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2022 Load Impact Evaluation of Pacific Gas and Electric Company's Residential Time-of-Use Rates

Ex-Post and Ex-Ante Report

CALMAC Study ID PGE0484

By

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EXECUTIVE SUMMARY

This report documents ex-post and ex-ante load impact evaluations for Pacific Gas and Electric Company's ("PG&E") residential time-of-use (TOU) rates for program year 2022. The report addresses the two primary objectives of providing: 1) estimates of ex-post load impacts for E-TOU-C, E-TOU-D, and EV2-A customers in 2022, and 2) ex-ante forecasts of load impacts for 2023 through 2033 that are based on PG&E's enrollment forecasts and the ex-post load impact estimates produced in this study and prior studies.

ES.1 Resources Covered

PG&E currently offers five TOU residential rates. E-TOU-C became available in 2018 and now serves as the default TOU rate. E-TOU-D opened for enrollment May 2020. EV2-A is a whole-house electric vehicle (EV) rate and EV-B is an EV-only rate. E-ELEC became available in December 2022 and is currently available to customers with qualifying electric technologies (e.g., electric vehicles, heat pumps, or battery storage). However, the rate will soon be the default rate for net energy metered (NEM) customers.

On July 3, 2015, the CPUC issued D.15-07-001, *CPUC Decision on Residential Rate Reform*, setting the course for residential rate reform, and for each of California's major investor-owned utilities (IOU)—PG&E, San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE) (the IOUs)—to implement residential Default Time-of-Use rates. Per the requirements of this Decision, the first phase of this transition Default Pilot was limited to a subset of the total eligible population, with the objective of understanding the operational and customer impacts of defaulting customers to a TOU rate in order to prepare for the full rollout of default TOU. The Default Pilot was evaluated in a previous study. The transition to default TOU was completed during the analysis timeframe of this study. Therefore, we estimate the load impacts for each default wave following their transition.

All rates except EV2-A and E-ELEC have two pricing periods: Peak and Off-Peak. (EV2-A and E-ELEC add a Partial Peak period from 3 to 4 p.m. and 9 p.m. to midnight on all days.) The TOU prices vary seasonally with summer defined as June through September and winter as all other months, while the hours included in the pricing periods do not. The Peak periods are defined as follows: E-TOU-C, E-ELEC and EV2-A is 4 p.m. to 9 p.m. on all days; and E-TOU-D is 5 p.m. to 8 p.m. on non-holiday weekdays. E-TOU-C includes a tiered rate structure in which customers receive a $/kWh credit for usage up to the amount of the tariff-defined baseline quantities; the latter varies geographically by Baseline Territory. This feature makes this rate more appealing to low-use customers, while E-TOU-D is likely to appeal to higher-use customers due to the absence of the tiered structure. EV2-A and E-ELEC do not contain the tiered structure. Many customers who have installed solar photovoltaic systems are also enrolled in a TOU rate and net metering (NEM). We attempt to estimate load impacts for NEM customers in this study.

ES.2 Evaluation Methodologies

The evaluation involved selecting quasi-experimental matched control groups and conducting difference-in-differences estimation using regression analysis. The ex-post analysis was conducted for former E-1 customers who newly enrolled in E-TOU-C, E-TOU-D, or EV2-A; and for E-TOU-C customers who enrolled in EV2-A. NEM and non-NEM customers were separately analyzed for E-TOU-C and E-TOU-D. To select the control-group, customers were matched on pre-enrollment load data from October 2020 to September 2021. Lastly, to estimate the impacts from enrolling in a TOU rate, differences between TOU and the matched control group customer loads were estimated for the average and peak load weekday in each month from October 2021 to September 2022. The EV2-A analysis did not employ a control group. Instead, we employed a structural break methodology to confirm EV ownership throughout the analysis period and estimated load impacts using a within treatment, before vs. after methodology.

ES.3 Ex-Post Load Impacts

Tables ES.1 and ES.2 show the estimated Peak-period load impacts for the average weekday in February and August 2022, respectively. For the E-TOU-C non-NEM customers, the results reflect all defaulted customers from April 2021 through April 2022. For all other rates, the results reflect customers who enrolled in the TOU rate from October 2021 through September 2022. The longer timeframe for the E-TOU-C non-NEM customers was used to obtain a complete picture of the default load impacts. Notice the brackets in the "% Impact" column, which show 80 percent confidence intervals around the estimated load impacts. The February 2022 percentage impact is statistically significantly different from zero for all rates, and the size of the confidence interval is inversely related to the number of enrolled customers (i.e., rates with high enrollment tend to have tighter confidence intervals).

Table ES.1: Peak-period Load Impacts by Rate, February Average Weekday[1]

Rate	NEM	Enrolled	Aggregate (MWh/hr)		Per-customer (kWh/hr)		% Impact	Temp. (°F)
			Ref.	Impact	Ref.	Impact		
E-TOU-C	No	1,043,329	725.2	15.6	0.695	0.015	2.2% [1.8 – 2.5%]	56.9
E-TOU-D	No	15,224	20.5	0.65	1.349	0.043	3.2% [2.6 – 3.8%]	57.0
E-1 to EV2-A	Both	2,056	2.55	0.44	1.242	0.213	17.1% [14.8 – 19.4%]	57.0
E-TOU-C to EV2-A	Both	1,253	1.30	0.20	1.037	0.159	15.3% [11.3 – 19.3%]	57.5
E-TOU-C	Yes	19,638	20.6	0.51	1.048	0.026	2.5% [1.9 – 3.1%]	57.0
E-TOU-D	Yes	971	1.62	0.06	1.669	0.062	3.7% [0.3 – 7.1%]	56.9

[1] The brackets accompanying the percentage load impacts represent the 10th and 90th percentile uncertainty adjusted load impacts.

As was the case for the February impacts, the August 2022 load impacts are all statistically significantly different from zero. The highest load impacts come from EV2-A customers, likely due to moving EV charging out of the peak period. Non-NEM E-TOU-C impacts are higher in August than February, though that pattern does not hold across all rates.

Table ES.2: Peak-period Load Impacts by Rate, August Average Weekday

Rate	NEM	Enrolled	Aggregate (MWh/hr)		Per-customer (kWh/hr)		% Impact	Temp. (°F)
			Ref.	Impact	Ref.	Impact		
E-TOU-C	No	1,265,748	1,142	36.9	0.902	0.029	3.2% [2.9 – 3.5%]	78.2
E-TOU-D	No	20,882	55.1	2.29	2.639	0.110	4.2% [3.8 – 4.6%]	88.1
E-1 to EV2-A	Both	3,420	5.22	0.69	1.526	0.202	13.2% [11.1 – 15.4%]	80.2
E-TOU-C to EV2-A	Both	2,747	2.83	0.23	1.031	0.085	8.2% [6.0 – 10.5%]	76.5
E-TOU-C	Yes	21,845	35.9	0.65	1.644	0.030	1.8% [1.3 – 2.4%]	87.9
E-TOU-D	Yes	1,288	3.98	0.35	3.087	0.268	8.7% [5.1 – 12.2%]	90.4

ES.4 Ex-Ante Load Impacts

Ex-ante load impacts were developed separately for the following TOU rates: E-TOU-C, E-TOU-D, and EV2-A. We also developed a forecast for E-ELEC NEM customers. However, because we have no information about customers enrolled in that rate, we used the E-TOU-C NEM per-customer forecast as the basis for the E-ELEC NEM forecast. In each case, the forecast represents *incremental* TOU load impacts, which are attributable to customers joining TOU rates during the forecast period. Customers who are already on TOU rates contribute to an *embedded* TOU load impact that is already reflected in PG&E's system load. The embedded TOU customers are not included in our forecast.

Figure ES.1 shows the yearly enrollments forecast for the month of August[2], for each customer group. The enrollment changes shown in the figure generally follow a smooth path, though E-TOU-D enrollments increase by a higher amount between 2025 and 2026 because E-TOU-B sunsets in November 2025, at which point those customers are expected to join E-TOU-D.

[2] August is referenced here because it is likely to be the CAISO/PG&E peak period in a given year.

Figure ES.1: Forecast August Enrollments by Year and Customer Group

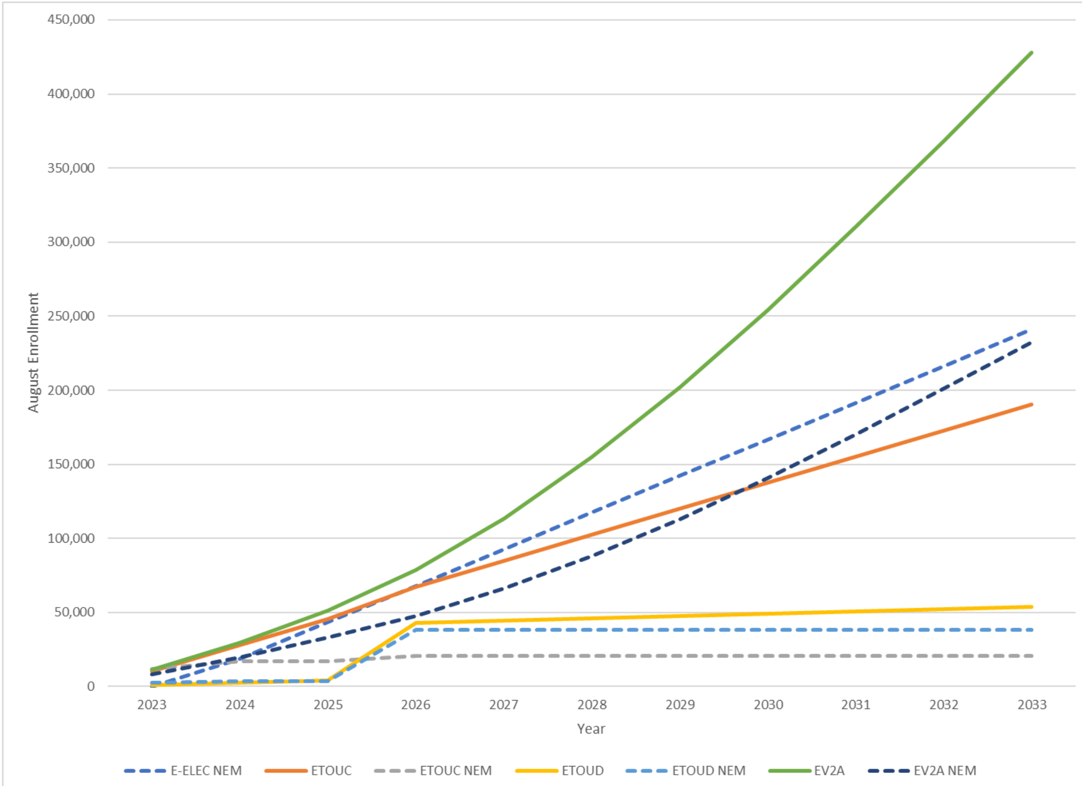
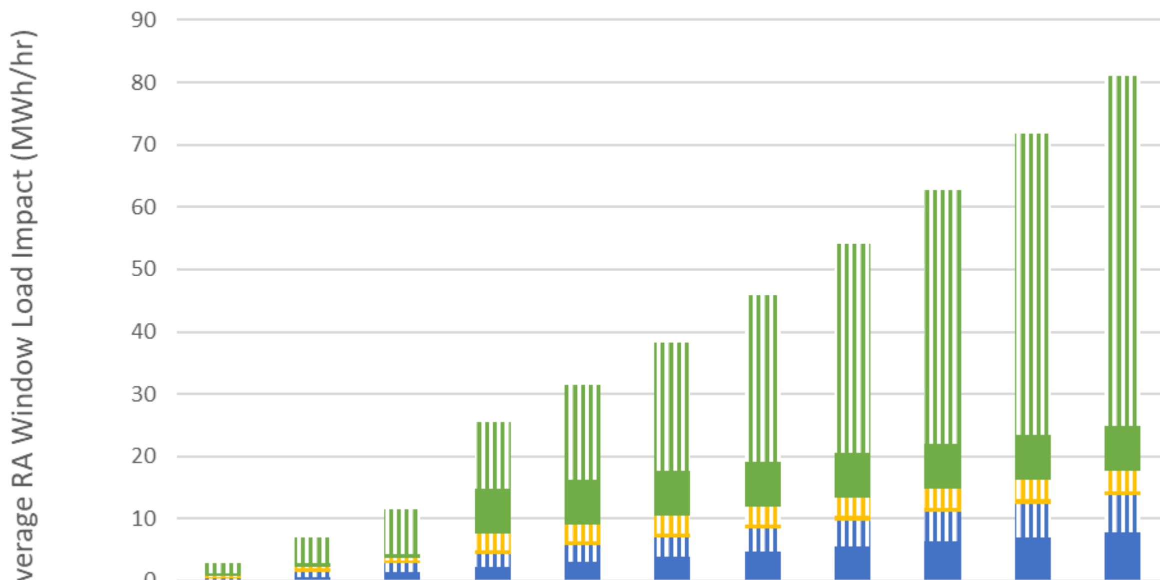


Figure ES.2 summarizes the forecast load impacts for each August during the forecast period. The values are the average load impacts during the Resource Adequacy window (4:00 to 9:00 p.m.) for the PG&E 1-in-2 peak month weather conditions. The load impacts increase over time due to the enrollment pattern shown in Figure ES.1. The share of impacts due to EV2-A increases over time, due to both the high share of incremental enrollment and high per-customer load impact relative to other TOU rates.

Figure ES.2: Average RA Window Load Impacts by Year, August PG&E 1-in-2 Peak Month



	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
EV2-A	1.7	4.2	7.2	10.8	15.2	20.6	26.7	33.5	40.8	48.4	56.1
E-TOUD NEM	0.5	0.7	0.7	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3
E-TOUD	0.1	0.1	0.2	2.5	2.6	2.7	2.8	2.9	3.0	3.1	3.2
E-TOUC NEM	0.4	0.5	0.5	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
E-TOUC	0.3	0.9	1.4	2.1	2.6	3.2	3.7	4.3	4.8	5.3	5.9
E-ELEC NEM	0.0	0.6	1.4	2.2	3.0	3.8	4.6	5.5	6.3	7.1	7.9
Total	2.9	7.0	11.5	25.5	31.5	38.3	45.8	54.1	62.8	71.8	81.0

Year

E-ELEC NEM E-TOUC E-TOUC NEM E-TOUD E-TOUD NEM EV2-A

1. INTRODUCTION AND PURPOSE OF THE STUDY

This report documents ex-post and ex-ante load impact evaluations for Pacific Gas and Electric Company's ("PG&E") residential time-of-use (TOU) rates for program year 2022, where the evaluations conform to the Load Impact Protocols adopted by the CPUC in D-08-04-050. The following rates are included in this evaluation (all have seasonally differentiated rates):

- E-TOU-C: available as a voluntary rate and serves as the default residential TOU rate. It has two TOU pricing periods (Peak and Off-Peak) that apply on all days of the year.
- E-TOU-D: available as a voluntary rate beginning in 2020. It differs from E-TOU-C by having a slightly shorter Peak period (5 to 8 p.m. vs. 4 to 9 p.m.), having weekends and holidays be all Off-Peak, and omitting the Baseline Credit.
- EV2-A: a whole-house EV rate with three TOU pricing periods (Peak, Part-Peak, and Off-Peak).

The primary goals of the evaluation are the following:

1. Estimate ex-post load impacts for each rate for program year 2022; and
2. Develop ex-ante load impact forecasts for the rates for 2023 through 2033.

While our study estimates TOU load impacts for customers who adopted a TOU rate at some point between October 2021 and September 2022, we also estimate load impacts specific to each E-TOU-C default wave. The default waves began in April 2021 and ended in April 2022, with the earlier waves focusing on the cool climate region and the later waves applying to the hot climate regions.

The report is organized as follows. Section 2 contains descriptions of the TOU rates; Section 3 describes the methods used to estimate ex-post load impacts and forecast ex-ante load impacts; Section 4 contains the ex-post load impact results, including analyses of load impacts by climate region and whether the customer was expected to be a structural benefiter on the TOU rate. Section 5 contains the ex-ante load impact forecasts. Section 6 provides a series of comparisons of ex-post and ex-ante results, for the current and previous evaluations.

2. DESCRIPTION OF TIME-OF-USE RATES

PG&E currently offers five TOU residential rates. E-TOU-C became available in 2018 and now serves as the default TOU rate. E-TOU-D opened for enrollment May 2020. EV2-A is a whole-house electric vehicle (EV) rate and EV-B is an EV-only rate.[3] E-ELEC became available in December 2022 and is currently available to customers with qualifying

[3] EV-B is excluded from this analysis due to an inability to estimate TOU load impacts. That is, we do not observe EV-only usage patterns in the absence of a TOU rate so there is no counterfactual upon which to base EV-B load impacts. That is, while EV-B separately meters EV charging, there is no corresponding non-TOU rate that can be used in either a treatment-only before vs. after analysis, or in a treatment vs. control-group analysis.

electric technologies (e.g., electric vehicles, heat pumps, or battery storage). However, the rate will soon be the default rate for net energy metered (NEM) customers.[4]

On July 3, 2015, the CPUC issued D.15-07-001, *CPUC Decision on Residential Rate Reform*, setting the course for residential rate reform, and for each of California's major investor-owned utilities (IOU)—PG&E, San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE) (the IOUs)—to implement residential Default Time-of-Use rates. Per the requirements of this Decision, the first phase of this transition Default Pilot was limited to a subset of the total eligible population[5], with the objective of understanding the operational and customer impacts of defaulting customers to a TOU rate in order to prepare for the full rollout of default TOU. The Default Pilot was evaluated in a previous study. The transition to default TOU was completed during the analysis timeframe of this study. Therefore, we estimate the load impacts for each default wave following their transition.

All rates except EV2-A and E-ELEC have two pricing periods: Peak and Off-Peak. (EV2-A and E-ELEC add a Partial Peak period from 3 to 4 p.m. and 9 p.m. to midnight on all days.) The TOU prices vary seasonally with summer defined as June through September and winter as all other months, while the hours included in the pricing periods do not. The Peak periods are defined as follows: E-TOU-C, E-ELEC, and EV2-A is 4 p.m. to 9 p.m. on all days; and E-TOU-D is 5 p.m. to 8 p.m. on non-holiday weekdays. E-TOU-C includes a tiered rate structure in which customers receive a $/kWh credit for usage up to the amount of the tariff-defined baseline quantities; the latter varies geographically by Baseline Territory. This feature makes this rate more appealing to low-use customers, while E-TOU-D is likely to appeal to higher-use customers due to the absence of the tiered structure. EV2-A and E-ELEC also do not contain the tiered structure.

Many customers who have installed solar photovoltaic systems are also enrolled in a TOU rate and NEM. We attempt to estimate load impacts for NEM customers in this study, though challenges exist in forming a valid control group (as described later).

The primary ex-post analyses contained in this study examine non-NEM E-1 customers who were defaulted onto E-TOU-C from E-1. In addition, we study customers who voluntarily changed from E-1 to E-TOU-C (NEM); E-1 to E-TOU-D (NEM and non-NEM); and E-1 or E-TOU-C to EV2-A (NEM and non-NEM) during the 2022 program year (October 2021 through September 2022).

3. STUDY METHODOLOGY

This section discusses project objectives and technical issues that are addressed in this study, and our approach to addressing those issues. We begin by discussing the ex-post load impact objectives and estimation methods, then turn to the ex-ante forecasts.

[4] E-ELEC is not included in our ex-post analysis due to its start date, but it is reflected in the ex-ante forecast.

[5] A sample of 160,525 customers was selected from the total eligible population after applying exclusions for Phase I of Transition. To test operational readiness, only accounts with a billing cycle falling in the second half of the month were chosen for the transition to the Default rate.

3.1 Ex-Post Load Impact Evaluation

3.1.1 Project Objectives

For non-event-based programs such as TOU rates, the load impact Protocols call for estimating hourly load impacts for each required day type, including the average weekday in each month and monthly system peak days. TOU customers who are net metered are included in this evaluation with some modifications to the methodology to account for the nature of their photovoltaic (PV) systems. The ex-post study estimates *incremental* TOU load impacts, which are the TOU load impacts attributable to newly enrolled customers. *Embedded* TOU load impacts (those attributable to existing TOU customers) are not included in the study. For the embedded customers, the current-year load profiles reflect TOU demand response. However, that response was also present prior to the current program year, making it difficult to estimate the impacts from joining a TOU rate.

As was the case during prior program years, PG&E is interested in differentiating load impacts for customers who do and do not receive a structural benefit from switching to the TOU rate. That is, customers with relatively less Peak-period usage can experience a bill reduction on a TOU rate without modifying their load profile. Such customers may be referred to as "structural benefiters." PG&E provided customer-specific indicators of structural benefiters, which we use to provide summaries of load impacts by structural benefiter status.

The primary ex-post analyses are conducted for five groups of customers, defined as those who changed rates from E-1 to E-TOU-C (separately for NEM and non-NEM), E-TOU-D (separately for NEM and non-NEM), and EV2-A (NEM and non-NEM combined).[6] While the TOU analysis is typically limited to customers migrating from the E-1 tiered rate, this year's EV2-A analysis also considered customers migrating from E-TOU-C to EV2-A. Because E-TOU-C is now the default residential rate for all new customers (including EV customers), we expect the bulk of the EV2-A adopters to come from E-TOU-C in future years.

3.1.2 Evaluation Methods

Estimating the load impacts of the TOU rates, as in all evaluations, requires a method for estimating what customers' usage would have been in the absence of the program; that is, what their usage pattern would have been had they not experienced the static time-varying TOU rates. Since the rates do not vary across days within a season, the logical sources of reference loads include: 1) contemporaneous control group customers, resulting in a treatment/control evaluation approach, or 2) pre-treatment usage data of the TOU participants, resulting in a before/after evaluation approach. If feasible, the two approaches may be combined in a difference-in-differences approach, as in our previous evaluations. Load impacts are calculated as the difference between the counter-factual reference loads and the observed loads of the enrolled customers. We implement the

[6] The sample size of EV2-A NEM customers was too small to merit separately reporting the results.

difference-in-differences approach for all analyses except EV2-A, which uses an approach that compares usage before vs. after EV2-A rate using only treatment customers.

For all analyses except default E-TOU-C, the incremental TOU load impacts will be estimated using customers who enrolled in the TOU rate on or after October 1, 2021. For the default E-TOU-C analysis, the treatment period begins when the customer's wave is transitioned, which varies from April 2021 to April 2022.

Sampling

Because of the large number of treatment customers in the default E-TOU-C analyses, we employed sampling to reduce the number of customers analyzed where appropriate. The decision to sample was made based on the number of treatment customers by wave, California Alternate Rates for Energy Program (CARE) status, and local capacity area (LCA). Table 3.1 shows the sampled percentage of customers for each of these subgroups.

Table 3.1: Sampling Plan by Default Wave and LCA

Wave #	Wave Month	LCA	CARE	Sampled %
1	Apr 2021	Northern Coast	No	5%
			Yes	10%
2	May 2021	Greater Bay Area	No	5%
			Yes	5%
3	Jun 2021	Greater Bay Area	No	5%
			Yes	5%
		Humboldt	No	10%
			Yes	25%
4	Jul 2021	Greater Bay Area	No	5%
			Yes	5%
5	Sep 2021	Greater Bay Area	No	5%
			Yes	10%
6	Oct 2021	Greater Bay Area	No	5%
			Yes	5%
		Other	No	5%
			Yes	10%
7	Feb 2022	Greater Fresno	No	5%
		Kern	No	25%
8	Mar 2022	Greater Bay Area	No	5%
			Yes	5%
		Northern Coast	No	5%
			Yes	10%
		Other	No	10%
			Yes	100%
9	Apr 2022	Other	No	5%
			Yes	100%
		Sierra	No	5%
		Stockton	No	10%

A separate sampling plan was developed to conduct the structural benefiter analysis. Because most customers fall in the "neutral" category, we needed to oversample the "benefiter" and "non-benefiter" statuses to ensure a sample size sufficiently large to obtain valid estimates. To avoid analyzing too many subgroups, we combined customers into two groups: waves 1 through 3 and waves 6 through 9. The former group contains customers from the cool and moderate climate zones while the latter also includes customers in the hot climate zone. Table 3.2 shows the sampling plan by wave group, climate zone, CARE status, and "best rate".[7]

Table 3.2: Sampling Plan for the Structural Benefiter Analysis

Wave Group	Climate Zone	CARE	Best Rate	Sampled %
Waves 1 to 3	Cool	No	E-TOU-C	100%
		Yes	E-TOU-C	100%
	Moderate	No	E-1	25%
			E-TOU-C	25%
		Yes	E-1	50%
			E-TOU-C	50%
Waves 6 to 9	Cool	No	E-TOU-C	50%
		Yes	E-TOU-C	100%
	Moderate	No	E-1	100%
			E-TOU-C	50%
		Yes	E-1	100%
			E-TOU-C	100%
	Hot	No	E-1	5%
			E-TOU-C	50%

We did not employ sampling for the other analyses (i.e., E-TOU-C NEM, E-TOU-D, and EV2A).

Control Group Selection

For the newly enrolled customers in E-TOU-C and E-TOU-D, the control group selection approach involves matching the newly enrolled TOU customers to customers who remain on E-1 throughout the analysis period. A two-step matching process is used. In the first stage, we request monthly billing data for the pre-treatment year (i.e., October 2020 through September 2021[8]) for the TOU and potential control group customers. During this time period, all customers are served on E-1, thus excluding treatment effects from the matching process. We then apply Euclidean distance matching using pre-treatment monthly billing data summary variables (average daily usage in summer and winter) to

[7] A best rate of E-TOU-C indicates a structural benefiter, while a best rate of E-1 indicates a structural non-benefiter.

[8] For the default E-TOU-C analysis, the pre-treatment period varies according to the wave. In each case, the pre-treatment period is the 12 months preceding the default month.

reduce the large number of available E-1 customers to a reduced set of preliminary matches for each TOU customer.[9]

In the second stage, we collapse pre-treatment period interval load data to pre-defined 24-hour profiles[10], for all TOU customers and the preliminary matched E-1 customers. We apply Euclidean distance minimization to load profiles for the pre-enrollment period (including a variable representing the average temperature for the dates included in the profile) and select control group matches (with replacement) for each TOU customer. In addition to the matching on seasonal profiles, the matching process is conducted by LCA and CARE status, ensuring perfect matches by those characteristics. Separate matches are selected by season. Finally, we request hourly load data for the full analysis period for the TOU customers and selected E-1 control group customers. These data are used in the ex-post load impact analysis, and in the development of reference loads for the ex-ante analysis.

Once the matched control group customers are selected, we use regression analysis to compare treatment and control group loads in the post-enrollment period, while controlling for differences in the pre-enrollment period (i.e., difference-in-differences).

Load Impact Estimation

The presence of matched control group customers means that the estimation equations for the incremental ex-post evaluation may be quite simple, essentially a formal regression analysis to compare the loads of treatment and control group customers on the day types that are required for load impact evaluations of non-event-based programs like TOU rates (average weekdays and system peak days by month). Since the pre-enrollment data that are used in the control group matching process are available, we include data for each non-holiday weekday in each month for the pre-enrollment period (for the average weekday analysis), resulting in difference-in-differences models. Separate models are estimated by hour, month, CARE status, and LCA, where the customer-level fixed-effects models are of the following form:[11]

$$kW_{c,d} = \alpha + \beta_{TOU} \times (TOU_c \times Post_d) + \beta_{Post} \times Post_d + \beta_{Mean17} \times Mean17_{c,d} + C_c + D_d + \varepsilon_{c,d}$$

The variables and coefficients in the equation are described in Table 3.3 below.

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[9] We then select the two nearest neighbors for each treatment customer for inclusion in the Stage 2 match. Exact matching was conducted within climate region.

[10] CA Energy Consulting selects the days to be included in the seasonal profiles from “core” months (June through August for summer; December through February for winter). Within each season, three profiles are developed based on daily average temperatures, weighted across the weather stations associated with the segment. The top 10 percent of days are defined as the extreme (i.e., hot in summer) profile, the middle 50 percent of days are defined as the typical profile, and all weekend days constitute the third profile.

[11] Note that the customer and date fixed effects preclude the need to include a stand-alone TOU_c variable because it is perfectly collinear with the customer’s fixed effect.

Table 3.3: Descriptions of Variables in the Ex-post Estimation Model

Symbol	Description
$kW_{c,d}$	Load in a particular hour for customer *c* on day *d*
TOU_c	Variable indicating whether customer *c* is a TOU (1) or Control (0) customer
$Post_d$	Variable indicating that day *d* is in the customer's post-enrollment period
$Mean17_{c,d}$	Average temperature during the first 17 hours of day *d* at the weather station associated with customer *c*
α	Estimated constant coefficient
β_{TOU}	Estimate of TOU load impact
β_{Post}	Estimate of usage change for treatment and control customers following TOU adoption by the treatment customers
β_{Mean17}	Estimate of effect of weather on customer usage
C_c	Customer fixed effects
D_d	Date fixed effects
$\varepsilon_{c,d}$	Error term

In some cases, small sample sizes prevent robust estimation for all months and subgroups. This problem can be especially acute in the early months of the analysis (October through December), when relatively few customers are enrolled in the TOU rate compared to the months later in the program year.

Other Analysis Objectives

In addition to the overall load impacts by TOU rate, PG&E is interested in the following analyses:

- Load impacts by CARE status;
- Load impacts by climate region; and
- Differences in load impacts by structural benefiter status.

The load impacts by CARE status and climate region can be estimated using a straightforward extension of our proposed analysis, by simply restricting the regression samples to the appropriate customers. Regarding differentiating load impacts for customers who do and do not receive a structural benefit from switching to the TOU rate, customers with relatively less on-peak usage can experience a bill reduction on TOU without modifying their load profile. Such customers can be referred to as "structural benefiters." PG&E provided its customer-specific indicators of structural benefiters, which we use to provide summaries of load impacts. As described above, we created a separate sampling plan to ensure representativeness for structural benefiters and non-benefiters.

EV2-A Load Impacts

Schedule EV2-A is a whole-house EV rate, which means that all the customer's usage (including the EV charging) is billed using the TOU rate. (EV-A is also a whole-house rate, but it is closed to new enrollment.) In contrast, EV-B requires a separate meter and apply only to customer's EV charging.

The difficulty in evaluating EV2-A customers arises from not knowing when customers adopt an electric vehicle and begin charging at home. For example, many customers who transition from E-1 or E-TOU-C to EV2-A may have done so because of an EV purchase, while others had the EV while on E-1 or E-TOU-C. To estimate customer demand response to the EV2-A rate, we need to observe customer charging (and other usage) behavior with and without the TOU prices. For customers who enroll in EV2-A at the same time they obtain and begin charging their EV, we have no way of knowing how the TOU rates affected their charging behavior.

To identify customers who had an electric vehicle prior to enrolling in the EV2-A rate, we estimate customer-specific structural breaks in usage. The structural break model identifies the most likely date on which there is a change to a customers' total usage that isn't accounted for in the regression specification. A statistical test identifies customers who do not have a statistically significant structural break in their usage level. Customers that do not exhibit a statistically significant change in total usage during the analysis period (which included the current program year and the 12 months prior to it) are assumed to have been charging an electric vehicle during the entire analysis period (while being served on E-1/E-TOU-C and EV2-A). The ex-post load impacts are subsequently estimated using a before/after analysis and represent the change due to the TOU rate, and not from adopting an electric vehicle. This type of analysis depends on having a sufficient sample of customers that enrolled in EV2-A and have an electric vehicle for the entire analysis period (i.e., pre- and post-EV2-A).

The EV-B rate presents further challenges that prevent the direct estimating of their ex-post load impacts. That is, because the rate only applies to metered EV usage, we are unable to obtain a counter-factual load that represents EV charging behavior in the absence of TOU pricing. If the customer joined from rate E-1, their usage on that rate will represent the whole house and thus not be comparable to the EV-only usage on EV-B. We therefore exclude this rate from our study.

NEM Customer Load Impacts

The NEM analysis is limited to customers migrating / transitioning from E-1, which means they will have been part of the NEM 1.0 regulations and be of an older vintage than the NEM 2.0 customers who were required to enroll in a TOU rate upon attaining NEM status.

The NEM customers we can include in the study are analyzed using methods like those described above, with three major distinctions. First, only customers that are NEM for the entire analysis period and have not made changes to their solar PV system are included.[12] Second, the solar photovoltaic generation capacity size is included in the matching process. Third, customers with large changes in load profiles between periods are not used in the analysis because the differences are more likely caused by

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

unobserved structural changes to a customer's solar PV system.[13] Each of these requirements helps prevent estimating TOU load impacts that are confounded by differences in solar generation capacity between periods and/or between the treatment and control groups, as opposed to only a behavioral response to TOU rates.[14]

3.2 Forecasting Ex-Ante Load Impacts

3.2.1 Objectives

The objectives of the ex-ante portion of the evaluation involve developing eleven-year forecasts of estimated program load impacts based on the ex-post findings of per-customer load impacts (to the extent possible) and PG&E's enrollment projections. The load impacts are to be provided for several customer sub-groups, day types, and weather scenarios, including the following:

- An average weekday in each month under each of the four weather scenarios (CAISO 1-in-2 and 1-in-10 weather years and PG&E 1-in-2 and 1-in-10 weather years);
- The monthly system peak day in each month under the four weather scenarios.

Only incremental TOU impacts are forecast. The following rates are included in our ex-ante forecast:

- E-TOU-C from E-1, NEM and non-NEM
- E-TOU-D from E-1, NEM and non-NEM
- EV2-A from E-TOU-C, NEM and non-NEM
- E-ELEC from E-1, NEM

The methods used to develop the forecast differ by rate, as described below.

3.2.2 Ex-ante evaluation approach

To develop ex-ante load impacts for the TOU rates, we first develop regression equations for the purposes of simulating reference loads using the temperature conditions contained in the scenarios required by the Protocols. The models use hourly load data from the pre-treatment period averaged across "cells" (e.g., for the average residential customer in each TOU rate and LCA). The reference load model explains hourly usage as a function of

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[13] This restriction depends on the availability of historical information regarding customers' NEM characteristics. For instance, if the date and change of customers' solar PV size is available, then it can be used to identify, and exclude from the analysis, customers that make changes to their solar PV system.

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

weather conditions, day type, time of day, and month. A typical form for the reference load model is the following:

$$Q_{i,t} = a + \sum_{i=2}^{24}\left(b_i^{Weather} \times h_i \times Weather_t\right) + \sum_{i=2}^{24}\left(b_i^{MON} \times h_i \times MON_t\right)$$
$$+ \sum_{i=2}^{24}(b_i^{FRI} \times h_i \times FRI_t) + \sum_{i=2}^{24}(b_i^{h} \times h_i) + \sum_{i=2}^{5}(b_i^{DOW} \times DOW_{i,t})$$
$$+ \sum_{i=7}^{9}(b_i^{MONTH} \times MONTH_{i,t}) + e_{i,t}$$

The variables are explained in Table 3.4 below.

Table 3.4: Descriptions of Variables in the Ex-ante Reference Load Model

Variable Name / Term	Variable / Term Description
$Q_{i,t}$	the customer group's usage in hour *i* of day *t*
a and the various *b*'s	the estimated parameters
h_i	a dummy variable for hour *i*
$Weather_{i,t}$	weather conditions during hour *i* and/or day *t* (e.g., measured by the average temperature during the first 17 hours of the day)
MON_t	a dummy variable for Monday
FRI_t	a dummy variable for Friday
$DOW_{i,t}$	a series of dummy variables for each day of the week
$MONTH_{i,t}$	a series of dummy variables for each month
$e_{i,t}$	the error term.

Per-customer *reference loads* are produced from the estimated equations by simulating (i.e., predicting) loads using the appropriate day type and weather conditions for each required month. They are then scaled up to total reference loads using the forecast enrollments provided by PG&E.

The ex-ante load impacts are derived from the ex-post estimates. Our preference is to use the impacts for each LCA in each month of the year, but some substitutions are made due to small sample sizes or otherwise unreliable estimates. The basis for the load impacts varies by group, as follows:

- Non-NEM E-TOU-C impacts are based on the PY2022 percentage load impacts for customers in all default waves. For the customers in the earlier default waves, the load impacts are from their second year on the rate while for the later default waves the impacts reflect the first year on the rate.
- Non-NEM E-TOU-D and NEM E-TOU-C forecasts use PY2022 percentage load impacts by LCA and month.
- NEM E-TOU-D impacts use a single set of PY2022 percentage load impacts for all LCAs. Many LCAs had low sample sizes, preventing us from using LCA-specific percentage load impacts.

- EV2-A (combined NEM and non-NEW) impacts use a single set of PY2022 *level* load impacts for all LCAs. Many LCAs had low sample sizes, preventing us from using LCA-specific load impacts. We used level rather than percentage impacts because we believe it better reflects the end-use being shifted (EVs).[15]
- E-ELEC NEM percentage impacts (and the corresponding reference loads) match those of E-TOU-C. This is done due to a lack of data for E-ELEC customers at this time.

Uncertainty-adjusted load impacts are based on the standard errors from the ex-post impact estimates used in the ex-ante study. Scenario-specific percent load impacts will be developed from 10th, 30th, 50th, 70th, and 90th percentile load changes estimated for the relevant program year.

As in all recent load impact evaluations, we present results of analyses of the relationship between current ex-post and ex-ante load impacts, focusing on key factors causing differences between them (e.g., differences between observed temperatures in 2022 and the temperatures in the various weather scenarios). We will also compare current and previous ex-post load impacts, and current and previous ex-ante load impacts.

4. EX-POST LOAD IMPACT STUDY FINDINGS

This section reports ex-post load impact findings for the customers who migrated from the standard E-1 residential rate to E-TOU-C or E-TOU-D, and from E-TOU-C to EV2-A. Relevant subsections report reference loads and load impacts for the average weekday by season, climate region, CARE status, and structural benefiter status. Typical hourly load profiles are also shown.

Many of the tables include the number of enrolled customers. Note that this is often higher than the number of customers included in the regression model, which is constrained to customers within a range of TOU start dates and the rate from which they migrated. In some cases, a low number of customers contributes to a wide confidence interval around the percentage load impact. Appendix Table L.1 shows the number of treatment customers represented in each of the results presented in this section.

4.1 Peak-period Load Impact Summaries

In the sub-sections below, we summarize average Peak-period load impacts by rate and the following: by season, climate region, CARE status, and structural benefiter status. In each case, the Peak period is defined according to the schedule's TOU period definitions, as described in Section 2. The range of percentage load impacts contained in each table represents an 80 percent confidence interval (corresponding to the 10th and 90th percentile uncertainty-adjusted load impacts required by the Protocols). With the exception of the E-TOU-C non-NEM results, the load impacts reflect customers who

[15] The EV2-A forecast uses the E-TOU-C to EV2-A load impacts as its basis, as most eligible E-1 customers underwent the TOU transition to E-TOU-C and E-TOU-C is now the default residential rate for all new incremental customers (including EV customers, which are projected to grow significantly over the forecast horizon).

adopted the TOU rate sometime between October 2021 and September 2022. In contrast, the E-TOU-C non-NEM results reflect all non-NEM customers who were defaulted onto E-TOU-C between April 2021 and April 2022. Therefore, the summer PY2022 load impacts include a mix of first- and second-year bill impacts, depending on the customer's default wave. This provides a complete view of the load impacts from the defaulted customer population, regardless of wave.

4.1.1 Peak-period impacts by Season

Tables 4.1 and 4.2 show the estimated Peak-period load impacts for the average weekday in February and August 2022, respectively. For the E-TOU-C non-NEM customers, the results reflect all defaulted customers from April 2021 through April 2022. For all other rates, the results reflect customers who enrolled in the TOU rate from October 2021 through September 2022. The longer timeframe for the E-TOU-C non-NEM customers was used to obtain a complete picture of the default load impacts. Notice the brackets in the "% Impact" column, which show 80 percent confidence intervals around the estimated load impacts. The February 2022 percentage impact is statistically significantly different from zero for all rates, and the size of the confidence interval is inversely related to the number of enrolled customers (i.e., rates with high enrollment tend to have tighter confidence intervals).

Table 4.1: Peak-period Load Impacts by Rate, February Average Weekday[16]

Rate	NEM	Enrolled	Aggregate (MWh/hr)		Per-customer (kWh/hr)		% Impact	Temp. (°F)
			Ref.	Impact	Ref.	Impact		
E-TOU-C	No	1,043,329	725.	15.6	0.695	0.015	2.2% [1.8 – 2.5%]	56.9
E-TOU-D	No	15,224	20.5	0.65	1.349	0.043	3.2% [2.6 – 3.8%]	57.0
E-1 to EV2-A	Both	2,056	2.55	0.44	1.242	0.213	17.1% [14.8 – 19.4%]	57.0
E-TOU-C to EV2-A	Both	1,253	1.30	0.20	1.037	0.159	15.3% [11.3 – 19.3%]	57.5
E-TOU-C	Yes	19,638	20.6	0.51	1.048	0.026	2.5% [1.9 – 3.1%]	57.0
E-TOU-D	Yes	971	1.62	0.06	1.669	0.062	3.7% [0.3 – 7.1%]	56.9

As was the case for the February impacts, the August 2022 load impacts are all statistically significantly different from zero. The highest load impacts come from EV2-A customers, likely due to moving EV charging out of the peak period. Non-NEM E-TOU-C impacts are higher in August than February, though that pattern does not hold across all rates. Note that EV2-A customers enrolling from E-1 have higher reference loads and load impacts (in level and percentage terms) than those enrolling from E-TOU-C.

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16 The brackets accompanying the percentage load impacts represent the 10th and 90th percentile uncertainty adjusted load impacts.

Table 4.2: Peak-period Load Impacts by Rate, August Average Weekday

Rate	NEM	Enrolled	Aggregate (MWh/hr)		Per-customer (kWh/hr)		% Impact	Temp. (°F)
			Ref.	Impact	Ref.	Impact		
E-TOU-C	No	1,265,748	1,142	36.9	0.902	0.029	3.2% [2.9 – 3.5%]	78.2
E-TOU-D	No	20,882	55.1	2.29	2.639	0.110	4.2% [3.8 – 4.6%]	88.1
E-1 to EV2-A	Both	3,420	5.22	0.69	1.526	0.202	13.2% [11.1 – 15.4%]	80.2
E-TOU-C to EV2-A	Both	2,747	2.83	0.23	1.031	0.085	8.2% [6.0 – 10.5%]	76.5
E-TOU-C	Yes	21,845	35.9	0.65	1.644	0.030	1.8% [1.3 – 2.4%]	87.9
E-TOU-D	Yes	1,288	3.98	0.35	3.087	0.268	8.7% [5.1 – 12.2%]	90.4

We now provide more detail on the default E-TOU-C (non-NEM) load impacts. We estimated separate load impacts for each default wave. A description of each wave, including the month in which the customers were defaulted, is shown in Table 4.3. The earliest waves (1 through 4) have two summers of load impacts to examine. The default process was not random: earlier waves focused on cool and moderate climate zones while later waves included the hot climate zone. CARE customers in the hot climate zone were excluded from the TOU Transition.[17]

[17] Our analysis excludes the December 2021 default wave consisting of customers with more than 10 service agreements due to comparatively small sample sizes within LCA and concerns about comparability with other customers. These service agreements account for approximate 2 percent of the defaulted total. In addition, NEM customers were transitioned during their true-up cycle regardless of region, which follows a different schedule than documented here. We evaluated NEM customers who adopted E-TOU-C during PY2022, which is consistent with our evaluations of the non-default TOU rates.

Table 4.3: Description of E-TOU-C Default Waves

Wave #	Default Month	Communities	LCAs Included
1	Apr 2021	Mendocino, Sonoma	Northern Coast
2	May 2021	Alameda	Greater Bay Area
3	Jun 2021	North Coast (Humboldt, Siskiyou, Trinity), Santa Clara	Greater Bay Area, Humboldt
4	Jul 2021	San Francisco	Greater Bay Area
5	Sep 2021	San Mateo	Greater Bay Area
6	Oct 2021	Central Coast (Monterrey, San Benito, San Luis Obispo, Santa Barbara, Santa Cruz)	Greater Bay Area, Other
7	Feb 2022	Fresno, Kern, Kings, Madera, Mariposa, Merced, Tulare	Greater Fresno, Kern
8	Mar 2022	Contra Costa, Marin, Napa, Solano	Greater Bay Area, Northern Coast, Other
9	Apr 2022	Alpine, Amador, Butte, Calaveras, Colusa, El Dorado, Glenn, Lake, Lassen, Nevada, Placer, Plumas, Sacramento, San Joaquin, Shasta, Sierra, Stanislaus, Sutter, Tehama, Tuolumne, Yolo, Yuba	Other, Sierra, Stockton

Tables 4.4, 4.5, and 4.6 show the average peak-period load impact in percentage terms, per-customer, and in aggregate, respectively, by default wave and month. Notice that customers in waves 1 through 4 had higher load impacts in their second summer on E-TOU-C. In addition, those early default waves had higher percentage load impacts than customers in the later default waves during the summer of 2022, though the level load impact was comparable. That is, because the later waves included customers from the hot climate zones, the overall load level was higher so that a lower percentage load impact is associated with a more comparable level load impact. This result is somewhat surprising, as we expected customers in the hot climate region would be more responsive (in level and percentage terms) because they had more load that could be shifted. It is possible their load impacts will increase in their second summer on E-TOU-C, which can be a topic for the next load impact evaluation to explore.

Table 4.4: Average E-TOU-C Percentage Peak-Period Load Impact by Month and Wave

Month	Wave								
	1	2	3	4	5	6	7	8	9
4/2021	3.0%								
5/2021	3.2%	2.5%							
6/2021	1.8%	4.2%	3.7%						
7/2021	2.6%	4.9%	3.9%	2.0%					
8/2021	1.3%	3.9%	5.2%	2.6%					
9/2021	4.7%	3.9%	3.1%	1.4%	1.0%				
10/2021	-5.7%	-1.9%	-1.7%	-0.4%	-1.0%	0.9%			
11/2021	1.3%	3.1%	5.1%	2.7%	3.2%	3.8%			
12/2021	1.3%	-0.1%	2.8%	0.6%	1.5%	1.5%			
1/2022	1.6%	1.7%	3.2%	2.6%	2.3%	2.9%			
2/2022	2.1%	2.0%	2.4%	1.8%	2.8%	1.8%	1.8%		
3/2022	3.1%	3.4%	3.1%	3.2%	3.1%	3.8%	2.0%	3.9%	
4/2022	-0.5%	2.9%	1.6%	-0.3%	2.7%	1.0%	-2.6%	0.5%	0.0%
5/2022	3.2%	5.6%	0.7%	1.5%	1.7%	2.4%	-2.0%	1.9%	-0.2%
6/2022	5.0%	5.7%	4.1%	1.6%	3.6%	1.7%	2.7%	1.0%	2.4%
7/2022	4.7%	5.6%	4.2%	2.9%	3.0%	1.1%	2.2%	2.5%	2.1%
8/2022	4.4%	5.4%	4.5%	3.2%	2.9%	0.3%	1.2%	3.1%	2.4%
9/2022	7.6%	4.2%	1.3%	3.5%	4.2%	1.0%	-0.5%	2.5%	3.5%

Table 4.5: Per-Customer E-TOU-C Peak-Period Load Impact (kWh/hour/customer) by Month and Wave

Month	Wave								
	1	2	3	4	5	6	7	8	9
4/2021	0.021								
5/2021	0.023	0.014							
6/2021	0.014	0.026	0.032						
7/2021	0.022	0.032	0.036	0.008					
8/2021	0.010	0.026	0.049	0.011					
9/2021	0.037	0.026	0.027	0.006	0.007				
10/2021	-0.037	-0.011	-0.011	-0.002	-0.006	0.006			
11/2021	0.011	0.020	0.039	0.014	0.024	0.026			
12/2021	0.012	-0.001	0.026	0.004	0.014	0.013			
1/2022	0.014	0.012	0.027	0.015	0.019	0.022			
2/2022	0.016	0.013	0.018	0.009	0.021	0.013	0.014		
3/2022	0.022	0.020	0.021	0.016	0.021	0.025	0.014	0.026	
4/2022	-0.004	0.016	0.010	-0.001	0.017	0.006	-0.018	0.003	0.000
5/2022	0.022	0.032	0.005	0.006	0.010	0.014	-0.020	0.014	-0.002
6/2022	0.041	0.037	0.037	0.006	0.024	0.011	0.050	0.010	0.035
7/2022	0.037	0.035	0.037	0.012	0.019	0.007	0.051	0.024	0.037
8/2022	0.038	0.037	0.044	0.013	0.019	0.002	0.027	0.034	0.043
9/2022	0.063	0.029	0.012	0.015	0.029	0.007	-0.009	0.025	0.048

Table 4.6: Total E-TOU-C Peak-Period Load Impact (MWh/hour) by Month and Wave

Month	Wave								
	1	2	3	4	5	6	7	8	9
4/2021	1.70								
5/2021	1.86	3.45							
6/2021	1.15	6.61	9.21						
7/2021	1.70	7.80	10.14	1.38					
8/2021	0.82	6.32	13.51	1.96					
9/2021	2.82	6.10	7.28	1.04	0.87				
10/2021	-2.84	-2.53	-3.04	-0.31	-0.79	1.04			
11/2021	0.79	4.57	10.18	2.25	2.96	4.73			
12/2021	0.90	-0.17	6.64	0.63	1.72	2.29			
1/2022	1.00	2.76	6.91	2.44	2.32	3.91			
2/2022	1.20	2.90	4.66	1.51	2.58	2.24	0.51		
3/2022	1.57	4.47	5.26	2.50	2.52	4.31	0.52	5.83	
4/2022	-0.25	3.55	2.57	-0.18	2.05	0.98	-0.63	0.75	-0.01
5/2022	1.58	6.98	1.26	0.98	1.22	2.42	-0.71	3.09	-0.13
6/2022	2.90	7.99	9.02	0.99	2.79	1.85	1.74	2.10	3.02
7/2022	2.57	7.39	8.91	1.80	2.19	1.19	1.75	5.14	3.17
8/2022	2.63	7.79	10.36	1.99	2.19	0.33	0.92	7.13	3.58
9/2022	4.27	6.00	2.69	2.19	3.20	1.09	-0.29	5.07	3.90

4.1.2 Peak-period impacts by Climate Region

Table 4.7 shows the average Peak-period load impact for the August 2022 average weekday, reported by climate region.[18] Due to smaller sample sizes, we omit NEM customers and the EV2-A rate from the summaries. Blue shading is used to help separate the rate-specific results.

Many of the results in the table make intuitive sense: reference loads and temperatures are progressively higher as one moves from cool to moderate to hot climate regions. The level load impact (in kWh/hour/customer) tends to be higher in hotter climate regions,

[18] Climate regions are defined by the customer's Baseline Territory. The "hot" region includes the P, R, S, and W territories; the "moderate" region includes the Q, X, and Y territories; and the "cool" region includes the T, V, and Z territories.

with the exception being the E-TOU-D CARE results, for which the moderate climate region impacts are lower than the cool region impacts in both level and percentage terms. Recall that there are no E-TOU-C CARE customers in the hot climate region, as these customers were exempt from the default process.

Table 4.7: Peak-period Load Impacts by Rate and Climate Region, August Average Weekday

Rate	CARE	Climate	Enrolled	Reference (kWh/hr/cust)	Impact (kWh/hr/cust)	% Impact	Temp. (°F)
E-TOU-C	No	Cool	313,883	0.486	0.018	3.7% [2.7 – 4.7%]	66.8
		Moderate	410,024	1.037	0.044	4.3% [3.4 – 5.2%]	77.7
		Hot	128,958	2.072	0.050	2.4% [1.7 – 3.0%]	91.5
	Yes	Cool	138,592	0.499	0.001	0.3% [-1.1 – 1.6%]	66.6
		Moderate	160,006	0.910	0.030	3.3% [2.1 – 4.5%]	77.3
		Hot	n/a	n/a	n/a	n/a	n/a
E-TOU-D	No	Cool	2,006	0.997	0.022	2.3% [0.0 – 4.5%]	70.2
		Moderate	7,100	2.152	0.062	2.9% [1.8 – 4.0%]	79.0
		Hot	9,670	3.388	0.144	4.3% [3.6 – 4.9%]	92.2
	Yes	Cool	470	0.989	0.052	5.2% [0.8 – 9.6%]	67.8
		Moderate	909	1.876	0.040	2.1% [-0.8 – 5.1%]	79.0
		Hot	727	3.626	0.134	3.7% [1.7 – 5.6%]	93.7

4.1.3 Peak-period impacts by CARE Status

Table 4.8 shows the average Peak-period load impact for the August 2022 average weekday, reported by CARE status.[19] Due to smaller sample sizes, we omit NEM customers and the EV2-A rate from the summaries. Blue shading is used to help separate the rate-specific results. For both rates we find that non-CARE customers have higher average reference loads, level load impacts, and percentage load impacts. In each case, the load impact is statistically significantly different from zero. Notice that for E-TOU-C the CARE customers have a notably lower average temperature than the non-CARE

[19] CARE customers include customers who are always or sometimes reported to be CARE during our analysis period.

customers. This is because CARE customers in the hot climate region were exempt from the default process.

Table 4.8: Peak-period Load Impacts by Rate and CARE Status, August Average Weekday

Rate	CARE	Reference (kWh/hr/cust)	Impact (kWh/hr/cust)	% Impact	Temp. (°F)
E-TOU-C	No	0.965	0.034	3.5% [3.1 – 3.8%]	79.4
	Always / Sometimes	0.718	0.016	2.3% [1.7 – 2.9%]	73.7
E-TOU-D	No	2.682	0.114	4.3% [3.9 – 4.7%]	88.2
	Always / Sometimes	2.259	0.069	3.0% [1.7 – 4.4%]	87.0

4.1.4 Peak-period impacts by Structural Benefiter Status

PG&E provided a variable indicating the expected best rate for defaulted TOU customers. We separately examined CARE and non-CARE customers by climate zone and for two sets of waves: "early", or waves 1 through 3; and "late", or waves 6 through 9. Three categories of customers were provided by PG&E:

- Benefiters: a customer who is expected to experience a significant bill reduction after switching to a TOU rate without changing their behavior;
- Non-benefiter: a customer who would be expected to pay significantly less by remaining on E-1 rather than switching to E-TOU-C; and
- Neutral: customers with expected bill impacts lower than the thresholds defined below.

In this case, benefiters and non-benefiters were defined by CARE status as follows:

- Non-CARE: bill change larger than $100 or 15 percent per year; and
- CARE: bill change larger than $50 or 10 percent per year.

These criteria identify most of the population as neutral. For the waves we examined, 2.7 percent of the customers were structural benefiters while 3.8 percent were non-benefiters.

Table 4.9 shows the average Peak-period load impact for the August 2022 average weekday, reported by wave group, CARE status, climate zone, and benefiter status. Blue shading is used to help separate the climate-zone level results.

It is difficult to draw any firm conclusions from the estimated load impacts. Many of the estimates are not statistically significantly different from zero and some of the point estimates are wrong-signed (indicating peak-period load *increases* following E-TOU-C adoption).

Table 4.9 Peak-period Impacts by Structural Benefiter Status, August Average Weekday

Wave	CARE	Climate Zone	Benefiter	Enrolled	Reference	Impact	% Impact	Temp
Early	Always / Sometimes	Cool	Yes	1,784	0.754	0.041	5.4% [1.8 – 9.0%]	67.2
		Moderate	No	3,219	2.122	0.066	3.1% [1.0 – 5.1%]	78.0
			Yes	3,337	1.188	0.046	3.9% [-0.6 – 8.4%]	77.4
	Never	Cool	Yes	2,310	1.178	0.014	1.2% [-2.3 – 4.7%]	67.7
		Moderate	No	6,362	2.303	0.005	0.2% [-1.7 – 2.2%]	77.7
			Yes	5,887	2.309	-0.109	-4.7% [-9.3 – -0.2%]	76.9
Late	Always / Sometimes	Cool	Yes	1,736	0.939	0.020	2.1% [-1.2 – 5.5%]	67.6
		Moderate	No	843	2.515	-0.123	-4.9% [-7.3 - -2.4%]	80.7
			Yes	1,859	1.124	-0.061	-5.5% [-10.8 – 0.0%]	80.1
	Never	Cool	Yes	3,430	1.440	-0.043	-3.0% [-6.5 - 0.6%]	68.5
		Moderate	No	26,240	3.464	-0.041	0.0% [-1.4 – 1.5%]	80.3
			Yes	2,863	3.584	-0.077	-2.5% [-6.2 – 1.2%]	78.6
		Hot	No	26,240	3.464	-0.041	-1.2% [-2.9% - 0.6%]	93.5
			Yes	2,863	3.584	-0.077	-2.1% [-6.3 – 2.0%]	91.4

4.2 Average Hourly Load Impacts

This subsection illustrates the hourly load and load impact profiles for the average weekdays in February and August 2022. In each case, we graph per-customer reference loads, observed loads, and load impacts with shading provided to indicate the rate's Peak period. The blue line represents the reference load, which is our estimate of the load that would have occurred had the customers remained in E-1 instead of changing to the TOU rate. The orange line is the observed load, while the dashed green line is the hourly load impact (the difference between the reference and observed loads).

Figures 4.1 and 4.2 show the estimates for E-TOU-C non-NEM customers in February and August 2022, respectively. The February results show a 2.2 percent reduction in peak-period usage. The August estimates show a 3.2 percent reduction in peak-period usage.

Figure 4.1: E-TOU-C Non-NEM February Average Weekday Hourly Impacts

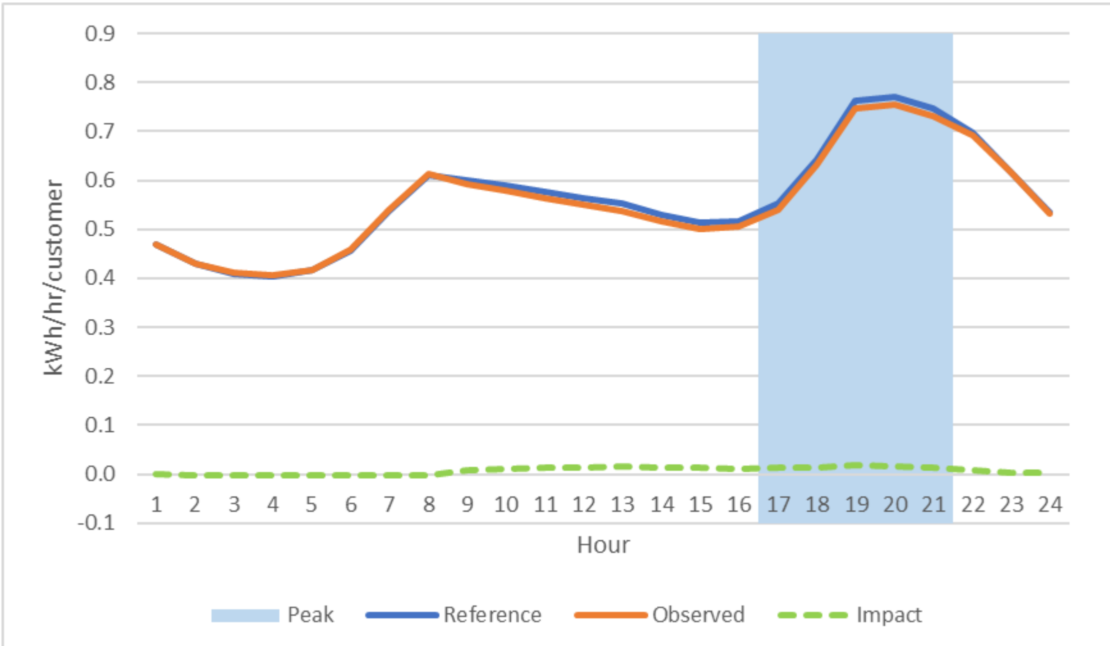
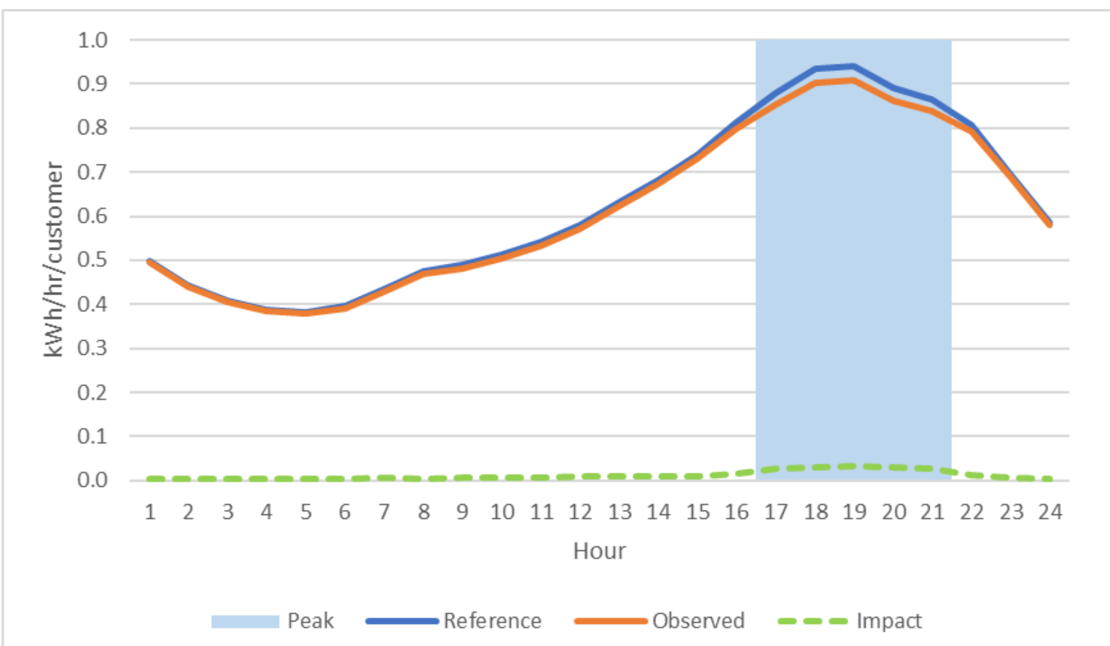


Figure 4.2: E-TOU-C Non-NEM August Average Weekday Hourly Impacts



Figures 4.3 and 4.4 show the estimates for E-TOU-C NEM customers. The typical load profile displays the familiar "duck curve" relative to the non-NEM load profiles shown above. As with the non-NEM figures, the load impacts largely occur during the peak period.

Figure 4.3: E-TOU-C NEM February Average Weekday Hourly Impacts

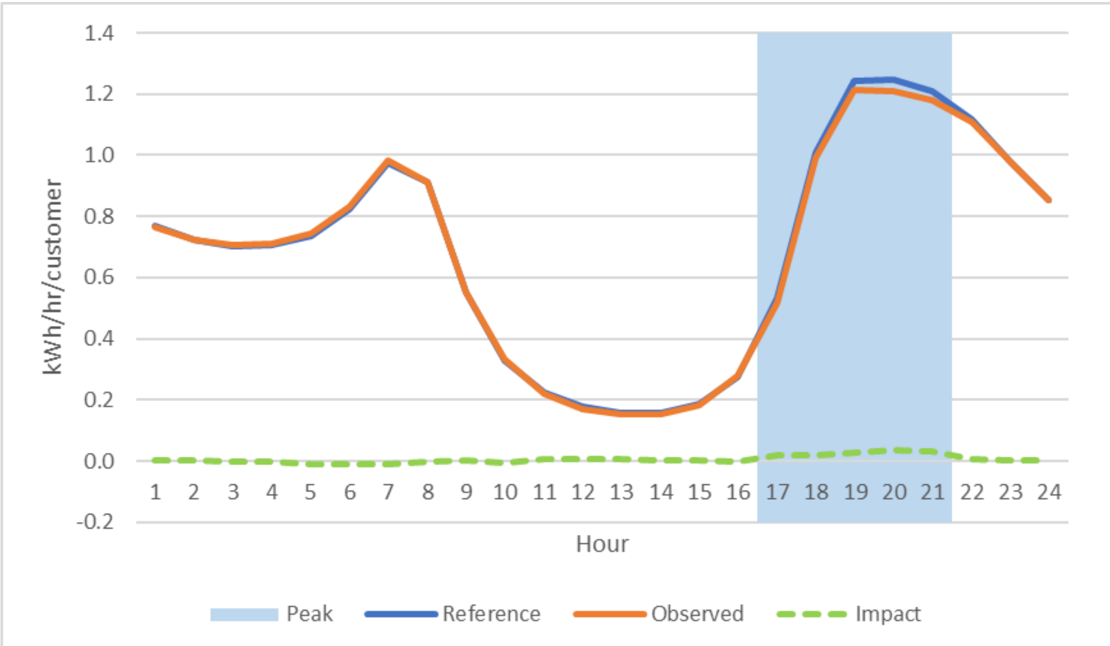
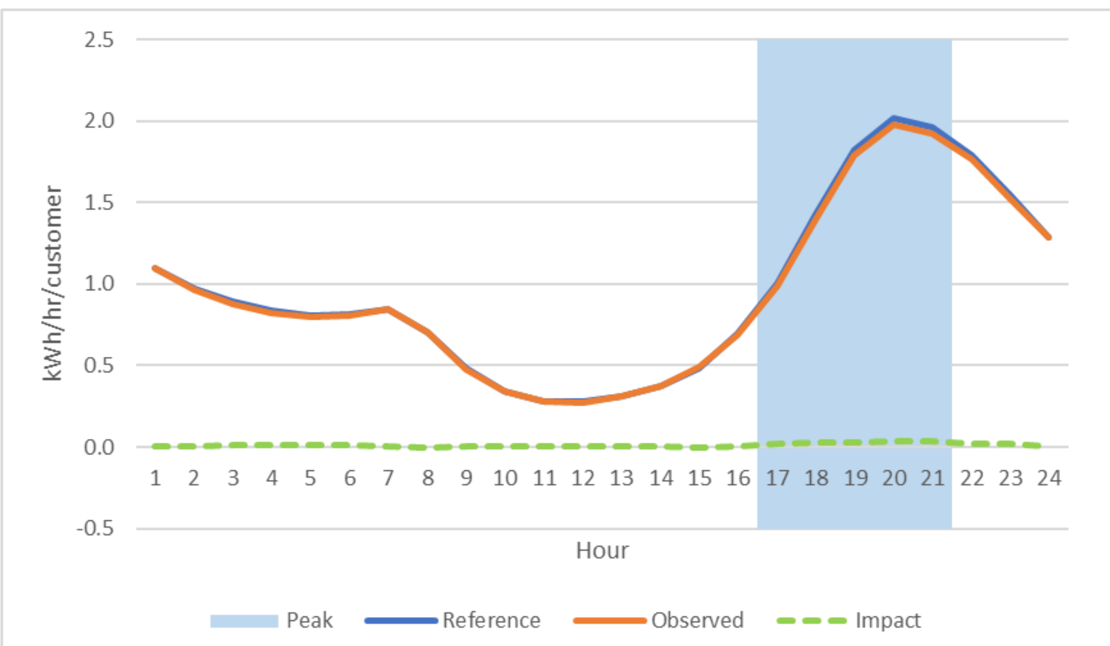


Figure 4.4: E-TOU-C NEM August Average Weekday Hourly Impacts



Figures 4.5 and 4.6 show the estimates for E-TOU-D non-NEM customers. The February load impacts average 3.2 percent during the peak period, with some load increases occurring earlier in the day. In contrast, the August impacts are largely concentrated during the peak period, during which they average 4.2 percent.

Figure 4.5: E-TOU-D Non-NEM February Average Weekday Hourly Impacts

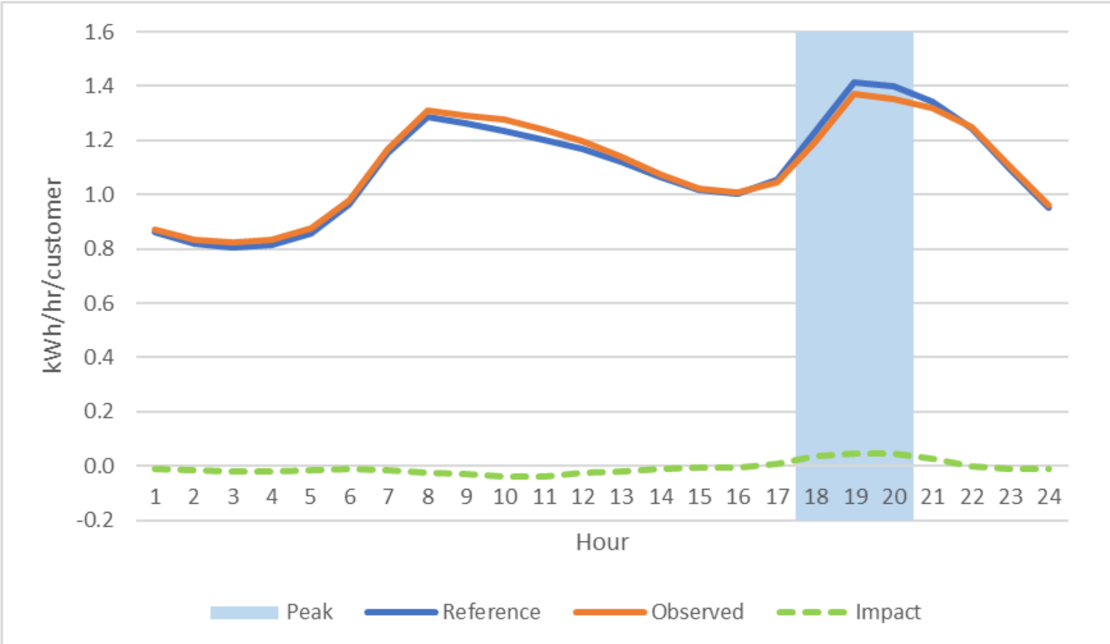
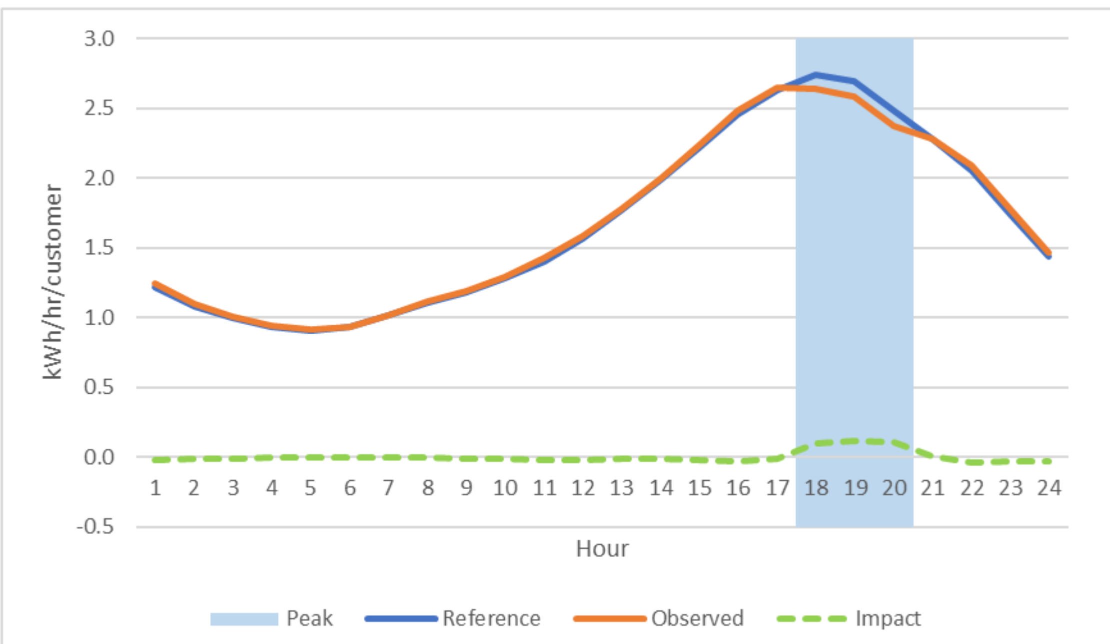


Figure 4.6: E-TOU-D Non-NEM August Average Weekday Hourly Impacts



Figures 4.7 and 4.8 show the estimates for E-TOU-D customers. The duck curve is once again evident. The February peak-period load impact is 3.7 percent and the August peak-period load impact is quite large at 8.7 percent.

Figure 4.7: E-TOU-D NEM February Average Weekday Hourly Impacts

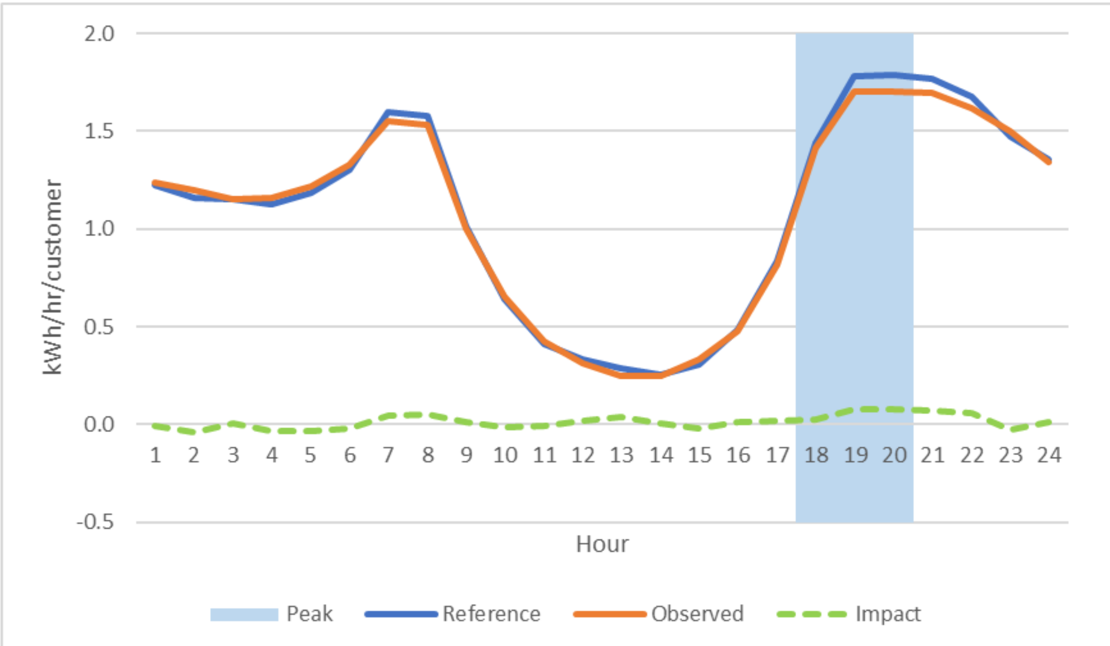
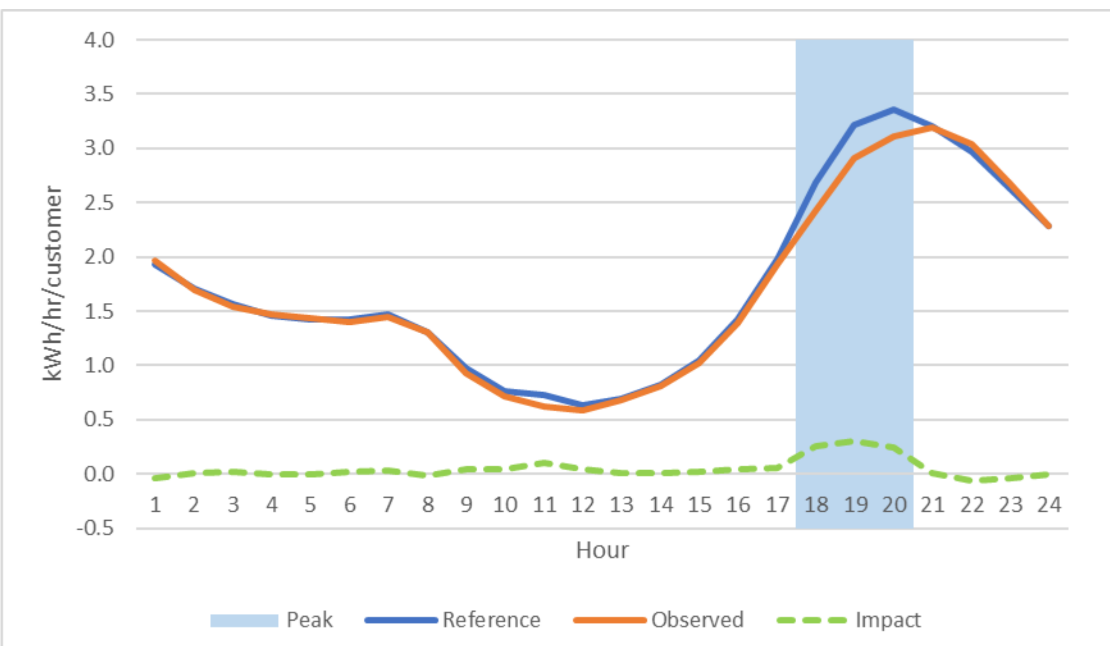


Figure 4.8: E-TOU-D NEM August Average Weekday Hourly Impacts



Figures 4.9 and 4.10 show the estimates for E-TOU-C to EV2-A customers, which combines NEM and non-NEM customers. The load impacts reflect somewhat large changes throughout the day, with usage generally being shifted from mid-day and peak-period hours to overnight and early morning hours.

Figure 4.9: E-TOU-C to EV2-A February Average Weekday Hourly Impacts

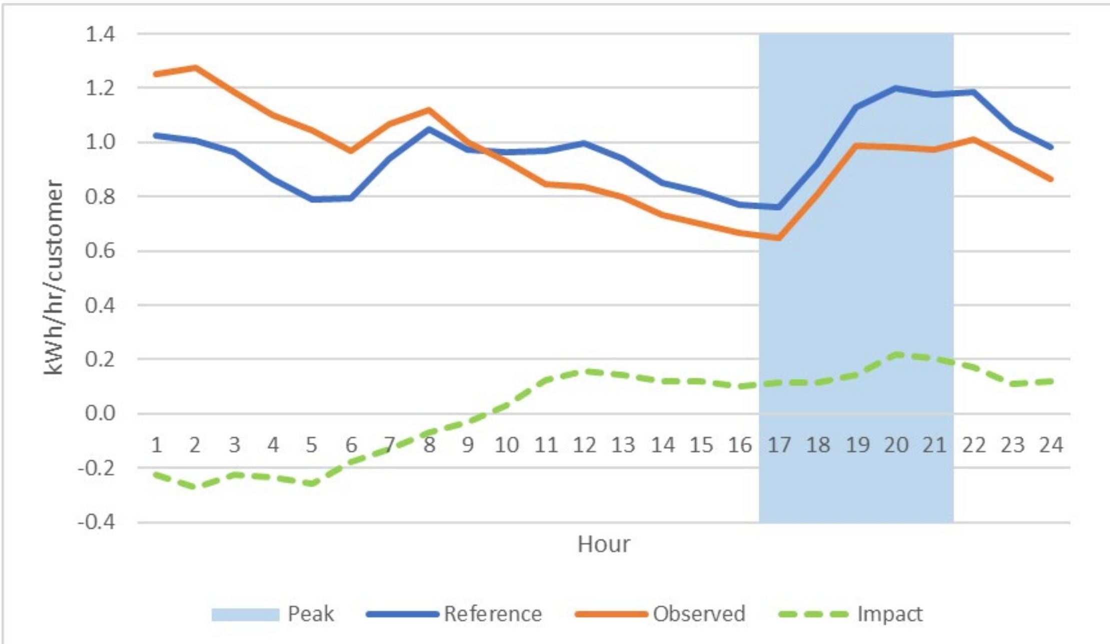
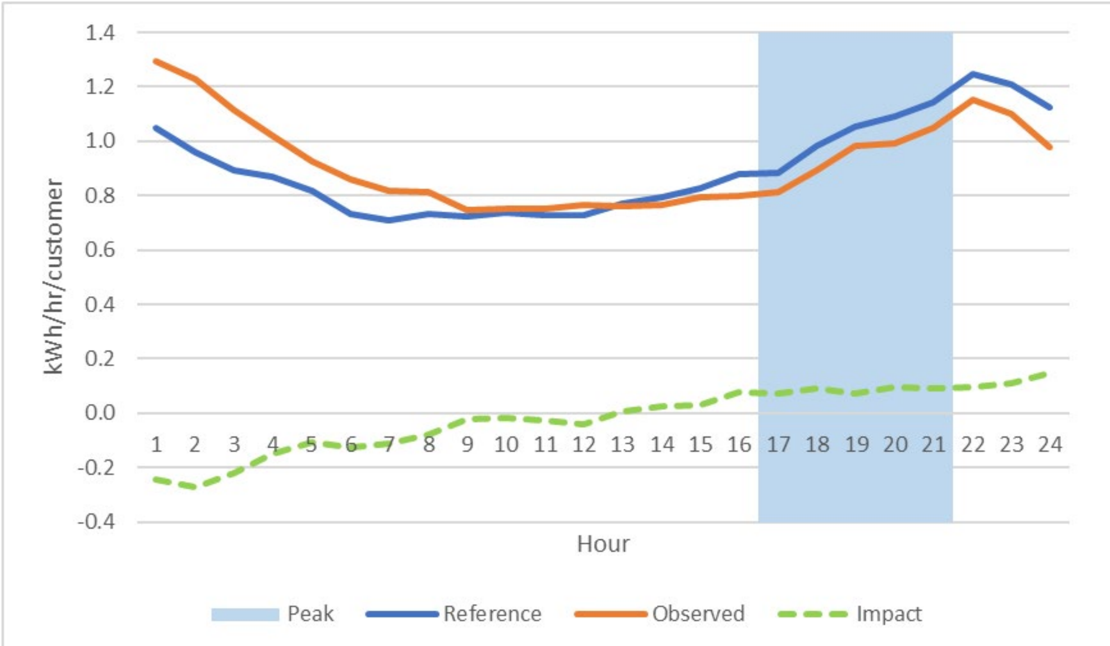


Figure 4.10: E-TOU-C to EV2-A August Average Weekday Hourly Impacts



Figures 4.11 and 4.12 show the estimates for E-1 to EV2-A customers, which combines NEM and non-NEM customers. In both February and August, these customers have higher peak-hour reference loads, level load impacts, and percentage load impacts than the E-TOU-C to EV2-A customers.

Figure 4.11: E-1 to EV2-A February Average Weekday Hourly Impacts

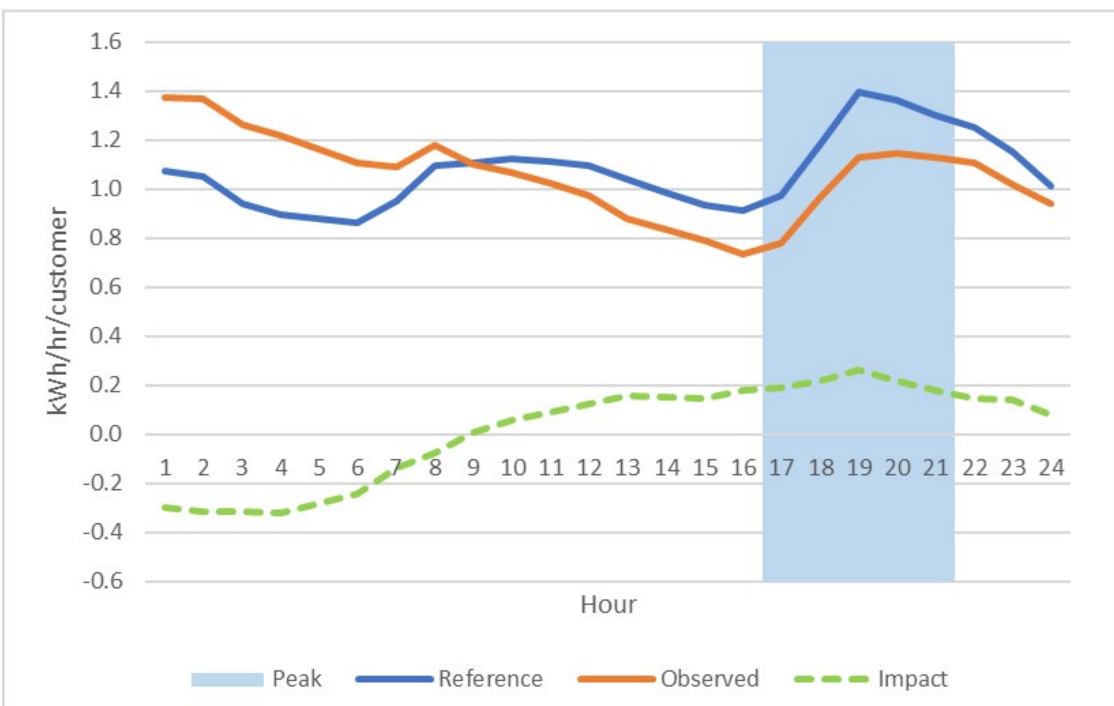
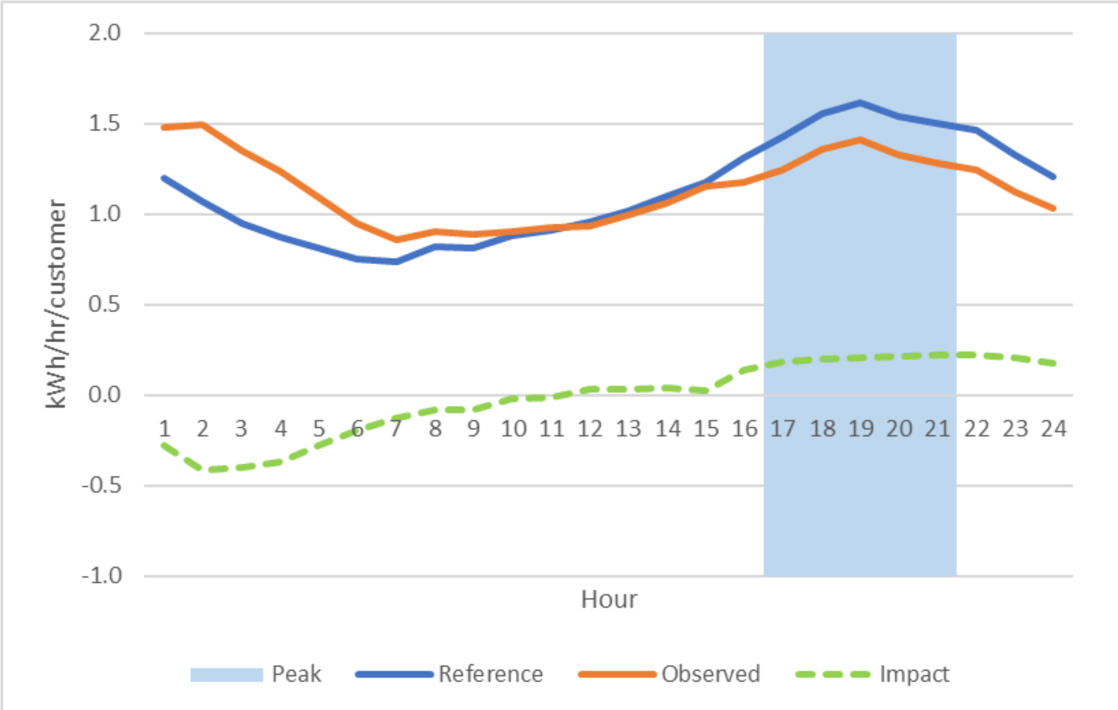


Figure 4.12: E-1 to EV2-A August Average Weekday Hourly Impacts



5. EX-ANTE LOAD IMPACTS

5.1 Overview and Enrollment Forecasts

Ex-ante load impacts were developed separately for the following TOU rates: E-TOU-C, E-TOU-D, and EV2-A. We also developed a forecast for E-ELEC NEM customers. However, because we have no information about customers enrolled in that rate, we used the E-TOU-C NEM per-customer forecast as the basis for the E-ELEC NEM forecast. In each case, the forecast represents *incremental* TOU load impacts, which are attributable to customers joining TOU rates during the forecast period. Customers who are already on TOU rates contribute to an *embedded* TOU load impact that is already reflected in PG&E's system load. The embedded TOU customers are not included in our forecast.

As with all ex-ante studies, we develop four sets of results associated with distinct weather scenarios, which are distinguished by:

- 1-in-2 weather conditions versus 1-in-10 weather conditions; and
- Whether the peak conditions are determined using the utility's peak or the utility's load at the time of CAISO's peak.

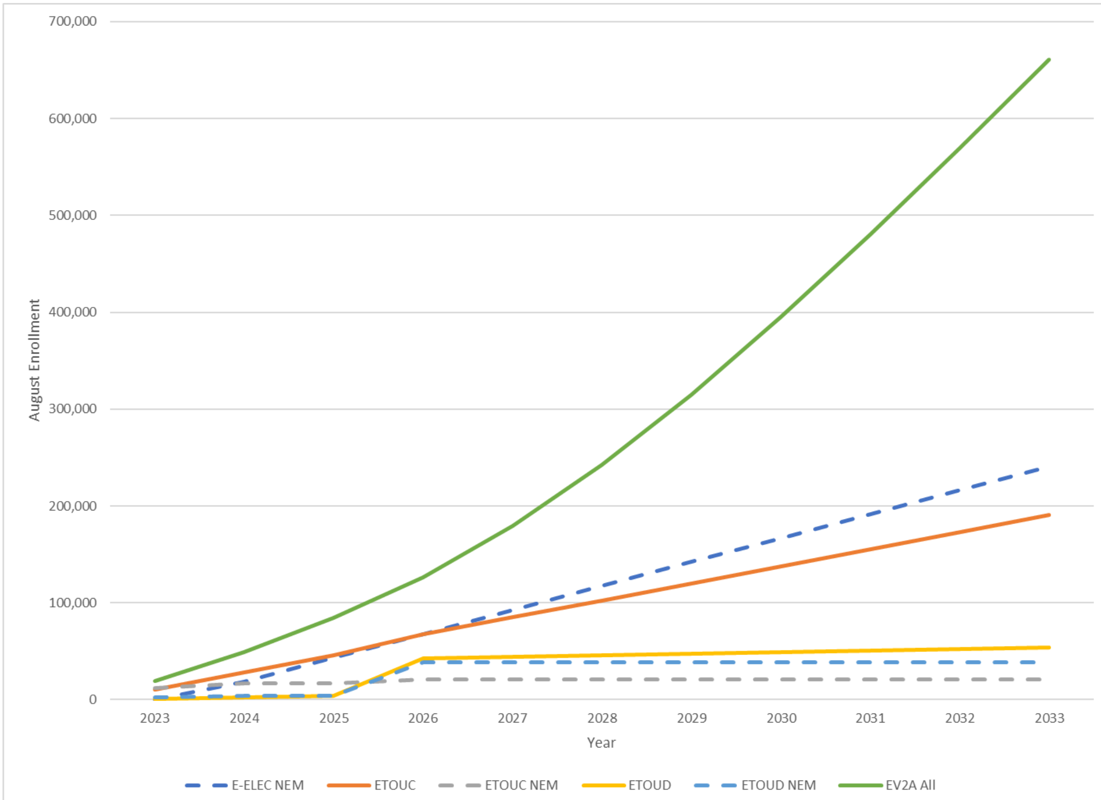
The weather conditions for each scenario were provided by PG&E.

Figure 5.1 shows the yearly enrollments forecast for the month of August[20], for each customer group (the EV2-A enrollment combines NEM and non-NEM customers). The

[20] August is referenced here because it is likely to be the CAISO/PG&E peak period in a given year.

enrollment changes shown in the figure generally follow a smooth path, though E-TOU-D enrollments increase by a higher amount between 2025 and 2026 because E-TOU-B sunsets in November 2025, at which point those customers are expected to join E-TOU-D.

Figure 5.1: Forecast August Enrollments by Year and Customer Group



5.2 Ex-Ante Load Impact Results

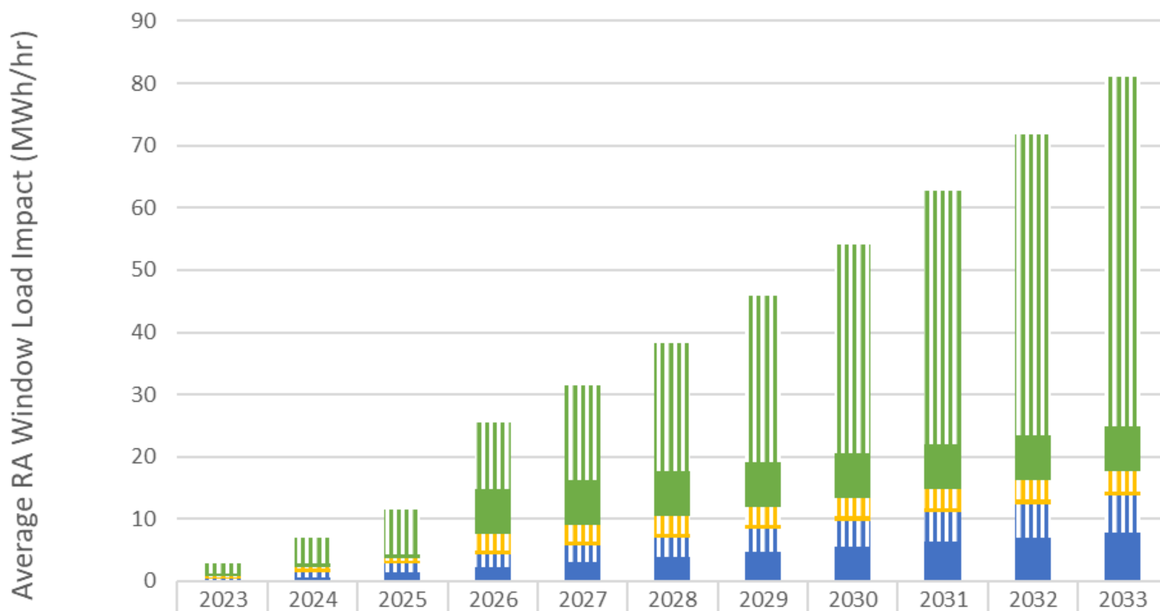
Ex-ante load impacts are developed for six groups of customers:

- E-TOU-C non-NEM;
- E-TOU-D non-NEM;
- E-TOU-C NEM;
- E-ELEC NEM;
- E-TOU-D NEM; and
- EV2-A customers.

The following sub-sections present the ex-ante forecasts for each of these groups.

Figure 5.2 summarizes the forecast load impacts for each August during the forecast period. The values are the average load impacts during the Resource Adequacy window (4:00 to 9:00 p.m.) for the PG&E 1-in-2 peak month weather conditions. The load impacts increase over time due to the enrollment pattern shown in Figure 5.1. The share of impacts due to EV2-A increases over time, due to both the high share of incremental enrollment and high per-customer load impact relative to other TOU rates.

Figure 5.2: Average RA Window Load Impacts by Year, August PG&E 1-in-2 Peak Month



	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
EV2-A	1.7	4.2	7.2	10.8	15.2	20.6	26.7	33.5	40.8	48.4	56.1
E-TOUD NEM	0.5	0.7	0.7	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3
E-TOUD	0.1	0.1	0.2	2.5	2.6	2.7	2.8	2.9	3.0	3.1	3.2
E-TOUC NEM	0.4	0.5	0.5	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
E-TOUC	0.3	0.9	1.4	2.1	2.6	3.2	3.7	4.3	4.8	5.3	5.9
E-ELEC NEM	0.0	0.6	1.4	2.2	3.0	3.8	4.6	5.5	6.3	7.1	7.9
Total	2.9	7.0	11.5	25.5	31.5	38.3	45.8	54.1	62.8	71.8	81.0

Year

E-ELEC NEM   E-TOUC   E-TOUC NEM   E-TOUD   E-TOUD NEM   EV2-A

5.2.1 Ex-ante load impacts for E-TOU-C non-NEM customers

Table 5.1 shows the E-TOU-C non-NEM customer load impacts, averaged during the Resource Adequacy window. The tables show monthly load impacts in 2023 associated with each of the four weather scenarios. Load impacts are highest in the September PG&E 1-in-10 scenario.

Table 5.1: E-TOU-C Non-NEM Ex-Ante Load Impacts, 2023 Monthly Peak Day during RA Window (MWh/hr)

Month	Enrollment	CAISO 1-in-10	CAISO 1-in-2	PG&E 1-in-10	PG&E 1-in-2
January	0	0.00	0.00	0.00	0.00
February	1,467	0.02	0.02	0.02	0.02
March	2,936	0.06	0.07	0.07	0.06
April	4,405	0.03	0.03	0.03	0.03
May	5,874	0.10	0.09	0.10	0.09
June	7,341	0.22	0.23	0.25	0.22
July	8,810	0.28	0.29	0.30	0.29
August	10,278	0.38	0.34	0.36	0.32
September	11,747	0.38	0.29	0.40	0.34
October	13,215	0.36	0.33	0.37	0.33
November	14,683	0.13	0.13	0.15	0.14
December	16,152	0.20	0.20	0.20	0.20

Figure 5.3 shows the hourly loads and load impacts associated with the August 2023 PG&E 1-in-2 weather scenario. The Peak-period load impact averages 3.0 percent. Figure 5.4 shows the same information for February 2024. The Peak-period load impact averages 2.1 percent.

Figure 5.3: E-TOU-C Non-NEM Ex-Ante Load Impacts, August 2023 PG&E 1-in-2 Peak Day

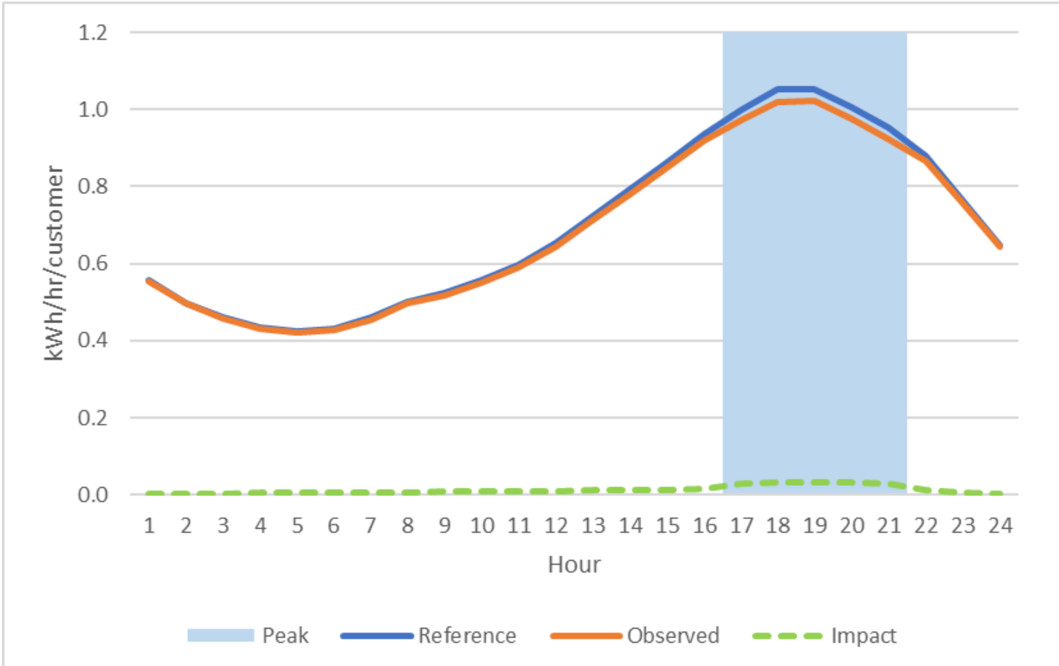
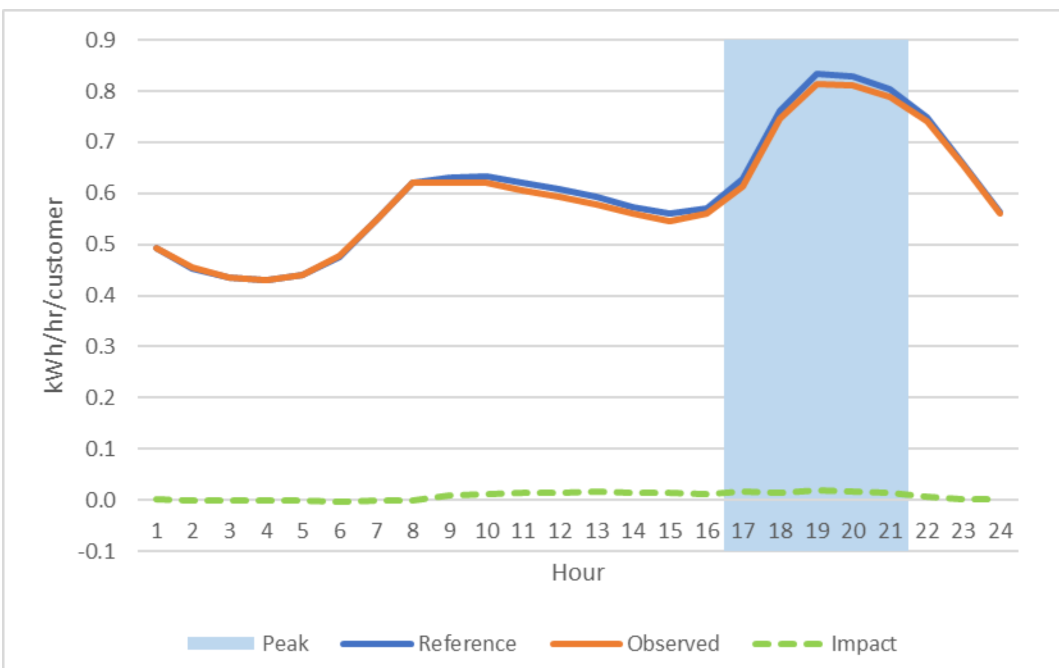


Figure 5.4: E-TOU-C Non-NEM Ex-Ante Load Impacts, February 2024 PG&E 1-in-2 Peak Day



5.2.2 Ex-ante load impacts for E-TOU-D non-NEM customers

Table 5.2 shows the E-TOU-D non-NEM customer load impacts, averaged during the Resource Adequacy window. The tables show monthly load impacts in 2023 associated with each of the four weather scenarios. Enrollment increases steadily throughout the year, which is reflected in the load impacts.

Table 5.2: E-TOU-D Non-NEM Ex-Ante Load Impacts, 2023 Monthly Peak Day during RA Window (MWh/hr)

Month	Enrollment	CAISO 1-in-10	CAISO 1-in-2	PG&E 1-in-10	PG&E 1-in-2
January	0	0.00	0.00	0.00	0.00
February	378	0.02	0.02	0.02	0.02
March	755	0.06	0.07	0.08	0.07
April	1,132	0.09	0.09	0.09	0.09
May	1,511	0.28	0.24	0.26	0.24
June	1,890	0.40	0.42	0.48	0.43
July	2,267	0.59	0.59	0.63	0.58
August	2,643	0.55	0.50	0.54	0.50
September	3,023	1.07	0.89	1.13	0.89
October	3,398	0.88	0.81	1.02	0.78
November	3,777	0.51	0.53	0.63	0.57
December	3,777	0.47	0.45	0.47	0.45

Figure 5.5 shows the hourly loads and load impacts associated with the August 2023 PG&E 1-in-2 weather scenario. The Peak-period load impact averages 4.2 percent. Figure 5.6 shows the same information for February 2024. The Peak-period load impact averages 3.1 percent.

Figure 5.5: E-TOU-D Non-NEM Ex-Ante Load Impacts, August 2023 PG&E 1-in-2 Peak Day

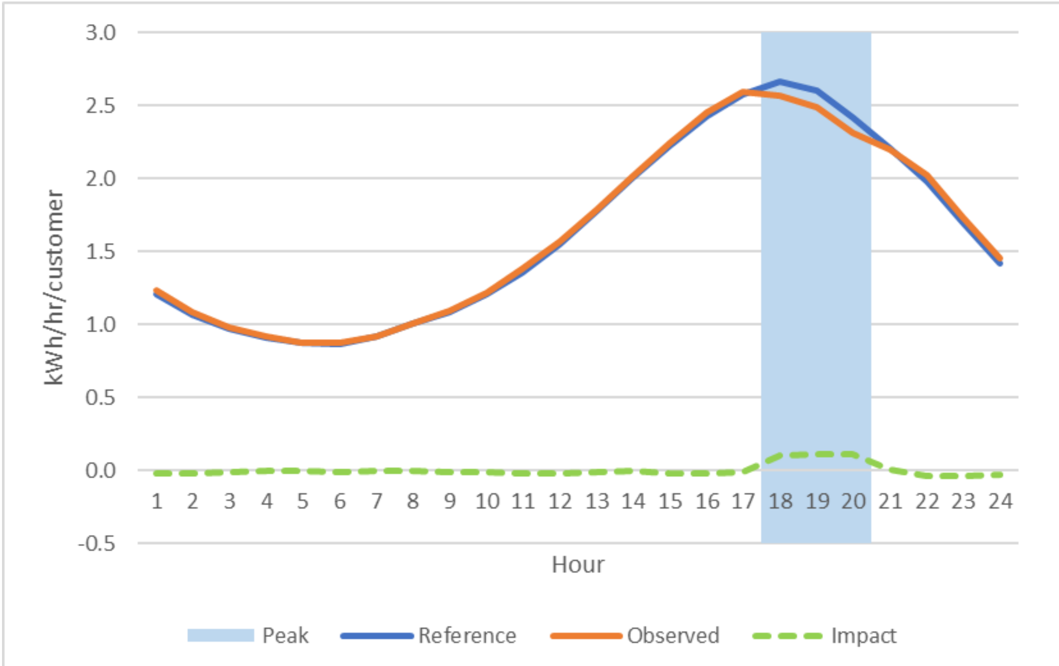
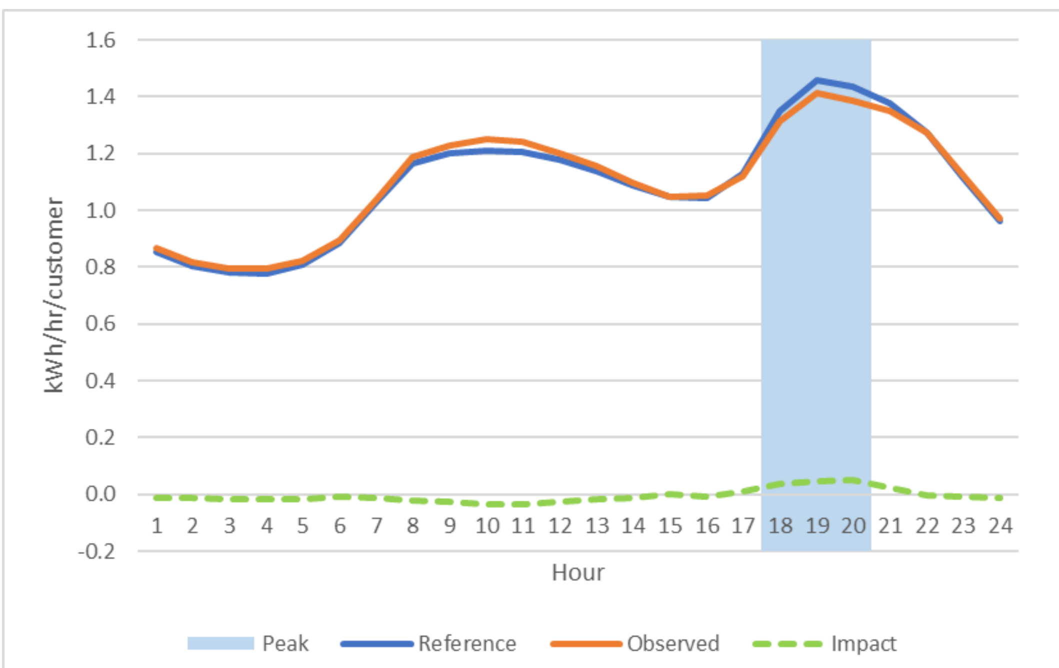


Figure 5.6: E-TOU-D Non-NEM Ex-Ante Load Impacts, February 2024 PG&E 1-in-2 Peak Day



5.2.3 Ex-ante load impacts for EV2-A customers

Table 5.3 shows the EV2-A customer load impacts, averaged during the Resource Adequacy window. The tables show monthly load impacts in 2023 associated with each of the four weather scenarios. The table reflects both NEM and non-NEM enrollments.

Table 5.3: EV2-A Ex-Ante Load Impacts, 2023 Monthly Peak Day during RA Window (MWh/hr)

Month	Enrollment	CAISO 1-in-10	CAISO 1-in-2	PG&E 1-in-10	PG&E 1-in-2
January	4,264	0.77	0.77	0.77	0.77
February	6,459	1.03	1.03	1.03	1.03
March	8,653	1.27	1.27	1.27	1.27
April	10,851	1.66	1.66	1.66	1.66
May	13,046	1.22	1.22	1.22	1.22
June	15,241	1.68	1.68	1.68	1.68
July	17,437	1.59	1.59	1.59	1.59
August	19,634	1.67	1.67	1.67	1.67
September	21,829	2.32	2.32	2.32	2.32
October	24,024	1.69	1.69	1.69	1.69
November	26,220	4.87	4.87	4.87	4.87
December	28,416	4.87	4.87	4.87	4.87

Figure 5.7 shows the hourly loads and load impacts associated with the August 2023 PG&E 1-in-2 weather scenario. The reference and observed loads represent non-NEM customers. The Peak-period load impact averages 7.0 percent, or 0.085 kWh/hour/customer. Figure 5.8 shows the same information for February 2024. The Peak-period load impact averages 14.2 percent, or 0.16 kWh/hour/customer.

Figure 5.7: EV2-A Ex-Ante Load Impacts, August 2023 PG&E 1-in-2 Peak Day

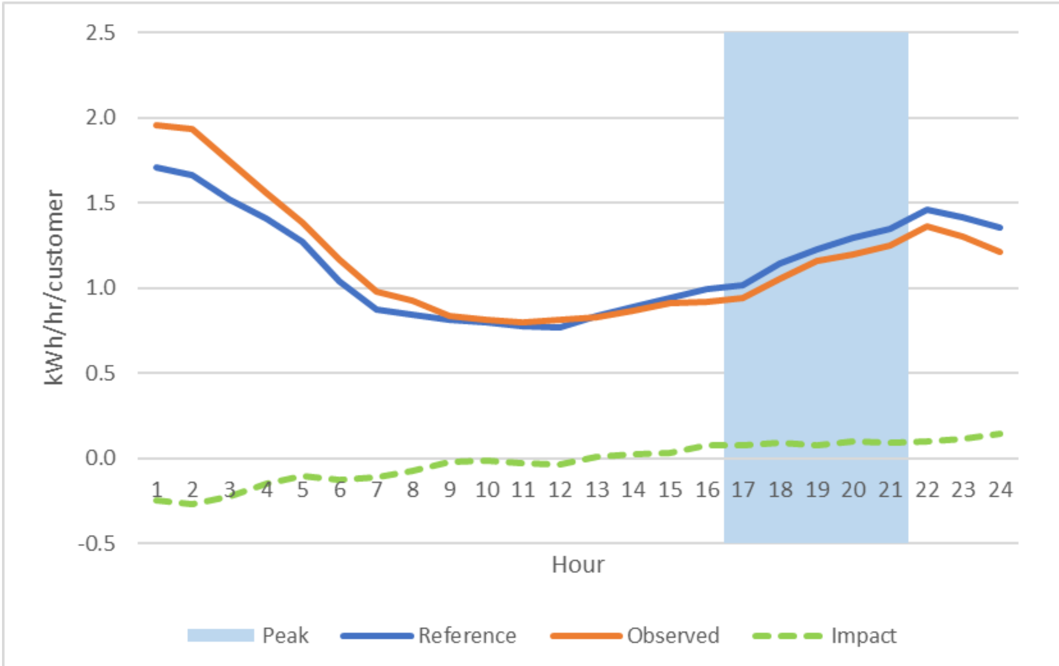
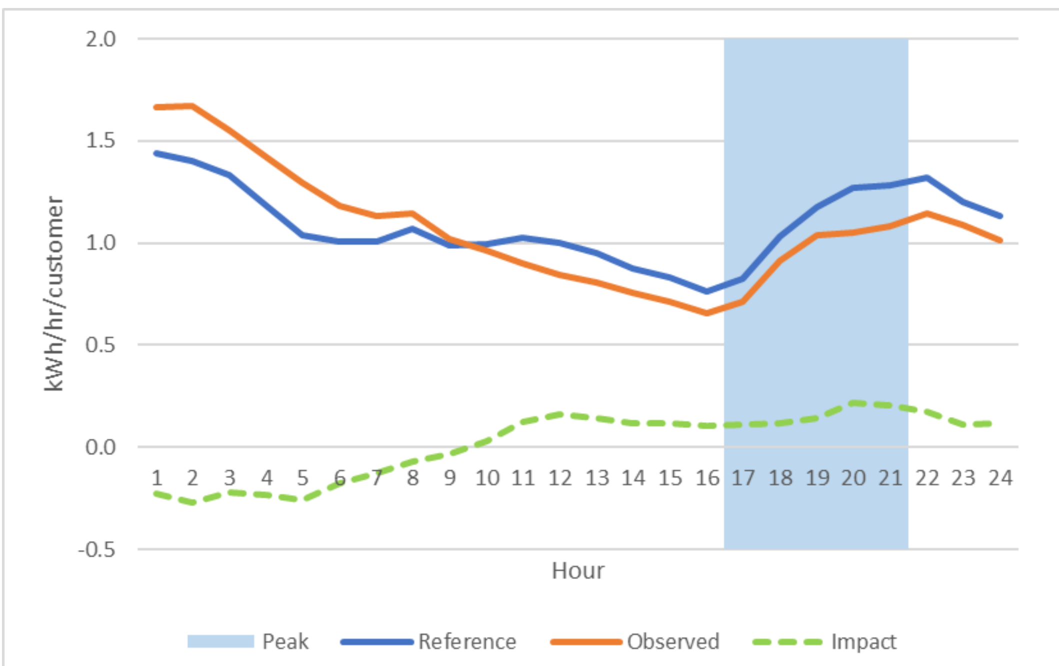


Figure 5.8: EV2-A Ex-Ante Load Impacts, February 2024 PG&E 1-in-2 Peak Day



5.2.4 Ex-ante load impacts for E-TOU-C NEM customers

Table 5.4 shows the NEM customer load impacts for E-TOU-C. The E-TOU-C incremental enrollments begin in February increase in steadily through the year. Load impacts tend to be highest in the PG&E 1-in-10 weather scenario, as expected.

Table 5.4: E-TOU-C NEM Ex-Ante Load Impacts, 2023 Monthly Peak Day during RA Window (MWh/hr)

Month	Enrollment	CAISO 1-in-10	CAISO 1-in-2	PG&E 1-in-10	PG&E 1-in-2
January	0	0.00	0.00	0.00	0.00
February	1,682	0.05	0.05	0.05	0.05
March	3,362	0.12	0.14	0.15	0.12
April	5,044	0.12	0.13	0.11	0.12
May	6,725	0.24	0.19	0.22	0.19
June	8,406	0.34	0.35	0.40	0.35
July	10,085	0.42	0.42	0.45	0.41
August	11,768	0.42	0.38	0.41	0.38
September	13,448	0.43	0.35	0.45	0.36
October	15,131	0.38	0.35	0.43	0.34
November	16,812	0.25	0.26	0.31	0.28
December	16,812	0.45	0.43	0.46	0.44

Figure 5.9 shows the hourly loads and load impacts associated with the August 2023 PG&E 1-in-2 weather scenario for NEM customers on E-TOU-C. The Peak-period load impact averages 1.7 percent (0.032 kWh/hour). Figure 5.10 shows the same information for February 2024. The Peak-period load impact averages 2.5 percent (0.028 kWh/hour).

Note that E-ELEC NEM load impacts (and reference loads) are identical to those shown in Figures 5.9 and 5.10 on a per-customer basis. However, E-ELEC NEM enrollment does not begin until December 2023 (and only 6,177 customers are forecasted for February 2024).

Figure 5.9: E-TOU-C NEM Ex-Ante Load Impacts, August 2023 PG&E 1-in-2 Peak Day

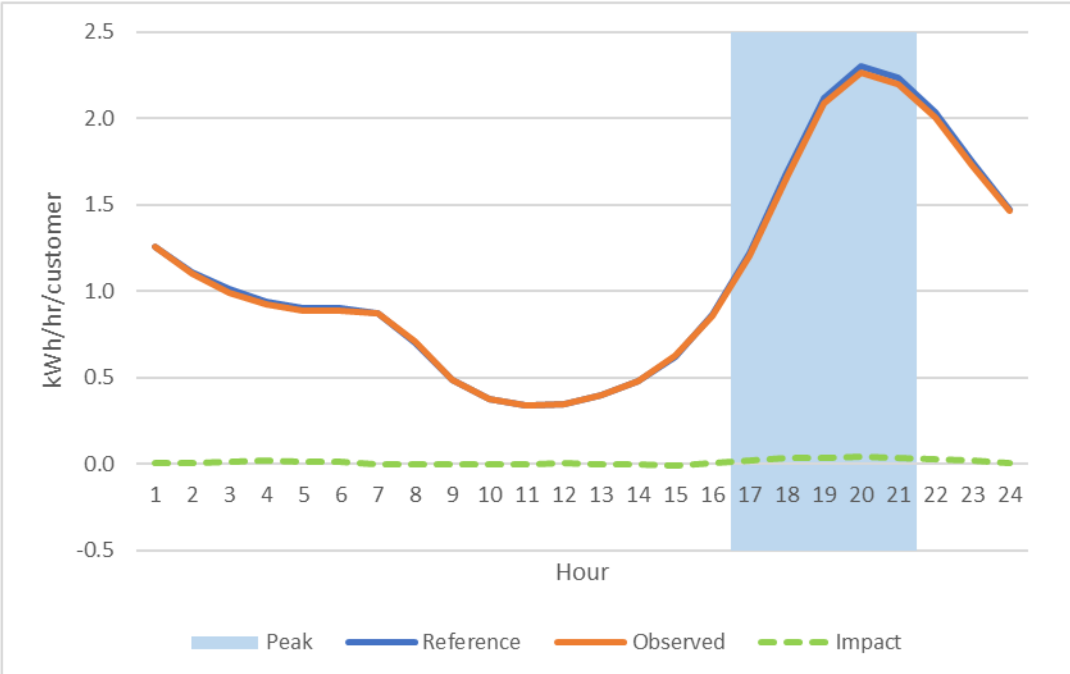
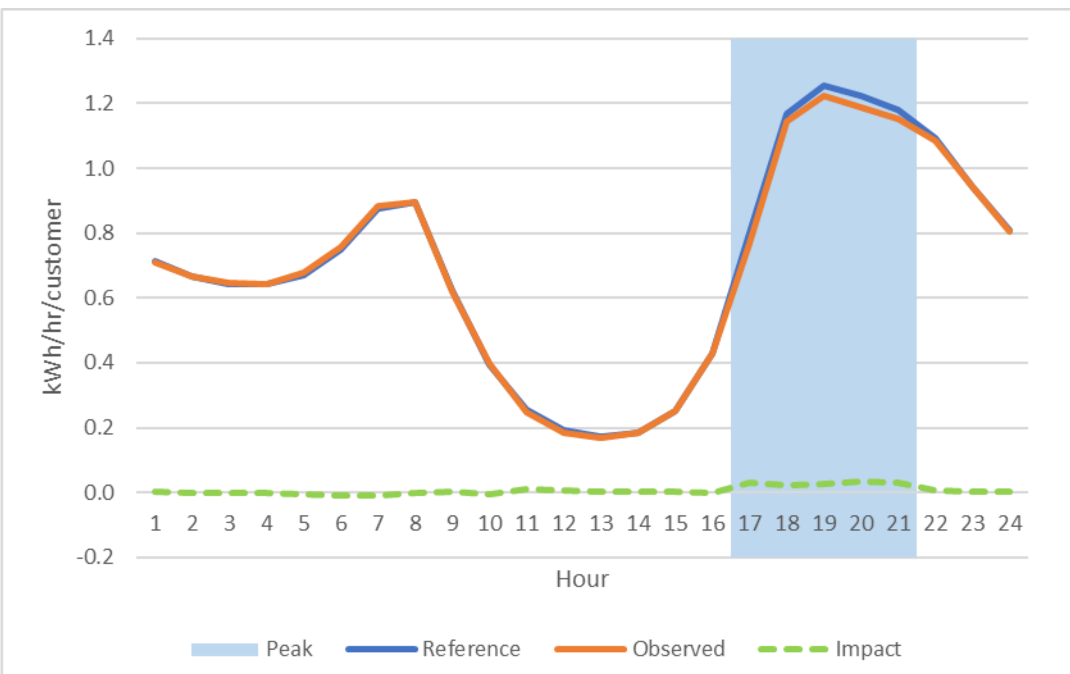


Figure 5.10: E-TOU-C NEM Ex-Ante Load Impacts, February 2024 PG&E 1-in-2 Peak Day



5.2.5 Ex-ante load impacts for E-TOU-D NEM customers

Table 5.5 shows the 2023 NEM customer load impacts for E-TOU-D. Load impacts tend to be highest in the PG&E 1-in-10 weather scenario.

Table 5.5: E-TOU-D NEM Ex-Ante Load Impacts, 2022 Monthly Peak Day during RA Window (MWh/hr)

Month	Enrollment	CAISO 1-in-10	CAISO 1-in-2	PG&E 1-in-10	PG&E 1-in-2
January	0	0.00	0.00	0.00	0.00
February	378	0.02	0.02	0.02	0.02
March	755	0.06	0.07	0.08	0.07
April	1,132	0.09	0.09	0.09	0.09
May	1,511	0.28	0.24	0.26	0.24
June	1,890	0.40	0.42	0.48	0.43
July	2,267	0.59	0.59	0.63	0.58
August	2,643	0.55	0.50	0.54	0.50
September	3,023	1.07	0.89	1.13	0.89
October	3,398	0.88	0.81	1.02	0.78
November	3,777	0.51	0.53	0.63	0.57
December	3,777	0.47	0.45	0.47	0.45

Figure 5.11 shows the hourly loads and load impacts associated with the August 2023 PG&E 1-in-2 weather scenario for NEM customers on E-TOU-D. The Peak-period load impact averages 8.7 percent (0.296 kWh/hour/customer). Figure 5.12 shows the same information for February 2024. The Peak-period load impacts average 3.6 percent (0.064 kWh/hour/customer).

Figure 5.11: E-TOU-D NEM Ex-Ante Load Impacts, August 2023 PG&E 1-in-2 Peak Day

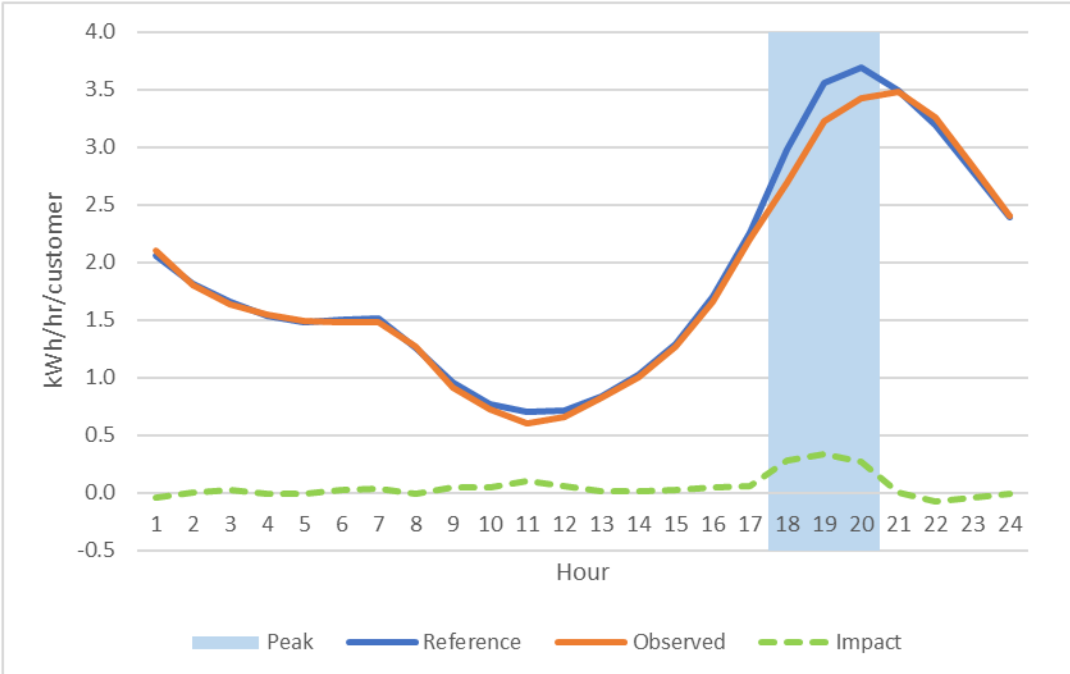
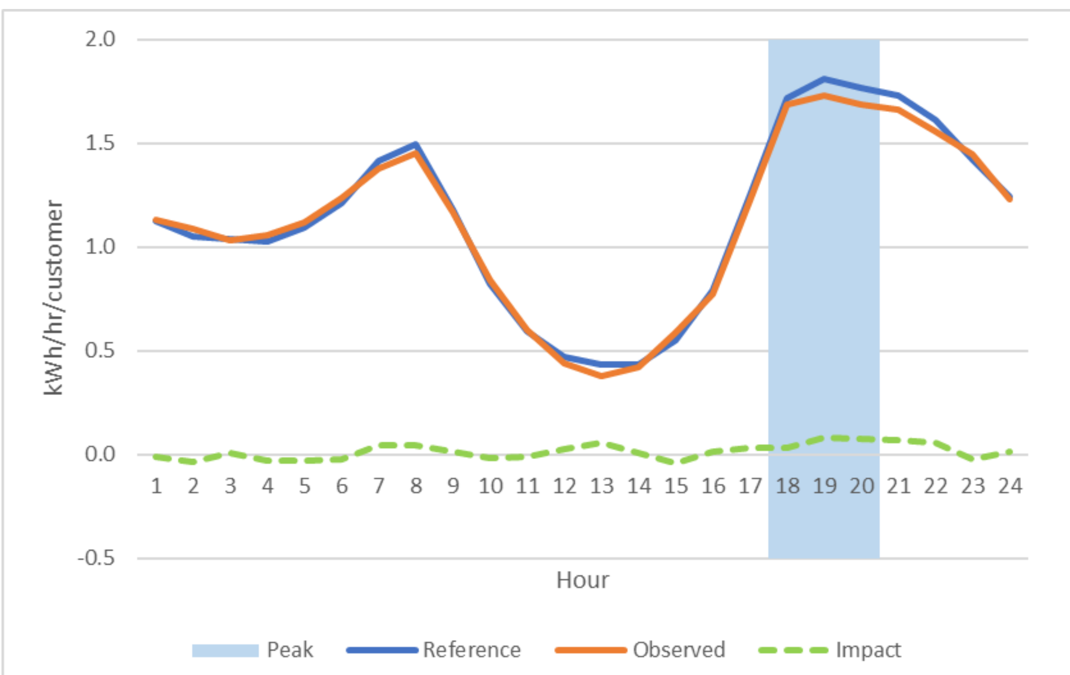


Figure 5.12: E-TOU-D NEM Ex-Ante Load Impacts, February 2024 PG&E 1-in-2 Peak Day



6. COMPARISONS OF RESULTS

In a continuing effort to clarify the relationships between ex-post and ex-ante results, this section compares several sets of estimated load impacts, including the following:

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

The term "current" refers to the present study, which includes ex-post and ex-ante results for PY2022. All results for the current study reflect load impacts for all defaulted customers (i.e., from April 2021 through April 2022). The term "previous" refers to findings in report for PY2021. In the final comparison above, we illustrate the linkage between the PY2022 ex-post load impacts and the ex-ante forecast (of the 1-in-2 August peak day) for 2023. While the study includes several rates, we focus on the E-TOU-C non-NEM forecast, which accounts for 95 percent of the residential TOU enrollments in 2022.

6.1 Previous versus current ex-post E-TOU-C non-NEM load impacts

Table 6.1 shows the average Peak-period reference loads and load impacts for the August average weekday during the current and previous program years. Enrollment is approximately 400,000 higher in the current study, which contributes to a large increase in the total load impact. In addition, the per-customer reference loads and load impacts are higher in the current study, perhaps in part due to the higher average peak-period temperature in August 2022. Note that the higher temperature in the current study is partly due to the inclusion of customers from the hot climate region, who were defaulted during PY2022 but would not have been included in the previous study. As stated above, the current study results include customers from all waves and climate regions, not only those who were defaulted during PY2022.

Table 6.1: Comparison of Average August Weekday Peak-period Ex-Post Impacts Across Studies, E-TOU-C Non-NEM

Level	Outcome	Previous	Current
Total	# SAIDs	840,034	1,265,748
	Reference (MW)	623.6	1,142
	Load Impact (MW)	17.2	36.9
	Avg. Temp.	74.9	78.2
Per SAID	Reference (kW)	0.74	0.90
	Load Impact (kW)	0.02	0.03
	% Load Impact	2.8%	3.2%

6.2 Previous versus current ex-ante E-TOU-C non-NEM load impacts

In this sub-section, we compare the ex-ante forecast prepared following PY2021 (the "previous study") to the ex-ante forecast contained in this study (the "current study"). In both cases, the forecast reflects defaulted customers in its enrollments. The

Table 6.2 reports the incremental load impact forecast for the August 2023 average weekday under PG&E 1-in-2 peak weather conditions. Because the ex-ante study only reflects incremental load impacts and the default process is complete, the enrollment number is dramatically lower in the current study. The per-customer load impact is the same, which is the result of offsetting lower reference loads and higher percentage load impacts in the current study.

Table 6.2: Comparison of Average August 2023 Weekday Peak-period Ex-Ante Impacts in the Previous and Current Studies, E-TOU-C Non-NEM

Level	Outcome	Previous Study	Current Study
Total	# SAIDs	1,415,921	10,278
	Reference (MW)	1,735	9
	Load Impact (MW)	40.6	0.3
	Avg. Temp.	83.3	77.6
Per SAID	Reference (kW)	1.23	0.89
	Load Impact (kW)	0.03	0.03
	% Load Impact	2.3%	3.1%

6.3 Previous ex-ante versus current ex-post E-TOU-C non-NEM load impacts

Table 6.3 provides a comparison of the ex-ante forecast of August 2022 average weekday load impacts prepared following PY2021 and the ex-post PY2022 load impacts estimated as part of this study. The ex-ante forecast shown in the table represents the August average weekday during a PG&E 1-in-2 weather year. The total enrollment and load impact (and thus the per-customer load impact) were quite close across the studies. However, the per-customer reference load and average temperature are lower in the current ex-post study, while the percentage impact is higher.

Table 6.3 Comparison of Previous Ex-Ante and Current Ex-Post Impacts, E-TOU-C Non-NEM

Level	Outcome	Ex-Ante for Aug. 2022 Avg. Weekday from PY2021 Study	Ex-Post for Aug. 2022 Avg. Weekday from PY2022 Study
Total	# SAIDs	1,227,871	1,265,748
	Reference (MW)	1,549	1,142
	Load Impact (MW)	36.4	36.9
	Avg. Temp.	83.8	78.2
Per SAID	Reference (kW)	1.26	0.90
	Load Impact (kW)	0.03	0.03
	% Load Impact	2.4%	3.2%

6.4 Current ex-post versus current ex-ante E-TOU-C non-NEM load impacts

Table 6.4 compares the PY2022 ex-post load impacts for the August average weekday to the corresponding ex-ante forecast for 2023 produced in this study. Because the ex-ante forecast only includes incremental enrollments and the default process is complete, enrollment and total impacts are much lower in the ex-ante forecast than they are in the ex-post impacts. However, the per-customer load impacts (in level and percentage terms) are very close. This is by design, as the ex-post impacts serve as the basis of the ex-ante forecast.

Table 6.4 Comparison of Current Ex-Post and Ex-Ante Load Impacts, E-TOU-C Non-NEM

Level	Outcome	Ex-Post for Aug. 2022 Avg. Weekday from PY2022 Study	Ex-Ante for Aug. 2023 Avg. Weekday from PY2022 Study
Total	# SAIDs	1,265,748	10,278
	Reference (MW)	1,142	9
	Load Impact (MW)	36.9	0.3
	Avg. Temp.	78.2	77.6
Per SAID	Reference (kW)	0.90	0.89
	Load Impact (kW)	0.03	0.03
	% Load Impact	3.2%	3.1%

APPENDICES

Appendix A E-1 to E-TOU-C Ex-Post Load Impact Tables:

2a. PGE_2022_Res_TOU_ETOUC_Ex_Post_CONFIDENTIAL.xlsx

2a. PGE_2022_Res_TOU_ETOUC_Ex_Post_PUBLIC.xlsx

Appendix B E-1 to E-TOU-D Ex-Post Load Impact Tables:

2b. PGE_2022_Res_TOU_ETOUD_Ex_Post_CONFIDENTIAL.xlsx

2b. PGE_2022_Res_TOU_ETOUD_Ex_Post_ PUBLIC.xlsx

Appendix C E-TOU-C to EV2-A Ex-Post Load Impact Tables:

2c. PGE_2022_Res_TOU_EV2A_Ex_Post_CONFIDENTIAL.xlsx

2c. PGE_2022_Res_TOU_EV2A_Ex_Post_PUBLIC.xlsx

Appendix D E-1 to E-TOU-C NEM Ex-Post Load Impact Tables:

2d. PGE_2022_Res_TOU_ETOUC_NEM_Ex_Post_CONFIDENTIAL.xlsx

2d. PGE_2022_Res_TOU_ETOUC_NEM_Ex_Post_PUBLIC.xlsx

Appendix E E-1 to E-TOU-D NEM Ex-Post Load Impact Tables:

2e. PGE_2022_Res_TOU_ETOUD_NEM_Ex_Post_CONFIDENTIAL.xlsx

2e. PGE_2022_Res_TOU_ETOUD_NEM_Ex_Post_PUBLIC.xlsx

Appendix F E-TOU-C Incremental Ex-Ante Load Impact Tables:

2f. PGE_2022_Res_TOU_ETOUC_Inc_Ex_Ante_PUBLIC.xlsx

Appendix G E-TOU-D Incremental Ex-Ante Load Impact Tables:

2g. PGE_2022_Res_TOU_ETOUD_Inc_Ex_Ante_PUBLIC.xlsx

Appendix H E-TOU-C NEM Incremental Ex-Ante Load Impact Tables:

2h. PGE_2022_Res_TOU_ETOUC_NEM_Inc_Ex_Ante_PUBLIC.xlsx

Appendix I E-TOU-D NEM Incremental Ex-Ante Load Impact Tables:

2i. PGE_2022_Res_TOU_ETOUD_NEM_Inc_Ex_Ante_PUBLIC.xlsx

Appendix J EV2-A Incremental Ex-Ante Load Impact Tables:

2j. PGE_2022_Res_TOU_EV2A_Inc_Ex_Ante_PUBLIC.xlsx

Appendix K Ex-Post Analysis Match Quality

Appendix L Regression Sample Sizes

Note: the Excel-based ex-ante appendices do not contain confidential information.

APPENDIX K. MATCH QUALITY

This appendix presents the summaries of our control-group matching process. Figures K.1 through K.8 illustrate the seasonal matches for E-TOU-C, E-TOU-D, E-TOU-B NEM, and E-TOU-C NEM customers. EV2-A is excluded because we did not employ control-group customers for that analysis. Each figure contains the average hourly profiles for the treatment and matched control-group customers on the average weekday that was withheld from the matching process (i.e., it represents and out-of-sample match quality). The mean percentage error (MPE) and mean absolute percentage error (MAPE) values associated with each figure are summarized in Table K.1.

Figure K.1: E-TOU-C Summer Match Quality

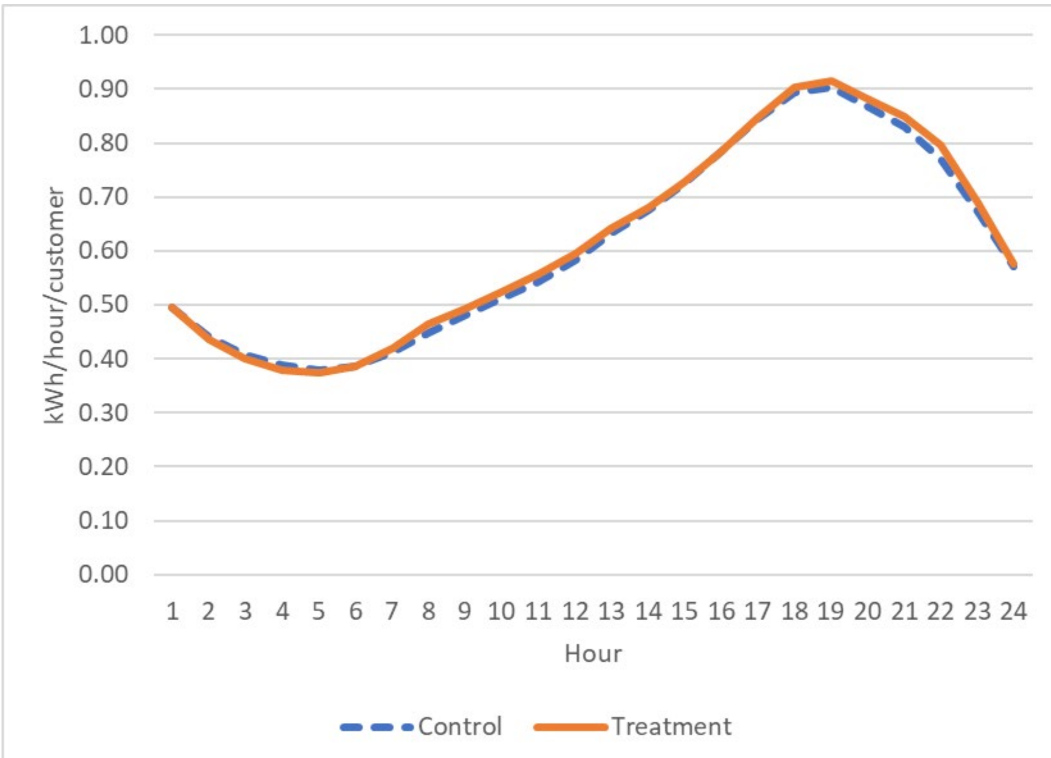


Figure K.2: E-TOU-C Winter Match Quality

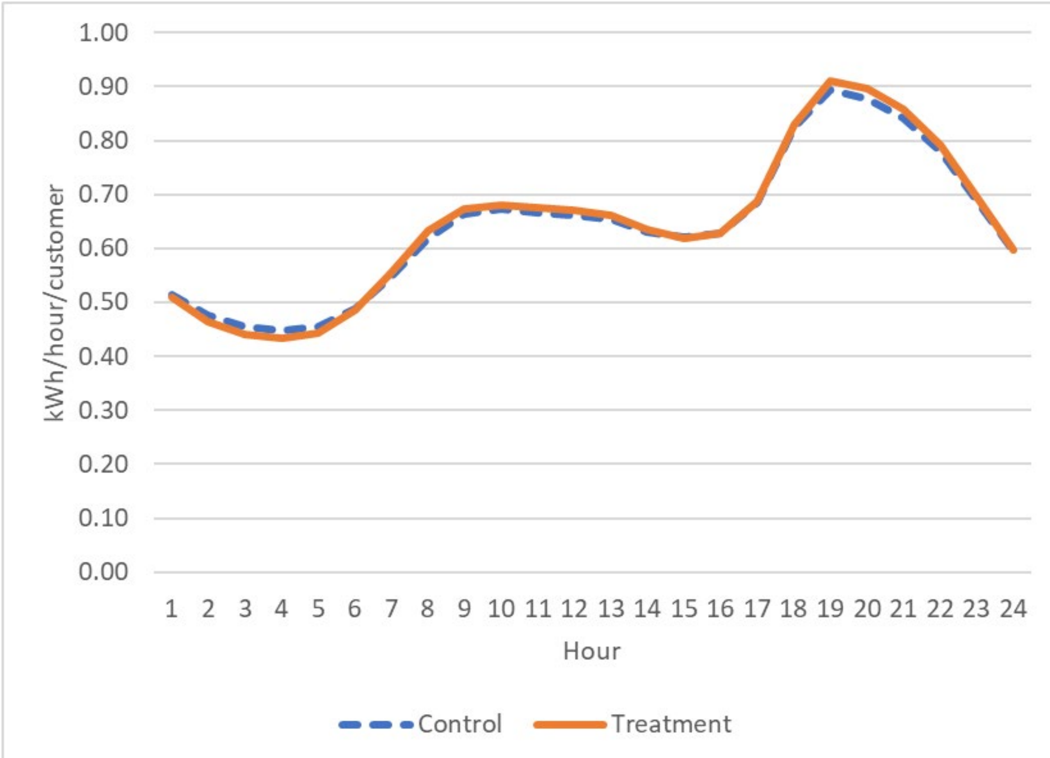


Figure K.3: E-TOU-D Summer Match Quality

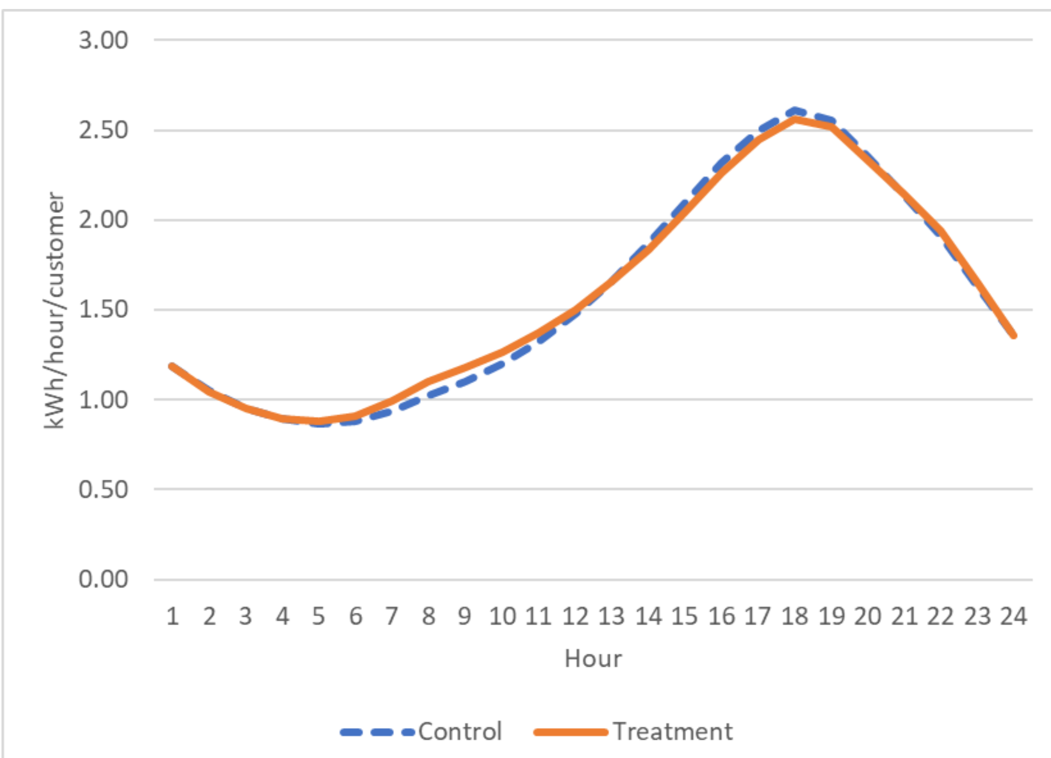


Figure K.4: E-TOU-D Winter Match Quality

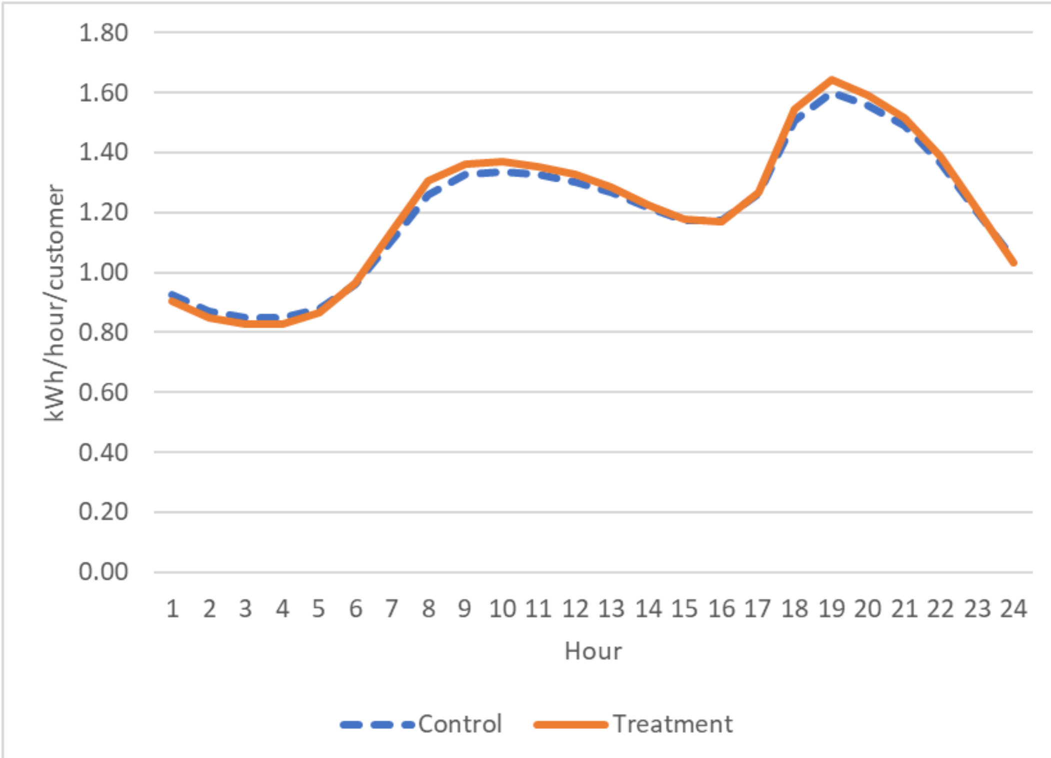


Figure K.5: E-TOU-C NEM Summer Match Quality

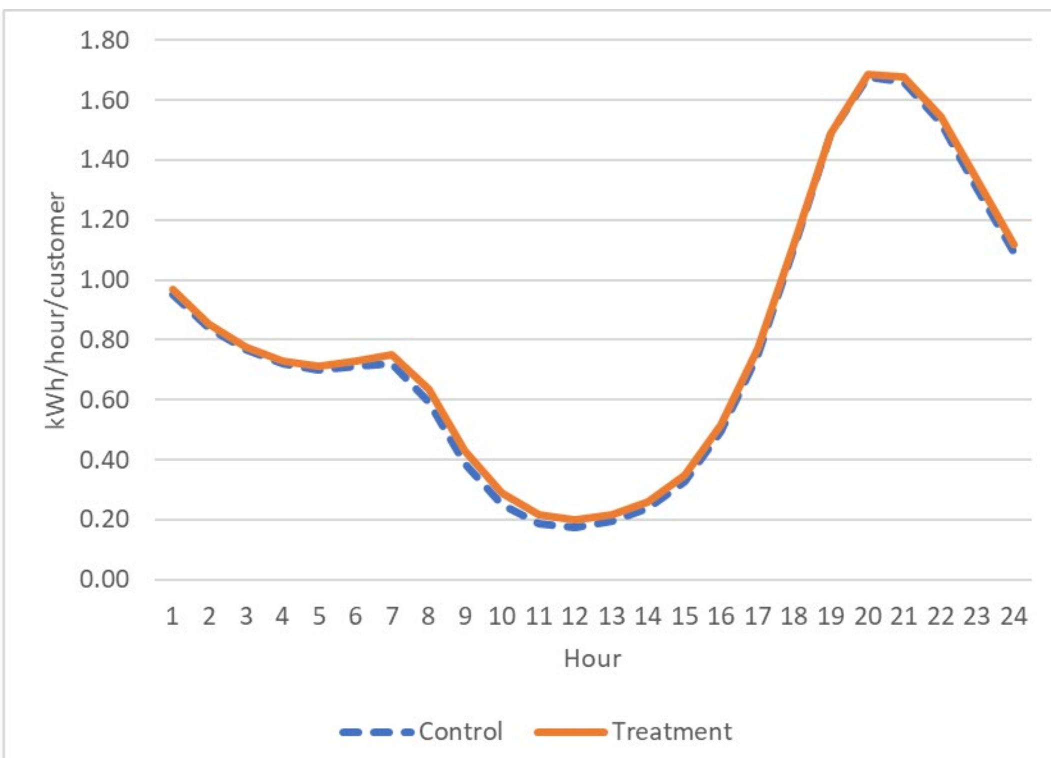


Figure K.6: E-TOU-C NEM Winter Match Quality

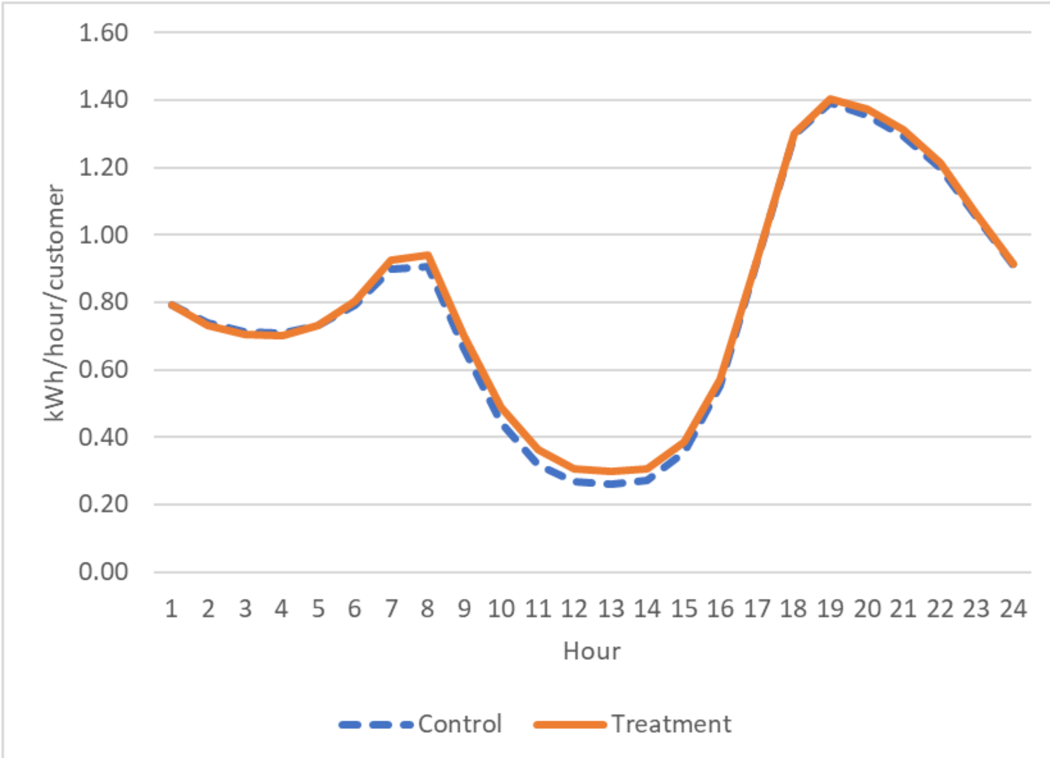


Figure K.7: E-TOU-D NEM Summer Match Quality

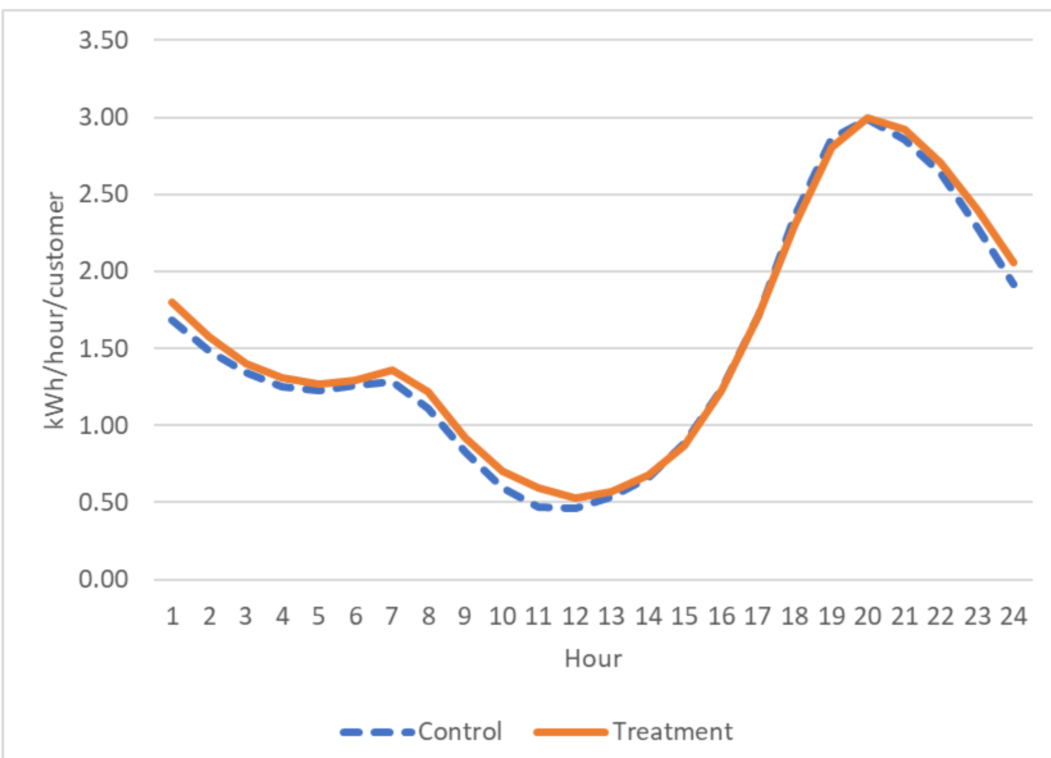


Figure K.8: E-TOU-D NEM Winter Match Quality

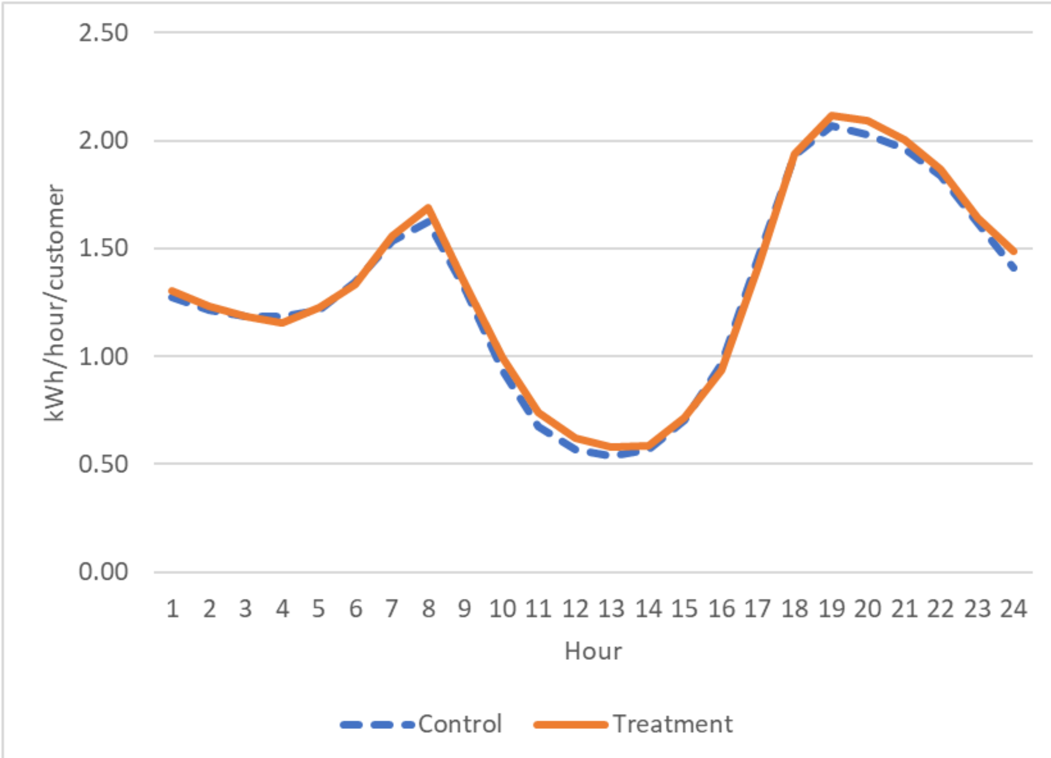


Table K.1 contains the MPE and MAPE values calculated across all 24 hours and the peak pricing period of the load profiles shown in the figures above. MPE provides an indicator of bias in the matches, while MAPE provides a measure of accuracy.

Table K.1: MPE and MAPE for the Withheld Profile

Season	Rate	All Hours		Peak Period	
		MPE	MAPE	MPE	MAPE
Summer	E-TOU-C	-4.4%	4.4%	-1.1%	1.1%
	E-TOU-C NEM	-1.0%	1.6%	-1.3%	1.3%
	E-TOU-D	-4.8%	5.4%	1.5%	1.6%
	E-TOU-D NEM	-1.0%	2.2%	1.5%	1.5%
Winter	E-TOU-C	-3.6%	3.8%	-0.9%	0.9%
	E-TOU-C NEM	-0.3%	1.5%	-1.5%	1.5%
	E-TOU-D	-2.3%	3.1%	-1.8%	1.8%
	E-TOU-D NEM	-0.6%	1.8%	-2.3%	2.3%

APPENDIX L. REGRESSION SAMPLE SIZES

This appendix presents the number of treatment customers represented in the ex-post impacts presented in Section 4. The number of customers in the models is typically quite a bit lower than the number of enrolled customers the model represents due to restrictions we apply to ensure a valid load impact estimate, or due to sampling in segments that have high numbers of customers (e.g., E-TOU-C Greater Bay Area non-NEM customers).

Table L.1: Sample Sizes for Load Impacts by Rate, CARE Status, and Season

Rate	CARE Status	# SAIDs in February Model	# SAIDs in August Model
E-TOU-C	All	54,280	71,454
E-TOU-C NEM		9,183	10,094
E-TOU-D		11,288	18,527
E-TOU-D NEM		280	341
EV2-A		226	449
E-TOU-C	Never	35,679	47,779
E-TOU-D		10,230	16,804
E-TOU-C	Always / Sometimes	18,602	23,675
E-TOU-D		1,058	1,724