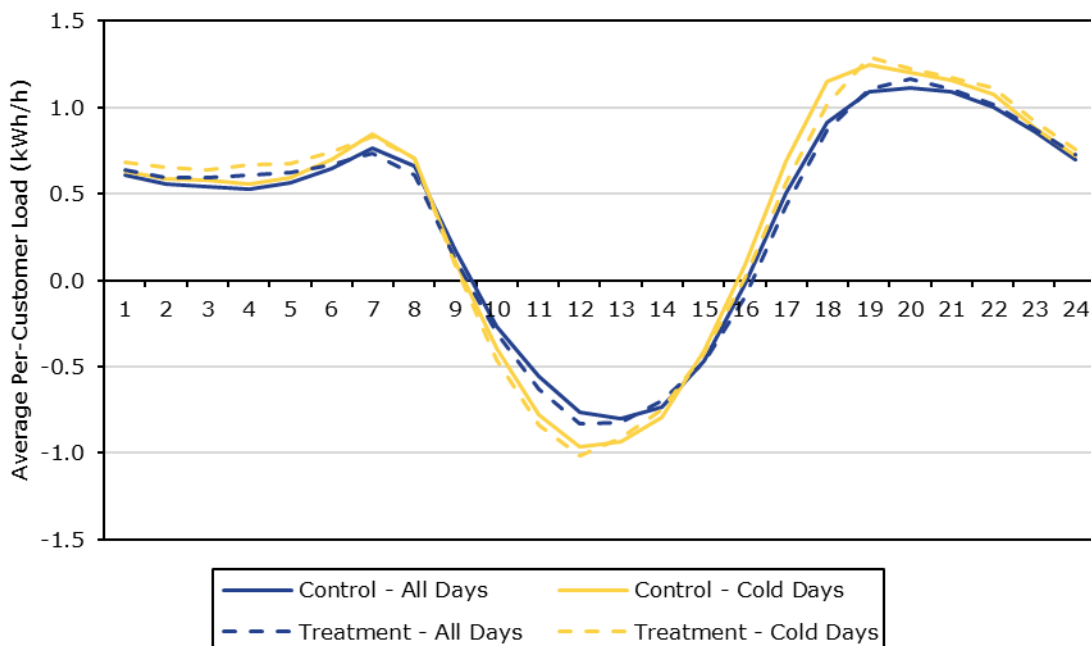


Figure 5.10: NEM CPP and Matched Control Group Load Profiles – Winter



5.4 Ex-Post TOU Load Impacts for CPP Customers

Since TOU-DR-P customers experience TOU prices on days that are not residential CPP event days, it is of interest to examine the impact of TOU prices on non-event day usage for these customers. This sub-section reports ex-post TOU load impact results for customers on the CPP (TOU-DR-P) rate. Table 5.4 summarizes peak-period loads and load impacts for the average

summer (October 2023, and June through September 2024) and winter (November 2023 through May 2024) weekdays, by month. Reported enrollment in CPP fell from 10,179 in October 2023 to 6,729 in September 2024.³⁹ A majority of the enrollment decreased between April and May was because of customers that transitioned to a CCA and were no longer eligible to be on the CPP rate. Peak load impacts varied between seasons, with estimated load reductions of 0.06 kWh/hour in all summer months and 0.04 kWh/hour in all winter months. An asterisk next to a load impact indicates that the result is statistically significant at the 10 percent level.

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

Month	Climate Zone	Enrolled	Aggregate		Per-Customer		Avg. Peak Temp.
			Peak Ref. Load (MWh/hr)	Peak Load Impact (MWh/hr)	Peak Ref. Load (kWh/hr)	Peak Load Impact (kWh/hr)	
Oct-2023	All	10,179	8.42	0.37	0.83	0.04	72
Nov-2023	All	9,939	8.24	0.27*	0.83	0.03*	64
Dec-2023	All	9,733	9.32	0.47*	0.96	0.05*	60
Jan-2024	All	9,585	8.60	0.57*	0.90	0.06*	57
Feb-2024	All	9,395	7.85	0.55*	0.84	0.06*	58
Mar-2024	All	9,273	5.61	0.21	0.60	0.02	61
Apr-2024	All	9,088	4.83	0.22	0.53	0.02	64
May-2024	All	6,980	3.51	0.18	0.50	0.03	65
Jun-2024	All	6,911	4.95	0.30*	0.72	0.04*	70
Jul-2024	All	6,831	8.06	0.54*	1.18	0.08*	75
Aug-2024	All	6,795	9.04	0.58*	1.33	0.09*	77
Sep-2024	All	6,729	6.60	0.46*	0.98	0.07*	71

Table 5.5 summarizes results by season and climate zone. The Inland climate zone has a decrease in average peak-hour loads of 0.07 kWh/hour in the summer and 0.04 in the winter compared to 0.05 kWh/hour in the Coastal climate zone during summer and 0.04 kWh/hour during winter. Load impacts in the Coastal climate zone are lower in winter relative to the Inland climate zone. An asterisk next to a load impact indicates that the result is statistically significant at the 10 percent level.

³⁹ The number of CPP customers included in the regressions is substantially smaller than the number used for CPP load impact regressions. This difference is due to the data requirements for the TOU analysis, including load histories for both the program year and the pre-treatment period, which served as the basis for control group matching. Moreover, TOU load impacts are based on incremental customers, which make up a small share of total customers on each rate. There were 184 non-NEM 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. As was the case with TOU-DR, a small group of 21 NEM TOU-DR-P customers were included in the regressions to estimate NEM customer load impacts.

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

Season	Climate Zone	Enrolled (Average)	Aggregate		Per-Customer		Avg. Peak Temp.
			Peak Ref. Load (MWh/hr)	Peak Load Impact (MWh/hr)	Peak Ref. Load (kWh/hr)	Peak Load Impact (kWh/hr)	
Summer	Coastal	4,929	4.59	0.27	0.93	0.05	72
	Inland	2,560	2.84	0.18*	1.11	0.07*	75
	All	7,489	7.43	0.45*	0.99	0.06*	73
Winter	Coastal	6,474	4.78	0.24*	0.74	0.038*	61
	Inland	2,667	2.07	0.11*	0.78	0.041*	60
	All	9,142	6.85	0.35*	0.75	0.04*	61

Table 5.6 shows the effect of TOU on average daily usage by month. CPP customers decreased their average daily usage during the winter months of January and February and increased their usage in all other months. There is an overall annual load increase of approximately 0.38 kWh/customer/day relative to the reference load. An asterisk next to a load impact indicates that the result is statistically significant at the 10 percent level. Only the March result is statistically significant at the 10 percent level.

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

Month	Climate Zone	Enrolled	Aggregate		Per-Customer		Avg. Daily Temp.
			Daily Ref. Load (MWh/day)	Daily Load Impact (MWh/day)	Daily Ref. Load (kWh/day)	Daily Load Impact (kWh/day)	
Oct-2023	All	10,179	100.11	-6.82	9.84	-0.67	67
Nov-2023	All	9,939	105.08	-2.98	10.57	-0.30	62
Dec-2023	All	9,733	126.64	-0.87	13.01	-0.09	58
Jan-2024	All	9,585	122.38	0.34	12.77	0.04	54
Feb-2024	All	9,395	115.17	0.25	12.26	0.03	56
Mar-2024	All	9,273	74.89	-5.98*	8.08	-0.64*	58
Apr-2024	All	9,088	68.01	-4.73	7.48	-0.52	60
May-2024	All	6,980	52.01	-3.47	7.45	-0.50	62
Jun-2024	All	6,911	67.03	-5.35	9.70	-0.77	67
Jul-2024	All	6,831	110.10	-2.35	16.12	-0.34	72
Aug-2024	All	6,795	123.34	-2.16	18.15	-0.32	73
Sep-2024	All	6,729	93.82	-4.09	13.94	-0.61	68

Figure 5.11 shows aggregate hourly observed and estimated reference loads and load impacts for residential CPP customers (both non-NEM and NEM) for the weekday in August. Figure 5.12 shows the same information for the average weekday in January. The January and August average loads exhibit load shifting (load increases) during the super off-peak hours and decreases in loads in four out of five peak hours for January and all peak hours for August.

Figure 5.11: Aggregate Hourly Loads and TOU Load Impacts (MWh/hour) – TOU-DR-P Customers (Average Weekday, August 2024)

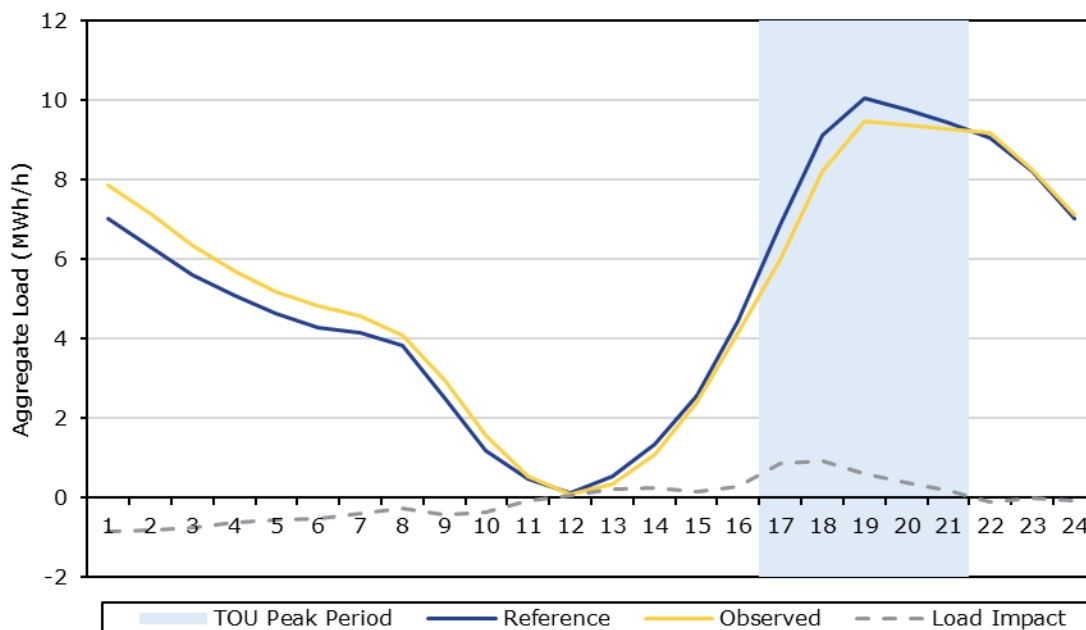
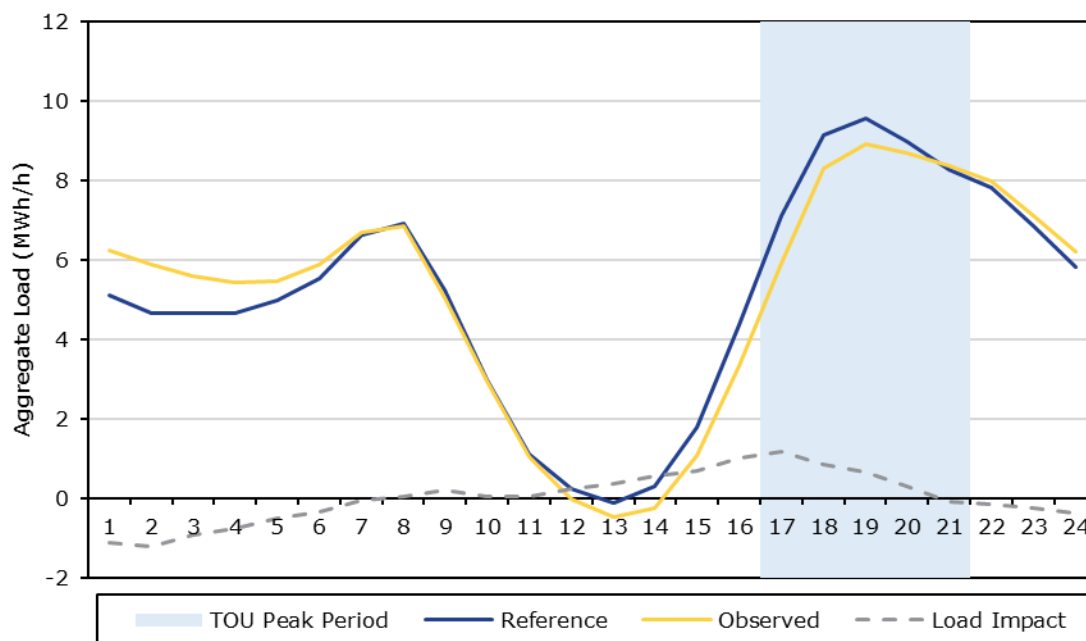


Figure 5.12: Aggregate Hourly Loads and TOU Load Impacts (MWh/hour) – CPP Customers (Average Weekday, January 2024)



6. EX-ANTE EVALUATION METHODOLOGY

This section describes the methodology for developing ex-ante load impact forecasts for the CPP and TOU rates. Ex-ante load impacts represent forecasts of load impacts that are expected to occur when program events are called in future years (CPP), or in TOU peak periods (TOU), under standardized weather conditions. The forecasts are based on per-customer load impacts from the ex-post evaluations, development of weather-sensitive reference loads, and incorporation of utility forecasts of program enrollments.

6.1 Per-Customer Load Impacts

CPP events are usually called during extreme weather scenarios. Weather-sensitive ex-ante load impacts for the relevant weather scenarios are constructed by applying percentage load impacts from ex-post to simulated weather-sensitive reference loads. Level load impacts from ex-post are used for NEM customers to avoid issues with percentage load impacts for these customers. SDG&E called three CPP events in 2024. The ex-ante analysis uses load impacts from these events as a basis for PY2024 ex-ante forecasts. Different ex-post percentage load impacts (or level load impacts in the case of NEM customers) by climate zone, dual enrollment ELRP and for customers who receive notifications are applied to simulated reference loads.

For TOU ex-ante load impacts (TOU-DR and TOU-DR-P customers), percentage load impacts from the ex-post analysis are applied to weather-sensitive observed loads that are developed as described in the following sub-section. NEM customer observed loads and level load impacts are used to avoid issues with percentage load impacts for these customers.

6.2 Per-Customer Reference Loads

Weather-sensitive reference loads for the average customer in each of the two climate zones are developed through a regression analysis of hourly load data for weekday non-event days in PY2024 for CPP and TOU customers. Customers are first sorted as weather sensitive or not.⁴⁰ Regression models are estimated separately for each hour of the day, by weather sensitivity, using daily observations for weekdays, and a regression equation 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 includes only the treatment customer loads during PY2024;
- Weather variables are included (e.g., Mean17, CDH, CDD, HDH and HDD);⁴¹ and
- Month specific variables are included in the models that are estimated by season to account for monthly differences in usage patterns.

The resulting equations are used to simulate “observed” loads under the two different weather scenarios. Simulated reference loads for the alternative scenarios are obtained by scaling up the simulated observed loads by the relevant estimated percentage TOU load impacts from the ex-post analysis.⁴² NEM customer observed loads and load impacts are estimated separately from non-NEM customers. For NEM customers, reference loads are calculated by adding the level load

⁴⁰ Customer-specific regressions are implemented to categorize customers as weather sensitive or not, by season. Weather sensitive customers have hourly loads that change 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:

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

where Q_t represents the average customer usage during event hours on day t . Event days are removed from the dataset. $MONTH_{i,t}$ represents each month. The variable of importance is $Weather_t$, which is defined as CDD65 for summer weather sensitivity or HDD65 for winter weather sensitivity. The regression is estimated for each customer and season specification. A customer is identified as weather sensitive if the weather coefficient ($b^{Weather}$) is positive and statistically significant.

⁴¹ 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: $CDH_{65} = \max(0, \text{temperature in } ^\circ\text{F} - \text{chosen temperature threshold})$. Likewise, heating degree hours (HDH) for each hour of the day are defined as: $HDH_{60} = \max(0, \text{chosen temperature threshold} - \text{temperature in } ^\circ\text{F})$. Cooling degree days (CDD) for each day are defined as $\max(0, (\text{maximum daily temperature} - \text{minimum daily temperature})/2 - \text{chosen temperature threshold})$. Likewise, heating degree days (HDD) for each day are defined as $\max(0, \text{chosen temperature threshold} - (\text{maximum daily temperature} - \text{minimum daily temperature})/2)$. Commonly used temperature thresholds for the calculation of CDH, CDD, HDH and HDD are 60, 65 and 70.

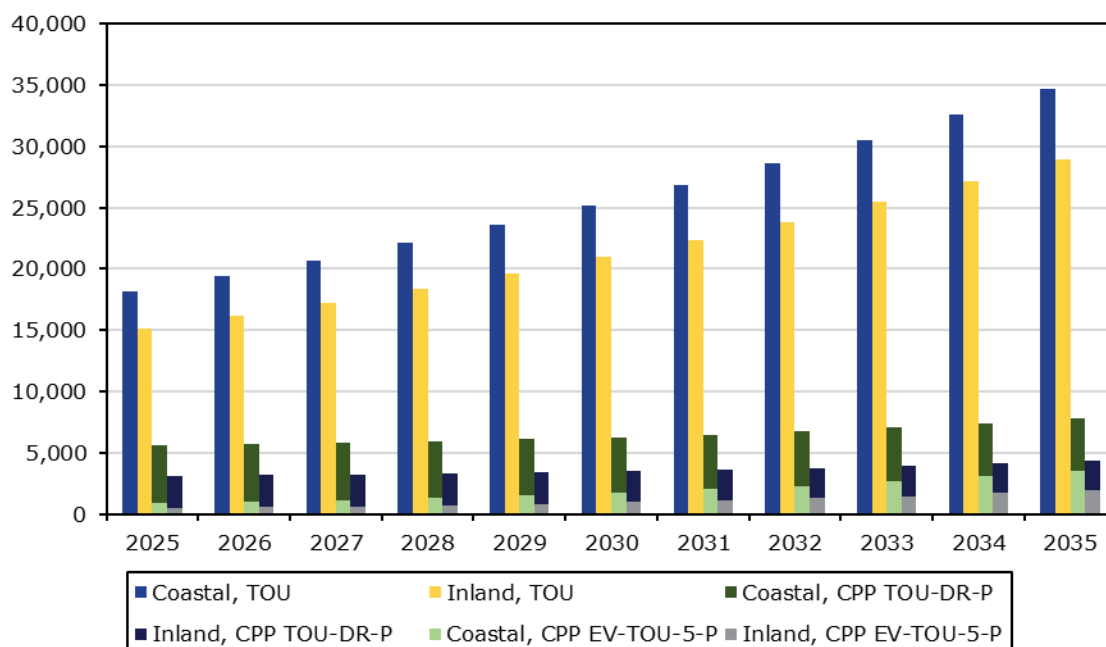
⁴² The adjustment takes the form of $\text{Reference} = \text{Observed} / (1 - \% \text{TOULoadImpact})$. Several alternative approaches were considered to develop the weather-sensitive reference load, including the same type of regression analysis using load data for the matched control group customers. The resulting reference loads were not sensitive to the data and approach used, although the selected approach produced more accurate loads during the swing months.

impacts from ex-post to the observed loads. The process for obtaining simulated reference and observed loads is completed separately for each reporting category.⁴³

6.3 Enrollment Forecast

Figure 6.1 shows SDG&E's enrollment forecasts for the TOU and CPP rates. Enrollment for TOU is anticipated to begin increasing after 2025. Enrollment is expected to be greater in the Coastal climate zone than in the Inland climate zone for both TOU and CPP customers, however the differences are more pronounced for CPP customers. This mirrors the fact that the rates have different enrollment ratios in the two climate zones. For CPP the EV-TOU-5 rate becomes a larger share of total enrollment year-to-year, starting at 15% of total CPP enrollment in 2025 and by 2035 it encompasses 45% of total enrollment.

Figure 6.1: Enrollments in TOU and CPP Rates



7. EX-ANTE LOAD IMPACT STUDY FINDINGS

This section presents the ex-ante CPP load impacts for rates EV-TOU-5 and TOU-DR-P and TOU load impacts for rates TOU-DR and TOU-DR-P.

⁴³ 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 non-NEM and NEM customers and TOU and CPP customers, separate panel regressions including only the customers in each group are estimated to simulate reference and observed loads for that group of customers.

7.1 Ex-Ante CPP Event Load Impacts

This subsection summarizes the ex-ante load impact forecasts for future CPP event days, for customers anticipated to be enrolled in CPP. Figure 7.1 illustrates the estimated aggregate reference loads, observed loads, and load impacts for an August system worst day in 2025 for the SDG&E 1-in-2 weather scenario. The average event-period load impact is 1.34 MWh/hour.

Figure 7.1: Aggregate Hourly Loads and CPP Load Impacts (MWh/hour) – (August 2025 SDG&E 1-in-2 System Worst Day)

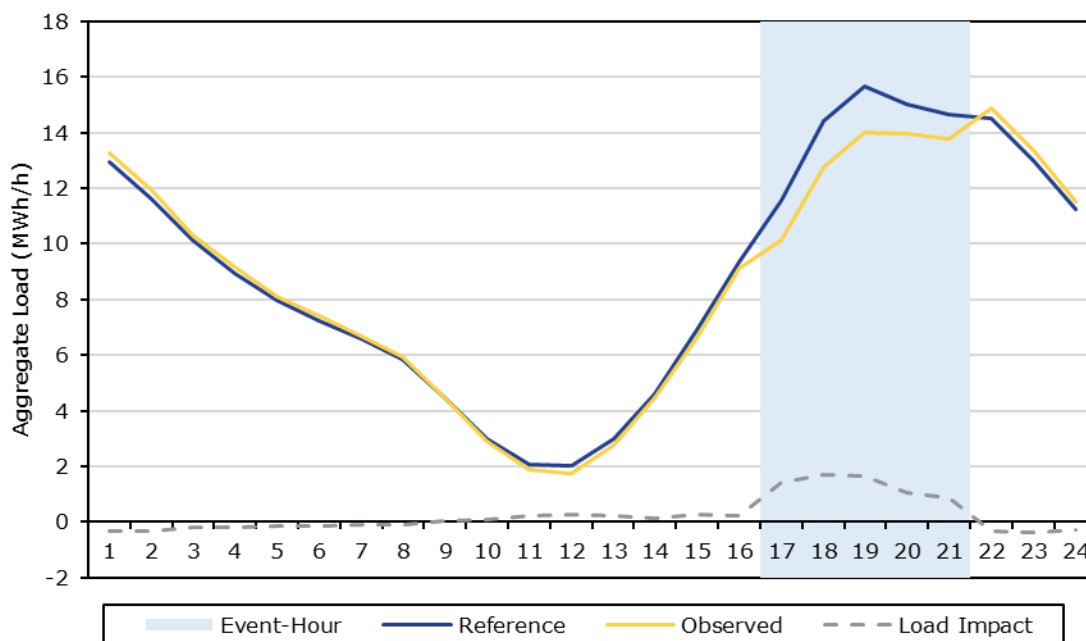


Figure 7.2 shows the monthly pattern of aggregate ex-ante load impacts for the average hour in the RA window (blue) and event window (gray) in 2024 for the SDG&E 1-in-2 system worst day. Table 7.1 provides more detailed information of aggregate and per-customer reference loads and load impacts over the RA window, as well as forecasted customer enrollment in each month. The RA window is 4 to 9 p.m. (HE 17-21) in all months except March, April, and May when it is 5 to 10 p.m. (HE 18-22). The event hours in all months are from 4 to 9 p.m. (HE 17-21). The lower RA window load impacts in March, April and May are driven by differences between the CPP event and RA window during these months as can be seen by contrasting RA window and event-hour aggregate load impacts in Figure 7.2. Per-customer load impacts are highest during summer months due to higher reference loads.

Figure 7.2: Aggregate CPP Load Impacts (MWh/hour), by Month – (2025 SDG&E 1-in-2 System Worst Day, RA Window and Event Hours)

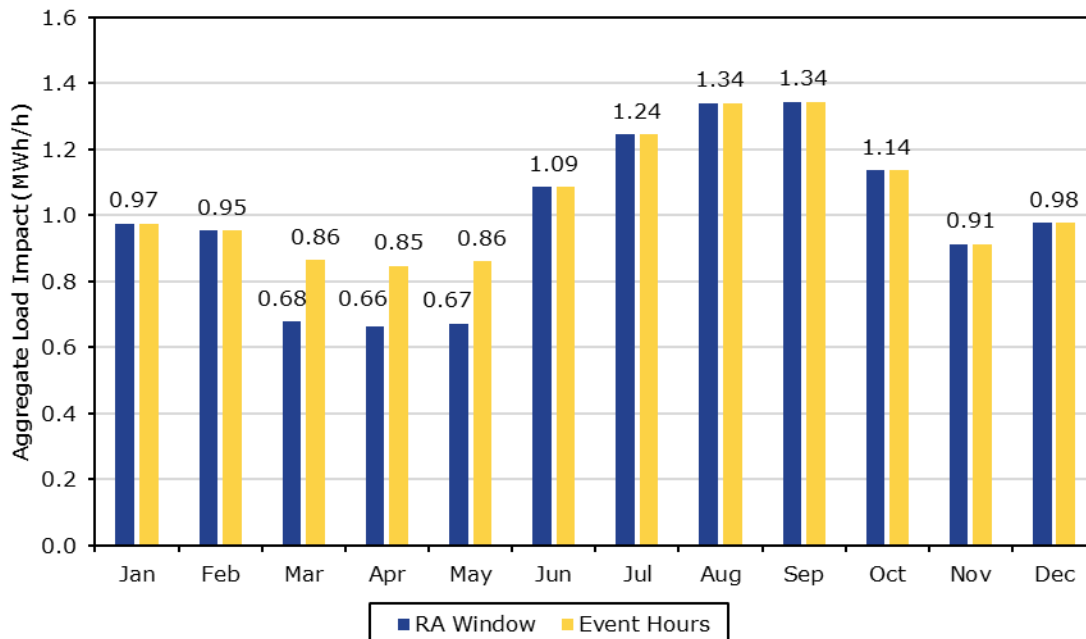
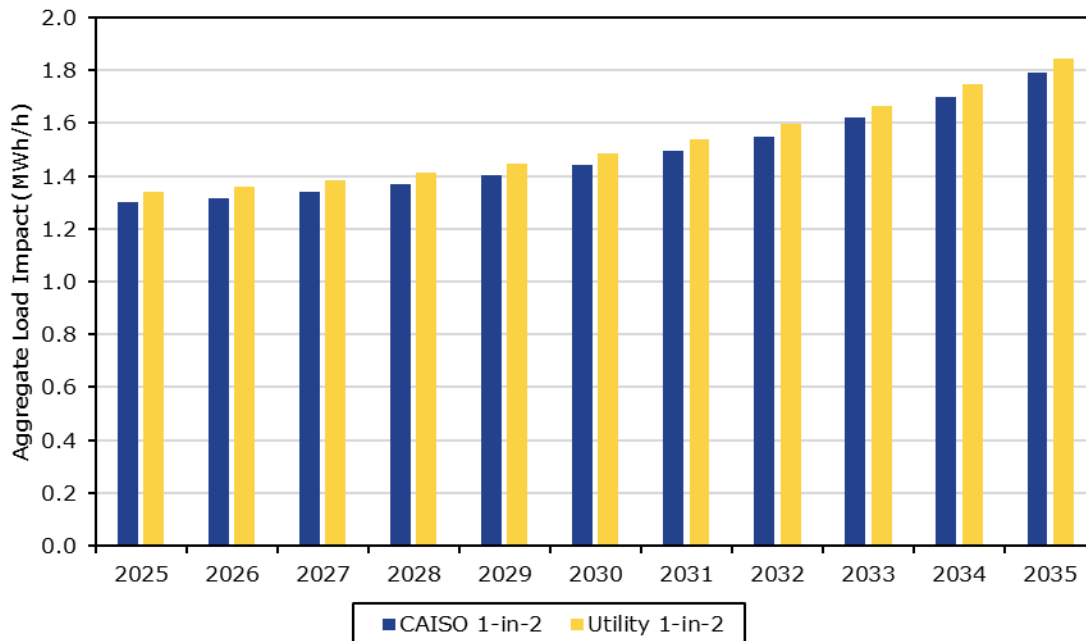


Table 7.1 Aggregate (MWh/hour) and Per-Customer (kWh/hour) CPP Load Impacts, by Month – (2025 SDG&E 1-in-2 Worst Day, RA Window)

Month	Enrolled	Aggregate		Per-Customer	
		Event Ref. Load (MWh/hr)	Event Load Impact (MWh/hr)	Event Ref. Load (kWh/hr)	Event Load Impact (kWh/hr)
January	8,752	8.64	0.97	0.99	0.11
February	8,752	8.06	0.95	0.92	0.11
March	8,752	6.35	0.68	0.73	0.08
April	8,752	5.62	0.66	0.64	0.08
May	8,752	5.93	0.67	0.68	0.08
June	8,752	8.72	1.09	1.00	0.12
July	8,752	12.16	1.24	1.39	0.14
August	8,752	14.25	1.34	1.63	0.15
September	8,752	14.88	1.34	1.70	0.15
October	8,752	11.20	1.14	1.28	0.13
November	8,752	7.47	0.91	0.85	0.10
December	8,752	9.00	0.98	1.03	0.11

Figure 7.3 illustrates the forecasted aggregate event load impacts for CPP by weather scenario. Load impacts increase over time as enrollments increase. 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-2 scenario corresponds with the largest load impacts.

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



7.2 Ex-Ante TOU Load Impacts

This subsection summarizes the ex-ante TOU peak load impact forecasts for customers anticipated to be enrolled in either the TOU (TOU-DR) or CPP (TOU-DR-P) rate. Figure 7.4 shows aggregate reference loads, observed loads, and load impacts for TOU and CPP customers, in 2025 for an SDG&E 1-in-2 average weekday in August. The average peak load impact is 3.15 MWh/hour.

Figure 7.4: Aggregate Hourly Loads and TOU Load Impacts (MWh/hour) – TOU and CPP Customers, (August 2025 SDG&E 1-in-2 Average Weekday)

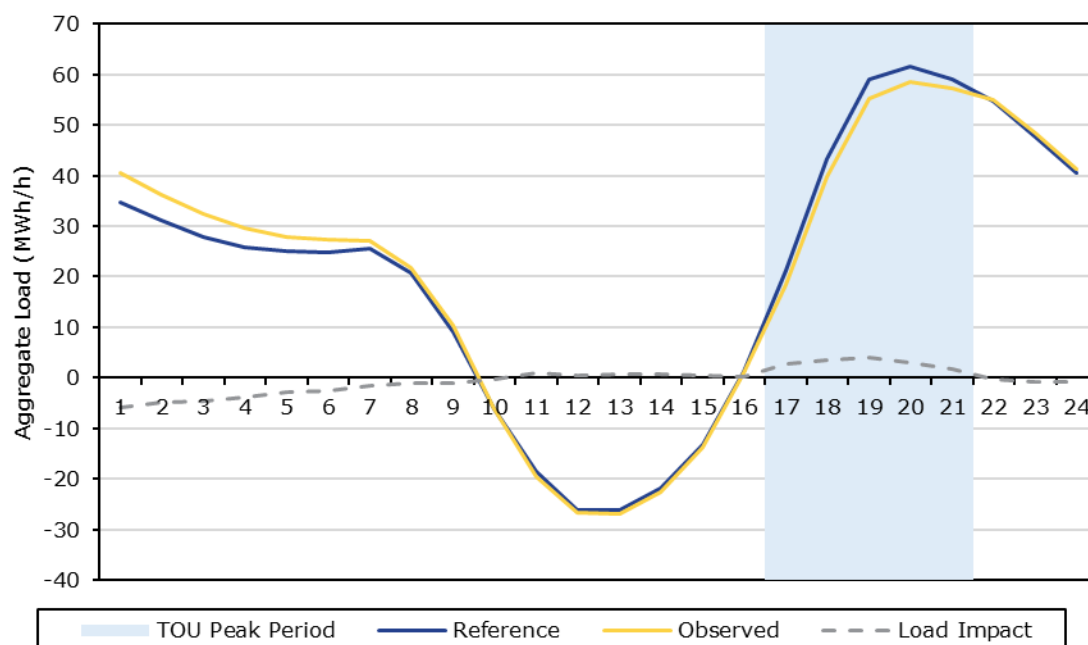


Figure 7.5 shows the seasonality of aggregate ex-ante TOU load impacts for TOU and CPP customers for the average hour in the RA window (blue) and the peak hours. Table 7.2 provides more detailed information of aggregate and per-customer reference loads and load impacts over the RA window, as well as customer forecasted enrollment in each month. The RA window is 4 to 9 p.m. (HE 17-21) in all months except March, April, and May, when it is 5 to 10 p.m. (HE 18-22). The peak period is 4 to 9 p.m. (HE 17-21) in all months. Aggregate and per-customer load impacts are the highest during summer months and the lowest in the shoulder months of May and November.⁴⁴ Load impacts are driven by seasonal differences in reference loads, with lower reference loads occurring during spring months.⁴⁵

⁴⁴ March and April are estimated separately because the midday off-peak hours differ from other months.

⁴⁵ The lowest aggregate and per-customer reference loads are in April, which is driven by PV generation by NEM customers.

Figure 7.5: Aggregate TOU Load Impacts (MWh/hour) by Month – TOU and CPP Customers, (2025 SDG&E 1-in-2 Average Weekday, RA Window and Peak Hours)

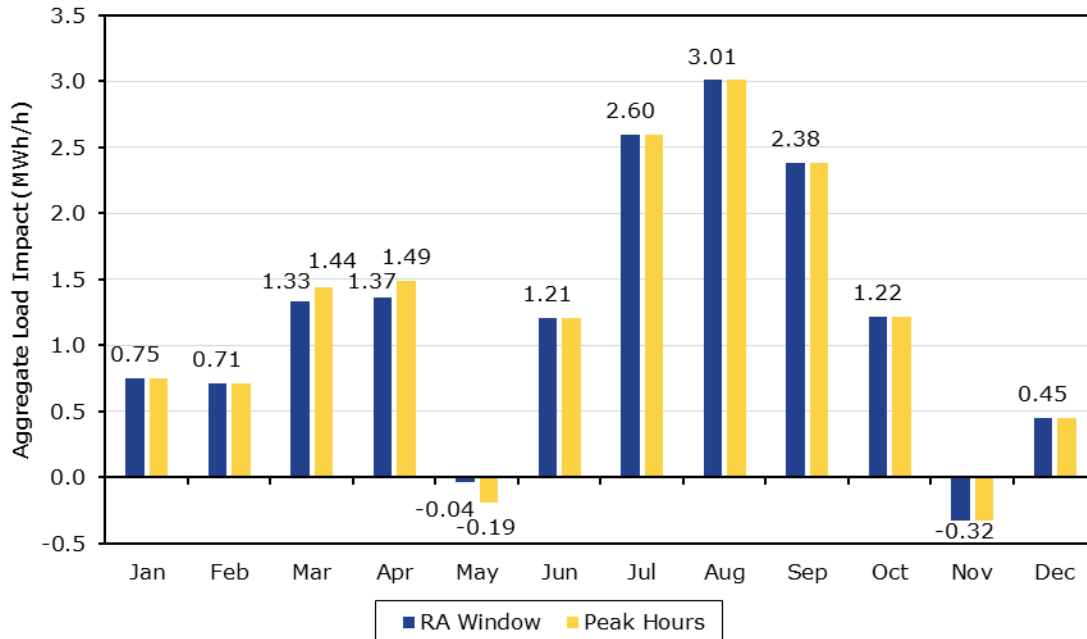
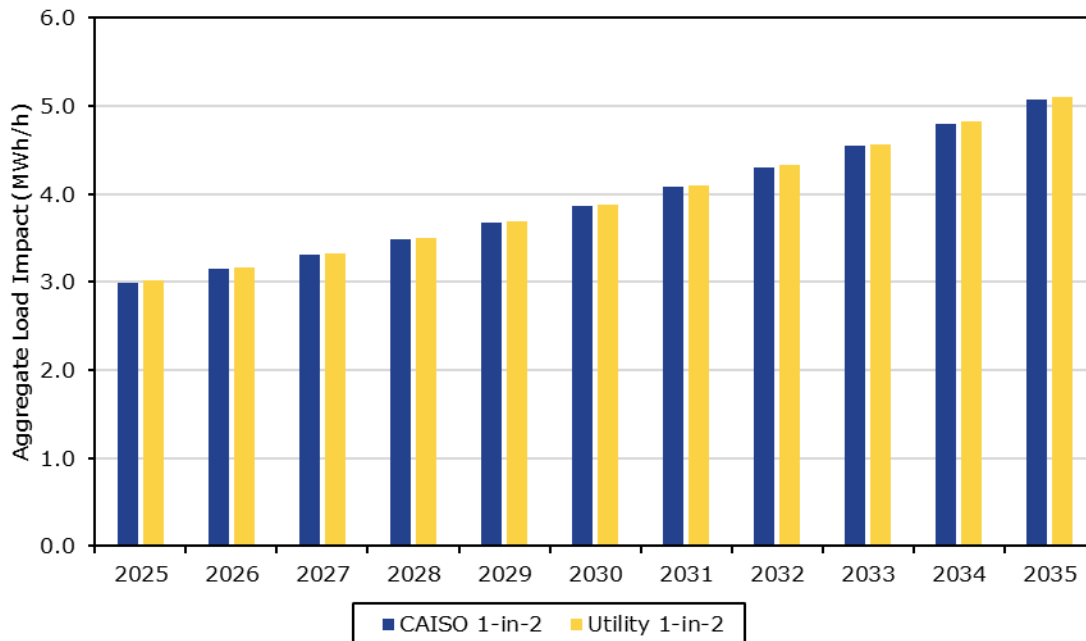


Table 7.2 Aggregate (MWh/hour) and Per-Customer (kWh/hour) TOU Load Impacts by Month - TOU and CPP Customers, (2025 SDG&E 1-in-2 Average Weekday, RA Window)

Month	Enrolled	Aggregate		Per-Customer	
		Peak Ref. Load (MWh/hr)	Peak Load Impact (MWh/hr)	Peak Ref. Load (kWh/hr)	Peak Load Impact (kWh/hr)
January	40,765	37.08	0.75	0.91	0.02
February	40,765	34.28	0.71	0.84	0.02
March	40,765	29.40	1.33	0.72	0.03
April	40,765	26.23	1.37	0.64	0.03
May	40,765	24.16	-0.04	0.59	0.00
June	40,765	22.17	1.21	0.54	0.03
July	40,765	41.19	2.60	1.01	0.06
August	40,765	48.79	3.01	1.20	0.07
September	40,765	43.35	2.38	1.06	0.06
October	40,765	33.66	1.22	0.83	0.03
November	40,765	34.17	-0.32	0.84	-0.01
December	40,765	40.08	0.45	0.98	0.01

Figure 7.6 shows the forecasted TOU aggregate load impacts for an August weekday over the forecast period by weather scenario. The load impact is largest for the Utility 1-in-2 scenario, which has equivalent temperatures for the average August weekday. TOU load impacts are largest for the Utility 1-in-2 scenarios on monthly system worst days.

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



8. COMPARISONS OF RESULTS

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

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

In the above list, “current study” refers to this report, which is based on findings from the 2024 program year; and “previous study” refers to the report that was developed following the 2023 program year. The comparison of results is provided for the CPP analysis as well as TOU analysis.

8.1 CPP Load Impacts

8.1.1 Previous Versus Current Ex-Post

Table 8.1 shows the average event-hour reference loads and CPP load impacts for the average weekday event during the current and previous program year.⁴⁶ The event hours were 4 to 9 p.m. in both program years. The aggregate enrollments are lower in 2024 than in 2023, which is primarily due to customers migrating to CCAs and consequently de-enrolling from CPP in 2024.

⁴⁶ The average weekday event in 2023 refers to the August 29th event since it was the only CPP event that year.

Even with fewer customers in 2024, aggregate reference loads and load impacts are higher than 2023. This is primarily because the current study includes EV-TOU-5-P customers whereas the previous study did not. EV-TOU-5-P customers have larger reference loads, on average (see Figure 4.4). The per-customer reference loads and load impacts are higher in 2024, as are event-hour temperatures. Percentage load impacts are similar between years (6.4% in 2023 and 8.3% in 2024).

Table 8.1: Previous vs. Current Ex-Post CPP Event Load Impacts

Result	Ex-Post 2023 Event Day PY2023 Study	Ex-Post 2024 Event Day PY2024 Study
# Enrolled	9,916	7,328
Reference (MWh/hour)	15.44	15.47
Load Impact (MWh/hour)	0.99	1.29
Per-customer Reference (kWh/hour)	1.56	2.11
Per-customer Load impact (kWh/hour)	0.10	0.18
Temperature	84.8	85.9
% NEM	30.9%	29.1%

8.1.2 Previous Versus Current Ex-Ante

In this sub-section, the ex-ante forecast prepared in PY2023 is compared to the ex-ante forecast contained in this study. Table 8.2 reports the average event-hour load impacts for the August 2025 system worst day under SGD&E 1-in-2 weather conditions. The per customer reference loads and load impacts are higher in the current study because of the inclusion of EV-TOU-5-P customers. Aggregate reference loads and load impacts are larger in the PY2024 ex-ante analysis due to an updated enrollment forecast that predicts increased enrollments in 2025 compared to the previous forecast which had a decreasing enrollment forecast.⁴⁷

⁴⁷ This year's enrollment forecast includes EVTOU-5-P CPP customers, which are the main driver of CPP enrollment increase.

Table 8.2: Previous vs. Current Ex-Ante CPP Event Load Impacts

Result	Ex-Ante 2025 System Worst Day PY2023 Study	Ex-Ante 2025 System Worst Day PY2024 Study
# Enrolled	5,233	8,752
Reference (MWh/hour)	6.75	14.25
Load Impact (MWh/hour)	0.49	1.34
Per-customer Reference (kWh/hour)	1.29	1.63
Per-customer Load Impact (kWh/hour)	0.09	0.15
Temperature	83.8	84.1
% NEM	30.9%	29.3%

8.1.3 Previous Ex-ante Versus Current Ex-Post

Table 8.3 provides a comparison of the ex-ante forecast of 2024 load impacts prepared in PY2023 and the PY2024 ex-post load impacts estimated as part of this study, averaged over the CPP event-window. The ex-ante forecast shown in the table represents the August system worst day during an SDG&E 1-in-2 weather year. The increase in aggregate reference loads is due to higher enrollments compared to the forecast, per-customer reference loads, and higher observed temperatures than the 1-in-2 weather year. The current study includes EV-TOU-5 customers, which contributes to higher per-customer reference loads. The per-customer load impact is 0.18 kWh/hour higher in ex-post than ex-ante, which drives the increase in aggregate load impacts.

Table 8.3: Previous Ex-Ante vs. Current Ex-Post CPP Event Load Impacts

Result	Ex-Ante 2024 System Worst Day PY2023 Study	Ex-Post 2024 Event Day PY2024 Study
# Enrolled	6,061	7,328
Reference (MWh/hour)	7.80	15.47
Load Impact (MWh/hour)	0.57	1.29
Per-customer Reference (kWh/hour)	1.29	2.11
Per-customer Load Impact (kWh/hour)	0.09	0.18
Temperature	83.8	85.9
% NEM	30.9%	29.1%

8.1.4 Current Ex-Post Versus Current Ex-Ante

Table 8.4 compares the CPP ex-post load impacts for the average weekday event against the ex-ante load impacts for 2025 for the SDG&E 1-in-2 August system worst day from this study. The

current ex-ante study forecasts higher enrollments, resulting in higher aggregate reference loads. Per-customer reference loads and load impacts are lower in ex-ante.

Table 8.4: Current Ex-Post vs. Current Ex-Ante CPP Event Load Impacts

Result	Ex-Post 2024 Event Day PY2024 Study	Ex-Ante 2025 System Worst Day PY2024 Study
# Enrolled	7,328	8,752
Reference (MWh/hour)	15.47	14.25
Load Impact (MWh/hour)	1.29	1.34
Per-customer Reference (kWh/hour)	2.11	1.63
Per-customer Load Impact (kWh/hour)	0.18	0.15
Temperature	85.9	84.1
% NEM	29.1%	29.3%

Table 8.5 compares the key components of the two analyses. As the table describes, the main source of difference between the analyses is the enrollment count differences between ex-post and ex-ante.

Table 8.5: Comparison of Ex-Post and Ex-Ante Factors, CPP Event

Factor	Ex-Post	Ex-Ante	Expected Impact
Weather	85.9 degrees Fahrenheit during HE 17-21.	84.1 degrees Fahrenheit during HE 17-21 of an SDG&E 1-in-2 August system worst day.	Decrease in load impacts.
Enrollment	7,327 customers enrolled.	8,752 customers.	The increase in ex-ante enrollments increase the aggregate load impact proportionately relative to ex-post.
Methodology	Climate zone-specific regressions using a matched control group and difference-in-differences analysis on event and event-like non-event days.	Treatment only customer regressions to estimate observed loads using PY2024 data.	No effect on percentage load impacts. The ex-post percentage load impacts are applied to reference loads of the various scenarios in the ex-ante study.

8.2 TOU Load Impacts

This section compares TOU load impacts over the RA window. All comparisons include both TOU and CPP customers.

8.2.1 Previous Versus Current Ex-Post

Table 8.6 shows the 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 increased in winter but were lower in during summer. Per-customer load impacts decreased during both seasons, which drives the decrease in aggregate load impacts. The 2024 summer per-customer load impact of 0.07 kWh/hour and the winter per-customer load impact of 0.02 kWh/hour are approximately half the 2023 per-customer load impacts in summer and winter, respectively. Per-customer reference loads increase during summer and decrease in the winter period, which leads to decreased aggregate reference loads during winter and increased aggregate reference loads during summer.

Table 8.6: Previous vs. Current Ex-Post TOU Load Impacts, TOU and CPP Customers

Season	Result	Ex-Post 2023 Avg. Weekday PY2023 Study	Ex-Post 2024 Avg. Weekday PY2024 Study
Summer (August)	# Enrolled	40,197	38,653
	Reference (MWh/hour)	41.81	45.21
	Load Impact (MWh/hour)	5.24	2.84
	Per-customer Reference (kWh/hour)	1.04	1.17
	Per-customer Load Impact (kWh/hour)	0.13	0.07
	Temperature	75.3	75.8
	% NEM	43.4%	45.5%
Winter (January)	# Enrolled	40,947	39,656
	Reference (MWh/hour)	40.15	36.82
	Load Impact (MWh/hour)	2.36	0.85
	Per-customer reference (kWh/hour)	0.98	0.93
	Per-customer load impact (kWh/hour)	0.06	0.02
	Temperature	55.3	56.9
	% NEM	39.3%	45.1%

8.2.2 Previous Versus Current Ex-Ante

Table 8.7 reports the average RA-window load impacts for the August and January 2025 average weekday under SDG&E 1-in-2 weather conditions. The TOU RA window and peak-period remains the same in both forecasts. The current study has a higher forecast enrollment in the summer and winter periods. The per-customer load impacts are lower in both the summer and winter months in the current forecast, with a corresponding decrease in aggregate load impacts even though the current forecast has higher enrollments.

Table 8.7: Previous vs. Current Ex-Ante TOU Load Impacts, TOU and CPP Customers

Season	Result	Ex-Ante 2025 Avg. Weekday PY2023 Study	Ex-Ante 2025 Avg. Weekday PY2024 Study
Summer (August)	# Enrolled	27,703	40,765
	Reference (MWh/hour)	29.95	48.79
	Load Impact (MWh/hour)	3.71	3.01
	Per-customer reference (kWh/hour)	1.08	1.20
	Per-customer load impact (kWh/hour)	0.13	0.07
	Temperature	76.5	76.7
	% NEM	44.9%	46.1%
Winter (January)	# Enrolled	27,703	40,765
	Reference (MWh/hour)	26.83	37.08
	Load Impact (MWh/hour)	1.86	0.75
	Per-customer reference (kWh/hour)	0.97	0.91
	Per-customer load impact (kWh/hour)	0.07	0.02
	Temperature	60.8	60.6
	% NEM	44.9%	46.1%

8.2.3 Previous Ex-Ante Versus Current Ex-Post

Table 8.8 provides a comparison of the ex-ante forecast of 2024 TOU load impacts prepared in the previous study and the PY2024 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 an SDG&E 1-in-2 weather year. The ex-post load impacts are based on the average weekday in August and January. Increased enrollments lead to larger aggregate reference loads in the summer and winter months. The difference in ex-ante results shown here corresponds to the differences in ex-post results seen in Table 8.6, with the exception of enrollments. The per-customer load impacts are notably lower than the predicted ex-ante load-impacts. The ex-post per-customer reference loads are higher than forecasted in summer and lower than forecasted in winter.

Table 8.8: Previous Ex-Ante vs. Current Ex-Post TOU Load Impacts, TOU and CPP Customersf

Season	Result	Ex-Ante 2024 Avg. Weekday PY2023 Study	Ex-Post 2024 Avg. Weekday PY2024 Study
Summer (August)	# Enrolled	31,728	38,653
	Reference (MWh/hour)	34.29	45.21
	Load Impact (MWh/hour)	4.24	2.84
	Per-customer reference (kWh/hour)	1.08	1.17
	Per-customer load impact (kWh/hour)	0.13	0.07
	Temperature	76.5	75.8
	% NEM	44.9%	45.5%
Winter (January)	# Enrolled	35,241	39,656
	Reference (MWh/hour)	33.97	36.82
	Load Impact (MWh/hour)	2.26	0.85
	Per-customer reference (kWh/hour)	0.96	0.93
	Per-customer load impact (kWh/hour)	0.06	0.02
	Temperature	60.8	56.9
	% NEM	43.9%	45.1%

8.2.4 Current Ex-Post Versus Current Ex-Ante

Table 8.9 compares the PY2024 ex-post TOU load impacts for the average weekday in August and January with the corresponding ex-ante forecast for 2025 (of the SDG&E 1-in-2 average weekday weather scenario) 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 for these months. The per-customer reference loads and load-impacts are similar between the two scenarios, with the slight differences explained by temperature differences between the ex-post weather conditions and the ex-ante weather scenarios, as well the proportion of NEM enrollments. Higher enrollments in 2025 compared to 2024 drive higher aggregate reference loads and load impacts.

Table 8.9: Current Ex-Post vs. Current Ex-Ante TOU Load Impacts, TOU and CPP Customers

Season	Result	Ex-Post 2024 Avg. Weekday PY2024 Study	Ex-Ante 2025 Avg. Weekday PY2024 Study
Summer (August)	# Enrolled	38,653	40,765
	Reference (MWh/hour)	45.21	48.79
	Load Impact (MWh/hour)	2.84	3.01
	Per-customer reference (kWh/hour)	1.17	1.20
	Per-customer load impact (kWh/hour)	0.07	0.07
	% Load Impact	6.3%	6.2%
	Temperature	75.8	76.7
	% NEM	45.5%	46.1%
Winter (January)	# Enrolled	39,656	40,765
	Reference (MWh/hour)	36.82	37.08
	Load Impact (MWh/hour)	0.85	0.75
	Per-customer reference (kWh/hour)	0.93	0.91
	Per-customer load impact (kWh/hour)	0.02	0.02
	% Load Impact	2.3%	2.0%
	Temperature	56.9	60.62
	% NEM	45.1%	46.1%

9. RECOMMENDATIONS

All three CPP events called in 2024 were September weekday events. We suggest calling more events during other months and weekends to provide more information regarding the responsiveness of the program under different event conditions, such as different temperatures, months, and days of week.

As adoption of EVs continues to increase over time, we recommend that SDG&E proceed to promote the TOU and CPP rates to customers with EVs. The current TOU load impacts illustrate increased usage in overnight hours, which aligns with EV charging, suggesting that more TOU customers have an EV (even if they are not signed up on an EV-specific TOU rate). The shift in usage to the overnight hours demonstrates of the effectiveness of TOU for EV customers. For the CPP rate, EV-TOU-5, increased enrollment will lead to more accurate estimates of CPP load impacts for this subset of customers that have higher reference loads, on average.

10. 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. We address this potential bias this by 1) including only NEM customers that are NEM for the entire analysis period, 2) including only customers whose PV system did not change size for the analysis period, 3) including solar size PV as an additional characteristic in the matching process for NEM customers, and 4) removing customers that have large changes in usage between the pre- and post-period.

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). For each customer, we calculate the average usage differences between the pre-treatment period and the treatment period. Customers with usage differences below the chosen threshold are kept in the analysis. The raw difference-in-difference assessment covers the mid-day period, HE 11–15, and the TOU peak/event period, HE 17–21. Customers who were part of a treatment-control pair with a difference-in-difference in either period that was larger than 1.5 kWh/hour were excluded from the regression sample.