



# **2025 Load Impact Evaluation of Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates for San Diego Gas & Electric**

## **CALMAC Study ID SDG0373**

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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 2025 ("PY2025"). 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.<sup>1</sup> 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 November through May, when the RA window is 5 to 10 p.m. In PY2025, SDG&E didn't call a CPP event and therefore ex-post CPP impacts are not estimated in this report. For ex-ante, we use PY2024 CPP impacts which are based on events called on September 5<sup>th</sup>, 6<sup>th</sup>, and 9<sup>th</sup>, 2024.

The ex-post load impact evaluations for the TOU analysis apply difference-in-differences analysis methods that compare hourly usage of treatment customers and a quasi-experimental matched controls. 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.

TOU customer<sup>2</sup> enrollment decreased from 31,291 to 30,312 customers between October 2024 and September 2025. Per-customer peak-period load impacts were 0.02 kWh/hour in summer and 0.01 kWh/hour in winter. Overall, TOU customers increased their energy consumption by an annual average of 0.64 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,<sup>3</sup> declined slightly from 7,200 to 7,123 customers between October 2024 and September 2025. The estimated TOU load impacts for CPP-enrolled customers (excluding EV-TOU-5-P) suggests peak period usage is reduced by 0.01 kWh/hour during the summer months and 0.01 kWh/hour during the winter months. The overall daily effect from TOU for CPP customers was an average annual increase of 0.21 kWh/customer/day.

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<sup>1</sup> 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.

<sup>2</sup> 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.

<sup>3</sup> EV-TOU-5-P customers are not included in the TOU analysis.

## **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 2025 ("PY2025"). 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 November through May, when the RA window is 5 to 10 p.m. In PY2025, SDG&E didn't call a CPP event and therefore CPP ex-post impacts are not estimated in this report. For ex-ante, we use PY2024 CPP impacts which are based on events called on September 5<sup>th</sup>, 6<sup>th</sup>, and 9<sup>th</sup>, 2024.

### **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 period and adjusts for usage differences on pre-treatment 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. The analysis is supplemented with a structural break methodology designed to identify and exclude customers who experienced large shifts in their usage during the two-year analysis period (e.g., acquisition and charging of EV), as such changes in usage coincident with transitioning to a TOU rate may incorrectly be attributed to a TOU effect. This approach is applied to both treatment and control customers prior to the matching process.

Since the analysis relies on a small and variable sample of incremental customers and these results are extrapolated to the entire population of TOU customers, we calculate rolling three-year average load impacts (the current program year plus the prior two years) using inverse-variance weighting, which assigns higher weight to more precise estimates. Moving to a three-year average, rather than relying solely on the current program year for the TOU estimate, helps mitigate volatility driven by limited sample sizes and year-specific conditions (e.g., weather variation). This approach produces more stable and representative results that better reflect population-level impacts.

## ES.3 Ex-Post Load Impacts

### ES.3.1 Ex-Post TOU Load Impacts – TOU Customers (TOU-DR)

Table ES.1 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 2024). The winter months are indicated by light blue shading. TOU enrollments decreased throughout the analysis period, with the numbers of enrolled customers decreasing from 31,291 in October 2024 to 30,312 in September 2025.<sup>4</sup> The per-customer load impacts are higher during the summer months at approximately 0.02 kWh/hour compared to 0.01 kWh/hour during winter months. The lowest load impacts occur during November and May when peak usage sees relatively no increase or decrease in kWh/customer/hour. An asterisk next to a load impact indicates that the result is statistically significant at the 10 percent level. All months except October, November, April, and May are statistically significant at the 10 percent level.

**Table ES.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-2024 | All          | 31,291   | 24.90                   | 0.26                      | 0.80                    | 0.01                      | 65              |
| Nov-2024 | All          | 31,139   | 26.76                   | 0.09                      | 0.86                    | 0.00                      | 58              |
| Dec-2024 | All          | 31,031   | 31.18                   | 0.38*                     | 1.00                    | 0.01*                     | 55              |
| Jan-2025 | All          | 31,111   | 29.06                   | 0.46*                     | 0.93                    | 0.01*                     | 55              |
| Feb-2025 | All          | 31,059   | 25.47                   | 0.37*                     | 0.82                    | 0.01*                     | 57              |
| Mar-2025 | All          | 31,060   | 19.47                   | 0.36*                     | 0.63                    | 0.01*                     | 56              |
| Apr-2025 | All          | 31,009   | 10.89                   | 0.26                      | 0.35                    | 0.01                      | 59              |
| May-2025 | All          | 31,008   | 12.61                   | -0.06                     | 0.41                    | 0.00                      | 63              |
| Jun-2025 | All          | 30,912   | 15.26                   | 0.42*                     | 0.49                    | 0.01*                     | 66              |
| Jul-2025 | All          | 30,732   | 19.31                   | 0.81*                     | 0.63                    | 0.03*                     | 68              |
| Aug-2025 | All          | 30,503   | 29.81                   | 1.12*                     | 0.98                    | 0.04*                     | 71              |
| Sep-2025 | All          | 30,312   | 31.50                   | 1.34*                     | 1.04                    | 0.04*                     | 71              |

Table ES.2 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

<sup>4</sup> The enrollment numbers in the tables differ from the number of customers used in the regression models, which is a subset of customers that have all the required data for conducting the ex-post load impact analysis. Specifically, there were 254 incremental customers who switched to the TOU-DR rate with quality load data sufficient for estimating the TOU load impacts. This includes both non-NEM and NEM customers as they are analyzed together. The aggregate TOU load impacts are then scaled to total enrollments.



reference loads during both periods. While customers in both climate zones decrease loads by 0.02 kWh/customer/hour on average during the peak period in summer months, Inland customers have a slightly higher load impact of 0.03 kWh/customer/hour. Inland customers also have a higher load impact than Coastal customers during winter months. The summer results are statistically significant at the 10 percent level.

**Table ES.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      | 16,268             | 10.38                   | 0.29*                     | 0.64                    | 0.02*                     | 67              |
|        | Inland       | 14,482             | 13.65                   | 0.38*                     | 0.94                    | 0.03*                     | 70              |
|        | <b>All</b>   | <b>30,750</b>      | <b>24.03</b>            | <b>0.67*</b>              | <b>0.78</b>             | <b>0.02*</b>              | <b>68</b>       |
| Winter | Coastal      | 16,559             | 11.06                   | 0.07                      | 0.67                    | 0.00                      | 57              |
|        | Inland       | 14,501             | 11.07                   | 0.11                      | 0.76                    | 0.01                      | 59              |
|        | <b>All</b>   | <b>31,060</b>      | <b>22.13</b>            | <b>0.19</b>               | <b>0.71</b>             | <b>0.01</b>               | <b>58</b>       |

Overall, TOU customers increased their energy consumption by an annual average of approximately 0.64 kWh/customer/day, representing a 10% increase. This is based on combining the TOU results across months and considering the effect of TOU on average *daily* usage.

### *ES.3.2 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.3 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 7,200 in October 2024 to approximately 7,123 in September 2025.<sup>5</sup> Peak load impacts were estimated at 0.01 kWh/hour across all summer months and 0.01 kWh/hour across all 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, November, or March through June.

<sup>5</sup> There were 248 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, this number includes both non-NEM and NEM customers.

**Table ES.3: 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-2024 | All          | 7,200    | 5.83                    | -0.07                     | 0.81                    | -0.01                     | 67              |
| Nov-2024 | All          | 7,165    | 5.82                    | 0.04                      | 0.81                    | 0.01                      | 60              |
| Dec-2024 | All          | 7,122    | 6.79                    | 0.07*                     | 0.95                    | 0.01*                     | 57              |
| Jan-2025 | All          | 7,112    | 6.18                    | 0.11*                     | 0.87                    | 0.01*                     | 58              |
| Feb-2025 | All          | 7,189    | 5.62                    | 0.08*                     | 0.78                    | 0.01*                     | 59              |
| Mar-2025 | All          | 7,173    | 4.83                    | 0.05                      | 0.67                    | 0.01                      | 58              |
| Apr-2025 | All          | 7,153    | 3.77                    | 0.02                      | 0.53                    | 0.00                      | 61              |
| May-2025 | All          | 7,156    | 4.29                    | 0.02                      | 0.60                    | 0.00                      | 66              |
| Jun-2025 | All          | 7,150    | 4.92                    | -0.03                     | 0.69                    | 0.00                      | 68              |
| Jul-2025 | All          | 7,133    | 6.06                    | 0.11*                     | 0.85                    | 0.02*                     | 71              |
| Aug-2025 | All          | 7,125    | 8.17                    | 0.22*                     | 1.15                    | 0.03*                     | 74              |
| Sep-2025 | All          | 7,123    | 8.14                    | 0.20*                     | 1.14                    | 0.03*                     | 73              |

On average, CPP customers increased their load by 0.21 kWh/customer/day over the course of the study period, representing a 2% daily increase. CPP customer usage is, on average, about twice that of TOU customers, meaning the 0.21 kWh increase represents an even smaller share of their overall daily usage than the 0.64 kWh/customer/day increase for TOU customers.

Table ES.4 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 customers decreased loads during the peak period by 0.01 kWh/customer/hour on average during summer and 0.01 kWh/customer/hour during the winter. The Inland climate zone has a decrease in average peak-hour loads of 0.01 kWh/hour in the summer and no decrease in the winter compared to 0.01 kWh/hour in the Coastal climate zone during both summer and during winter. These results are not statistically significant.

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

| Season | Climate Zone | Enrolled (Average) | Aggregate               |                           | Per-Customer            |                           | 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      | 4,457              | 3.85                    | 0.05                      | 0.86                    | 0.01                      | 70              |
|        | Inland       | 2,690              | 2.77                    | 0.04                      | 1.03                    | 0.01                      | 72              |
|        | <b>All</b>   | <b>7,146</b>       | <b>6.62</b>             | <b>0.09</b>               | <b>0.93</b>             | <b>0.01</b>               | <b>71</b>       |
| Winter | Coastal      | 4,476              | 3.36                    | 0.03                      | 0.75                    | 0.01                      | 60              |
|        | Inland       | 2,676              | 1.95                    | 0.01                      | 0.73                    | 0.00                      | 60              |
|        | <b>All</b>   | <b>7,153</b>       | <b>5.31</b>             | <b>0.04</b>               | <b>0.74</b>             | <b>0.01</b>               | <b>60</b>       |

### ES.3 Ex-Ante Load Impacts

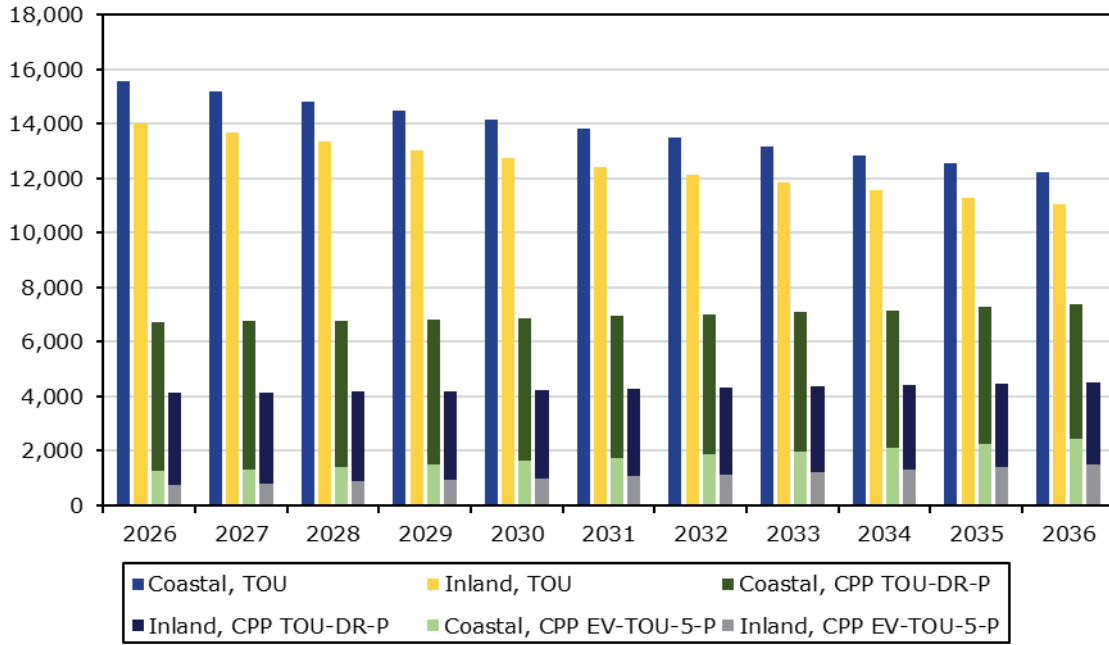
Due to no events being called in PY2025, the ex-ante analysis for CPP events applies the PY2024 ex-post CPP event load impacts to reference loads calculated using PY2025 customer load data. CPP event load impacts for different weather scenarios are developed by applying the estimated load impact from the ex-post analysis to weather-sensitive reference loads. The reference loads are estimated by obtaining weather-specific coefficients using regression models, similar to those used in the ex-post analysis, and subsequently applying those coefficients to two distinct weather scenarios. Since June 1, 2022, the CPP event window coincides with the June through October RA window (4 to 9 p.m.).

For TOU load impacts, including the TOU rate itself and the TOU portion of the CPP rate, hourly percentage load impacts derived from the three-year averaged ex-post analysis are applied to weather-sensitive reference loads 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.3.1 Enrollment Forecast

Figure ES.1 shows SDG&E's enrollment forecasts for the TOU and CPP rates, separated by climate zone. Enrollment for TOU is anticipated to decrease each year while CPP rates expect enrollment growth, mostly attributed to EV-TOU-5 rate growth. 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. For CPP, the EV-TOU-5 rate becomes a larger share of total enrollment year-to-year, starting at 17% of total CPP enrollment in 2026 and by 2036 it encompasses 33% of total CPP enrollment.

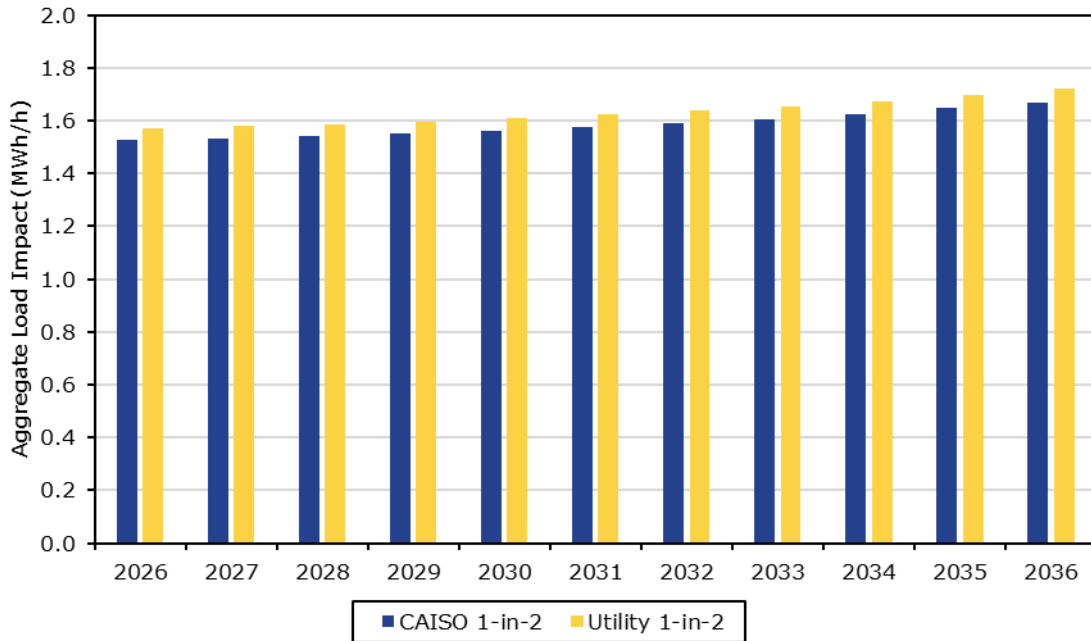
**Figure ES.1: Enrollments in TOU and CPP Rates**



### *ES.3.2 Ex-Ante CPP Event Load Impacts*

Figure ES.2 illustrates the 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 1.57 MWh/hour in 2026 to 1.72 MWh/hour in 2036.

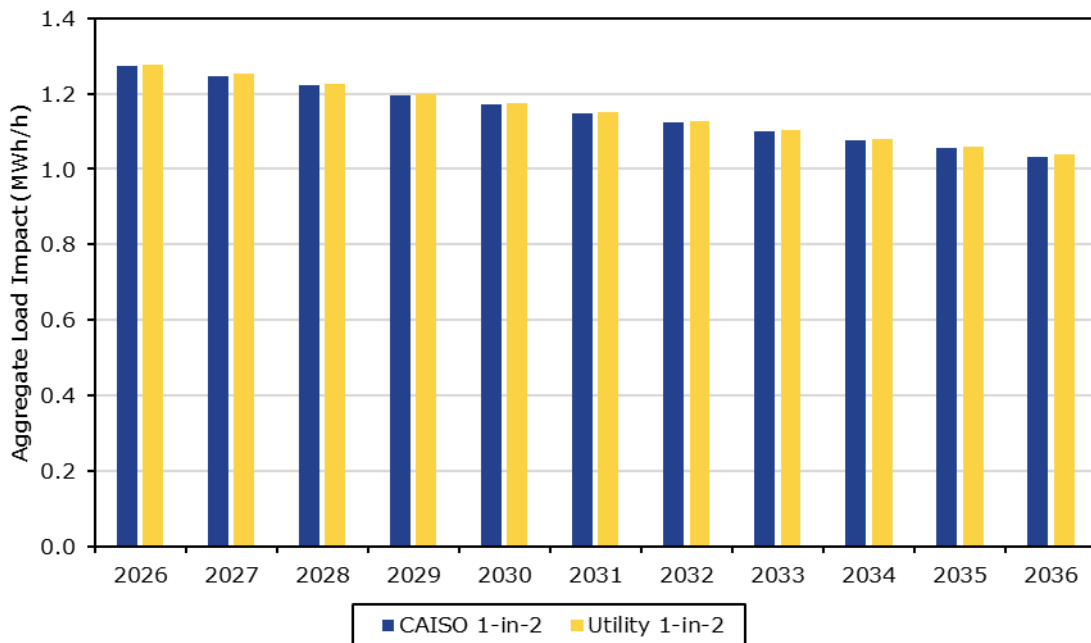
**Figure ES.2: Aggregate CPP Load Impacts (MWh/hour), by Year and Weather Scenario (August System Worst Day, RA Window)**



### *ES.3.3 Ex-Ante TOU Load Impacts*

Aggregate TOU load impacts, including the TOU rate itself and the TOU portion of the CPP rate, during the average peak hour are forecast to decrease each year, commensurate with decreasing enrollments. Figure ES.3 shows differences in the aggregate peak TOU load impact forecasts for customers enrolled in TOU-DR and TOU-DR-P during 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 decrease from 1.28 MWh/hour in 2026 to 1.04 MWh/hour in 2036.

**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 program year 2025 ("PY2025"). 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.<sup>6</sup> No ex-post CPP analysis was conducted this program year as no CPP events were called during PY2025. 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 and TOU-DR-P, since the TOU-DR-P customers experience TOU rates on days that are not CPP event days, while CPP load impacts are estimated for TOU-DR-P and EV-TOU-5-P customers.<sup>7</sup> 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.

Throughout this report, all hours reported are in prevailing time.

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.<sup>8</sup> CCA customers cannot be enrolled in the CPP.<sup>9</sup> 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 46 percent for customers included in the TOU analysis (TOU-DR and TOU-DR-P) and 26 percent for customers included in the CPP analysis (TOU-DR-P and EV-TOU-5-P).

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<sup>6</sup> 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.

<sup>7</sup> TOU ex-post load impacts are estimated only for customers who enrolled in TOU-DR-P or TOU-DR rates during PY2025 (October 2024 to September 2025), 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.

<sup>8</sup> 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.

<sup>9</sup> 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.

**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-2024 | 15,666  | 15,625 | 31,291 | 5,218    | 1,982 | 7,200 | 728        | 239 | 967   |
| Nov-2024 | 15,579  | 15,560 | 31,139 | 5,244    | 1,921 | 7,165 | 759        | 271 | 1,030 |
| Dec-2024 | 15,486  | 15,545 | 31,031 | 5,238    | 1,884 | 7,122 | 810        | 299 | 1,109 |
| Jan-2025 | 15,457  | 15,654 | 31,111 | 5,253    | 1,859 | 7,112 | 864        | 333 | 1,197 |
| Feb-2025 | 15,471  | 15,588 | 31,059 | 5,355    | 1,834 | 7,189 | 923        | 364 | 1,287 |
| Mar-2025 | 15,460  | 15,600 | 31,060 | 5,357    | 1,816 | 7,173 | 967        | 405 | 1,372 |
| Apr-2025 | 15,451  | 15,558 | 31,009 | 5,368    | 1,785 | 7,153 | 1,009      | 431 | 1,440 |
| May-2025 | 15,481  | 15,527 | 31,008 | 5,374    | 1,782 | 7,156 | 1,054      | 450 | 1,504 |
| Jun-2025 | 15,454  | 15,458 | 30,912 | 5,370    | 1,780 | 7,150 | 1,108      | 468 | 1,576 |
| Jul-2025 | 15,321  | 15,411 | 30,732 | 5,348    | 1,785 | 7,133 | 1,153      | 483 | 1,636 |
| Aug-2025 | 15,130  | 15,373 | 30,503 | 5,339    | 1,786 | 7,125 | 1,215      | 501 | 1,716 |
| Sep-2025 | 14,981  | 15,331 | 30,312 | 5,337    | 1,786 | 7,123 | 1,276      | 517 | 1,793 |

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 TOU ex-post load impact results; Section 5 describes the methods used to develop the CPP and TOU ex-ante load impacts; Section 6 contains the TOU and CPP ex-ante load impact results; Section 7 provides a series of comparisons of ex-post and ex-ante results; Section 8 provides recommendations.

## 2. DESCRIPTION OF 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 June 1, 2025, for TOU-DR customers during summer months (June 1<sup>st</sup> through October 31<sup>st</sup>) are \$0.599, \$0.528, and \$0.450 per kWh for the on-peak, off-peak, and super-peak periods, respectively.<sup>10, 11</sup> Thus, the peak to super-off-peak price ratio

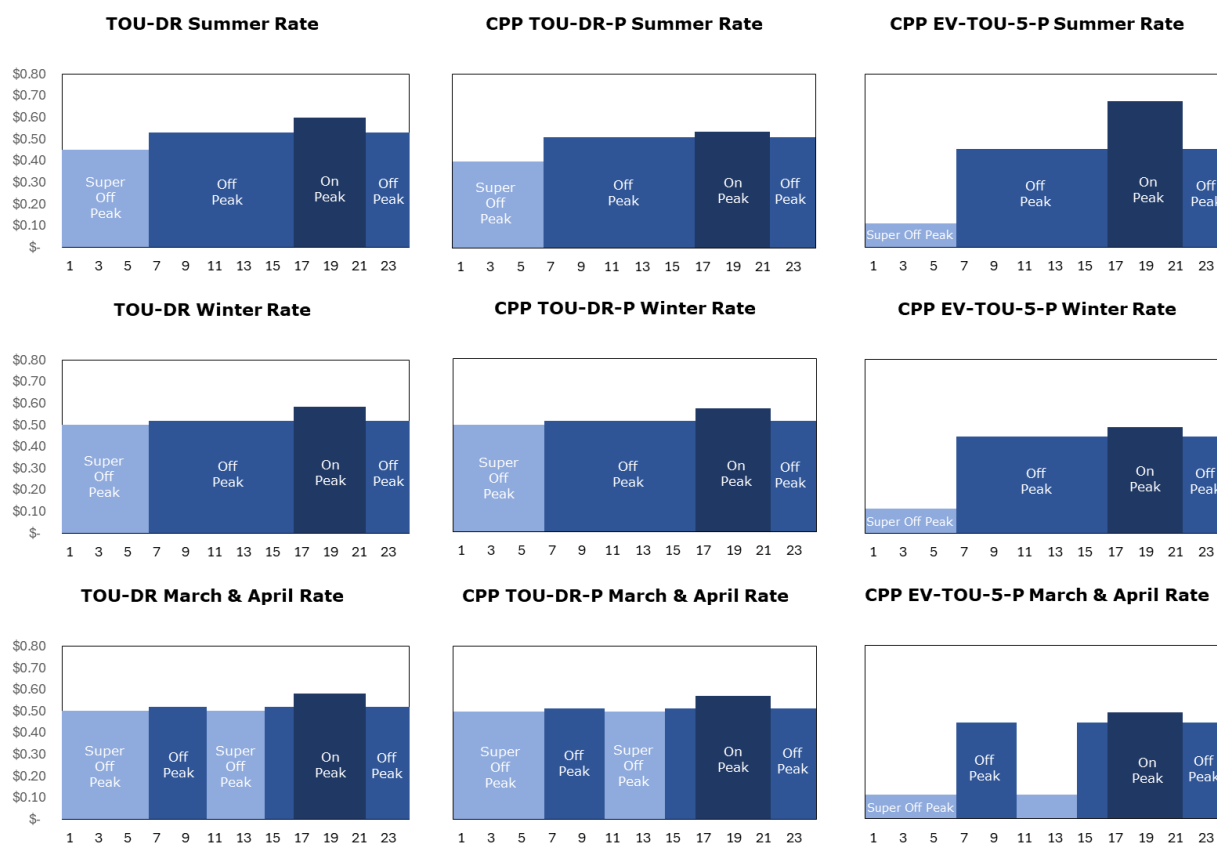
<sup>10</sup> See Schedule TOU-DR, TOU-DR-P, EV-TOU-5-P for current rates and Residential Time-of-Use periods at <https://www.sdge.com/total-electric-rates>.

<sup>11</sup> 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 21 percent of all customers included in the analysis, the rates shown in Figure 2.1 only reflect prices charged to Non-CARE customers.



is 1.33-to-1. Summer TOU charges for TOU-DR-P customers are somewhat lower, at \$0.535, \$0.510, and \$0.398 per kWh, implying a peak to super-off-peak price ratio of 1.34-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 4.26-to-1. For EV-TOU-5-P customers, the summer rates are \$0.672, \$0.453, and \$0.111 for the on-peak, off-peak, and super-peak periods, respectively, meaning the peak to super-off-peak price ratio is 6.05-to-1. With the CPP event-price adder of \$1.16 per kWh the peak to super-off-peak ratio increases to 16.50-to-1. Figure 2.1 illustrates the hourly TOU rates for each TOU period, rate, and season.<sup>12</sup> 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 Rate<sup>13</sup>**



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. CPP participants are eligible for bill protection for the first full season following their enrollment,

<sup>12</sup> 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.

<sup>13</sup> See Schedules TOU-DR, TOU-DR-P, and EV-TOU-5-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>.

which guarantees that their bill will be no larger than what it would have been under their otherwise applicable tariff. During PY2025, SDG&E called no CPP events.

### 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 2023 through September 2025;
- *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).<sup>14</sup>

#### 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. We use hourly load data for TOU and CPP enrollees and potential control group customers from the previous year (pre-enrollment year for new enrollees) to select matched control group customers for TOU and CPP enrollees based on average customer load profiles. For the TOU evaluation, which includes both TOU and CPP customers (excluding EV-TOU-5-P), we match on average load profiles during the pre-enrollment period.

The analysis is supplemented with a structural break methodology designed to identify and exclude customers who experienced large shifts in their usage during the two-year analysis period (e.g., acquisition and charging of EV). This exclusion is done because such changes in usage coincident with transitioning to a TOU rate may incorrectly be attributed to a TOU effect. Following matching and the elimination of customers with structural changes in their usage, fixed-effects panel regression models are estimated on treatment and matched control customers, which produce difference-in-differences estimates of average TOU period load impacts (for both TOU and for TOU-DR-P non-event days).

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<sup>14</sup> No CPP events were called during PY2025.

### 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 and adjusts for usage differences during the pre-treatment period. 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,<sup>15</sup> 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, as well as a random sample of customers on a DR rate. These are customers that were not on a TOU rate for the entire two-year period between October 2023 and September 2025.

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 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, and thus from the ex-post analysis entirely due to the absence of CPP events in PY2025. EV-TOU-5-P customers are still analyzed in the ex-ante evaluation.

For the TOU load impact analysis, which includes both TOU-DR and TOU-DR-P customers, only incremental treatment customers are included. Incremental customers are those who were on a non-TOU rate during PY2024 and switched to TOU-DR or TOU-DR-P at some point during PY2025. The matching is performed based on loads during the pre-treatment period (October 2023 through September 2024). To be included in the analysis, customers must have sufficient pre-treatment data history to provide a quality difference-in-difference analysis.<sup>16</sup> The matching is performed separately by season, thus allowing different threshold dates that define incremental customers. For the regression analysis, customers are pooled into a single annual model to maintain a consistent relationship between load impacts and weather throughout the year.

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 2023 through May 2024, while matching for the *summer* season used data for October 2023 and June through September 2024.

Matching is based on Euclidean distance minimization between treatment and potential control group customer loads based on the metric below.

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

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<sup>15</sup> 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.

<sup>16</sup> 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.

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 that include CARE status and solar photovoltaic generation capacity size for NEM customers.<sup>17</sup> 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., can 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. 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.<sup>18</sup>

### *3.2.2 Structural Break Analysis*

One challenge in estimating the effect of TOU rates is isolating customers' responses to adopting TOU rates from other unrelated changes in energy usage. For example, the acquisition of an electric vehicle can confound analysis. If a customer purchases and begins charging an electric vehicle concurrently with adopting a TOU rate, the resulting increase in electricity consumption may be incorrectly attributed to the rate change. When detailed information regarding the timing of EV or other major technology acquisitions is unavailable, structural break analysis can be utilized to identify customers exhibiting persistent, significant changes in total daily usage and determine when these changes occur.

We implement a structural break model for both treatment and control groups to pinpoint the most probable date (if any) on which a customer's total daily usage shifts that is not accounted for within the regression specification. A statistical test is used to identify customers who do not

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<sup>17</sup> 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.

<sup>18</sup> 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.

experience a statistically significant structural break in their usage levels. Only those customers who do not show a substantial change in total daily usage during the analysis period are retained. To ensure only customers with large and significant changes are excluded, we remove customers whose daily usage differs by more than 8 kWh before and after the identified structural break date.<sup>19</sup>

### 3.2.3 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.

Accordingly, a fixed-effects specification was used to estimate TOU load impacts, incorporating interaction terms to estimate potential difference between TOU-DR and TOU-DR-P customers.

### 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 annual model is estimated for each hour of the day:

$$\begin{aligned} kWh_{c,d} = & \beta_0 + \beta_1 \times TOU_c \times Post_{c,d} + \beta_2 \times Post_{c,d} + \beta_3 \times TOU_c \times Post_{c,d} \times CPP_c \\ & + \beta_4 \times Weather_{c,d} + \beta_5 \times Weather_{c,d} \times NEM_c + \beta_6 \times Inland_c \times Weather_{c,d} \\ & + \beta_7 \times TOU_c \times Post_{c,d} \times Weather_{c,d} + \beta_8 \times TOU_c \times Post_{c,d} \times Weekend_d \\ & + \beta_9 \times Winter_d \times Post_{c,d} + \beta_{10} \times March\_April_d \times Post_{c,d} \\ & + \beta_{11} \times Winter_d \times CPP_c + \beta_{12} \times March\_April_d \times CPP_d \\ & + \beta_{13} \times Weekend_d \times CPP_c + C_c + D_d + \varepsilon_{c,d} \end{aligned}$$

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

**Table 3.1: 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 |

<sup>19</sup> The 8 kWh/day threshold was selected because it captures most instances of EV charging-related usage changes while preserving a sufficient sample size for analysis.

| Symbol              | Description   |
|---------------------|---|
| $CPP_c$             | Variable indicating whether customer $c$ is in CPP (1) or not (0)   |
| $NEM_c$             | 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 $c$  |
| $Weekend_d$         | Variable indicating that date $d$ is a weekend  |
| $Winter_d$          | Variable indicating that date $d$ is in the winter period according to the tariff definition.                             |
| $March\_April_d$    | Variable indicating that date $d$ is in March or April.   |
| $C_c$               | Customer Fixed Effects  |
| $D_d$               | Date Fixed Effects  |
| $\varepsilon_{c,d}$ | Error term  |
| $\beta_0$           | Estimated constant coefficient  |
| $\beta_1$           | Estimated TOU load impact for all TOU customers   |
| $\beta_2$           | Estimated load impact for control customers during post-enrollment period   |
| $\beta_3$           | Estimated incremental TOU load impact for CPP customers   |
| $\beta_4$           | Estimated load impact of weather  |
| $\beta_5$           | Estimated load impact of NEM status interacted with weather   |
| $\beta_6$           | Estimated load impact of Inland climate zone interacted with weather  |
| $\beta_7$           | Estimated TOU load impact interacted with weather   |
| $\beta_8$           | Estimated incremental TOU load impact on a weekend <sup>20</sup>  |
| $\beta_9$           | Estimated load impact in the winter during post enrollment period   |
| $\beta_{10}$        | Estimated load impact in March and April during post enrollment period  |
| $\beta_{11}$        | Estimated load impact for CPP customers in the winter   |
| $\beta_{12}$        | Estimated load impact for CPP customers in March and April  |
| $\beta_{13}$        | Estimate load impact for CPP customers on a weekend.  |

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  $\beta_1$  coefficient is the estimated average TOU load impact for each hour. The  $\beta_3$  coefficient is the estimated incremental TOU load impact for CPP customers. The  $\beta_7$  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

<sup>20</sup> Since the May system worst day for PY2025 was on a Saturday, this year's analysis was expanded to include weekends, and the model was updated to estimate weekend-specific load impacts.

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.<sup>21</sup>

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 estimated coefficients from the model are applied to weather conditions to a subset of customers in each segment.

Since the analysis relies on a small and variable sample of incremental customers and these results are extrapolated to the entire population of TOU customers, we calculate rolling three-year average load impacts (the current program year plus the prior two years) using inverse-variance weighting, which assigns higher weight to more precise estimates. Moving to a three-year average, rather than relying solely on the current program year for the TOU estimate, helps mitigate volatility driven by limited sample sizes and year-specific conditions (e.g., weather variation). This approach produces more stable and representative results that better reflect population-level impacts. Table 3.2 provides an example calculation of inverse variance weighted load impact.

**Table 3.2: Example of Inverse Variance Weighted Load Impacts**

| Year  | Standard Error | Variance | Inverse Variance (1/Variance) | Relative Weight | Load Impact (kWh/hour) |
|---|----------------|----------|-------------------------------|-----------------|------------------------|
| 2023  | 0.046          | 0.00216  | 462.76                        | 14%             | 0.08                   |
| 2024  | 0.031          | 0.00099  | 1,009.62                      | 30%             | 0.09                   |
| 2025  | 0.023          | 0.00054  | 1,856.50                      | 56%             | 0.01                   |
| <b>Weighted Average Load Impact (kWh/hour):</b> |                |          |                               | 0.04            |                        |

### 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 5<sup>th</sup> and 95<sup>th</sup> percentile scenarios are generated from these distributions.

<sup>21</sup> To estimate the load impact on a weekend system worst day the estimate of  $\beta_8$  is added.



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. Statistics such as the mean absolute percentage error ("MAPE") and mean percent error ("MPE"), which provide formal estimates of the percent differences between treatment and control group loads, are also reported. The MAPE offers a measure of accuracy while MPE offers a measure of bias.

## **4. TOU EX-POST LOAD IMPACT STUDY FINDINGS**

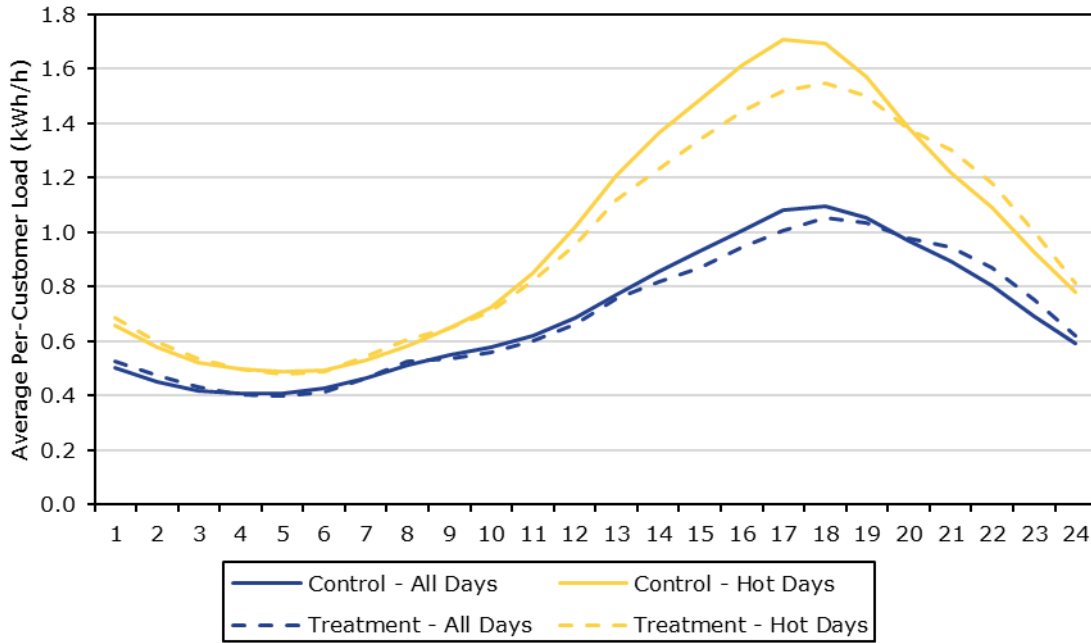
This section presents the match quality and estimates of monthly peak TOU load impacts for the TOU (TOU-DR) and CPP (TOU-DR-P) customers.

### **4.1 TOU Control Group Matching Results for TOU Customers**

Treatment customers are matched according to load profiles, climate zone, CARE status, NEM status, and solar system size to provide more accurate control for annual variations in energy usage. Figure 4.1 and Figure 4.2 illustrate the match quality of the load component 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 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 -0.5 percent, while the mean absolute percentage error (MAPE) is 3.8 percent. During the summer peak hours (4 to 9 p.m.) the MPE is -1.4 and MAPE is 3.9 percent. In the winter months, over the 24-hour period, the MPE is -0.4 percent and the MAPE is 2.4 percent. Over the winter peak hours, the MPE is 0.5% and MAPE is 1.2 percent.



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



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

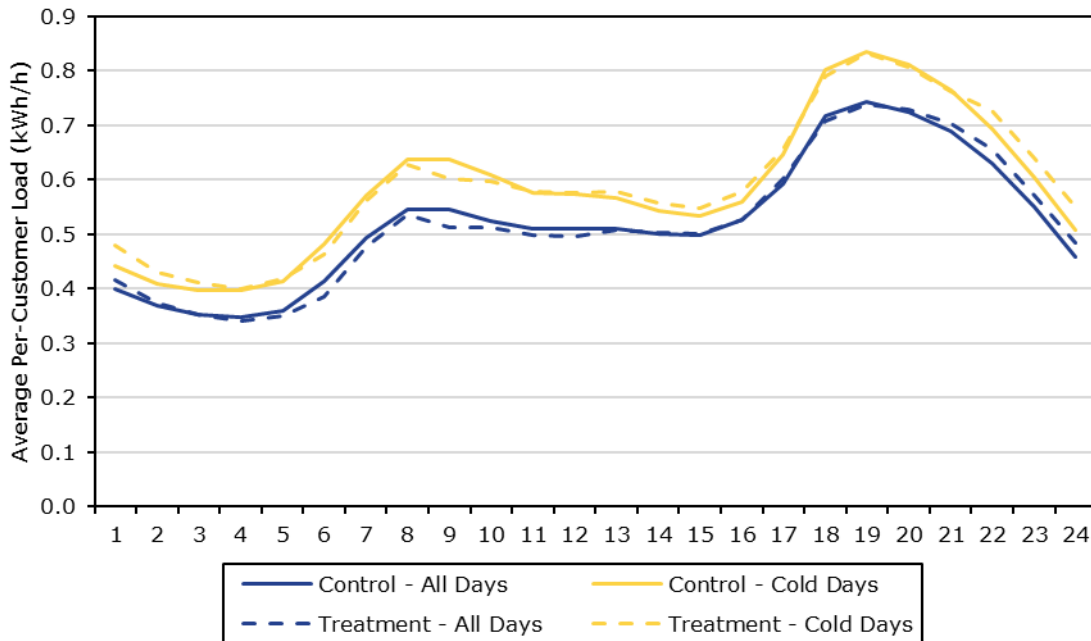
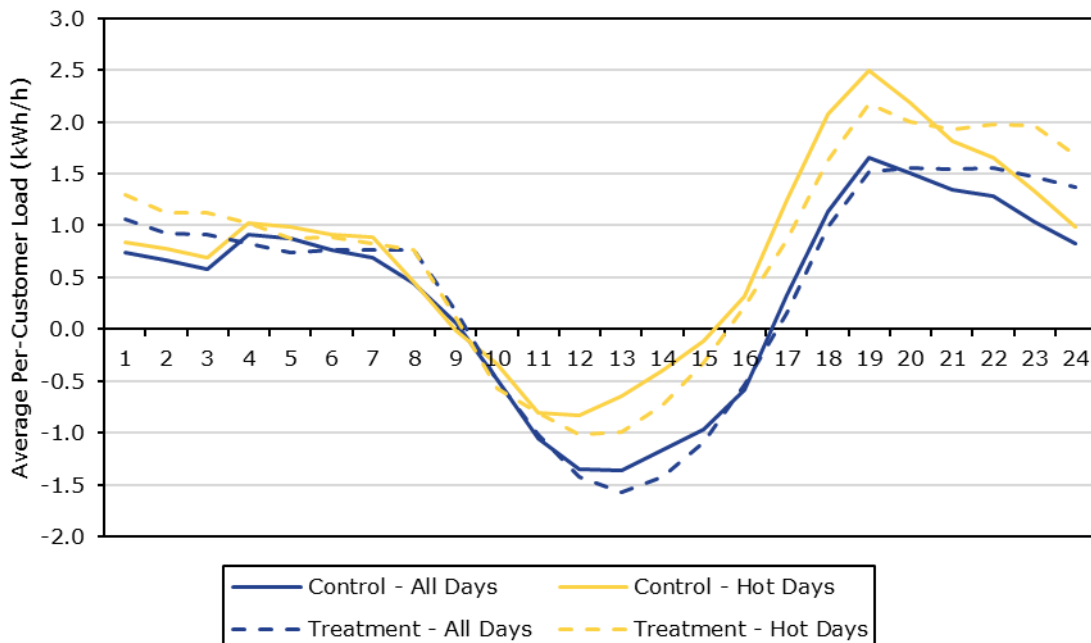


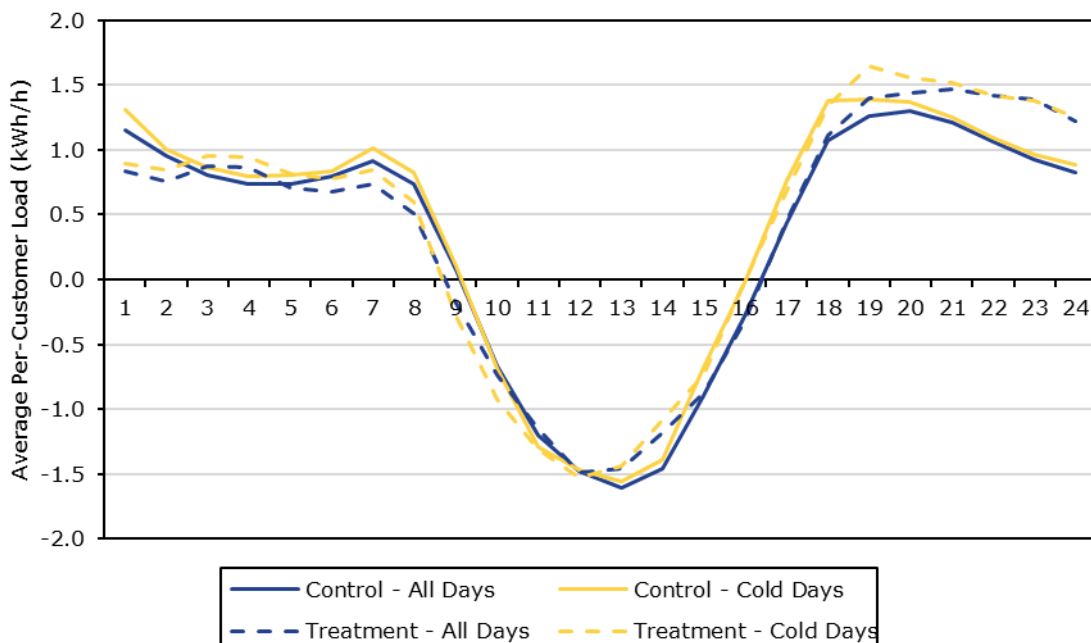
Figure 4.3 and Figure 4.4 illustrate the quality of the matches for the TOU (TOU-DR) NEM customers, similar to the above figures. Eligible control group customers for this analysis include NEM customers on a DR rate that reside in the same climate zone as the treatment customers. In the summer months, the mean error (ME) of the TOU profile compared to the control-group profile over the 24-hour period is 0.07 kWh/hour, while the mean absolute error (MAE) is 0.18 kWh/hour. Over the peak-hour period the ME is -0.04 kWh/hour and the MAE is 0.14 kWh/hour.

In the winter months, over the 24-hour period, the ME is 0.04 kWh/hour and the MAE is 0.16 kWh/hour. Over the winter peak-hour period both ME and MAE is 0.12 kWh/hour.

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



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



## 4.2 Ex-Post TOU Load Impacts for TOU Customers

This sub-section shows ex-post TOU load impact results for those customers enrolled in the TOU (TOU-DR) rate. Table 4.1 summarizes the average reference loads and TOU load impacts for the TOU peak period (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 2024). The winter months are indicated by light blue shading. Enrollments decreased throughout the period, with the number of enrolled customers decreasing from 31,291 in October 2024 to 30,312 in September 2025.<sup>22</sup> As described in Section 3.2.3, the TOU methodology estimates load impacts 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 0.02 kWh/hour compared to 0.01 kWh/hour during winter months. The lowest load impacts occur during November and May when peak usage sees relatively no increase or decrease in kWh/customer/hour. An asterisk next to a load impact indicates that the result is statistically significant at the 10 percent level. All months except October, November, April, and May are statistically significant at the 10 percent level.

**Table 4.1: 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-2024 | All          | 31,291   | 24.90                   | 0.26                      | 0.80                    | 0.01                      | 65              |
| Nov-2024 | All          | 31,139   | 26.76                   | 0.09                      | 0.86                    | 0.00                      | 58              |
| Dec-2024 | All          | 31,031   | 31.18                   | 0.38*                     | 1.00                    | 0.01*                     | 55              |
| Jan-2025 | All          | 31,111   | 29.06                   | 0.46*                     | 0.93                    | 0.01*                     | 55              |
| Feb-2025 | All          | 31,059   | 25.47                   | 0.37*                     | 0.82                    | 0.01*                     | 57              |
| Mar-2025 | All          | 31,060   | 19.47                   | 0.36*                     | 0.63                    | 0.01*                     | 56              |
| Apr-2025 | All          | 31,009   | 10.89                   | 0.26                      | 0.35                    | 0.01                      | 59              |
| May-2025 | All          | 31,008   | 12.61                   | -0.06                     | 0.41                    | 0.00                      | 63              |
| Jun-2025 | All          | 30,912   | 15.26                   | 0.42*                     | 0.49                    | 0.01*                     | 66              |
| Jul-2025 | All          | 30,732   | 19.31                   | 0.81*                     | 0.63                    | 0.03*                     | 68              |
| Aug-2025 | All          | 30,503   | 29.81                   | 1.12*                     | 0.98                    | 0.04*                     | 71              |
| Sep-2025 | All          | 30,312   | 31.50                   | 1.34*                     | 1.04                    | 0.04*                     | 71              |

Table 4.2 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

<sup>22</sup> The enrollment numbers in the tables differ from the number of customers used in the regression models, which is a subset of customers that have all the required data for conducting the ex-post load impact analysis. Specifically, there were 254 incremental customers who switched to the TOU-DR rate with quality load data sufficient for estimating the TOU load impacts. This includes both non-NEM and NEM customers as they are analyzed together. The aggregate TOU load impacts are then scaled to total enrollments.

than Coastal reference loads during both periods. While customers in both climate zones decrease loads by 0.02 kWh/customer/hour on average during the peak period in summer months, Inland customers have a slightly higher load impact of 0.03 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 4.2: 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      | 16,268             | 10.38                   | 0.29*                     | 0.64                    | 0.02*                     | 67              |
|        | Inland       | 14,482             | 13.65                   | 0.38*                     | 0.94                    | 0.03*                     | 70              |
|        | <b>All</b>   | <b>30,750</b>      | <b>24.03</b>            | <b>0.67*</b>              | <b>0.78</b>             | <b>0.02*</b>              | <b>68</b>       |
| Winter | Coastal      | 16,559             | 11.06                   | 0.07                      | 0.67                    | 0.00                      | 57              |
|        | Inland       | 14,501             | 11.07                   | 0.11                      | 0.76                    | 0.01                      | 59              |
|        | <b>All</b>   | <b>31,060</b>      | <b>22.13</b>            | <b>0.19</b>               | <b>0.71</b>             | <b>0.01</b>               | <b>58</b>       |

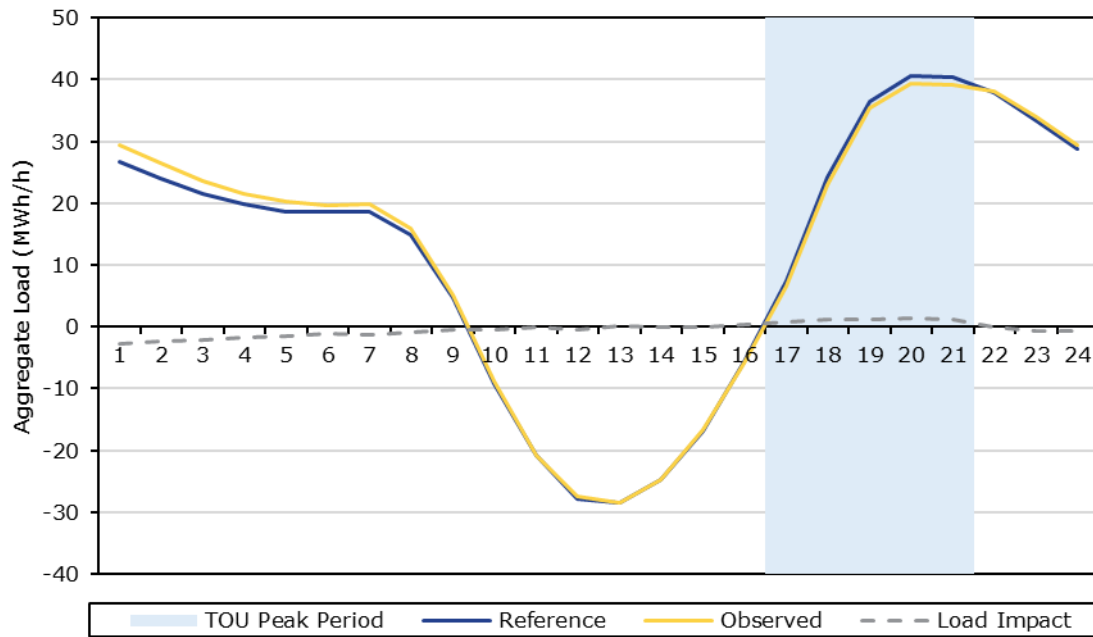
Table 4.3 shows the effect of TOU on average *daily* usage by month. TOU customers increased their daily energy consumption in every month. An asterisk next to a load impact indicates that the result is statistically significant at the 10 percent level. Results in December through March and June through September are statistically significant.

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

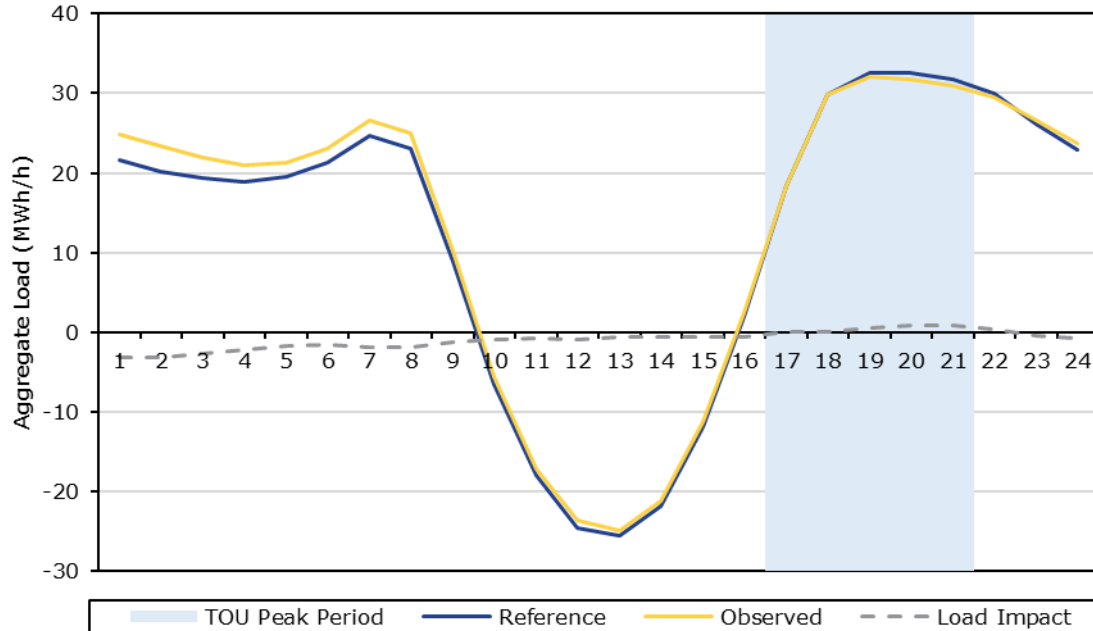
| Month    | Climate Zone | Enrolled | Aggregate                 |                             | Per-Customer              |                             | Avg. Daily Temp. |
|----------|--------------|----------|---------------------------|-----------------------------|---------------------------|-----------------------------|------------------|
|          |              |          | Daily Ref. Load (MWh/day) | Daily Load Impact (MWh/day) | Daily Ref. Load (kWh/day) | Daily Load Impact (kWh/day) |                  |
| Oct-2024 | All          | 31,291   | 217.19                    | -20.31                      | 6.94                      | -0.65                       | 64               |
| Nov-2024 | All          | 31,139   | 217.02                    | -24.97                      | 6.97                      | -0.80                       | 57               |
| Dec-2024 | All          | 31,031   | 342.26                    | -23.83*                     | 11.03                     | -0.77*                      | 54               |
| Jan-2025 | All          | 31,111   | 294.79                    | -23.56*                     | 9.48                      | -0.76*                      | 53               |
| Feb-2025 | All          | 31,059   | 227.50                    | -22.81*                     | 7.32                      | -0.73*                      | 56               |
| Mar-2025 | All          | 31,060   | 177.12                    | -23.04*                     | 5.70                      | -0.74*                      | 56               |
| Apr-2025 | All          | 31,009   | 35.00                     | -21.76                      | 1.13                      | -0.70                       | 58               |
| May-2025 | All          | 31,008   | 32.63                     | -24.31                      | 1.05                      | -0.78                       | 62               |
| Jun-2025 | All          | 30,912   | 95.13                     | -19.07*                     | 3.08                      | -0.62*                      | 65               |
| Jul-2025 | All          | 30,732   | 134.32                    | -13.77*                     | 4.37                      | -0.45*                      | 68               |
| Aug-2025 | All          | 30,503   | 283.17                    | -10.94*                     | 9.28                      | -0.36*                      | 70               |
| Sep-2025 | All          | 30,312   | 297.86                    | -11.05*                     | 9.83                      | -0.36*                      | 70               |

Figure 4.5 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 4.6 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 are statistically significant for the peak hours in hours ending ("HE") 19 through 21. For both winter and summer there appears to be evidence of statistically significant load shifting to super off-peak and off-peak hours as reference loads are below observed loads in HE 1 through HE 10, as well as in HE 12, HE 23 and HE 24 in August; and HE 1 through HE 16, as well as in HE23 and HE24 in January.

**Figure 4.5: Aggregate Hourly Loads and TOU Load Impacts(MWh/hour) – TOU Customers (Average Weekday, August 2025)**



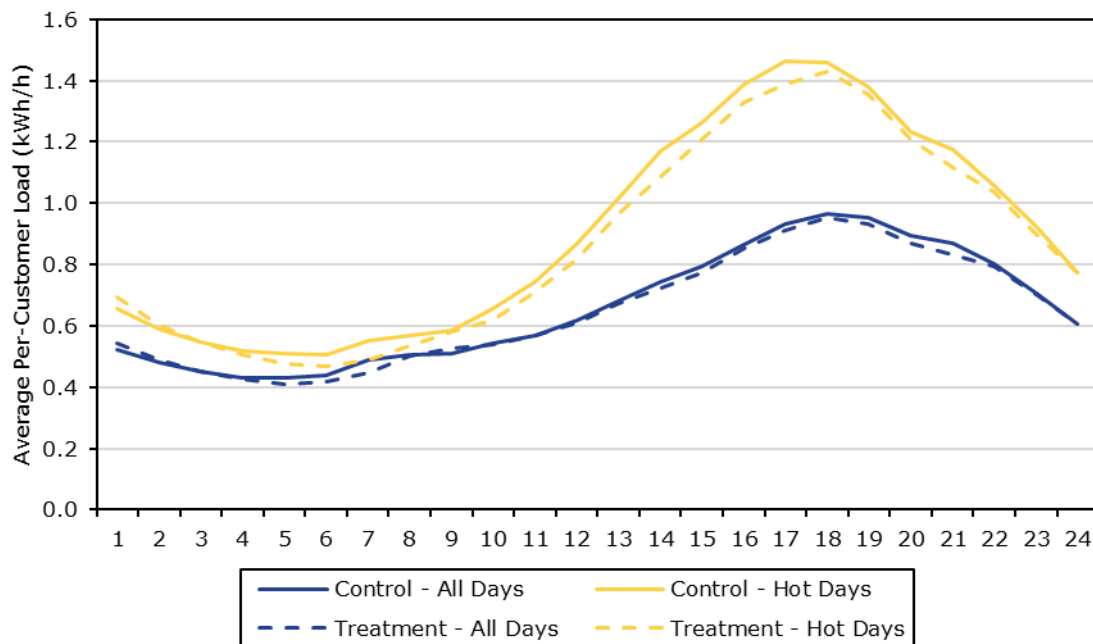
**Figure 4.6: Aggregate Hourly Loads and TOU Load Impacts (MWh/hour) – TOU Customers (Average Weekday, January 2025)**



### 4.3 TOU Control Group Matching Results for CPP Customers

Figure 4.7 and Figure 4.8 illustrate the match quality for the non-NEM residential CPP (TOU-DR-P) customers on non-event days.<sup>23</sup> 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 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 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 -1.5 percent, while the mean absolute percentage error (MAPE) is 2.3 percent. During the summer peak hours (4 to 9 p.m.) the MPE is -2.6 percent and the MAPE is 2.6 percent. In the winter months, over the 24-hour period, the MPE is 0.6 percent and the MAPE is 3.3 percent. Over the winter peak hours, the MPE is -0.1 percent and the MAPE is 2.2 percent.

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



<sup>23</sup> EV-TOU-5-P is not included in the TOU analysis.

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

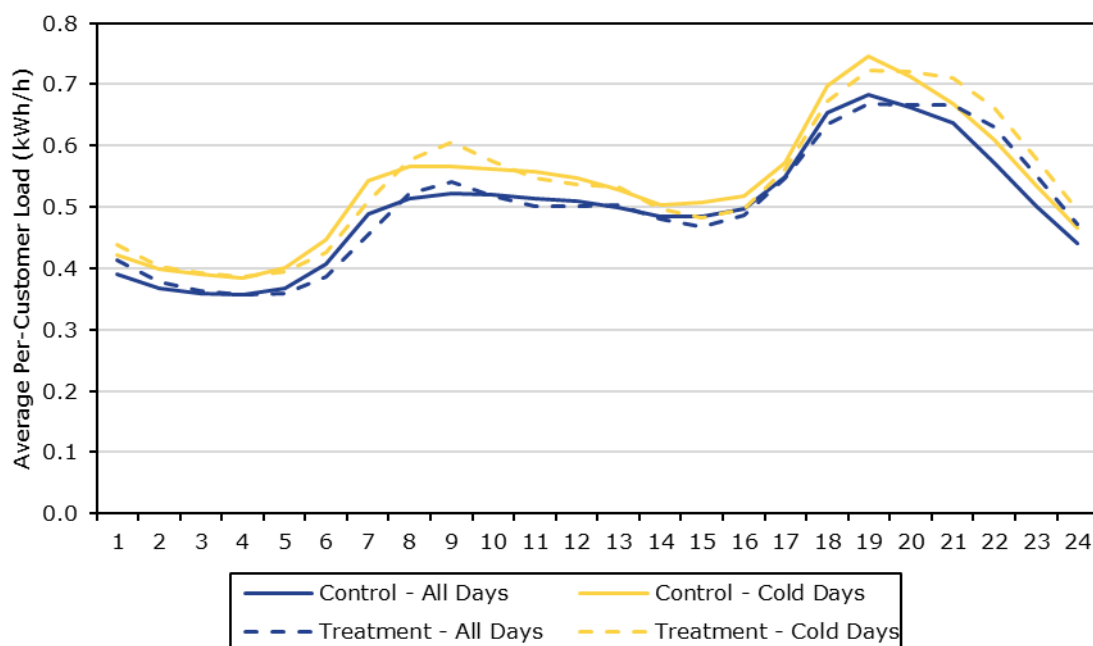
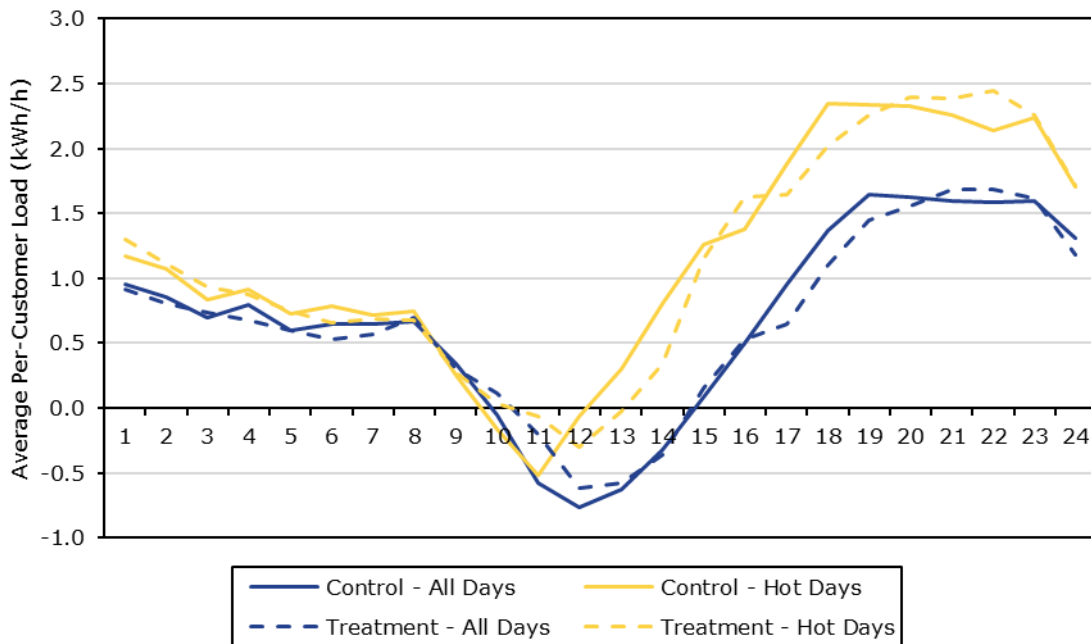


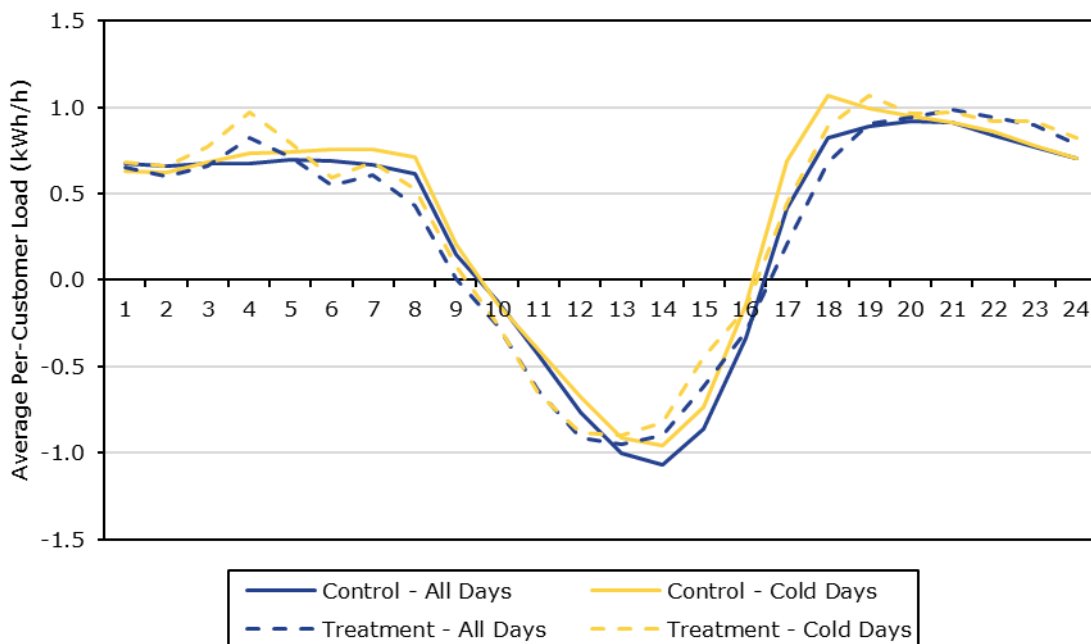
Figure 4.9 and Figure 4.10 illustrate match quality for the NEM residential CPP (TOU-DR-P) customers on non-event days. The figures show the average CPP and matched control-group customer load profiles for the summer and winter months, respectively. Eligible control group customers for this analysis include NEM customers on a DR rate in the same climate zone as the treatment customers. Two pairs of loads are shown, one for weekdays, and one for the hottest (or coldest) days. In the summer months, the mean error (ME) of the TOU profile compared to the control-group profile over the 24-hour period is -0.01 kWh/hour and the mean absolute error (MAE) is 0.11 kWh/hour. Over the peak-hour period the ME is -0.15 kWh/hour and the MAE is 0.19. In the winter months, over the 24-hour period the ME is -0.02 kWh/hour, and the MAE is 0.11 kWh/hour. Over the winter peak-hour period the ME is -0.05 kWh/hour, and the MAE is 0.09 kWh/hour.



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



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



#### 4.4 Ex-Post TOU Load Impacts for CPP Customers

Since TOU-DR-P customers experience TOU prices on 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 4.4 summarizes peak-period loads and load impacts for the average

summer (October 2024, and June through September 2025) and winter (November 2024 through May 2025) weekdays, by month. Reported enrollment in CPP fell from 7,200 in October 2024 to 7,123 in September 2025.<sup>24</sup> Peak load impacts were estimated at 0.01 kWh/hour across all summer months and 0.01 kWh/hour across all 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, November, or March through June.

**Table 4.4: 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-2024 | All          | 7,200    | 5.83                    | -0.07                     | 0.81                    | -0.01                     | 67              |
| Nov-2024 | All          | 7,165    | 5.82                    | 0.04                      | 0.81                    | 0.01                      | 60              |
| Dec-2024 | All          | 7,122    | 6.79                    | 0.07*                     | 0.95                    | 0.01*                     | 57              |
| Jan-2025 | All          | 7,112    | 6.18                    | 0.11*                     | 0.87                    | 0.01*                     | 58              |
| Feb-2025 | All          | 7,189    | 5.62                    | 0.08*                     | 0.78                    | 0.01*                     | 59              |
| Mar-2025 | All          | 7,173    | 4.83                    | 0.05                      | 0.67                    | 0.01                      | 58              |
| Apr-2025 | All          | 7,153    | 3.77                    | 0.02                      | 0.53                    | 0.00                      | 61              |
| May-2025 | All          | 7,156    | 4.29                    | 0.02                      | 0.60                    | 0.00                      | 66              |
| Jun-2025 | All          | 7,150    | 4.92                    | -0.03                     | 0.69                    | 0.00                      | 68              |
| Jul-2025 | All          | 7,133    | 6.06                    | 0.11*                     | 0.85                    | 0.02*                     | 71              |
| Aug-2025 | All          | 7,125    | 8.17                    | 0.22*                     | 1.15                    | 0.03*                     | 74              |
| Sep-2025 | All          | 7,123    | 8.14                    | 0.20*                     | 1.14                    | 0.03*                     | 73              |

Table 4.5 summarizes results by season and climate zone. The Inland climate zone has a decrease in average peak-hour loads of 0.01 kWh/hour in the summer and no decrease in the winter compared to 0.01 kWh/hour in the Coastal climate zone during both summer and winter. These results are not statistically significant.

<sup>24</sup> There were 248 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, this number includes both non-NEM and NEM customers.

**Table 4.5: TOU Peak Load Impacts for CPP Customers – Average Weekday by Season & Climate Zone**

| Season | Climate Zone | Enrolled (Average) | Aggregate               |                           | Per-Customer            |                           | 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      | 4,457              | 3.85                    | 0.05                      | 0.86                    | 0.01                      | 70              |
|        | Inland       | 2,690              | 2.77                    | 0.04                      | 1.03                    | 0.01                      | 72              |
|        | <b>All</b>   | <b>7,146</b>       | <b>6.62</b>             | <b>0.09</b>               | <b>0.93</b>             | <b>0.01</b>               | <b>71</b>       |
| Winter | Coastal      | 4,476              | 3.36                    | 0.03                      | 0.75                    | 0.01                      | 60              |
|        | Inland       | 2,676              | 1.95                    | 0.01                      | 0.73                    | 0.00                      | 60              |
|        | <b>All</b>   | <b>7,153</b>       | <b>5.31</b>             | <b>0.04</b>               | <b>0.74</b>             | <b>0.01</b>               | <b>60</b>       |

Table 4.6 shows the effect of TOU on average daily usage by month. CPP customers decreased their average daily usage during August and increased their usage in all other months. There is an overall annual load increase of approximately 0.21 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. December, January, February, July, and August are statistically significant at the 10 percent level.

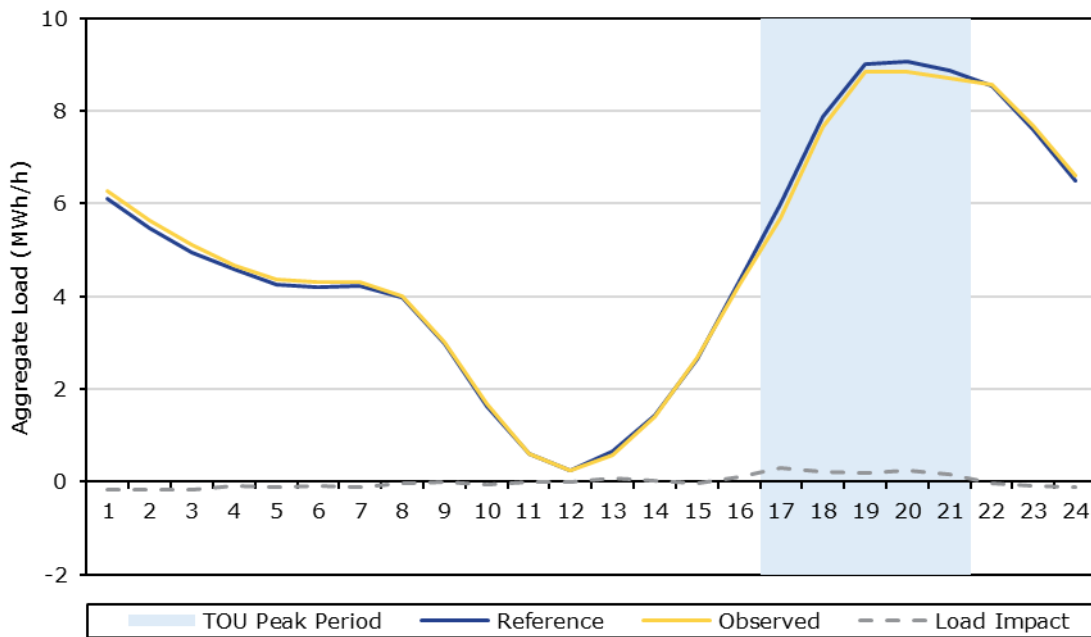
**Table 4.6: TOU Average Daily Load Impacts for CPP Customers, by Month**

| 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-24 | All          | 7,200    | 82.94                     | -2.65                       | 11.52                     | -0.37                       | 65               |
| Nov-24 | All          | 7,165    | 80.18                     | -1.82                       | 11.19                     | -0.25                       | 58               |
| Dec-24 | All          | 7,122    | 100.47                    | -1.55*                      | 14.11                     | -0.22*                      | 55               |
| Jan-25 | All          | 7,112    | 92.04                     | -1.38*                      | 12.94                     | -0.19*                      | 54               |
| Feb-25 | All          | 7,189    | 81.11                     | -1.26*                      | 11.28                     | -0.18*                      | 57               |
| Mar-25 | All          | 7,173    | 74.50                     | -2.16                       | 10.39                     | -0.30                       | 56               |
| Apr-25 | All          | 7,153    | 57.89                     | -2.29                       | 8.09                      | -0.32                       | 59               |
| May-25 | All          | 7,156    | 60.26                     | -1.72                       | 8.42                      | -0.24                       | 64               |
| Jun-25 | All          | 7,150    | 73.06                     | -2.08                       | 10.22                     | -0.29                       | 67               |
| Jul-25 | All          | 7,133    | 86.58                     | -0.66*                      | 12.14                     | -0.09*                      | 69               |
| Aug-25 | All          | 7,125    | 115.89                    | 0.14*                       | 16.26                     | 0.02*                       | 72               |
| Sep-25 | All          | 7,123    | 116.48                    | -0.28*                      | 16.35                     | -0.04*                      | 72               |

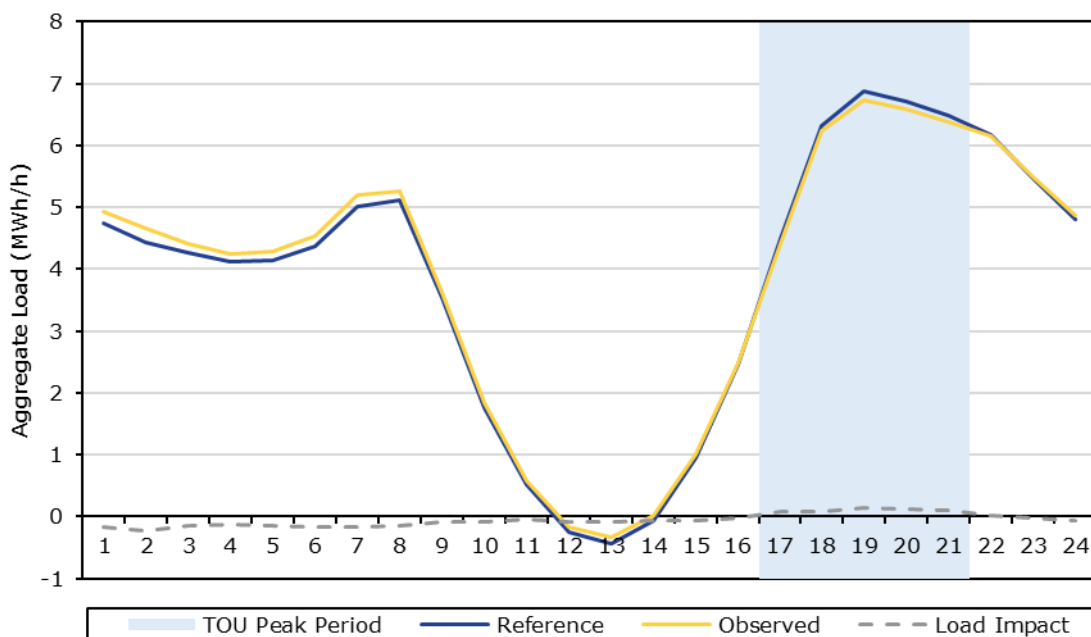
Figure 4.11 shows aggregate hourly observed and estimated reference loads and load impacts for residential CPP customers (both non-NEM and NEM) for the weekday in August. Figure 4.12

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 during all peak hours.

**Figure 4.11: Aggregate Hourly Loads and TOU Load Impacts (MWh/hour) – TOU-DR-P Customers (Average Weekday, August 2025)**



**Figure 4.12: Aggregate Hourly Loads and TOU Load Impacts (MWh/hour) – CPP Customers (Average Weekday, January 2025)**



## 5. EX-ANTE EVALUATION METHODOLOGY

This section describes the methodology for developing ex-ante load impact forecasts for the CPP and TOU rates. Ex-ante load impacts represent forecasts of load impacts that are expected to occur when program events are called in future years (CPP), or in TOU peak periods (TOU), under standardized weather conditions. The forecasts are based on per-customer load impacts from the ex-post evaluations (PY2025 for TOU and PY2024 for CPP events), development of weather-sensitive reference loads, and incorporation of utility forecasts of program enrollments. The per-customer CPP load impacts from PY2024 were used to forecast CPP load impacts, as no CPP events were called in PY2025.

### 5.1 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 PY2025 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.

### 5.2 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 PY2025 for CPP and TOU customers. Customers are first sorted as weather sensitive or not.<sup>25</sup> 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:

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<sup>25</sup> 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.

- The analysis includes only the treatment customer loads during PY2025;
- Weather variables are included (e.g., Mean17, CDH, CDD, HDH and HDD);<sup>26</sup> 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.<sup>27</sup> 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 impacts from ex-post to the observed loads. The process for obtaining simulated reference and observed loads is completed separately for each reporting category.<sup>28</sup>

### 5.3 Enrollment Forecast

Figure 5.1 shows SDG&E’s enrollment forecasts for the TOU and CPP rates. Enrollment for TOU decreases throughout the forecast. 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. For CPP the EV-TOU-5 rate becomes a larger share of total enrollment year-to-year, starting at 17% of total CPP enrollment in 2026 and by 2036 it encompasses 33% of total enrollment.

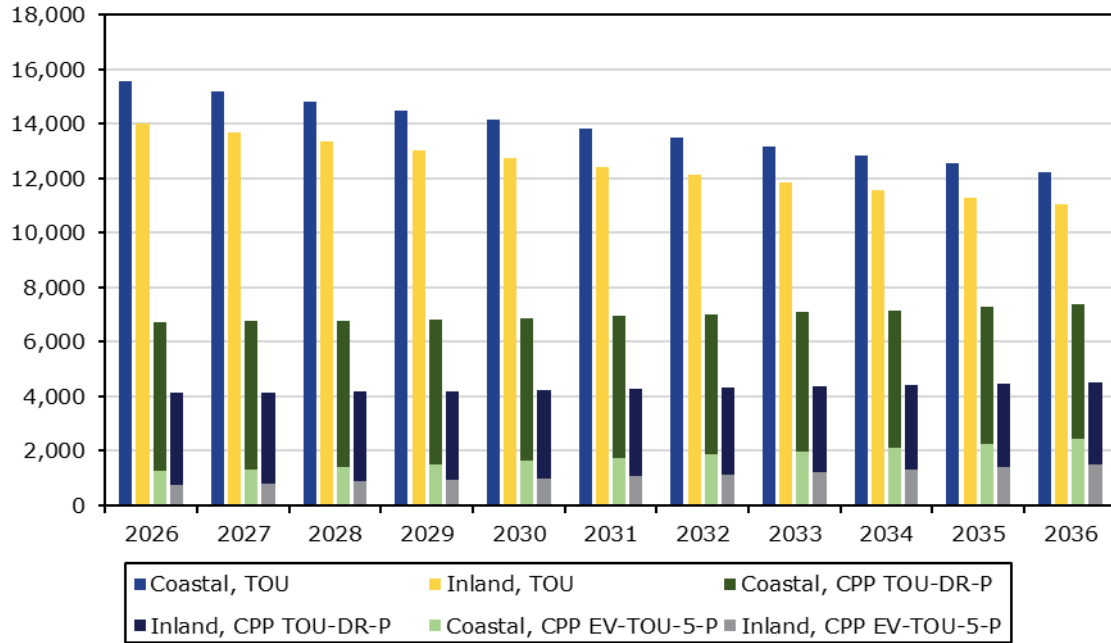
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<sup>26</sup> Mean17 is the average temperature in degrees Fahrenheit during the first 17 hours of the day. Cooling degree hours (CDH) for each hour of the day are defined as:  $CDH_{65} = \max(0, \text{temperature in } ^\circ\text{F} - \text{chosen temperature threshold})$ . 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.

<sup>27</sup> 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.

<sup>28</sup> The use of panel regressions limits results to only apply to the customer type included in the regressions, as opposed to customer-specific regressions for which sub-categories can be created by combining pieces from the individual regressions. Therefore, any sub-categorization of results needs to be processed separately to account for possible differences in weather sensitivity and load profiles. For 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.

**Figure 5.1: Enrollments in TOU and CPP Rates**



## 6. 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.

### 6.1 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 6.1 illustrates the estimated aggregate reference loads, observed loads, and load impacts for an August system worst day in 2026 for the SDG&E 1-in-2 weather scenario. The average event-period load impact is 1.57 MWh/hour.

**Figure 6.1: Aggregate Hourly Loads and CPP Load Impacts (MWh/hour) – (August 2026 SDG&E 1-in-2 System Worst Day)**

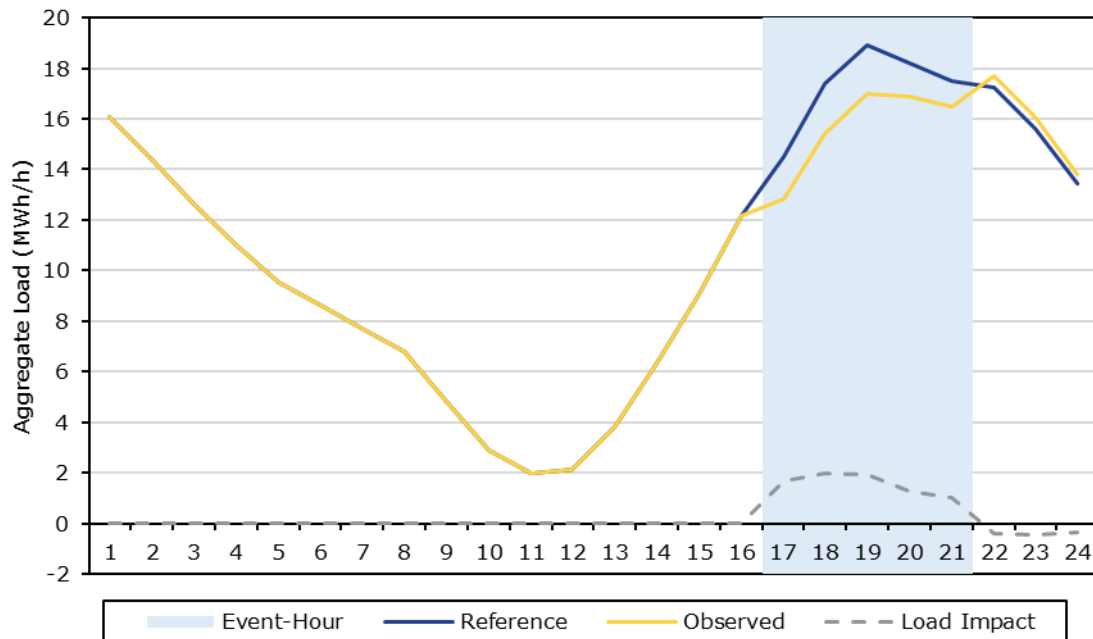
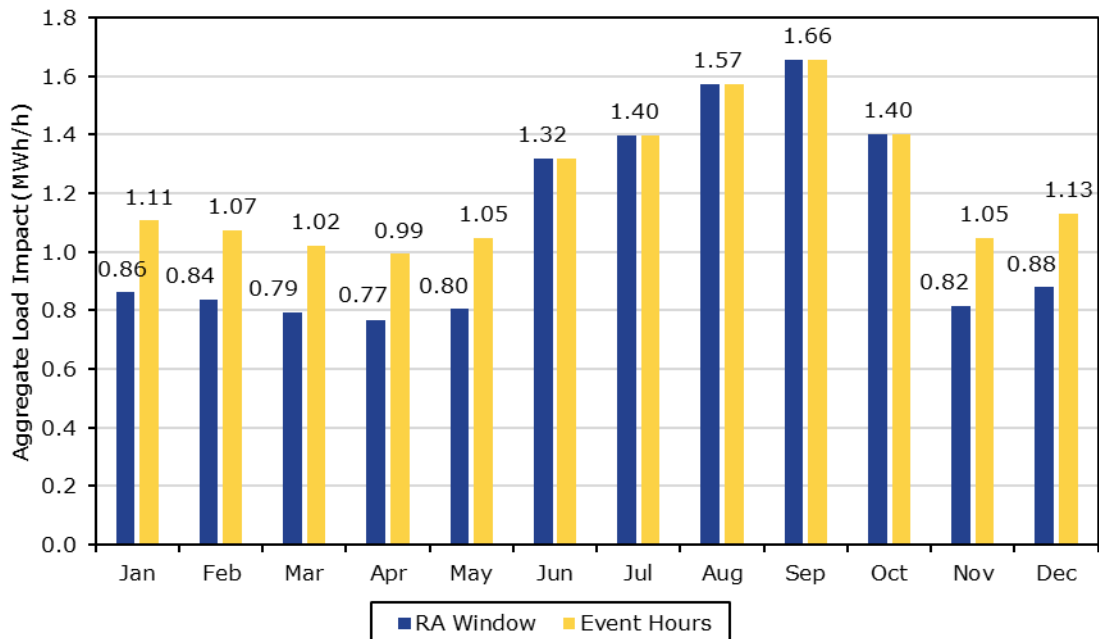


Figure 6.2 shows the monthly pattern of aggregate ex-ante load impacts for the average hour in the RA window (blue) and event window (yellow) in 2026 for the SDG&E 1-in-2 system worst day. Table 6.1 provides more detailed information of aggregate and per-customer reference loads and load impacts over the RA window, as well as forecasted customer enrollment each month. The RA window is 4 to 9 p.m. (HE 17-21) in all months except November through 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 November through 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 6.2. Per-customer load impacts are highest during summer months due to higher reference loads.



**Figure 6.2: Aggregate CPP Load Impacts (MWh/hour), by Month – (2026 SDG&E 1-in-2 System Worst Day, RA Window and Event Hours)**

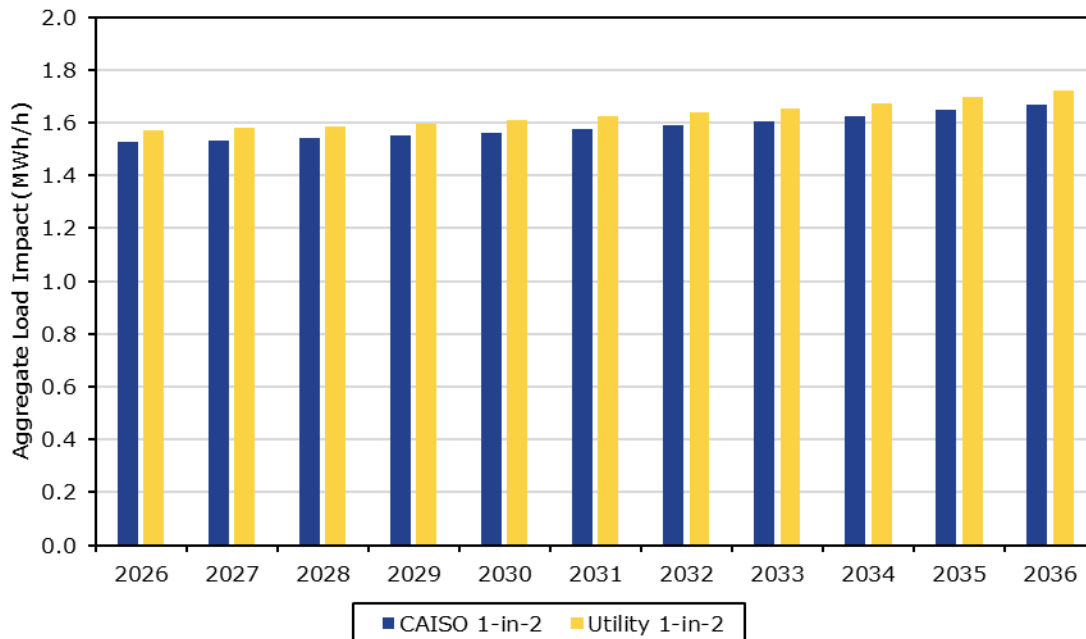


**Table 6.1 Aggregate (MWh/hour) and Per-Customer (kWh/hour) CPP Load Impacts, by Month – (2026 SDG&E 1-in-2 Worst Day, RA Window)**

| 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   | 10,841   | 10.75                    | 0.86                       | 0.99                     | 0.08                       |
| February  | 10,841   | 9.99                     | 0.84                       | 0.92                     | 0.08                       |
| March     | 10,841   | 8.75                     | 0.79                       | 0.81                     | 0.07                       |
| April     | 10,841   | 7.68                     | 0.77                       | 0.71                     | 0.07                       |
| May       | 10,841   | 8.56                     | 0.80                       | 0.79                     | 0.07                       |
| June      | 10,841   | 11.89                    | 1.32                       | 1.10                     | 0.12                       |
| July      | 10,841   | 13.41                    | 1.40                       | 1.24                     | 0.13                       |
| August    | 10,841   | 17.30                    | 1.57                       | 1.60                     | 0.15                       |
| September | 10,841   | 19.26                    | 1.66                       | 1.78                     | 0.15                       |
| October   | 10,841   | 15.02                    | 1.40                       | 1.39                     | 0.13                       |
| November  | 10,841   | 9.52                     | 0.82                       | 0.88                     | 0.08                       |
| December  | 10,841   | 11.34                    | 0.88                       | 1.05                     | 0.08                       |

Figure 6.3 illustrates the forecasted aggregate event load impacts for CPP by weather scenario. The aggregate CPP 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 6.3: Aggregate CPP Load Impacts (MWh/hour), by Year and Weather Scenario - (August Peak Day, RA Window)**



## 6.2 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 6.4 shows aggregate reference loads, observed loads, and load impacts for TOU and CPP customers, in 2026 for an SDG&E 1-in-2 average weekday in August. The average peak load impact is 1.28 MWh/hour.

**Figure 6.4: Aggregate Hourly Loads and TOU Load Impacts (MWh/hour) – TOU and CPP Customers, (August 2026 SDG&E 1-in-2 Average Weekday)**

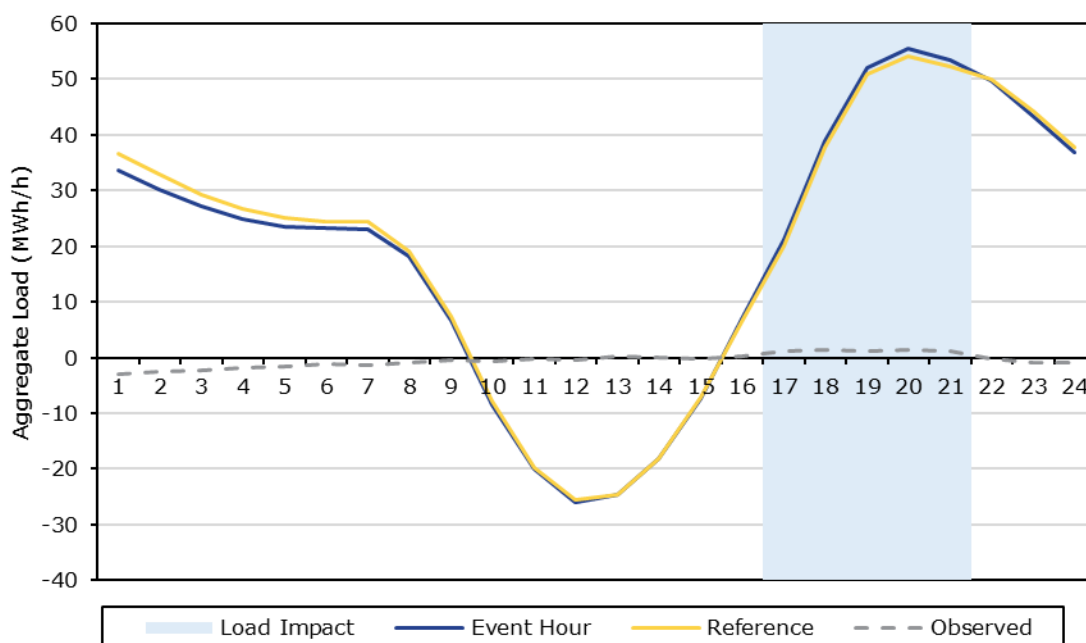
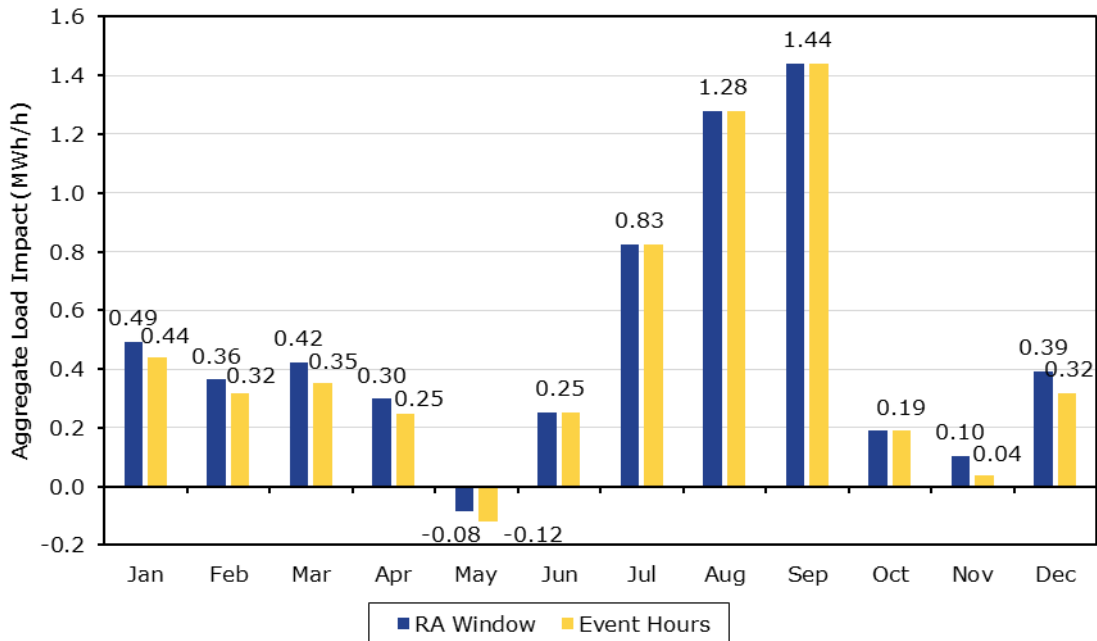


Figure 6.5 shows the seasonality of aggregate ex-ante TOU load impacts for TOU and CPP customers for the average hour in the RA window (blue) and the peak hours. Table 6.2 provides more detailed information of aggregate and per-customer reference loads and load impacts over the RA window, as well as customer forecasted enrollment in each month. The RA window is 4 to 9 p.m. (HE 17-21) in all months except November through 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.<sup>29</sup> Load impacts are driven by seasonal differences in reference loads, with lower reference loads occurring during spring months.<sup>30</sup>

<sup>29</sup> March and April are estimated separately because the midday off-peak hours differ from other months.

<sup>30</sup> The lowest aggregate and per-customer reference loads are in April, which is driven by PV generation by NEM customers.

**Figure 6.5: 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)**

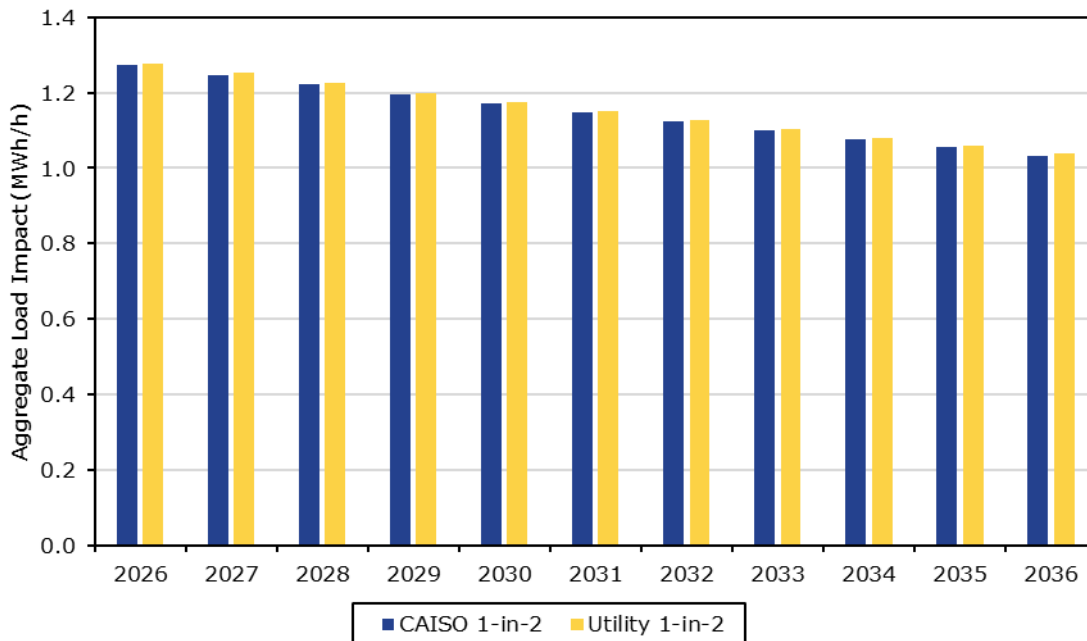


**Table 6.2 Aggregate (MWh/hour) and Per-Customer (kWh/hour) TOU Load Impacts by Month - TOU and CPP Customers, (2026 SDG&E 1-in-2 Average Weekday, RA Window)**

| 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   | 38,417   | 37.22                   | 0.49                      | 0.97                    | 0.01                      |
| February  | 38,417   | 34.29                   | 0.36                      | 0.89                    | 0.01                      |
| March     | 38,417   | 29.89                   | 0.42                      | 0.78                    | 0.01                      |
| April     | 38,417   | 24.62                   | 0.30                      | 0.64                    | 0.01                      |
| May       | 38,417   | 26.18                   | -0.08                     | 0.68                    | 0.00                      |
| June      | 38,417   | 23.09                   | 0.25                      | 0.60                    | 0.01                      |
| July      | 38,417   | 32.27                   | 0.83                      | 0.84                    | 0.02                      |
| August    | 38,417   | 44.30                   | 1.28                      | 1.15                    | 0.03                      |
| September | 38,417   | 44.66                   | 1.44                      | 1.16                    | 0.04                      |
| October   | 38,417   | 33.79                   | 0.19                      | 0.88                    | 0.00                      |
| November  | 38,417   | 33.65                   | 0.10                      | 0.88                    | 0.00                      |
| December  | 38,417   | 39.25                   | 0.39                      | 1.02                    | 0.01                      |

Figure 6.6 shows the forecasted TOU aggregate load impacts for an August weekday over the forecast period by weather scenario. The aggregate TOU load impacts decrease over time as enrollments decrease. 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 6.6: Aggregate TOU Load Impacts (MWh/hour) – TOU and CPP Customers, by Year and Weather Scenario (Average August Weekday, RA Window)**



## 7. COMPARISONS OF RESULTS

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

- TOU 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 2025 program year; and “previous study” refers to the report that was developed following the 2024 program year. The comparison of results is provided for the CPP analysis as well as TOU analysis.

### 7.1 CPP Load Impacts

#### 7.1.1 Previous Versus Current Ex-Ante

In this sub-section, the ex-ante forecast prepared in PY2024 is compared to the ex-ante forecast contained in this study. In contrast to previous years, this report does not include a comparison between previous and current ex-post CPP results, since there were no CPP events called this year. As a result, last year’s ex-post CPP results are carried forward and used to inform the current year’s ex-ante estimates. Table 7.1 reports the average event-hour load impacts for the August 2026 system worst day under SGD&E 1-in-2 weather conditions. Aggregate reference

loads and load impacts are larger in the PY2025 ex-ante analysis due to an updated enrollment forecast that predicts increased enrollments in 2026 compared to the previous forecast.

**Table 7.1: Previous vs. Current Ex-Ante CPP Event Load Impacts**

| Result                              | Ex-Ante<br>2026 System<br>Worst Day<br>PY2024 Study | Ex-Ante<br>2026 System<br>Worst Day<br>PY2025 Study |
|-------------------------------------|---|---|
| # Enrolled                          | 8,881   | 10,841  |
| Reference (MWh/hour)                | 14.54   | 17.30   |
| Load Impact (MWh/hour)              | 1.36  | 1.57  |
| Per-customer Reference (kWh/hour)   | 1.64  | 1.60  |
| Per-customer Load Impact (kWh/hour) | 0.15  | 0.15  |
| Temperature                         | 84.0  | 84.5  |
| % NEM                               | 29%   | 25%   |

## 7.2 TOU Load Impacts

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

### 7.2.1 Previous Versus Current Ex-Post

Table 7.2 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. The PY2025 enrollment numbers were lower during both the summer and winter seasons. Per-customer load impacts also decreased during both seasons, which leads to a decrease in aggregate load impacts. The PY2025 summer per-customer load impact of 0.04 kWh/hour and the winter per-customer load impact of 0.01 kWh/hour are approximately half the PY2024 per-customer load impacts. The per-customer reference loads for the summer in PY2025 are reduced, likely due to lower average temperatures. Combined with lower enrollments, these factors contribute to a decreased aggregate reference load in PY2025.

**Table 7.2: Previous vs. Current Ex-Post TOU Load Impacts, TOU and CPP Customers**

| Season              | Result                              | Ex-Post<br>2024 Avg. Weekday<br>PY2024 Study | Ex-Post<br>2025 Avg. Weekday<br>PY2025 Study |
|---------------------|-------------------------------------|--|--|
| Summer<br>(August)  | # Enrolled                          | 38,653                                       | 37,628                                       |
|                     | Reference (MWh/hour)                | 45.21  | 37.98  |
|                     | Load Impact (MWh/hour)              | 2.84   | 1.34   |
|                     | Per-customer Reference (kWh/hour)   | 1.17   | 1.01   |
|                     | Per-customer Load Impact (kWh/hour) | 0.07   | 0.04   |
|                     | Temperature                         | 75.8   | 72.6   |
|                     | % NEM                               | 45.5%  | 45.6%  |
| Winter<br>(January) | # Enrolled                          | 39,656                                       | 38,223                                       |
|                     | Reference (MWh/hour)                | 36.82  | 35.23  |
|                     | Load Impact (MWh/hour)              | 0.85   | 0.56   |
|                     | Per-customer reference (kWh/hour)   | 0.93   | 0.92   |
|                     | Per-customer load impact (kWh/hour) | 0.02   | 0.01   |
|                     | Temperature                         | 56.9   | 56.3   |
|                     | % NEM                               | 45.1%  | 45.8%  |

### 7.2.2 Previous Versus Current Ex-Ante

Table 7.3 reports the average RA-window load impacts for the August and January 2026 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 smaller enrollment forecast 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, further amplified by lower enrollments.

**Table 7.3: Previous vs. Current Ex-Ante TOU Load Impacts, TOU and CPP Customers**

| Season              | Result                              | Ex-Ante<br>2026 Avg. Weekday<br>PY2024 Study | Ex-Ante<br>2026 Avg. Weekday<br>PY2025 Study |
|---------------------|-------------------------------------|--|--|
| Summer<br>(August)  | # Enrolled                          | 42,918                                       | 38,417                                       |
|                     | Reference (MWh/hour)                | 51.28  | 44.29  |
|                     | Load Impact (MWh/hour)              | 3.16   | 1.28   |
|                     | Per-customer reference (kWh/hour)   | 1.19   | 1.15   |
|                     | Per-customer load impact (kWh/hour) | 0.07   | 0.03   |
|                     | Temperature                         | 76.6   | 77.0   |
|                     | % NEM                               | 46.3%  | 44.2%  |
| Winter<br>(January) | # Enrolled                          | 42,918                                       | 38,417                                       |
|                     | Reference (MWh/hour)                | 39.04  | 37.22  |
|                     | Load Impact (MWh/hour)              | 0.77   | 0.49   |
|                     | Per-customer reference (kWh/hour)   | 0.91   | 0.97   |
|                     | Per-customer load impact (kWh/hour) | 0.02   | 0.01   |
|                     | Temperature                         | 60.6   | 58.2   |
|                     | % NEM                               | 46.3%  | 44.2%  |

### 7.2.3 Previous Ex-Ante Versus Current Ex-Post

Table 7.4 provides a comparison of the ex-ante forecast of 2025 TOU load impacts prepared in the previous study and the PY2025 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. The current ex-post enrollments are lower than the forecasted ex-ante enrollments from the previous study, which, together with lower per-customer load impacts in ex-post relative to ex-ante, result in lower aggregate load impacts. The ex-post per-customer reference loads are lower than forecasted in summer, which is likely due to lower ex-post temperatures.



**Table 7.4: Previous Ex-Ante vs. Current Ex-Post TOU Load Impacts, TOU and CPP Customers**

| Season              | Result                              | Ex-Ante<br>2025 Avg. Weekday<br>PY2024 Study | Ex-Post<br>2025 Avg. Weekday<br>PY2025 Study |
|---------------------|-------------------------------------|--|--|
| Summer<br>(August)  | # Enrolled                          | 40,765                                       | 37,628                                       |
|                     | Reference (MWh/hour)                | 48.79  | 37.98  |
|                     | Load Impact (MWh/hour)              | 3.01   | 1.34   |
|                     | Per-customer reference (kWh/hour)   | 1.20   | 1.01   |
|                     | Per-customer load impact (kWh/hour) | 0.07   | 0.04   |
|                     | Temperature                         | 76.7   | 72.6   |
|                     | % NEM                               | 46.1%  | 45.6%  |
| Winter<br>(January) | # Enrolled                          | 40,765                                       | 38,223                                       |
|                     | Reference (MWh/hour)                | 37.08  | 35.23  |
|                     | Load Impact (MWh/hour)              | 0.75   | 0.56   |
|                     | Per-customer reference (kWh/hour)   | 0.91   | 0.92   |
|                     | Per-customer load impact (kWh/hour) | 0.02   | 0.01   |
|                     | Temperature                         | 60.6   | 56.3   |
|                     | % NEM                               | 46.1%  | 45.8%  |

#### 7.2.4 Current Ex-Post Versus Current Ex-Ante

Table 7.5 compares the PY2025 ex-post TOU load impacts for the average weekday in August and January with the corresponding ex-ante forecast for 2026 (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 overlaps with the TOU peak period in August. In January the RA window is from HE 18 to HE 22, while the peak period is from HE 17 to HE 21. The per-customer reference loads and load-impacts are similar between the two scenarios during the winter months, with larger differences observed during the summer months, due to milder weather in ex post. The marginally lower per-customer load impact in ex-ante relative to ex-post despite the higher reference load is explained by a larger share of CPP customers in ex-ante, which have a lower load impact.

**Table 7.5: Current Ex-Post vs. Current Ex-Ante TOU Load Impacts, TOU and CPP Customers**

| Season              | Result                              | Ex-Post<br>2025 Avg. Weekday<br>PY2025 Study | Ex-Ante<br>2026 Avg. Weekday<br>PY2025 Study |
|---------------------|-------------------------------------|--|--|
| Summer<br>(August)  | # Enrolled                          | 37,628                                       | 38,417                                       |
|                     | Reference (MWh/hour)                | 37.98  | 44.29  |
|                     | Load Impact (MWh/hour)              | 1.34   | 1.28   |
|                     | Per-customer reference (kWh/hour)   | 1.01   | 1.15   |
|                     | Per-customer load impact (kWh/hour) | 0.036  | 0.033  |
|                     | Temperature                         | 72.6   | 77.0   |
|                     | % NEM                               | 45.6%  | 44.2%  |
| Winter<br>(January) | # Enrolled                          | 38,223                                       | 38,417                                       |
|                     | Reference (MWh/hour)                | 35.23  | 37.22  |
|                     | Load Impact (MWh/hour)              | 0.56   | 0.49   |
|                     | Per-customer reference (kWh/hour)   | 0.92   | 0.97   |
|                     | Per-customer load impact (kWh/hour) | 0.01   | 0.01   |
|                     | Temperature                         | 56.3   | 58.2   |
|                     | % NEM                               | 45.8%  | 44.2%  |

## 8. RECOMMENDATIONS

No CPP events were called in 2025 due to the mild weather conditions. We suggest calling events under a range of event conditions, including milder weather, to provide more information on responsiveness across different weather scenarios. We also recommend calling events in a variety of months and on different days of the week, such as weekend, to broaden understanding of customer responsiveness.

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 the effectiveness of TOU for EV customers. For the CPP rate, EVTOU5, increased enrollment will lead to more accurate estimates of CPP load impacts for this subset of customers that have higher reference loads, on average.

## 9. 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.