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2023 Load Impact Evaluation of Pacific Gas and Electric Company's Residential Time-of-Use Rates

Ex-Post and Ex-Ante Report

CALMAC Study ID PGE0496

By

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Table of Contents

List of Figures

List of Tables

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 the program year 2023 (PY2023), defined as October 2022 through September 2023. The report addresses the two primary objectives of providing: 1) estimates of ex-post load impacts for E-TOU-C, E-TOU-D, EV2-A, and E-ELEC incremental enrollments during PY2023 and 2) ex-ante forecasts of load impacts for 2024 through 2034 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

The following rates are included in this evaluation (all have seasonally differentiated rates):

1. 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.
2. 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.
3. EV2-A: a voluntary whole-house electric vehicle (EV) rate with three TOU pricing periods (Peak, Part-Peak, and Off-Peak).
4. E-ELEC: available as a voluntary rate to customers with qualifying electric technologies (e.g., EVs, heat pumps, or battery storage). It contains the same pricing period definitions as EV2-A but adds a daily Basic Service Charge (BSC), expressed in $ per meter per day, to the rate structure.

Table ES.1 provides a comparison of the TOU rates, including the presence/level of the BSC, the presence/level of the minimum bill, the energy rates by season and pricing period, and the season and pricing period definitions.[1]

Table ES.1: TOU Rate Summaries

<table>
<tr><th>Season</th><th>Charge Type</th><th>E-TOU-C</th><th>E-TOU-D</th><th>EV2-A</th><th>E-ELEC</th></tr>
<tr><td rowspan="2">All</td><td>BSC ($/Day)</td><td colspan="3">N/A</td><td>$0.49281</td></tr>
<tr><td>Min. Bill ($/Day)</td><td colspan="3">$0.37612</td><td>N/A</td></tr>
<tr><td rowspan="4">Summer</td><td>Peak</td><td>$0.61806</td><td>$0.58758</td><td>$0.65713</td><td>$0.63580</td></tr>
<tr><td>Part-Peak</td><td>N/A</td><td>N/A</td><td>$0.54664</td><td>$0.47392</td></tr>
<tr><td>Off-Peak</td><td>$0.53462</td><td>$0.45262</td><td>$0.34462</td><td>$0.41724</td></tr>
<tr><td>Baseline Credit</td><td>($0.10556)</td><td colspan="3">N/A</td></tr>
<tr><td rowspan="4">Winter</td><td>Peak</td><td>$0.51536</td><td>$0.49798</td><td>$0.53002</td><td>$0.40429</td></tr>
<tr><td>Part-Peak</td><td>N/A</td><td>N/A</td><td>$0.51332</td><td>$0.38220</td></tr>
<tr><td>Off-Peak</td><td>$0.48701</td><td>$0.45937</td><td>$0.34462</td><td>$0.36834</td></tr>
<tr><td>Baseline Credit</td><td>($0.10556)</td><td colspan="3">N/A</td></tr>
<tr><td rowspan="3">Definitions</td><td>Summer</td><td colspan="4">Jun-Sep</td></tr>
<tr><td>Peak Period</td><td>4-9 pm all days</td><td>5-8 pm NHWD</td><td colspan="2">4-9 pm all days</td></tr>
<tr><td>Part-Peak Period</td><td colspan="2">N/A</td><td colspan="2">3-4 pm, 9 pm-midnight all days</td></tr>
</table>

[1] The rates correspond to values in tariffs posted to PG&E's web site in February 2024.

The baseline credit contained in E-TOU-C is applicable up to a tariff-specified Baseline Quantity defined by the customer's Baseline Territory and whether the customer qualifies as All-Electric. This feature makes E-TOU-C more appealing to low-use customers (by lowering the marginal energy rate for lower-use customers), while E-TOU-D is likely to appeal to higher-use customers due to the absence of the Baseline Credit. EV2-A and E-ELEC also do not contain the tiered structure.

Residential customers may also choose to be served on Schedule E-1, which is a tiered (i.e., increasing block), non-time differentiated rate that once served as the default residential rate. E-1 has the same minimum bill provision as the TOU rates (except for E-ELEC) and an energy rate that increases at usage levels above 100% of the customer's Baseline Quantity (which is defined in the same manner as in E-TOU-C).

ES.2 Evaluation Methodologies

The study examines customers who change rates to one of E-TOU-C, E-TOU-D, EV2-A, or E-ELEC during the program year. Load impacts may differ depending on the rate the customer is coming from. For example, an E-1 customer that changes to a TOU rate may shift less load across pricing periods than a customer that changes from one TOU rate to another. Table ES.2 lists the eleven rate transitions included in the study, along with indications of the method used to estimate load impacts.

Table ES.2: Rate Transitions Included in the Study

<table>
<tr><th rowspan="2">Rate Transition</th><th rowspan="2">NEM Included?</th><th colspan="2">Load Impact Estimation Methodology</th></tr>
<tr><th>Include Control Group?</th><th>Basis of Load Impact Estimate[2]</th></tr>
<tr><td>E-1 to E-TOU-C</td><td>No</td><td rowspan="4">Yes</td><td rowspan="4">Difference-in-differences
$(T_1 – C_1) – (T_0 – C_0)$</td></tr>
<tr><td>E-1 to E-TOU-C</td><td>Yes</td></tr>
<tr><td>E-1 to E-TOU-D</td><td>No</td></tr>
<tr><td>E-1 to E-TOU-D</td><td>Yes</td></tr>
<tr><td>E-1 to EV2-A</td><td>Combined</td><td rowspan="7">No</td><td rowspan="7">Within-treatment, pre-treatment vs. treatment periods
$(T_1 – T_0)$</td></tr>
<tr><td>E-TOU-C to EV2-A</td><td>Combined</td></tr>
<tr><td>E-TOU-D to EV2-A</td><td>Combined</td></tr>
<tr><td>E-1 to E-ELEC</td><td>No</td></tr>
<tr><td>E-TOU-C to E-ELEC</td><td>No</td></tr>
<tr><td>E-TOU-D to E-ELEC</td><td>No</td></tr>
<tr><td>EV2-A to E-ELEC</td><td>No</td></tr>
</table>

NEM and non-NEM customers are separately analyzed for the E-1 to E-TOU-C and E-TOU-D transitions to ensure robust estimates for each group. The methods used to study EV2-A allow us to combine NEM and non-NEM customers (which has the additional benefit of mitigating sample size concerns). Only non-NEM customers are studied for E-ELEC because NEM customers were not eligible for the rate for most of the program year.

[2] T_1 = the treatment customer usage in the treatment period; C_1 = the control-group customer usage in the treatment period; T_0 = the treatment customer usage in the pre-treatment period; and C_0 = the control-group customer usage in the pre-treatment period.

The evaluation methodology differed by rate transition. For customers transitioning to E-TOU-C or E-TOU-D, we select quasi-experimental matched control groups and conduct difference-in-differences estimation using regression analysis. To select the control-group, customers were matched on pre-enrollment load data from October 2021 to September 2022. 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). The load impact can vary by local capacity area and according to temperatures, allowing for different weather effects by climate region.

For customers transitioning to EV2-A or E-ELEC, we conduct an analysis using only treatment customers. A structural break methodology is applied in an attempt to confirm ownership and use of the relevant electric end-use (e.g., an electric vehicle) throughout the analysis period. Load impacts are estimated using a within-treatment, before vs. after methodology that allows the load impact to vary according to temperatures.

Ex-post and ex-ante load impacts are produced using the same regression models. The two types of per-customer impacts are differentiated only by the weather conditions used to simulate the load impacts and associated standard errors from the estimated model parameters. The per-customer impacts are then scaled to the historical or forecast enrollment to obtain the aggregate load impact.

ES.3 Ex-Post Load Impacts

Tables ES.3 and ES.4 show the estimated peak-period load impacts for the average weekday in February and August 2023, respectively. The brackets in the "% Impact" column show the 80% confidence interval around the estimated load impacts.

We have the following observations about the results:

- E-TOU-D per-customer reference loads and load impacts tend to be higher than those of E-TOU-C. This aligns with the rate designs for each rate schedule, with E-TOU-D expected to benefit customers with higher usage levels due to the absence of a tiered rate structure (via the Baseline Credit).
- Customers transitioning to EV2-A tend to have higher percentage load impacts than customers transitioning to other TOU rates. This is likely because of the large end use (the EV) that can be shifted out of the peak period.
- August average temperature differences are indicative of participating customer locations, particularly the share of customers in the Greater Bay Area LCA. For example, the share of EV2-A customers in the Greater Bay Area is more than double that of E-TOU-D (73% vs. 36% in August 2023).
- August load impacts tend to be higher than February impacts for the E-TOU-C and E-TOU-D customers but are lower in August for the customers transitioning to EV2-A and E-ELEC. The latter finding may be due to additional EV charging demand in February vs. August.

Table ES.3: Peak-Period Load Impacts by Rate, February Average Weekday

Adopted TOU Rate	Enrolled	Aggregate (MWh/hr)		Per-customer (kWh/hr)		% Impact	Temp. (°F)
		Ref.	Impact	Ref.	Impact		
E-TOU-C	24,676	20.8	0.7	0.843	0.027	3.2% [1.9% - 4.4%]	49.6
E-TOU-D	7,607	12.2	0.5	1.599	0.065	4.1% [3.0% - 5.1%]	49.6
EV2-A	10,693	14.5	2.7	1.352	0.250	18.5% [17.2% - 19.8%]	50.3
E-ELEC	718	1.4	0.2	1.928	0.262	13.6% [11.6% - 15.6%]	48.7

Table ES.4: Peak-Period Load Impacts by Rate, August Average Weekday

Adopted TOU Rate	Enrolled	Aggregate (MWh/hr)		Per-customer (kWh/hr)		% Impact	Temp. (°F)
		Ref.	Impact	Ref.	Impact		
E-TOU-C	48,256	47.7	3.1	0.988	0.063	6.4% [5.4% - 7.4%]	81.7
E-TOU-D	13,635	32.0	1.9	2.345	0.142	6.0% [5.3% - 6.8%]	85.0
EV2-A	22,353	31.1	3.3	1.392	0.150	10.7% [9.6% - 11.9%]	78.9
E-ELEC	6,997	14.2	0.8	2.026	0.110	5.4% [4.1% - 6.7%]	78.7

ES.4 Ex-Ante Load Impacts

Ex-ante load impacts are developed for each of the TOU rates. In each case, the forecast represents *incremental* TOU load impacts attributable to customers joining TOU rates during the forecast period. Customers already on TOU rates contribute to an *embedded* TOU load impact already reflected in PG&E's system load. The embedded TOU customers are not included in our forecast.

Load impacts are forecast for each month from 2024 through 2034, distinguished by:

- Monthly peak day and average weekday;
- 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.

Figure ES.1 shows the yearly enrollment forecast for August for each adopted TOU rate. The enrollment changes shown in the figure generally follow a smooth path. However, E-TOU-D enrollments increase by a higher amount between 2025 and 2026 because E-TOU-B[3] sunsets in

[3] Like E-TOU-D, E-TOU-B's rate structure is intended to appeal to higher-use customers. It is closed to new enrollment.

2025, at which point those customers are expected to join E-TOU-D. By 2034, customers moving to EV2-A from E-1, E-TOU-C, or E-TOU-D account for the highest share of incremental TOU customers (764,995), with more than double the number of customers moving from E-1 to E-TOU-C (306,708 customers).

Figure ES.1: Forecast August Enrollments by Year and Adopted TOU Rate

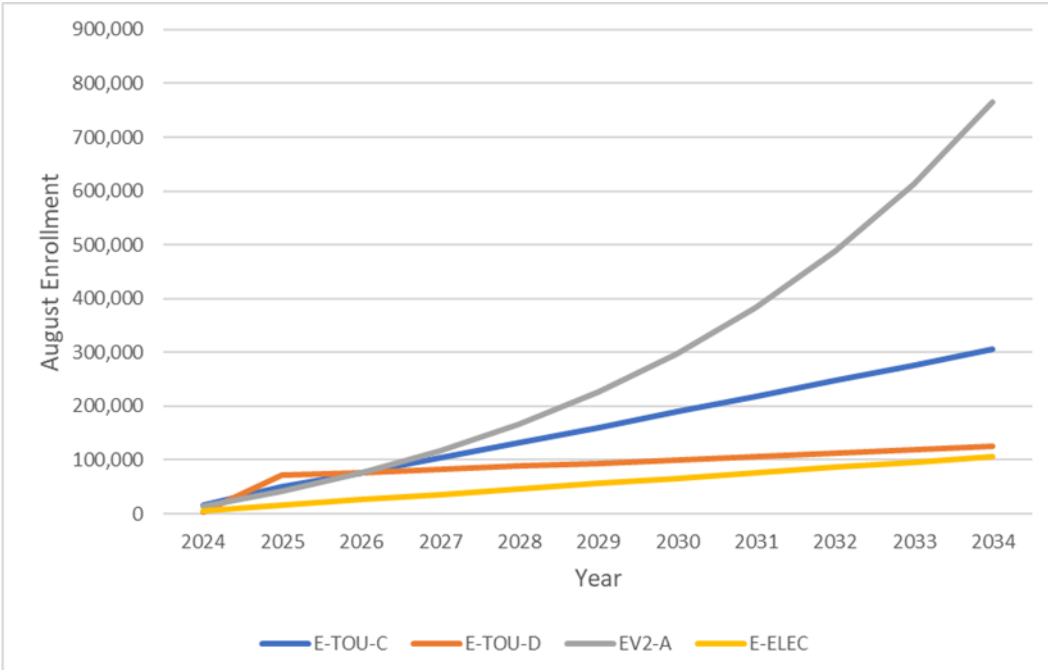


Figure ES.2 illustrates the forecast load impacts for each August during the forecast period. The values are the average load impacts during the Resource Adequacy window (4:00 to 9:00 p.m. during that month) for the PG&E 1-in-2 average weekday weather conditions. The load impacts increase over time due 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. Table ES.5 shows the same data in tabular form. The total incremental TOU load impact increases from 4.7 MWh/hr in 2024 to 195.3 MWh/hr in 2034.

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

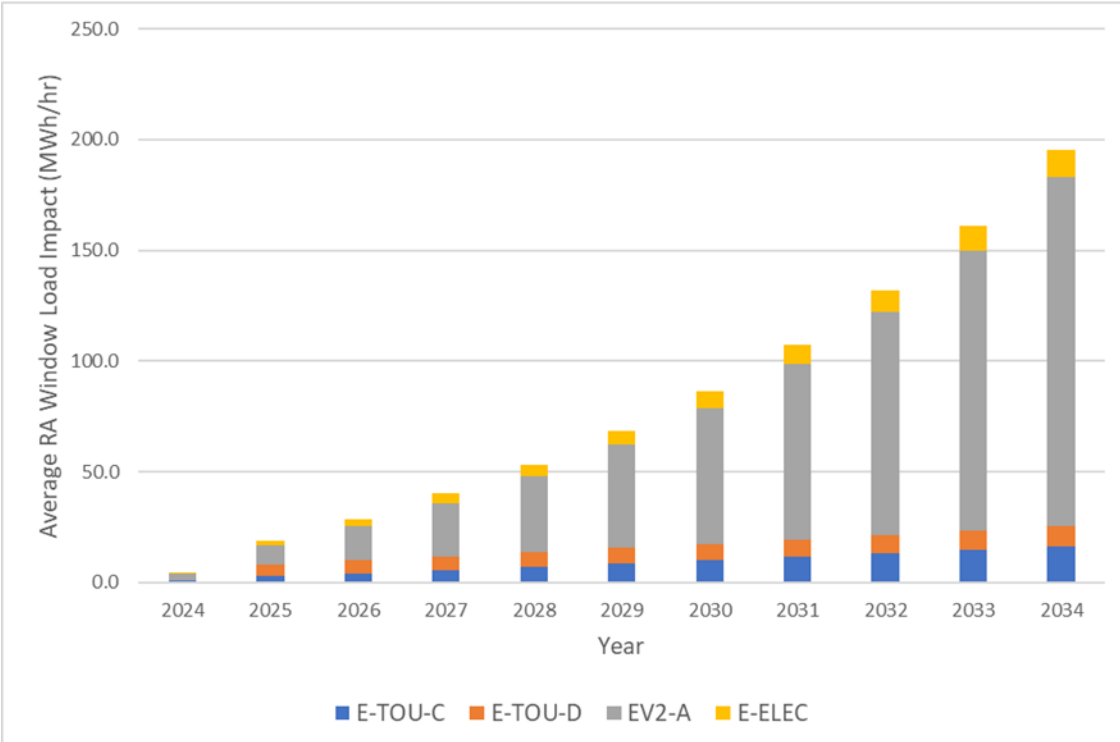


Table ES.5: Average RA Window Load Impacts by Year, August PG&E 1-in-2 Peak Month

Year	Load Impact by Adopted TOU Rate (MWh/hr)				Total
	E-TOU-C	E-TOU-D	EV2-A	E-ELEC	
2024	0.8	0.2	3.0	0.7	4.7
2025	2.8	5.3	8.8	1.9	18.6
2026	4.2	5.7	15.7	3.0	28.6
2027	5.6	6.1	24.1	4.2	40.1
2028	7.1	6.6	34.3	5.4	53.3
2029	8.6	7.0	46.5	6.5	68.6
2030	10.1	7.4	61.3	7.7	86.5
2031	11.6	7.9	79.0	8.9	107.4
2032	13.1	8.3	100.5	10.0	132.0
2033	14.6	8.8	126.3	11.2	161.0
2034	16.2	9.3	157.5	12.4	195.3

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 the program year 2023 (defined as October 2022 through September 2023), 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):

1. 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.
2. 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.
3. EV2-A: a voluntary whole-house electric vehicle (EV) rate with three TOU pricing periods (Peak, Part-Peak, and Off-Peak).
4. E-ELEC: available as a voluntary rate to customers with qualifying electric technologies (e.g., EVs, heat pumps, or battery storage). It contains the same pricing period definitions as EV2-A but adds a daily Basic Service Charge (BSC), expressed in $ per meter per day, to the rate structure.

The primary goals of the evaluation are the following:

1. Estimate ex-post load impacts for each rate for program year 2023; and
2. Develop ex-ante load impact forecasts for the rates for 2024 through 2034.

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 for customers expected to be a structural benefiter on E-TOU-C.
- 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 the following residential TOU rates: E-TOU-C became available in 2018 and now serves as the default TOU rate;[4] E-TOU-D opened for enrollment in May 2020; EV2-A is a whole-house electric vehicle (EV) rate;[5] and 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). Net energy metered (NEM) customers became eligible to join E-ELEC in July 2023.

Table 2.1 provides a comparison of the TOU rates, including the presence/level of the Basic Service Charge (BSC), presence/level of the of the minimum bill, the energy rates by season and pricing period, and the season and pricing period definitions.[6] The baseline credit contained in E-TOU-C is applicable up to a tariff-specified Baseline Quantity defined by the customer's Baseline Territory and whether the customer qualifies as All-Electric. This feature makes E-TOU-C more appealing to low-use customers (by lowering the marginal energy rate for lower-use customers), while E-TOU-D is likely to appeal to higher-use customers due to the absence of the Baseline Credit. EV2-A and E-ELEC also do not contain the tiered structure.

Table 2.1: TOU Rate Summaries

Season	Charge Type	E-TOU-C	E-TOU-D	EV2-A	E-ELEC
All	BSC ($/Day)	N/A			$0.49281
	Min. Bill ($/Day)	$0.37612			N/A
Summer	Peak	$0.61806	$0.58758	$0.65713	$0.63580
	Part-Peak	N/A	N/A	$0.54664	$0.47392
	Off-Peak	$0.53462	$0.45262	$0.34462	$0.41724
	Baseline Credit	($0.10556)	N/A		
Winter	Peak	$0.51536	$0.49798	$0.53002	$0.40429
	Part-Peak	N/A	N/A	$0.51332	$0.38220
	Off-Peak	$0.48701	$0.45937	$0.34462	$0.36834
	Baseline Credit	($0.10556)	N/A		
Definitions	Summer	Jun-Sep			
	Peak Period	4-9 pm all days	5-8 pm NHWD	4-9 pm all days	
	Part-Peak Period	N/A		3-4 pm, 9 pm-midnight all days	

Table 2.2 provides the rates for Schedule E-1, which is a tiered (i.e., increasing block), non-time differentiated rate that once served as the default residential rate. E-1 has the same minimum

[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, 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 and subsequent application of the default process to all applicable PG&E customers were evaluated in previous studies.

[5] PG&E also offers EV-B, which is an EV-only TOU rate. 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.

[6] The rates correspond to values in tariffs posted to PG&E's web site in February 2024.

bill provision as the TOU rates (except for E-ELEC) and an energy rate that increases at usage levels above 100% of the customer's Baseline Quantity (which is defined in the same manner as in E-TOU-C). This rate serves as one of the counterfactual rates when estimating incremental TOU load impacts. For example, we estimate load impacts as customers change from E-1 to E-TOU-C.

Table 2.2: Rate Schedule E-1 Summary

Charge Type	Rate
Minimum Bill ($/Day)	$0.37612
Tier 1 Usage (0% to 100% of Baseline)	$0.42009
Tier 2 Usage (101% to 400% of Baseline)	$0.52566
Tier 3 Usage (Over 400% of Baseline)	$0.52566

3. STUDY METHODOLOGY

The study examines customers who change rates to one of E-TOU-C, E-TOU-D, EV2-A, or E-ELEC during the program year, defined as October 2022 through September 2023. Load impacts may differ depending on the rate the customer is coming from. For example, an E-1 customer that changes to a TOU rate may shift less load across pricing periods than a customer that changes from one TOU rate to another. Table 3.1 lists the eleven rate transitions included in the study, along with indications of the method used to estimate load impacts.

Table 3.1: Rate Transitions Included in the Study

Rate Transition	NEM Included?	Load Impact Estimation Methodology	
		Include Control Group?	Basis of Load Impact Estimate[7]
E-1 to E-TOU-C	No	Yes	Difference-in-differences $(T_1 - C_1) - (T_0 - C_0)$
E-1 to E-TOU-C	Yes		
E-1 to E-TOU-D	No		
E-1 to E-TOU-D	Yes		
E-1 to EV2-A	Combined	No	Within-treatment, pre-treatment vs. treatment periods $(T_1 - T_0)$
E-TOU-C to EV2-A	Combined		
E-TOU-D to EV2-A	Combined		
E-1 to E-ELEC	No		
E-TOU-C to E-ELEC	No		
E-TOU-D to E-ELEC	No		
EV2-A to E-ELEC	No		

NEM and non-NEM customers are separately analyzed for the E-1 to E-TOU-C and E-TOU-D transitions to ensure robust estimates for each group. The methods used to study EV2-A allow us to combine NEM and non-NEM customers (which has the additional benefit of mitigating sample size concerns). Only non-NEM customers are studied for E-ELEC because NEM customers were not eligible for the rate for most of the program year.

[7] T_1 = the treatment customer usage in the treatment period; C_1 = the control-group customer usage in the treatment period; T_0 = the treatment customer usage in the pre-treatment period; and C_0 = the control-group customer usage in the pre-treatment period.

The evaluation methodology differed by rate transition. For customers transitioning to E-TOU-C or E-TOU-D, we select quasi-experimental matched control groups and conduct difference-in-differences estimation using regression analysis. For customers transitioning to EV2-A or E-ELEC, we conduct an analysis using only treatment customers. A structural break methodology is applied in an attempt to confirm ownership and use of the relevant electric end-use (e.g., an electric vehicle) throughout the analysis period. Load impacts are estimated using a within-treatment, before vs. after methodology that allows the load impact to vary according to temperatures. Additional details for each of these methods are included below.

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. 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 of joining a TOU rate.

The primary ex-post analyses are conducted for the eleven rate transition groups listed in Section 2 and summarized at the level of the "destination" TOU rate. While the TOU analysis previously focused on customers migrating from the E-1 tiered rate, other transitions have increased in importance now that E-1 is no longer the default residential rate.

3.1.2 Evaluation Methods

Estimating the load impacts of the TOU rates, as in all evaluations, requires a method for estimating what a 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. We implement the difference-in-differences approach for transitions to E-TOU-C and E-TOU-D and a treatment-only, before vs. after analysis for transitions to EV2-A and E-ELEC. The incremental TOU load impacts are estimated using customers who enrolled in the TOU rate on or after October 1, 2022.

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 2021 through September

2022) for the TOU and potential control-group customers. During this time period, both groups of 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 reduce the large number of available E-1 customers to a reduced set of preliminary matches for each TOU customer.[8]

In the second stage, we collapse pre-treatment period interval load data to pre-defined 24-hour profiles[9] 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 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 with a Control Group

For customers transitioning to E-TOU-C and E-TOU-D, a control group is employed to estimate load impacts as the difference between treatment and control group usage during the program year, adjusted for the difference between the two group's usage during the pre-treatment year (when all customers took service on E-1). This is implemented using hour-specific models for each season and rate transition group.[10] The model allows for the load impact to vary by local capacity area (LCA), climate region, and with temperature conditions. The weather variables are cooling degree days (CDDs) and heating degree days (HDDs).[11] The weather effect is allowed to differ by climate region to account for factors such as varying air conditioner penetration rates.

The model takes the following form:

[8] We then select the two nearest neighbors (six for NEM customers) for each treatment customer for inclusion in the Stage 2 match. Exact matching was conducted within LCA, CARE status, and climate region.

[9] 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% of days are defined as the extreme (i.e., hot in summer) profile, the middle 50% of days are defined as the typical profile, and all weekend days constitute the third profile.

[10] Summer models are estimated using May through September in all analyses except E-TOU-C NEM, which uses April through October (this definition produced more consistent load impact estimates in across the "swing" months for that group).

[11] Cooling degree days are calculated on a daily basis as follows: CDD = MAX{0,(Max Temp + Min Temp)/2 – 60}. Heating degree days are calculated on a daily basis as follows: HDD = MAX{0,60 – (Max Temp + Min Temp)/2}.

$$
\begin{aligned}
kW_{C,D} = \alpha &+ \sum_{L} \beta_{L,T} \times (LCA_{L,C} \times TOU_C \times Post_{C,D}) \\
&+ \sum_{R} \beta_{CDD,R,T} \times (TOU_C \times Post_{C,D} \times CDD_{C,D} \times Region_{R,C}) \\
&+ \sum_{R} \beta_{HDD,R,T} \times (TOU_C \times Post_{C,D} \times HDD_{C,D} \times Region_{R,C}) + \beta_{Post} \times Post_{C,D} \\
&+ \sum_{R} \beta_{CDD,R} \times (Region_{R,C} \times CDD_{C,D}) + \sum_{R} \beta_{HDD,R} \times (Region_{R,C} \times HDD_{C,D}) \\
&+ C_C + D_D + \varepsilon_{C,D}
\end{aligned}
$$

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

Table 3.2: Descriptions of Variables in the Ex-Post Estimation Model

Variable/Parameter	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
$LCA_{L,C}$	Variable indicating that customer *C* is in LCA *L*
$Post_D$	Variable indicating that day *D* is in the customer's post-enrollment period
$CDD_{C,D}$	CDDs for customer *C* on day *D*
$HDD_{C,D}$	HDDs for customer *C* on day *D*
$Region_{R,C}$	Variable indicating that customer *C* is in climate region *R*
α and various βs	Estimated coefficients
C_C	Customer fixed effects
D_D	Date fixed effects
$\varepsilon_{C,D}$	Error term

After a model is estimated, the relevant load impacts and standard errors are produced from the coefficient estimates and the associated variance-covariance matrix. That is, any given reported load impact combines the LCA-specific load impact with the effect of weather on the load impact (including the climate region effects interacted with weather).

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 including the appropriate interaction terms in the model. Specifically, the CARE load impacts are produced from an interaction of a CARE indicator variable with the load impact estimate. Further differentiating CARE status by climate region is accomplished using the climate region interaction terms described above.

PG&E is also interested in differentiating load impacts for customers who receive a structural benefit from switching to E-TOU-C. That is, customers with relatively less peak-period usage can experience a bill reduction on E-TOU-C without modifying their load profile. Such customers may be referred to as "structural benefiters." PG&E provided customer-specific data specifying each customer's "best rate" at historical usage, which we use to identify benefiters and estimate a separate regression model for them. The analysis is conducted in the same manner as the CARE/climate region analyses using only benefiters and their matched control-group customers in the analysis.

EV2-A and E-ELEC Load Impacts

Schedule EV2-A is a whole-house EV rate, which means the entirety of the customer's usage (including the EV charging) is billed using the TOU rate.[12] Schedule E-ELEC is a whole-house rate available to residential customers who have one or more of the following electric end uses: EV charging, energy storage, or electric heat pump for water heating or climate control.

The key challenge in estimating the incremental TOU load impacts for these rates is distinguishing between TOU rate effects and technology adoption effects. That is, we are interested in understanding how EV charging behavior is affected by the TOU rate but do not want to include the effect of purchasing (and beginning to charge) the EV on the customer's usage profile. Because the technology acquisition and rate adoption are likely to occur at the same time (e.g., if a customer switches to EV2-A shortly after buying an EV or switches to E-ELEC after installing a heat pump), we will not be able to distinguish between TOU response and technology adoption effects for many transitioning customers. Studying the TOU response requires observing usage behavior with the EV (or other qualifying end use) while being served on the counterfactual rate.

To identify customers who had an EV or qualifying end use prior to enrolling in EV2-A or E-ELEC, we estimate customer-specific structural breaks in usage. The structural break model identifies the most likely date (if any) on which there is a change to a customer's 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 EV (or other E-ELEC eligible end use) during the entire analysis period. The ex-post load impacts are subsequently estimated using a before/after analysis using the customers with no structural break. The estimated model takes the following form:

$$kW_{C,D} = \alpha + \beta_T \times Post_{C,D} + \beta_{T,CDD} \times Post_{C,D} \times CDD_{C,D} + \beta_{T,HDD} \times Post_{C,D} \times HDD_{C,D} + C_C + \varepsilon_{C,D}$$

[12] In contrast, EV-B requires a separate meter and applies only to customer's EV charging. 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.

The variable definitions may be found in Table 3.1. Separate models are estimated for each applicable rate transition, season, and hour of day. The model allows the load impact to vary with weather conditions.

NEM Customer Load Impacts

Separate NEM analyses are conducted for customers who transition from E-1 to E-TOU-C or E-TOU-D.[13] Therefore, the customers in the study 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 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.[14] Second, the solar PV generation capacity size is included in the matching process. Third, customers with changes in load profiles between periods that are not matched by their matched control-group customer (i.e., the difference-in-difference load change for the pair is large) are not used in the analysis because the differences are more likely caused by unobserved structural changes to a customer's solar PV system or electricity demand.[15] 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.

Once the matches are developed, the NEM customer load impacts are estimated using the same difference-in-differences method described above.

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:

[13] NEM customers are included with the non-NEM customers in the "to EV2-A" analyses. There were too few NEM customers to separately study, and the absence of a control group meant that the methodology did not need to differ for NEM and non-NEM customers. No E-ELEC NEM customers are included in the study because they were not eligible to join the rate until July 2023.

[14] 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 in time.

[15] This screen was also applied to the E-1 to E-TOU-D non-NEM analysis to account for one LCA that exhibited the effects of exogenous load changes on load impacts.

- 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. While the ex-ante study is conducted at the level of the eleven rate changes in the ex-post study (listed in Section 2), the forecasts are summarized at the rate level (e.g., all customers joining E-TOU-C) to reduce the volume of reported results. The methods used to develop the forecasts are described below.

3.2.2 Ex-Ante Evaluation Approach

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

$$
\begin{aligned}
kW_{i,t} = \alpha &+ \sum_{i=2}^{24}\left(\beta_i^{Weather} \times h_i \times Weather_t\right) + \sum_{i=2}^{24}\left(\beta_i^{MON} \times h_i \times MON_t\right) \\
&+ \sum_{i=2}^{24}(\beta_i^{FRI} \times h_i \times FRI_t) + \sum_{i=2}^{24}(\beta_i^{h} \times h_i) + \sum_{i=2}^{5}(\beta_i^{DOW} \times DOW_{i,t}) \\
&+ \sum_{i=6}^{10}(\beta_i^{MONTH} \times MONTH_{i,t}) + \varepsilon_{i,t}
\end{aligned}
$$

The variables are explained in Table 3.3 below.

Table 3.3: Descriptions of Variables in the Ex-Ante Reference Load Model

Variable Name / Term	Variable / Term Description
$kW_{i,t}$	the customer group's usage in hour *i* of day *t*
α and the various β'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., CDDs and HDDs)
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
$\varepsilon_{i,t}$	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 simulated using the ex-post regression models. That is, we predict the ex-ante load impact and associated standard error in the same manner as in the ex-post study but using ex-ante weather and day types in place of the ex-post conditions.[16]

Uncertainty-adjusted load impacts are based on the standard errors associated with the load impact predictions described above. Scenario-specific load impacts are developed for the 10th, 30th, 50th, 70th, and 90th percentile scenarios.

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 2023 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 each of the four TOU rates listed in Section 2. 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 G.1 shows the number of treatment customers represented in each of the analyses.

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 shown in Table 2.1. The load impacts reflect customers who adopted the TOU rate sometime between October 2022 and September 2023.

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 2023, respectively. The brackets in the "% Impact" column show the 80% confidence interval around the estimated load impacts.

[16] For some months in the spring and fall, forecast load impacts can be out of scale with those of other months if the ex-ante temperatures are out of the range of historical experience. In these cases, we replace the forecast load impacts with percentage or level load impacts from a neighboring month for the same rate and customer group.

We have the following observations about the results:

- E-TOU-D per-customer reference loads and load impacts tend to be higher than those of E-TOU-C. This aligns with the rate designs for each rate schedule, with E-TOU-D expected to benefit customers with higher usage levels due to the absence of a tiered rate structure (via the Baseline Credit).
- Customers transitioning to EV2-A tend to have higher percentage load impacts than customers transitioning to other TOU rates. This is likely because of the large end use (the EV) that can be shifted out of the peak period.
- August average temperature differences are indicative of participating customer locations, particularly the share of customers in the Greater Bay Area LCA. For example, the share of EV2-A customers in the Greater Bay Area is more than double that of E-TOU-D (73% vs. 36% in August 2023).
- August load impacts tend to be higher than February impacts for the E-TOU-C and E-TOU-D customers but are lower in August for the customers transitioning to EV2-A and E-ELEC. The latter finding may be due to additional EV charging demand in February vs. August.
- As shown in Section 6.1, the August E-TOUC per-customer load impacts are significantly lower this year versus the previous evaluation (0.063 vs. 0.029 kWh/hr/customer). This may be due to the type of customers that can be included in the ex-post study in the two evaluations. That is, this study reflects voluntary E-TOU-C rate changers who have a history on E-1 versus the defaulted E-1 customers reflected in the previous study.

Table 4.1: Peak-Period Load Impacts by Rate, February Average Weekday[17]

Adopted TOU Rate	Enrolled	Aggregate (MWh/hr)		Per-customer (kWh/hr)		% Impact	Temp. (°F)
		Ref.	Impact	Ref.	Impact		
E-TOU-C	24,676	20.8	0.7	0.843	0.027	3.2% [1.9% - 4.4%]	49.6
E-TOU-D	7,607	12.2	0.5	1.599	0.065	4.1% [3.0% - 5.1%]	49.6
EV2-A	10,693	14.5	2.7	1.352	0.250	18.5% [17.2% - 19.8%]	50.3
E-ELEC	718	1.4	0.2	1.928	0.262	13.6% [11.6% - 15.6%]	48.7

[17] 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

Adopted TOU Rate	Enrolled	Aggregate (MWh/hr)		Per-customer (kWh/hr)		% Impact	Temp. (°F)
		Ref.	Impact	Ref.	Impact		
E-TOU-C	48,256	47.7	3.1	0.988	0.063	6.4% [5.4% - 7.4%]	81.7
E-TOU-D	13,635	32.0	1.9	2.345	0.142	6.0% [5.3% - 6.8%]	85.0
EV2-A	22,353	31.1	3.3	1.392	0.150	10.7% [9.6% - 11.9%]	78.9
E-ELEC	6,997	14.2	0.8	2.026	0.110	5.4% [4.1% - 6.7%]	78.7

4.1.2 Peak-Period Impacts by Climate Region

Table 4.3 shows the average peak-period load impact for the August 2023 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) is higher in hotter climate regions, though the E-TOU-D percentage load impacts are highest for the moderate climate region for both CARE and non-CARE customers.

[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.

Table 4.3: 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	7,597	0.431	0.005	1.2% [-0.7% - 3.0%]	67.3
		Moderate	13,233	0.795	0.028	3.6% [2.4% - 4.7%]	76.2
		Hot	11,674	1.450	0.144	9.9% [8.3% - 11.5%]	88.1
	Yes	Cool	1,778	0.620	0.024	3.8% [-0.1% - 7.5%]	66.3
		Moderate	3,023	0.929	0.046	5.0% [2.5% - 7.4%]	76.3
		Hot	7,888	1.772	0.169	9.6% [7.9% - 11.2%]	88.8
E-TOU-D	No	Cool	1,480	0.987	0.017	1.7% [-0.3% - 3.7%]	67.5
		Moderate	3,193	1.922	0.096	5.0% [3.8% - 6.1%]	76.8
		Hot	3,229	2.813	0.110	3.9% [2.9% - 4.9%]	88.7
	Yes	Cool	402	1.268	0.043	3.4% [0.7% - 6%]	66.8
		Moderate	781	2.007	0.119	5.9% [4.2% - 7.6%]	77.2
		Hot	3,635	3.315	0.141	4.3% [3.2% - 5.3%]	89.7

4.1.3 Peak-Period Impacts by CARE Status

Table 4.4 shows the average peak-period load impact for the August 2023 average weekday, reported by CARE status.[19] Due to smaller sample sizes, we omit NEM customers and the EV2-A and E-ELEC rates from the summaries. Blue shading is used to help separate the rate-specific results.

CARE customers tend to experience higher temperatures and have higher reference loads than non-CARE customers. For E-TOU-C, CARE customers have a higher level and percentage load impact than non-CARE customers. For E-TOU-D, only the level load impact is higher for CARE customers, with the percentage impact slightly lower.

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

Table 4.4: Peak-Period Load Impacts by Rate and CARE Status, August Average Weekday

Rate	CARE	Enrolled	Reference (kWh/hr/cust)	Impact (kWh/hr/cust)	% Impact	Temp. (°F)
E-TOU-C Non-NEM	No	32,503	0.805	0.043	5.4% [4.3% - 6.5%]	79.9
	Always / Sometimes	12,688	1.236	0.097	7.9% [5.8% - 10%]	83.9
E-TOU-D Non-NEM	No	7,903	2.006	0.126	6.3% [5.3% - 7.3%]	82.4
	Always / Sometimes	4,818	2.795	0.167	6.0% [4.7% - 7.3%]	87.9

4.1.4 Peak-Period Impacts for E-TOU-C Non-NEM Structural Benefiters

PG&E provided data indicating the expected best rate for the customers who transitioned from E-1 to E-TOU-C. Three categories of customers were provided by PG&E:

- Benefiters: a customer who is expected to experience a significant bill reduction after switching to E-TOU-C 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% per year; and
- CARE: bill change larger than $50 or 10% per year.[20]

These criteria identify most of the population as neutral. In our analysis sample, 12% of the customers were identified as benefiters, while only 0.4% were non-benefiters. Due to the low share of non-benefiter customers, our analysis focuses on the benefiters.

We estimated separate regression models for the E-TOU-C benefiters, with estimates differentiated by climate region, thus making them comparable to the non-CARE results in the top panel of Table 4.3.

Table 4.5 shows the average peak-period load impact for the August 2023 average weekday, reported by climate region for non-CARE customers.

When comparing to the results for all E-TOU-C customers by climate region in Table 4.3, we find that the benefiters tend to have higher reference loads. It is difficult to draw firm conclusions about differences in benefiter load impacts versus all customers due to the size of the confidence intervals for benefiters, though the point estimates tend to be higher for the benefiters.

[20] Results for CARE structural benefiters are excluded due to small sample sizes.

Table 4.5 Peak-Period Impacts for E-TOU-C non-NEM Structural Benefiters, August Average Weekday

Climate Region	# Enrolled in Model	Reference (kWh/hr/cust)	Impact (kWh/hr/cust)	% Impact	Temp. (°F)
Cool	149	0.668	0.017	2.6% [-3.6% - 8.1%]	69.8
Moderate	245	1.068	0.029	2.7% [-1.5% - 6.6%]	76.6
Hot	125	1.634	0.229	14.0% [9.0% - 18.5%]	87.3

4.2 Average Hourly Load Impacts

This subsection illustrates the hourly load and load impact profiles for the average weekdays in February and August 2023. 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 on the counterfactual rate instead of changing to the TOU rate in question. 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 customers in February and August 2023, respectively. The February results show a 3.2% reduction in peak-period usage. The August estimates show a 6.4% reduction in peak-period usage.

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

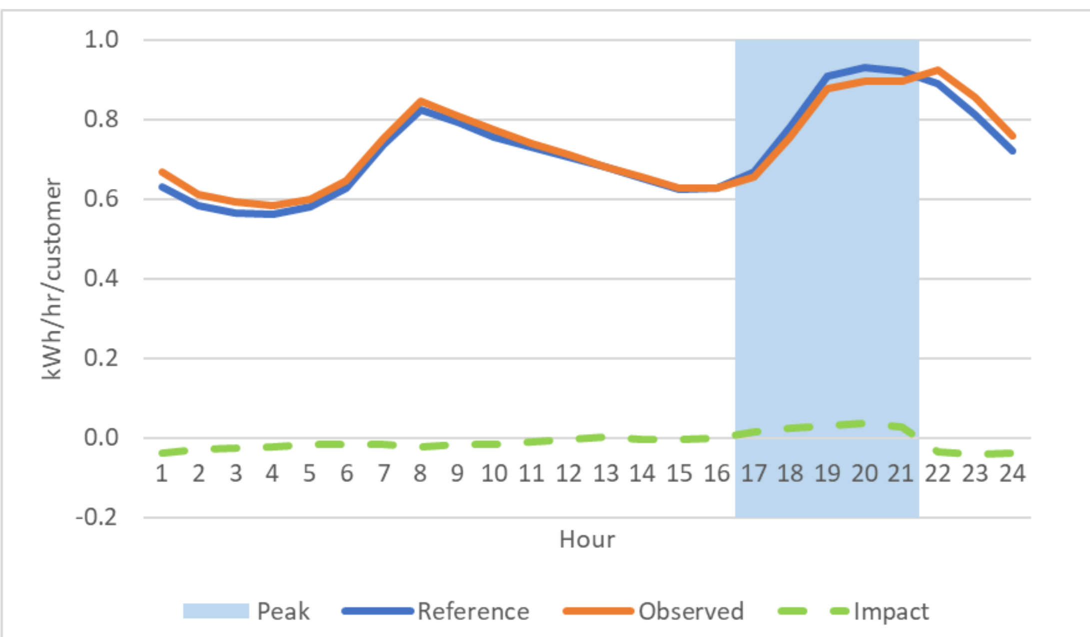
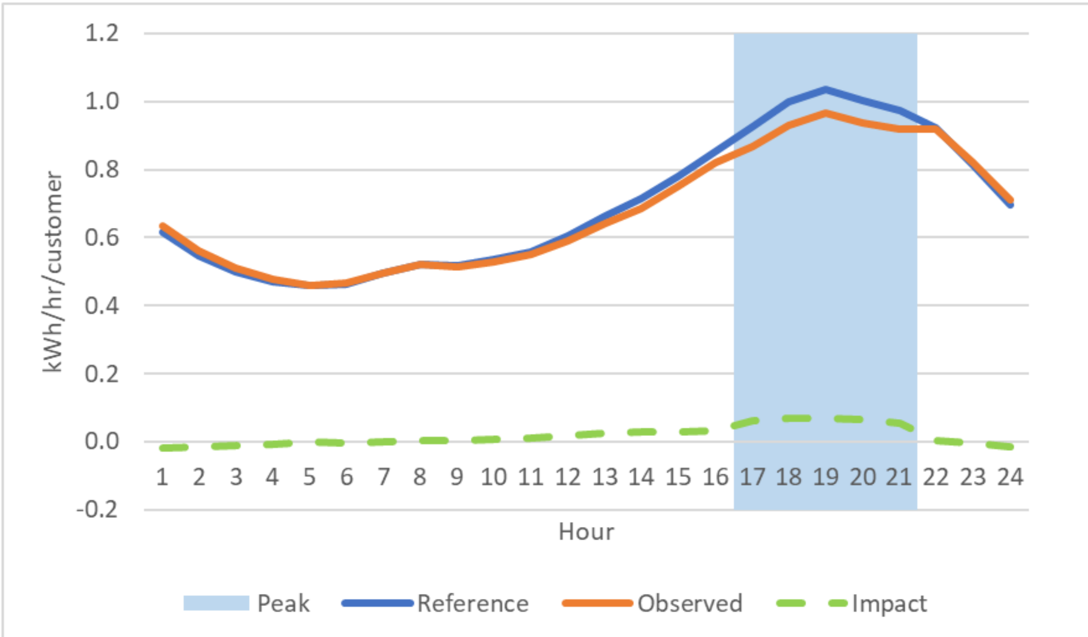


Figure 4.2: E-TOU-C August Average Weekday Hourly Impacts



Figures 4.3 and 4.4 show the estimates for E-TOU-D customers. The February load impacts average 4.1% 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 6.0%.

Figure 4.3: E-TOU-D February Average Weekday Hourly Impacts

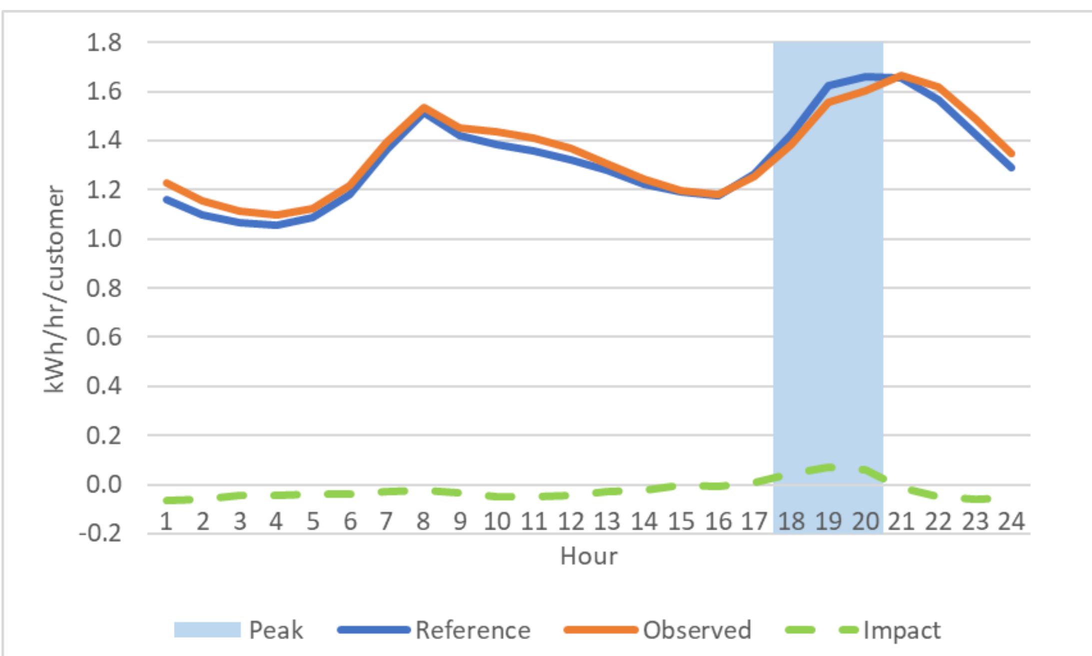
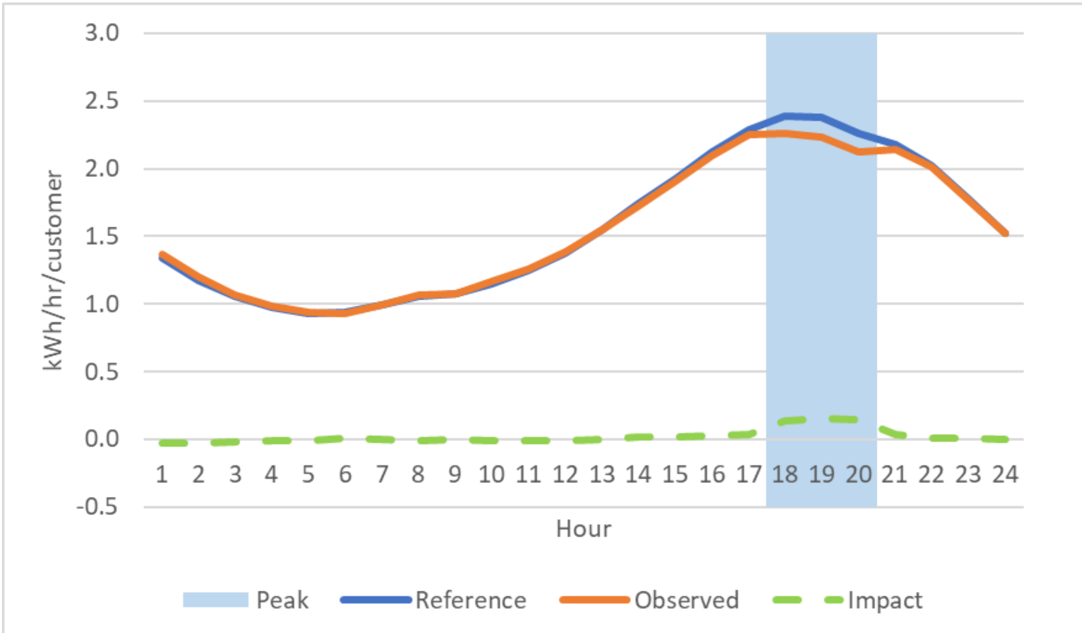


Figure 4.4: E-TOU-D August Average Weekday Hourly Impacts



Figures 4.5 and 4.6 show the estimates for EV2-A 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. The February results show an 18.5% reduction in peak-period usage. The August estimates show a 10.7% reduction in peak-period usage.

Figure 4.5: EV2-A February Average Weekday Hourly Impacts

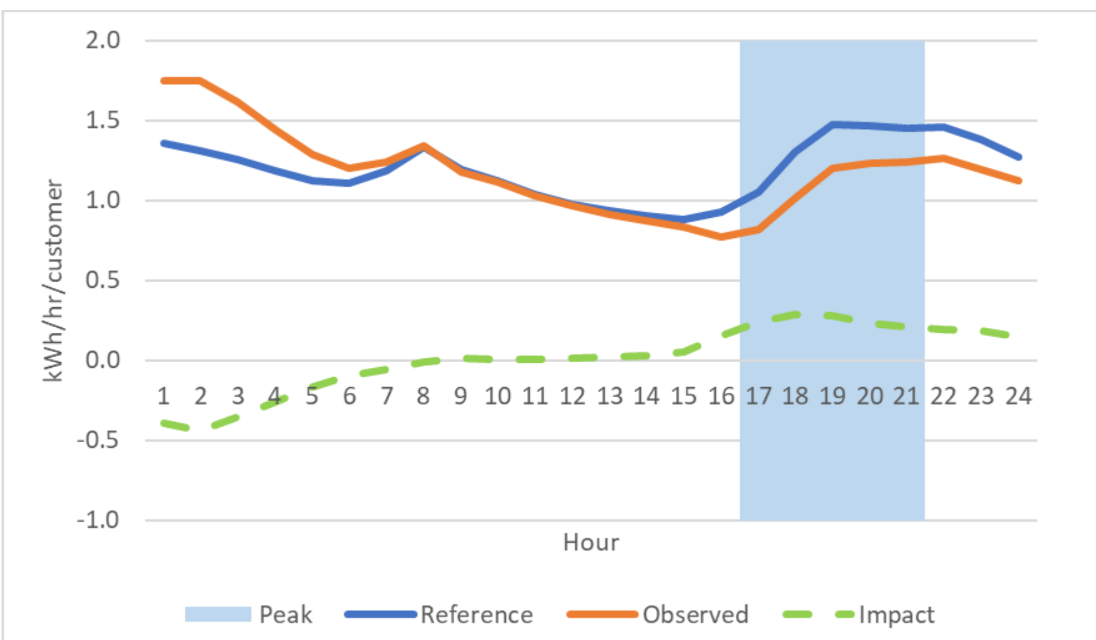
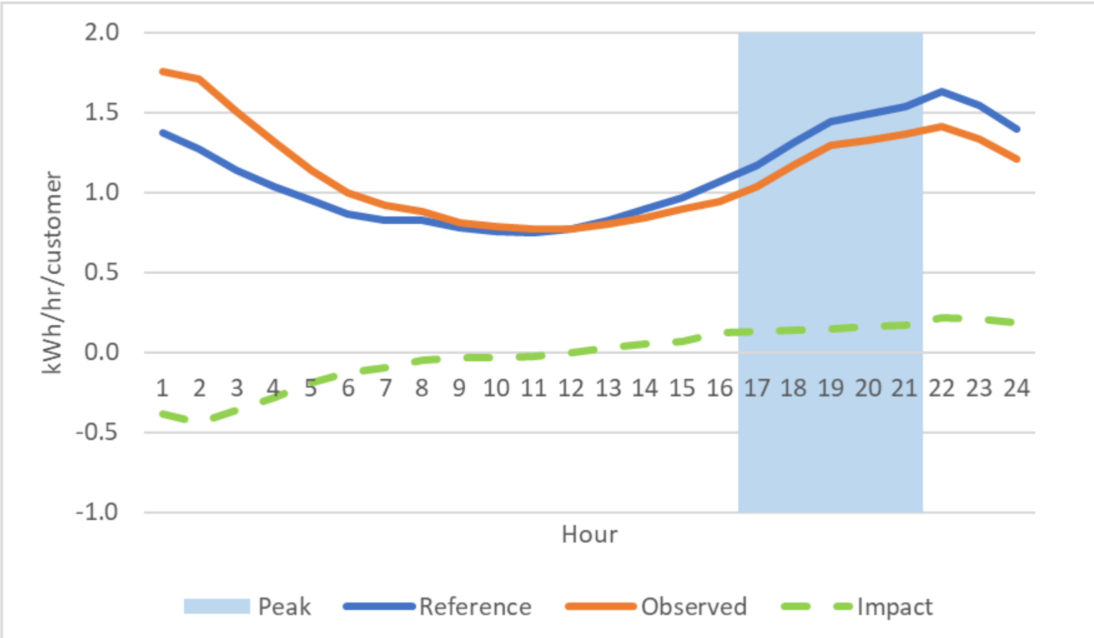


Figure 4.6: EV2-A August Average Weekday Hourly Impacts



Figures 4.7 and 4.8 show the estimates for E-ELEC customers. The load impact pattern is similar to that of EV2-A customers. In this case, the February load impacts are based on relatively few enrolled customers (the rate opened to enrollment in the prior December), which may limit the extent to which these results generalize to larger populations. The February results show a 13.6% reduction in peak-period usage. The August estimates show a 5.4% reduction in peak-period usage.

Figure 4.7: E-ELEC February Average Weekday Hourly Impacts

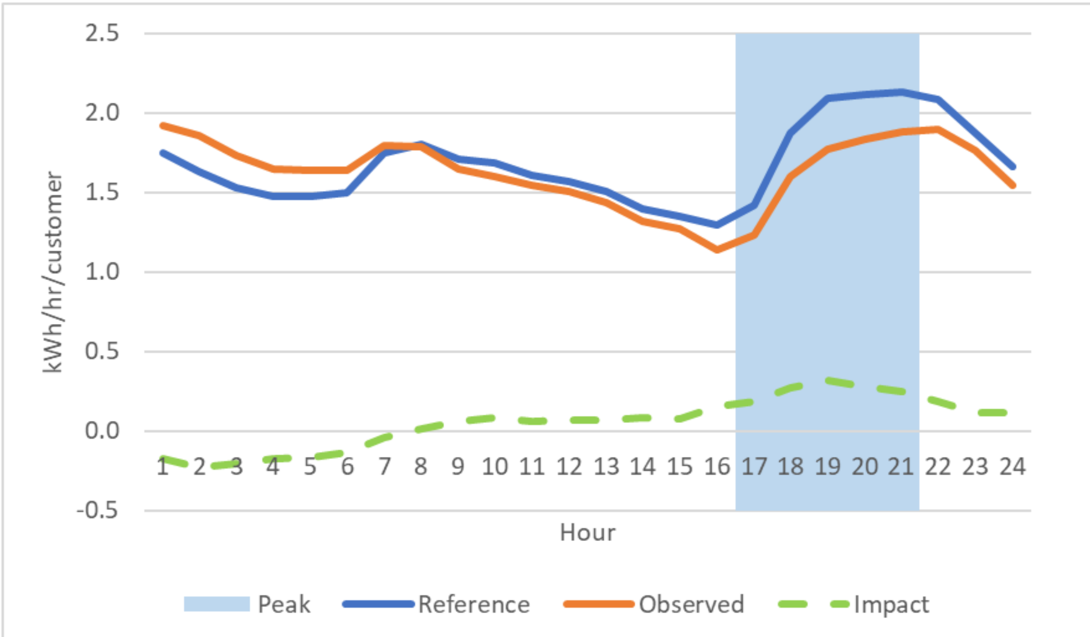
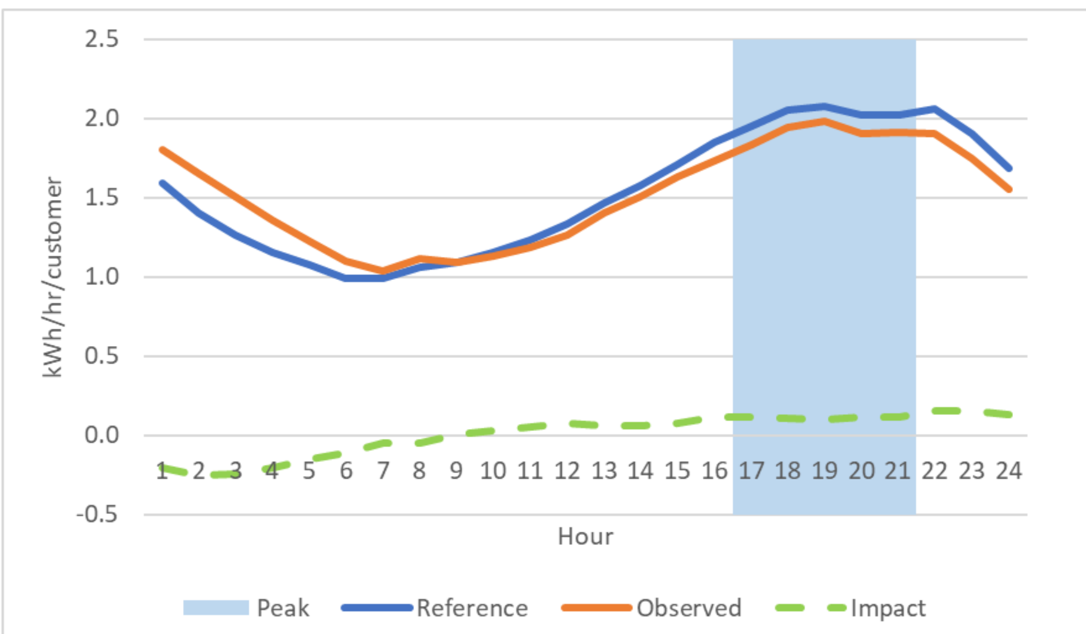


Figure 4.8: E-ELEC August Average Weekday Hourly Impacts



5. EX-ANTE LOAD IMPACTS

5.1 Overview and Enrollment Forecasts

Ex-ante load impacts are developed for eleven rate transition groups of customers[21]:

1. E-1 to E-TOU-C non-NEM;
2. E-1 to E-TOU-C NEM;
3. E-1 to E-TOU-D non-NEM;
4. E-1 to E-TOU-D NEM;
5. E-1 to EV2-A;
6. E-TOU-C to EV2-A;
7. E-TOU-D to EV2-A;
8. E-1 to E-ELEC;
9. E-TOU-C to E-ELEC;
10. E-TOU-D to E-ELEC; and
11. EV2-A to E-ELEC.

We then combine the transition-level forecasts to the rate level, separately summarizing forecasts for all customers transitioning to E-TOU-C, E-TOU-D, EV2-A, and E-ELEC. In each case, the forecast represents *incremental* TOU load impacts attributable to customers joining TOU rates during the forecast period. Customers already on TOU rates contribute to an *embedded* TOU load impact 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 enrollment forecast for August[22] for each adopted TOU rate.[23] Additional detail by rate transition is shown in Table 5.1, which shows enrollments for each of the eleven rate transitions for the next three years and the last year of the forecast.

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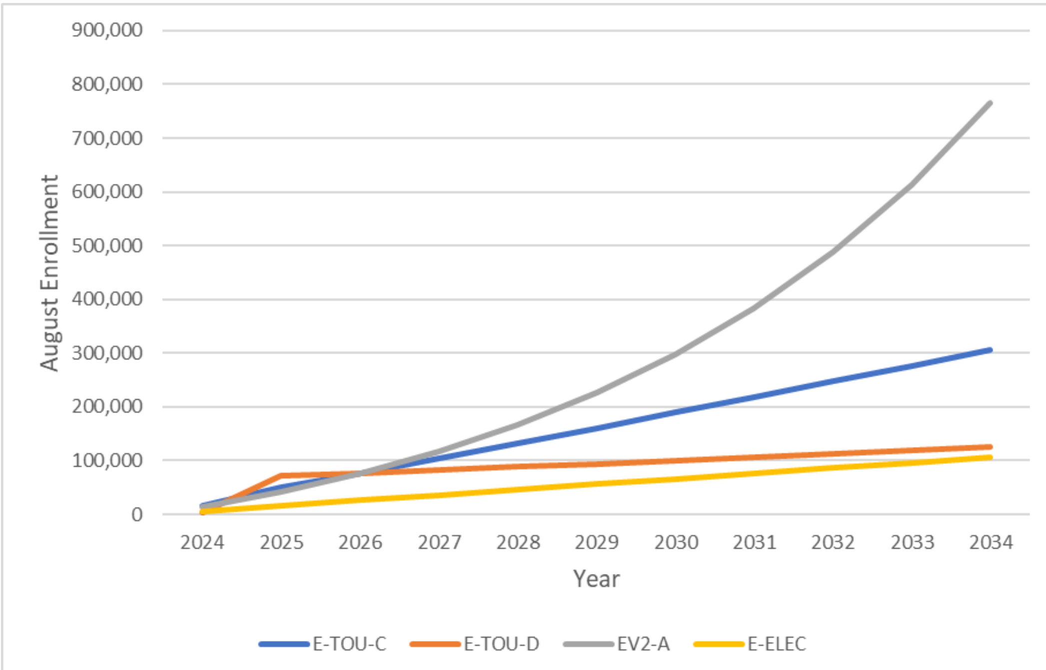
[21] Forecast enrollments for E-ELEC NEM customers are added to the corresponding non-NEM rate transition enrollments (e.g., E-1 to E-ELEC non-NEM) to ensure those customers are represented in the forecast. We were not able to estimate ex-post load impacts for E-ELEC NEM customers because they were not eligible to join E-ELEC until July 2023.

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

[23] The EV2-A and E-ELEC enrollments combine NEM and non-NEM customers.

The enrollment changes shown in the figure generally follow a smooth path. However, E-TOU-D enrollments increase by a higher amount between 2025 and 2026 because E-TOU-B[24] sunsets in 2025, at which point those customers are expected to join E-TOU-D. By 2034, customers moving to EV2-A from E-1, E-TOU-C, or E-TOU-D account for the highest share of incremental TOU customers (764,995), with more than double the number of customers moving from E-1 to E-TOU-C (306,708 customers).

Figure 5.1: Forecast August Enrollments by Year and Adopted TOU Rate



[24] Like E-TOU-D, E-TOU-B's rate structure is intended to appeal to higher-use customers. It is closed to new enrollment.

Table 5.1: Forecast August Enrollments by Year and Customer Group

Rate Transition	NEM	Enrollment			
		2024	2025	2026	2034
E-1 to E-TOU-C	No	12,440	37,422	59,223	242,427
E-1 to E-TOU-C	Yes	3,130	12,225	17,753	64,281
E-1 to E-TOU-D	No	1,626	35,823	39,156	67,746
E-1 to E-TOU-D	Yes	987	35,652	37,878	56,964
E-1 to EV2-A	Both	12,938	38,157	68,559	686,170
E-TOU-C to EV2-A	Both	1,271	3,745	6,731	67,368
E-TOU-D to EV2-A	Both	218	638	1,145	11,457
E-1 to E-ELEC	Both	1,813	4,921	8,029	32,893
E-TOU-C to E-ELEC	Both	2,107	5,719	9,331	38,227
E-TOU-D to E-ELEC	Both	756	2,060	3,356	13,724
EV2-A to E-ELEC	Both	1,176	3,192	5,208	21,336

5.2 Ex-Ante Load Impact Results

The following sub-sections present the ex-ante forecasts for each of the four TOU rates.

Figure 5.2 illustrates 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. during that month) for the PG&E 1-in-2 average weekday 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. Table 5.2 shows the same data in tabular form. The total incremental TOU load impact increases from 4.7 MWh/hr in 2024 to 195.3 MWh/hr in 2034.

The largest difference in aggregate load impacts between this forecast and the one prepared following PY2022 is due to the EV2-A customers. The prior study assumed that all incremental enrollments in EV2-A came from E-TOU-C, while the current study assumes that most of the incremental enrollments in EV2-A come from E-1 (as seen in Table 5.1). Because the E-1 to EV2-A per-customer load impacts are higher than those of E-TOU-C to EV2-A, the aggregate EV2-A load impact in 2033 (the last forecast year in the PY2022 study) more than doubles relative to the previous study despite similar forecast enrollment levels.

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

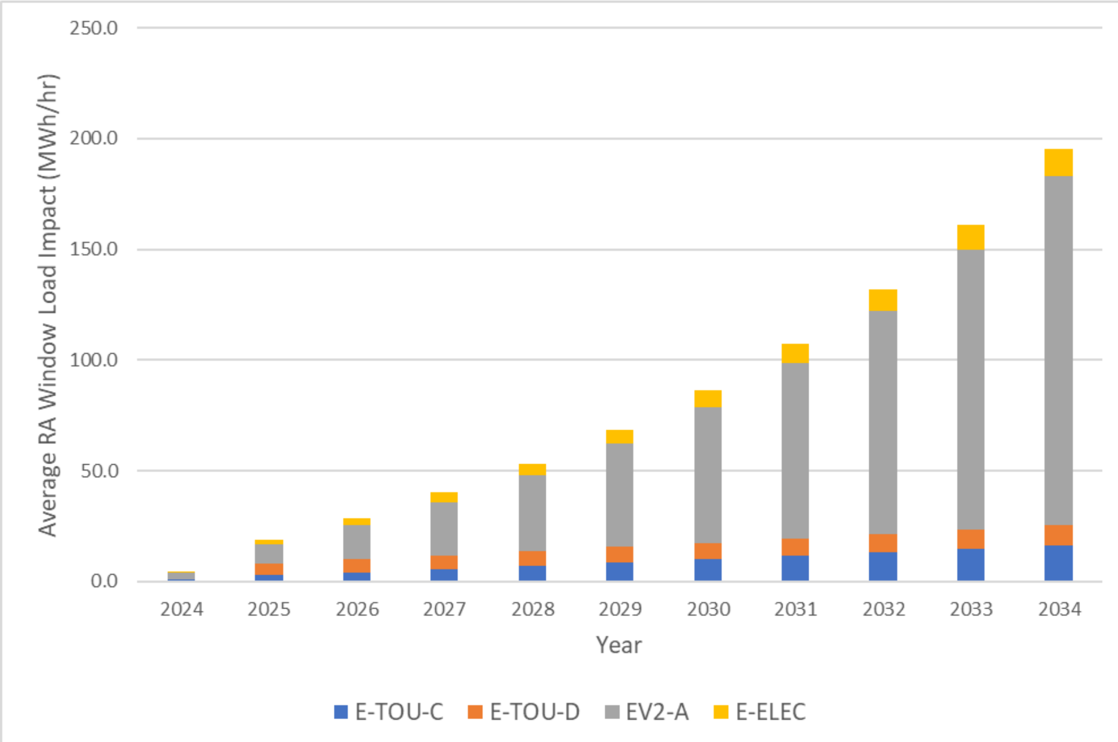


Table 5.2: Average RA Window Load Impacts by Year, August PG&E 1-in-2 Peak Month

Year	Load Impact by Adopted TOU Rate (MWh/hr)				Total
	E-TOU-C	E-TOU-D	EV2-A	E-ELEC	
2024	0.8	0.2	3.0	0.7	4.7
2025	2.8	5.3	8.8	1.9	18.6
2026	4.2	5.7	15.7	3.0	28.6
2027	5.6	6.1	24.1	4.2	40.1
2028	7.1	6.6	34.3	5.4	53.3
2029	8.6	7.0	46.5	6.5	68.6
2030	10.1	7.4	61.3	7.7	86.5
2031	11.6	7.9	79.0	8.9	107.4
2032	13.1	8.3	100.5	10.0	132.0
2033	14.6	8.8	126.3	11.2	161.0
2034	16.2	9.3	157.5	12.4	195.3

5.2.1 Ex-Ante Load Impacts for E-TOU-C Customers

Table 5.3 shows the E-TOU-C customer peak-period load impacts, averaged during the Resource Adequacy window. The tables show monthly load impacts in 2025 associated with each of the four weather scenarios. Total load impacts increase with enrollments and tend to be higher in the

1-in-10 weather scenarios. When examining the PG&E 1-in-2 weather scenario, the aggregate load impact is highest in August.

Table 5.3: E-TOU-C Ex-Ante Load Impacts, 2025 Average Weekdays 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	33,852	0.95	0.94	0.96	0.93
February	36,102	1.00	0.95	0.98	0.96
March	38,354	0.90	0.83	0.65	0.83
April	40,607	1.32	1.29	1.28	1.28
May	42,864	1.14	1.12	1.18	1.08
June	45,124	2.31	2.30	2.34	2.32
July	47,385	2.94	2.65	2.94	2.73
August	49,647	2.74	2.88	2.83	2.76
September	51,911	2.51	2.44	2.47	2.44
October	54,178	2.45	2.07	2.36	2.03
November	56,448	1.48	1.47	1.56	1.48
December	58,722	1.58	1.59	1.59	1.58

Figure 5.3 shows the hourly loads and load impacts associated with the August 2024 PG&E 1-in-2 average weekday weather scenario. The peak-period load impact averages 5.2%. Figure 5.4 shows the same information for February 2025. The peak-period load impact averages 3.3%.

Figure 5.3: E-TOU-C Ex-Ante Load Impacts, August 2024 PG&E 1-in-2 Average Weekday

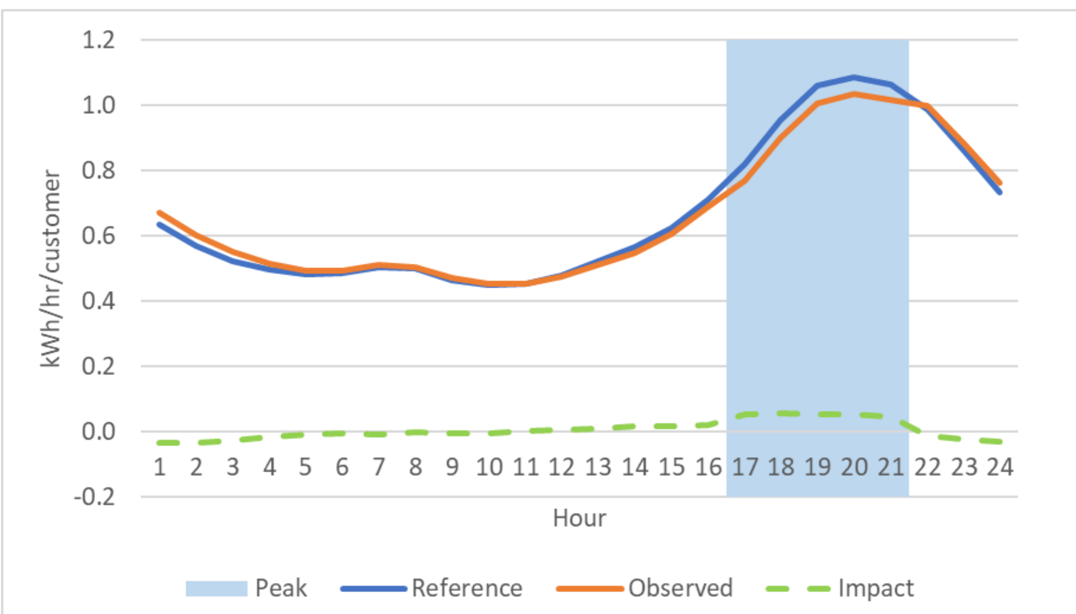
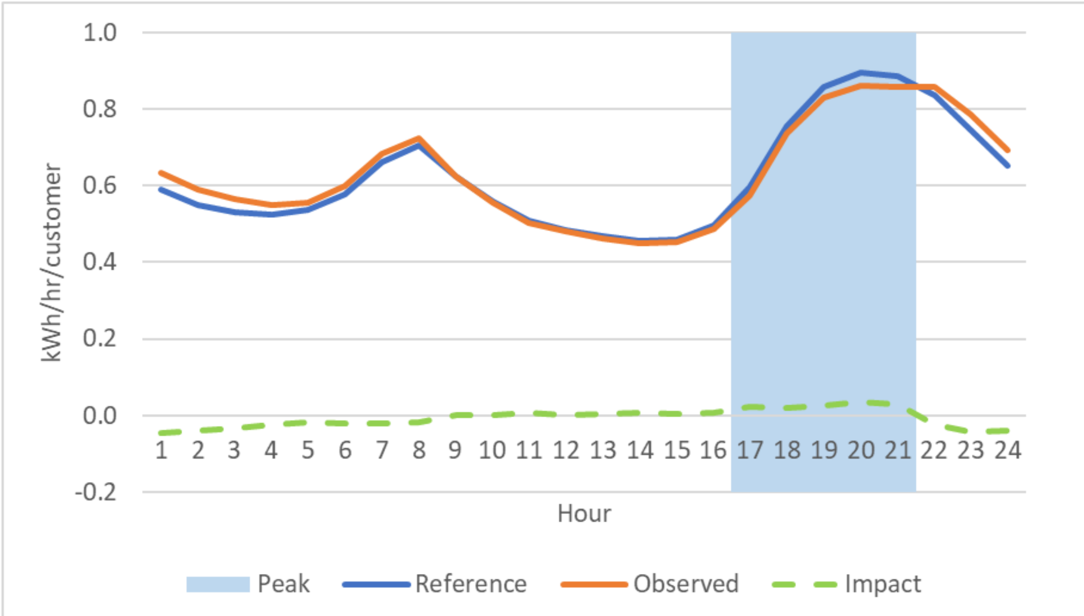


Figure 5.4: E-TOU-C Ex-Ante Load Impacts, February 2025 PG&E 1-in-2 Average Weekday



5.2.2 Ex-Ante Load Impacts for E-TOU-D Customers

Table 5.4 shows the E-TOU-D customer peak-period load impacts, averaged during the Resource Adequacy window. The tables show monthly load impacts in 2025 associated with each of the four weather scenarios. When examining the PG&E 1-in-2 weather scenario, the aggregate load impact is highest in July.

Table 5.4: E-TOU-D Ex-Ante Load Impacts, 2025 Monthly Average Weekdays 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	68,264	5.59	5.83	5.36	5.85
February	68,721	5.59	5.88	5.81	5.86
March	69,178	5.08	5.00	5.00	5.00
April	69,635	4.00	4.14	4.28	4.32
May	70,094	4.57	4.41	4.54	4.36
June	70,554	5.27	5.22	5.27	5.24
July	71,014	5.20	5.25	5.20	5.31
August	71,475	5.19	5.29	5.12	5.28
September	71,936	5.07	5.33	5.00	5.20
October	72,397	5.08	5.30	5.13	5.27
November	72,859	6.46	6.36	6.38	6.46
December	73,321	5.74	6.14	5.85	6.06

Figure 5.5 shows the hourly loads and load impacts associated with the August 2024 PG&E 1-in-2 average weekday weather scenario. The peak-period load impact averages 5.3%. Figure 5.6 shows the same information for February 2025. The peak-period load impact averages 8.8%.

Figure 5.5: E-TOU-D Ex-Ante Load Impacts, August 2024 PG&E 1-in-2 Average Weekday

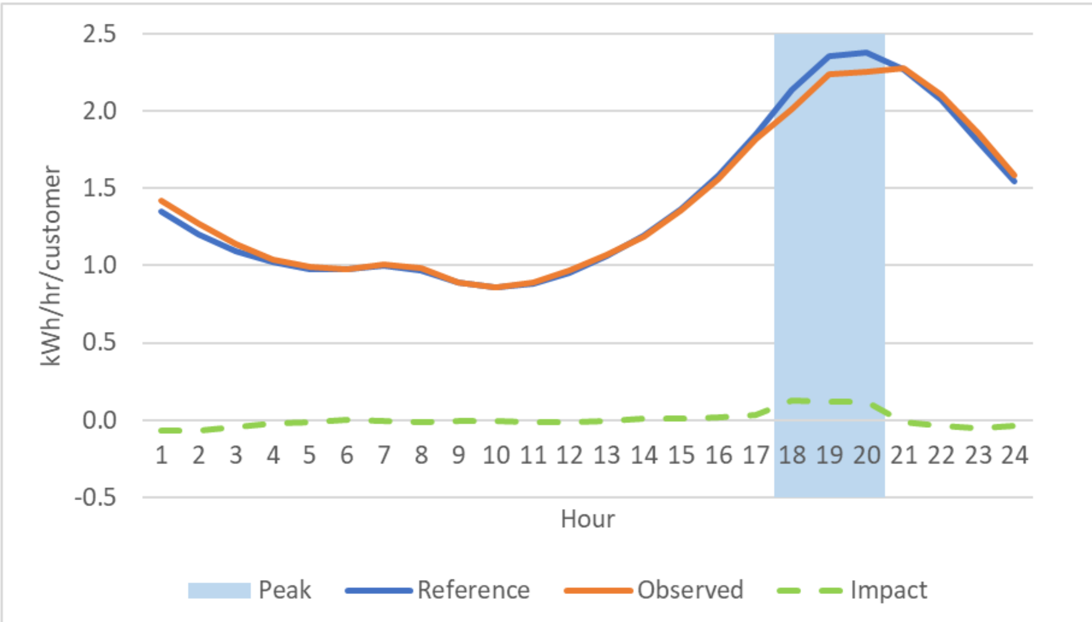
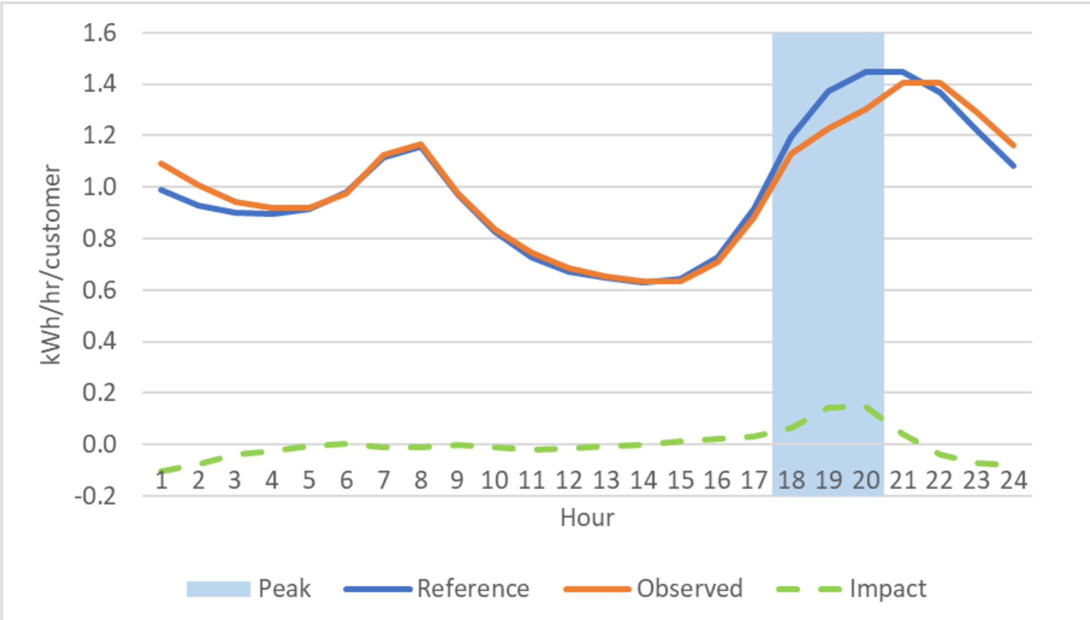


Figure 5.6: E-TOU-D Ex-Ante Load Impacts, February 2025 PG&E 1-in-2 Average Weekday



5.2.3 Ex-Ante Load Impacts for EV2-A Customers

Table 5.5 shows the EV2-A customer peak-period load impacts, averaged during the Resource Adequacy window. The tables show monthly load impacts in 2025 associated with each of the four weather scenarios. Load impacts peak at the end of the year when enrollment is highest.

Table 5.5: EV2-A Ex-Ante Load Impacts, 2025 Monthly Average Weekdays 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	25,150	6.33	6.15	6.52	6.11
February	27,634	6.91	6.58	6.68	6.60
March	30,118	7.09	7.15	7.21	7.15
April	32,605	7.44	7.49	7.56	7.54
May	35,088	5.36	4.76	5.50	4.53
June	37,571	6.81	7.27	7.03	7.36
July	40,054	8.72	8.18	8.72	8.03
August	42,540	8.67	9.28	9.38	8.76
September	45,022	9.26	8.11	9.58	9.01
October	47,503	10.20	10.43	10.26	10.44
November	49,988	11.57	11.76	11.57	11.54
December	52,475	13.50	12.99	13.42	13.04

Figure 5.7 shows the hourly loads and load impacts associated with the August 2024 PG&E 1-in-2 average weekday weather scenario. The peak-period load impact averages 16.8%. Figure 5.8 shows the same information for February 2025. The peak-period load impact averages 23.7%.

The level load impact is only slightly higher in February (0.24 vs. 0.21 kWh/hr/customer, with a larger difference in the reference loads (1.23 vs. 1.01 kWh/hr/customer in August and February, respectively).

Figure 5.7: EV2-A Ex-Ante Load Impacts, August 2024 PG&E 1-in-2 Average Weekday

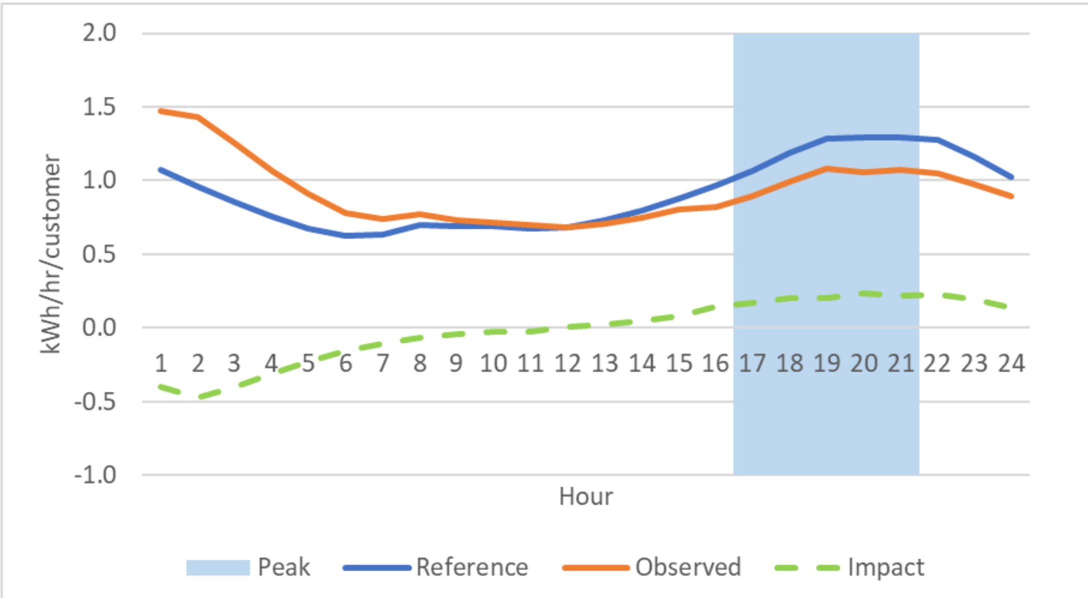
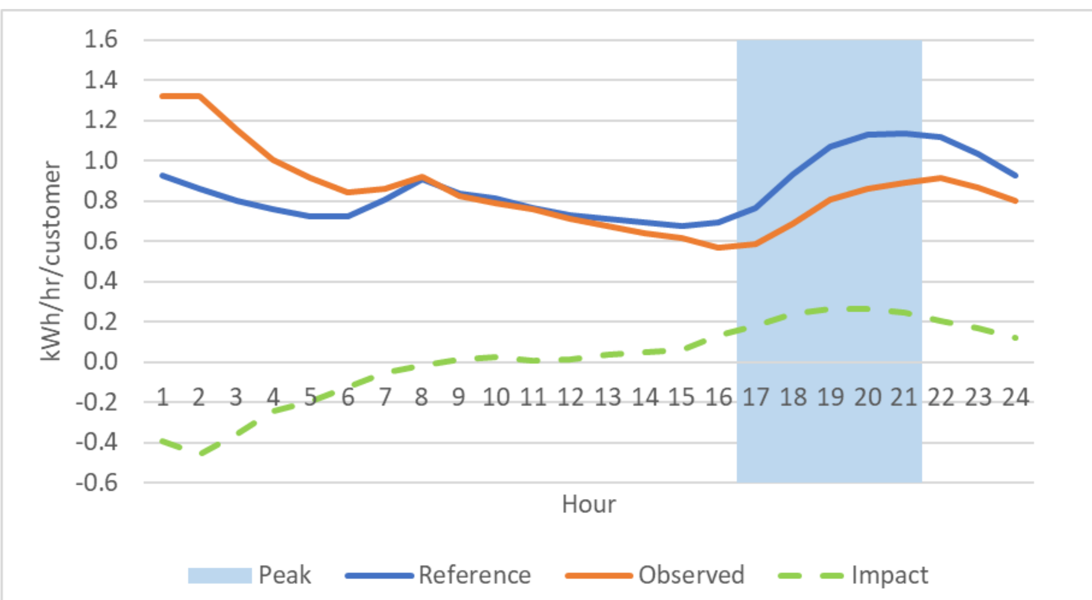


Figure 5.8: EV2-A Ex-Ante Load Impacts, February 2025 PG&E 1-in-2 Average Weekday



5.2.4 Ex-Ante Load Impacts for E-ELEC Customers

Table 5.6 shows the E-ELEC customer peak-period load impacts, averaged during the Resource Adequacy window. The tables show monthly load impacts in 2025 associated with each of the four weather scenarios.

Table 5.6: E-ELEC Ex-Ante Load Impacts, 2025 Monthly Average Weekdays 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	10,040	2.56	2.70	2.41	2.73
February	10,876	2.81	3.07	2.99	3.05
March	11,712	3.64	3.59	3.54	3.59
April	12,548	1.07	1.07	1.07	1.06
May	13,384	1.37	1.27	1.38	1.23
June	14,220	1.55	1.59	1.56	1.60
July	15,056	1.79	1.75	1.79	1.71
August	15,892	1.84	1.90	1.92	1.85
September	16,728	1.95	1.83	1.98	1.93
October	17,564	1.81	1.48	1.71	1.48
November	18,400	5.41	5.28	5.37	5.44
December	19,236	4.70	5.06	4.76	5.02

Figure 5.9 shows the hourly loads and load impacts associated with the August 2024 PG&E 1-in-2 average weekday weather scenario. The peak-period load impact averages 6.2%t. Figure 5.10 shows the same information for February 2025. The peak-period load impact averages 18.3%. Note that the winter estimates may not be reliable given that the rate opened to enrollment in December 2022, thus limiting enrollment during this program year. As described in the ex-post results, while E-ELEC was available to customers with electric heat pumps, battery storage, or EVs, the load impacts from this program year appear to primarily reflect EV charging behavior.

Figure 5.9: E-ELEC Ex-Ante Load Impacts, August 2024 PG&E 1-in-2 Average Weekday

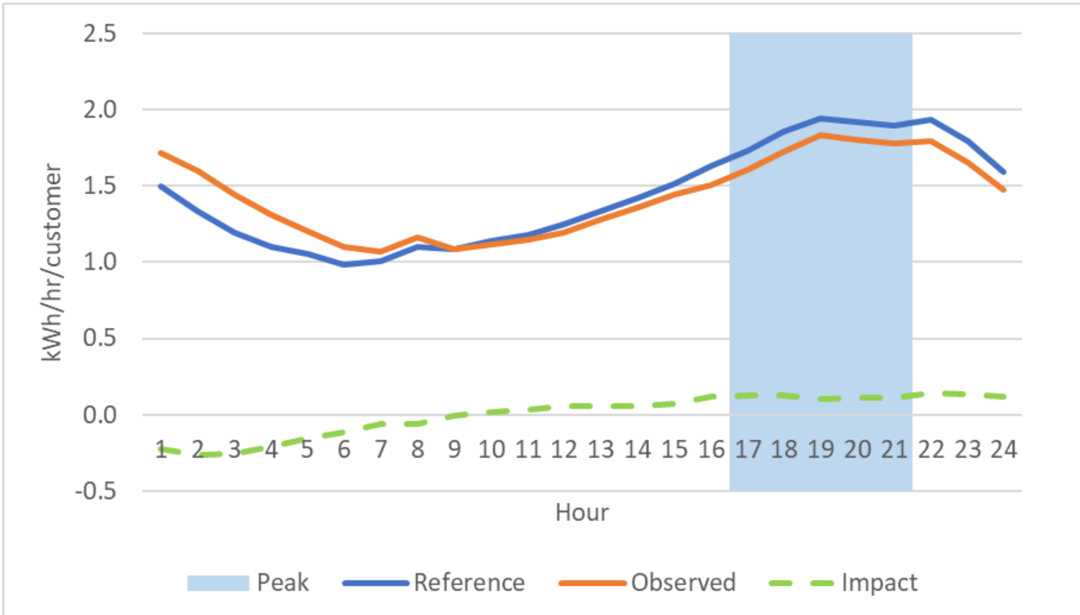
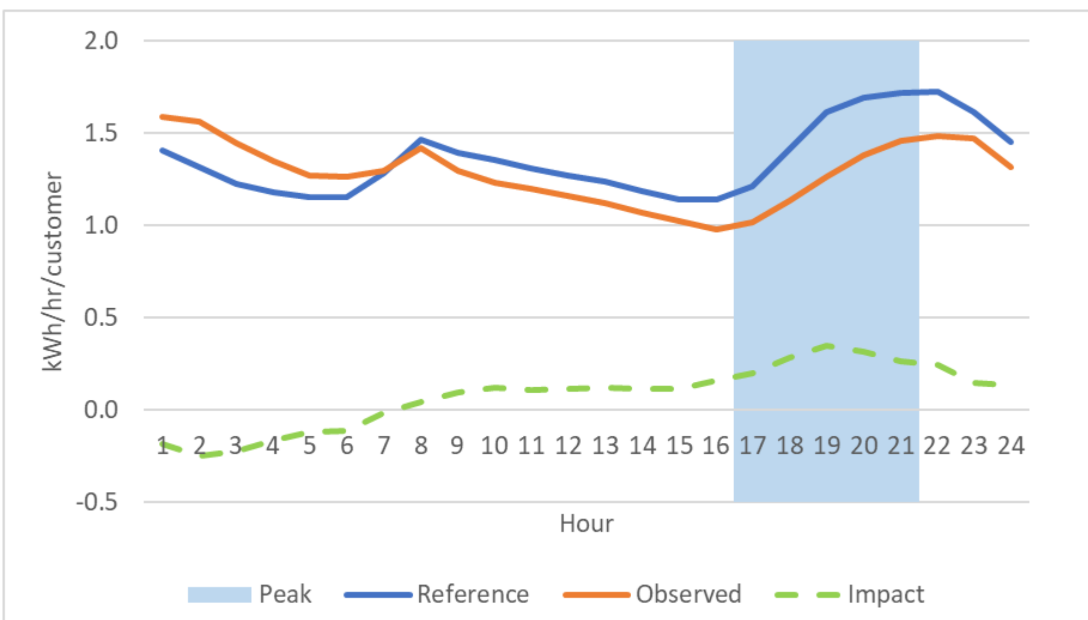


Figure 5.10: E-ELEC Ex-Ante Load Impacts, February 2025 PG&E 1-in-2 Average Weekday



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 for PY2023 and ex-ante forecasts for 2024 through 2034. The term “previous” refers to findings in the report for PY2022. In the final comparison above, we compare the PY2023 ex-post load impacts to the ex-ante forecast (of the PG&E 1-in-2 August peak day) for 2024. The sub-sections below summarize results by TOU rate.

Appendix H provides additional detail by summarizing the results of this section by rate transition. For example, this section jointly summarizes all customers who adopted EV2-A, while Appendix H separately summarizes EV2-A customers who transitioned from E-1, E-TOU-C, and E-TOU-D.

6.1 Previous Versus Current Ex-Post 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. E-ELEC was not available to customers until December 2022 and, therefore, was not included in the PY2022 study.

A major difference across evaluations is that PY2022 included the E-TOU-C default process, which concluded prior to PY2023. This leads to a large reduction in enrollment and aggregate impacts for E-TOU-C and a smaller reduction for E-TOU-D. Percentage impacts are higher for the PY2023 E-TOU-C customers relative to their PY2022 counterparts, which may be due to the type of customers that can be included in the ex-post study (voluntary E-TOU-C rate changers who have a history on E-1 included in this study versus the defaulted E-1 customers reflected in the previous study).

EV2-A per-customer load impacts are higher in the current study (in both level and percentage terms), which may reflect the rate transitions in the two studies. That is, the previous study reported results only for customers transitioning from E-TOU-C to EV2-A, while the current study includes customers transitioning from E-1, E-TOU-C, and E-TOU-D to EV2-A. The fact that customers transitioning from E-1 are significantly more responsive than customers transitioning from another TOU rate contributes to higher PY2023 impacts relative to those of PY2022.

Table 6.1: Comparison of Average August Weekday Peak-period Ex-Post Impacts Across Studies

TOU Rate	Previous Ex-Post					Current Ex-Post				
	Enrolled	PC Impact (kW/cust)	Agg Impact (MW)	% Impact	Peak Temp.	Enrolled	PC Impact (kW/cust)	Agg Impact (MW)	% Impact	Peak Temp.
E-TOU-C	1,287,593	0.029	37.58	3.2%	78.4	48,256	0.063	3.06	6.4%	81.7
E-TOU-D	22,170	0.119	2.64	4.5%	88.3	13,635	0.142	1.93	6.0%	85.0
EV2-A	2,747	0.085	0.23	8.2%	76.5	22,353	0.150	3.34	10.7%	78.9
E-ELEC	N/A	N/A	N/A	N/A	N/A	6,997	0.110	0.77	5.4%	78.7

6.2 Previous Versus Current Ex-Ante Load Impacts

In this sub-section, we compare the ex-ante forecast prepared following PY2022 (the "previous study") to the ex-ante forecast contained in this study (the "current study").

Table 6.2 reports the incremental load impact forecast for the August 2024 average weekday under PG&E 1-in-2 peak weather conditions. The "Previous Ex-Ante" results are based on the difference between enrollments in August 2024 and December 2023. (In contrast, the filed PY2022 study contains an ex-ante forecast with incremental enrollments relative to 2022.) This "re-basing" improves comparability to the "Current Ex-Ante" results, which represent load impacts incremental to 2023. Note that E-TOU-C NEM and E-TOU-D NEM did not have any incremental enrollments from December 2023 to August 2024. Therefore, the "Previous Ex-Ante" impacts for E-TOU-C and E-TOU-D represent entirely non-NEM customers.

Per-customer load impacts are forecast to be higher in the current study for all but the E-TOU-D customers. Incremental enrollment is lower in the current study for EV2-A and E-ELEC, but higher for E-TOU-C and E-TOU-D. These factors combine to produce uniformly higher aggregate load impacts in the current ex-ante forecast.

The E-ELEC forecasts reflect different assumptions across evaluations. In the PY2022 study, significant NEM enrollments were forecast for that transition group (approximately 20% of total incremental TOU enrollment). In the absence of any ex-post evidence, we used E-1 to E-TOU-C NEM per-customer reference loads and load impacts as a proxy for the group's load impacts. In contrast, the PY2023 study forecasts relatively low NEM enrollments for E-ELEC transitions (approximately 7% of E-ELEC enrollment and 1% of total incremental TOU enrollment). Therefore, we included E-ELEC NEM customers in the ex-ante forecast by combining their forecast enrollments with those of the corresponding non-NEM customers (e.g., E-1 to E-ELEC non-NEM and E-1 to E-ELEC NEM customer enrollments are combined, with the per-customer load impacts based on the E-1 to E-ELEC non-NEM ex-post load impacts).

Table 6.2: Comparison of Average August 2024 Weekday Peak-period Ex-Ante Impacts in the Previous and Current Studies

TOU Rate	Previous Ex-Ante					Current Ex-Ante				
	Enrolled	PC Impact (kW/cust)	Agg Impact (MW)	% Impact	Peak Temp.	Enrolled	PC Impact (kW/cust)	Agg Impact (MW)	% Impact	Peak Temp.
E-TOU-C	11,745	0.027	0.32	3.1%	77.6	15,570	0.052	0.81	5.2%	80.7
E-TOU-D	1,019	0.088	0.09	4.1%	83.6	2,613	0.121	0.32	5.3%	85.2
EV2-A	20,712	0.085	1.76	8.1%	76.8	13,302	0.153	2.04	13.3%	76.9
E-ELEC[25]	16,471	0.028	0.45	1.7%	87.1	5,852	0.117	0.68	6.2%	77.1

6.3 Previous Ex-Ante Versus Current Ex-Post Load Impacts

Table 6.3 provides a comparison of the ex-ante forecast of August 2023 average weekday load impacts prepared following PY2022 and the ex-post PY2023 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.

Enrollment was higher in the ex-post study versus the forecast for all but the E-ELEC rate.

In addition, most of the ex-post per-customer load impacts were higher than the forecast level. The combination of the enrollment and per-customer load impact differences produced a higher total TOU load impact for the ex-post study.

Table 6.3 Comparison of Previous Ex-Ante and Current Ex-Post Impacts

TOU Rate	Previous Ex-Ante					Current Ex-Post				
	Enrolled	PC Impact (kW/cust)	Agg. Impact (MW)	% Impact	Peak Temp.	Enrolled	PC Impact (kW/cust)	Agg. Impact (MW)	% Impact	Peak Temp.
E-TOU-C	22,046	0.027	0.60	2.1%	82.5	48,256	0.063	3.06	6.4%	81.7
E-TOU-D	3,536	0.208	0.73	7.8%	87.4	13,635	0.142	1.93	6.0%	85.0
EV2-A	19,634	0.085	1.67	8.1%	76.8	22,353	0.150	3.34	10.7%	78.9
E-ELEC[26]	18,529	0.028	0.51	1.7%	87.2	6,997	0.110	0.77	5.4%	78.7

6.4 Current Ex-Post Versus Current Ex-Ante Load Impacts

Table 6.4 compares the PY2023 ex-post load impacts for the August average weekday to the corresponding ex-ante forecast for 2024 produced in this study. The ex-ante per-customer load impacts are produced from the same model that estimates the ex-post load impacts, so any differences in those impacts are due to a change in the distribution of enrolled customers across rate transitions and LCAs, and/or a difference between ex-post vs. ex-ante temperatures.[27]

[25] The "Previous Ex-Ante" result reflects August 2024 because August 2023 had no forecast enrollment.

[26] The "Previous Ex-Ante" result reflects August 2024 because August 2023 had no forecast enrollment.

[27] Ex-ante and ex-post reference loads have different sources. Specifically, ex-ante reference loads are simulated from regression models whereas ex-post reference loads are based on the observed loads of treatment customers during the applicable historical month plus the estimated load impacts. These differences in reference loads have the potential to produce differences in *percentage* load impacts at the same level of load impact.

Table 6.4 Comparison of Current Ex-Post and Ex-Ante Load Impacts

TOU Rate	Current Ex-Post					Current Ex-Ante				
	Enrolled	PC Impact (kW/cust)	Agg Impact (MW)	% Impact	Peak Temp.	Enrolled	PC Impact (kW/cust)	Agg Impact (MW)	% Impact	Peak Temp.
E-TOU-C	48,256	0.063	3.06	6.4%	81.7	15,570	0.052	0.81	5.2%	80.7
E-TOU-D	13,635	0.142	1.93	6.0%	85.0	2,613	0.121	0.32	5.3%	85.2
EV2-A	22,353	0.150	3.34	10.7%	78.9	13,302	0.153	2.04	13.3%	76.9
E-ELEC	6,997	0.110	0.77	5.4%	78.7	5,852	0.117	0.68	6.2%	77.1

7. APPENDICES

Appendix A Ex-Post Load Impact Tables:

2a. PGE_2023_Res_TOU_ Ex_Post_CONFIDENTIAL.xlsx

2a. PGE_2023_Res_TOU_ Ex_Post_PUBLIC.xlsx

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

2b. PGE_2023_Res_TOU_ETOUC_Inc_Ex_Ante_PUBLIC.xlsx

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

2c. PGE_2023_Res_TOU_ETOUD_Inc_Ex_Ante_PUBLIC.xlsx

Appendix D To EV2-A Incremental Ex-Ante Load Impact Tables:

2d. PGE_2023_Res_TOU_EV2A_Inc_Ex_Ante_PUBLIC.xlsx

Appendix E To E-ELEC Incremental Ex-Ante Load Impact Tables:

2e. PGE_2023_Res_TOU_EELEC_Inc_Ex_Ante_PUBLIC.xlsx

Appendix F Ex-Post Analysis Match Quality

Appendix G Regression Sample Sizes

Appendix H Comparison of Results by Rate Transition

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

APPENDIX F. MATCH QUALITY

This appendix presents the summaries of our control-group matching process. Figures F.1 through F.8 illustrate the seasonal matches for E-TOU-C, E-TOU-D, E-TOU-C NEM, and E-TOU-D NEM customers. EV2-A and E-ELEC transitioner groups are excluded because we did not employ control-group customers for those analyses. 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 an 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 F.1.

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

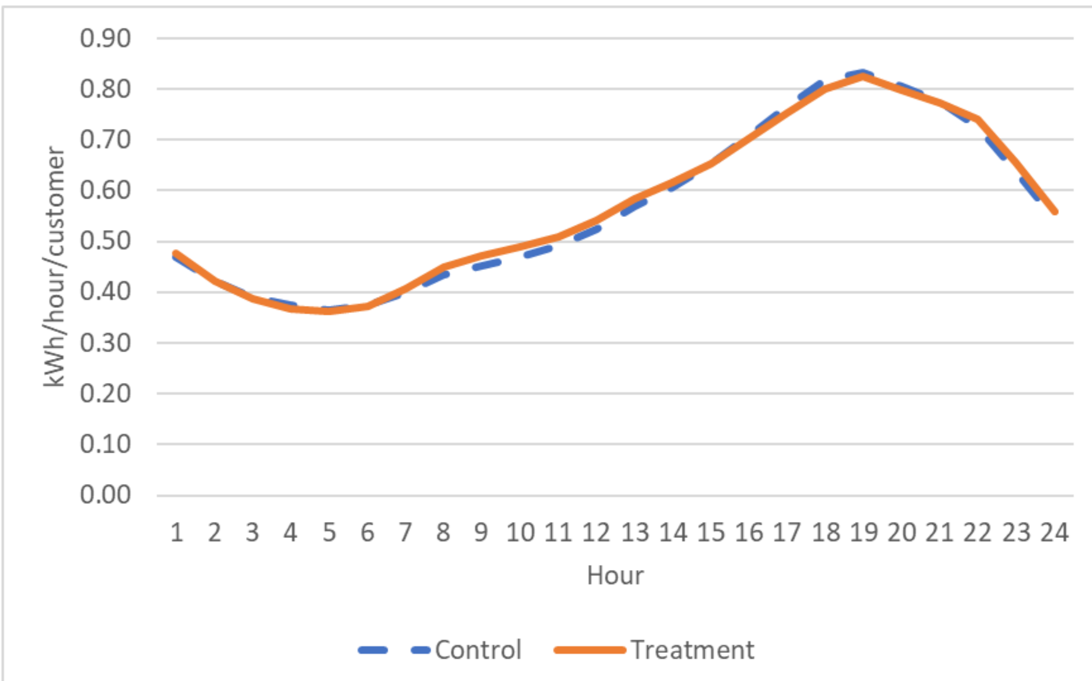


Figure F.2: E-TOU-C Winter Match Quality

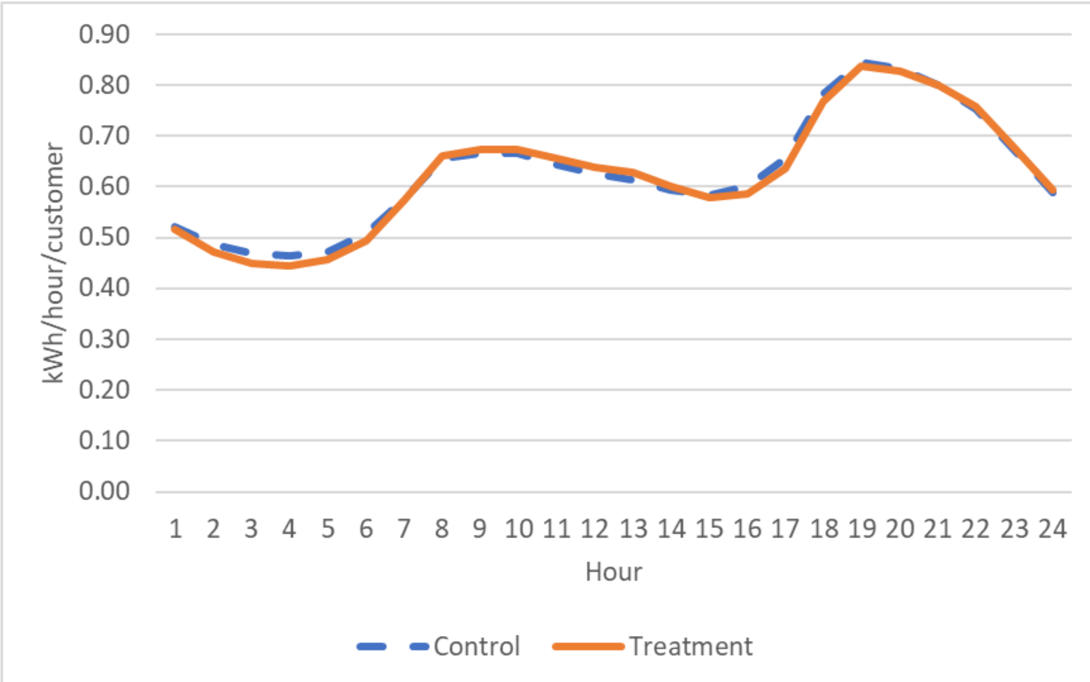


Figure F.3: E-TOU-D Summer Match Quality

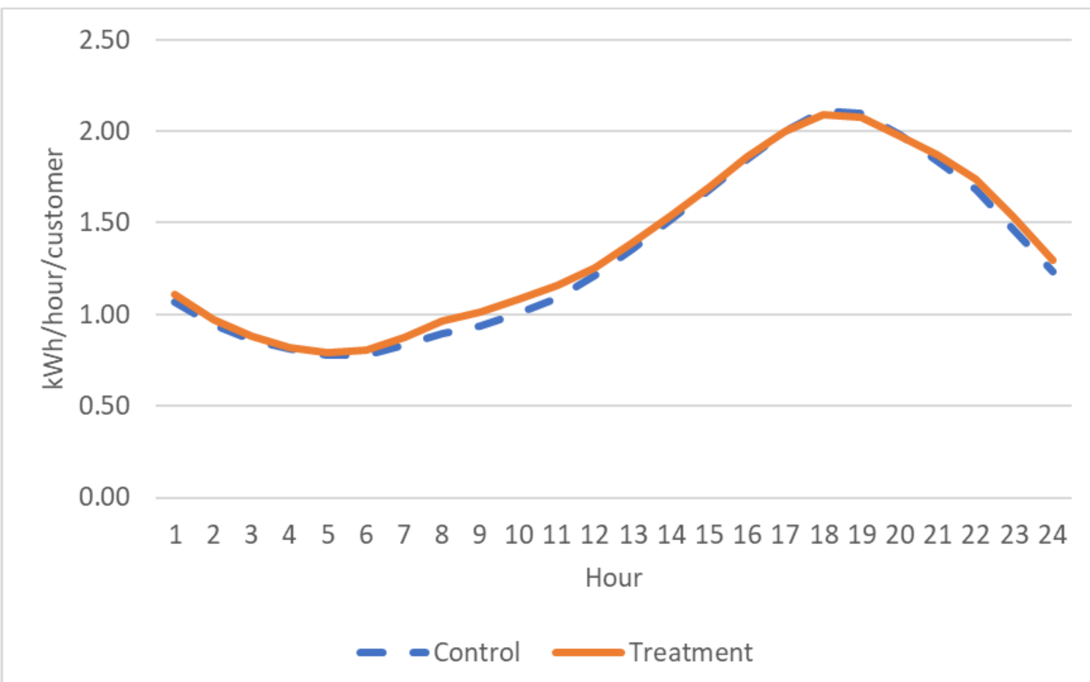


Figure F.4: E-TOU-D Winter Match Quality

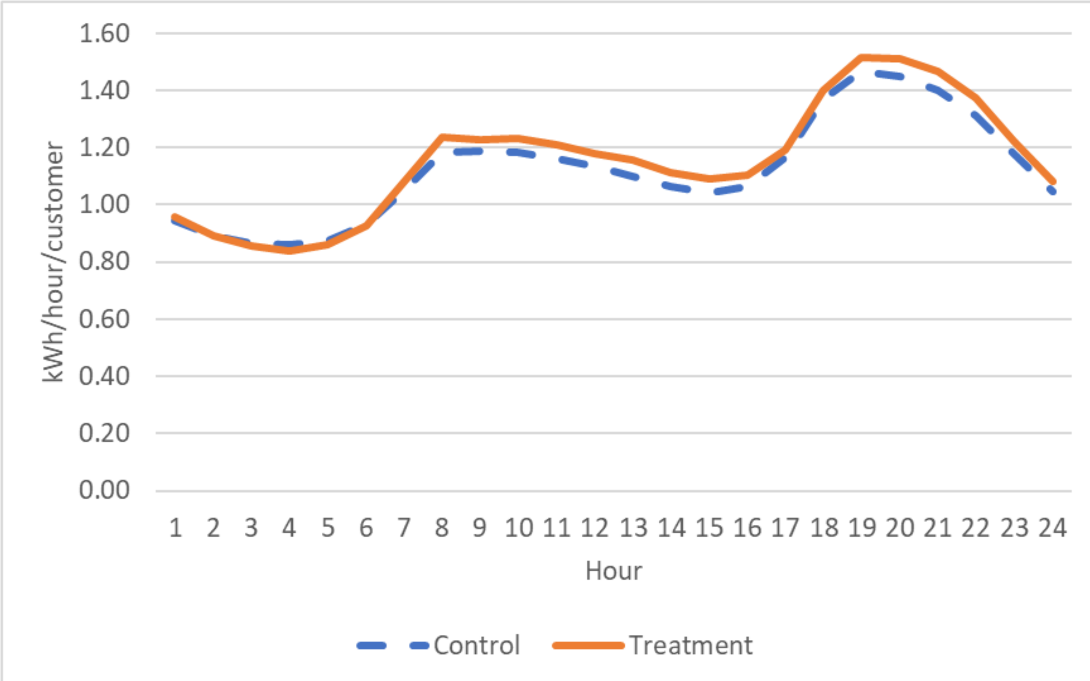


Figure F.5: E-TOU-C NEM Summer Match Quality

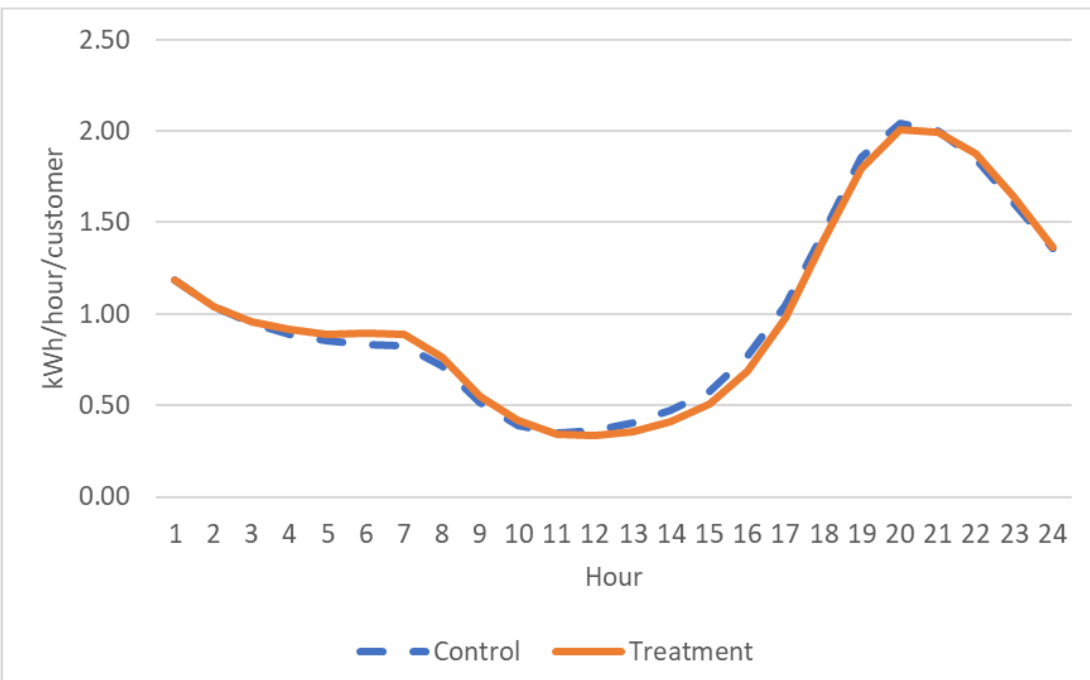


Figure F.6: E-TOU-C NEM Winter Match Quality

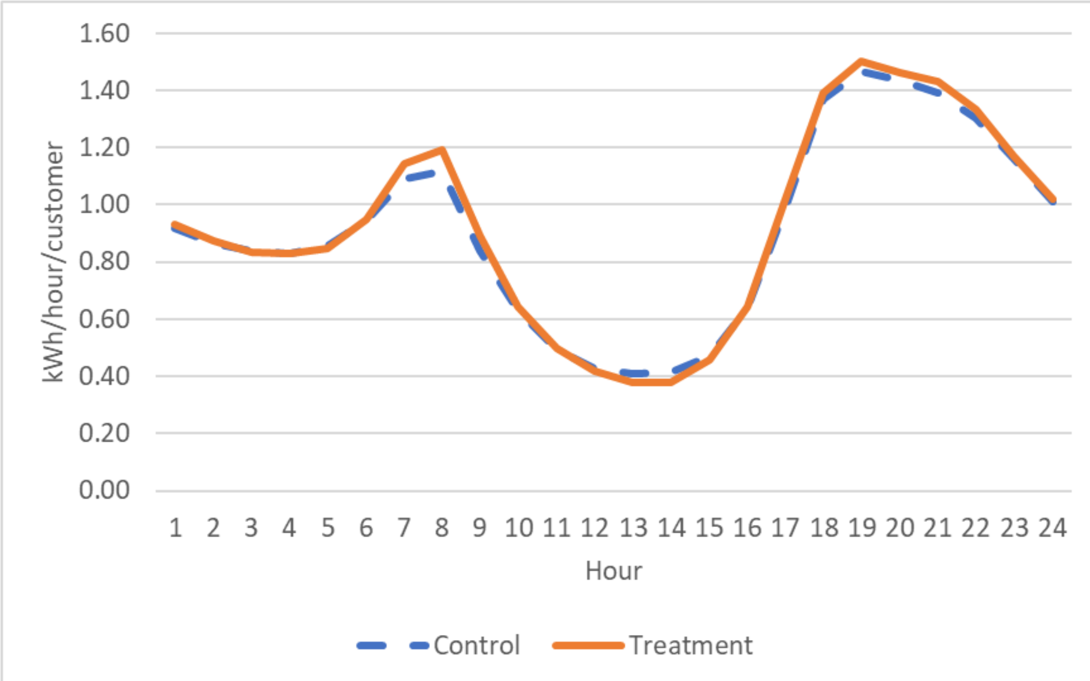


Figure F.7: E-TOU-D NEM Summer Match Quality

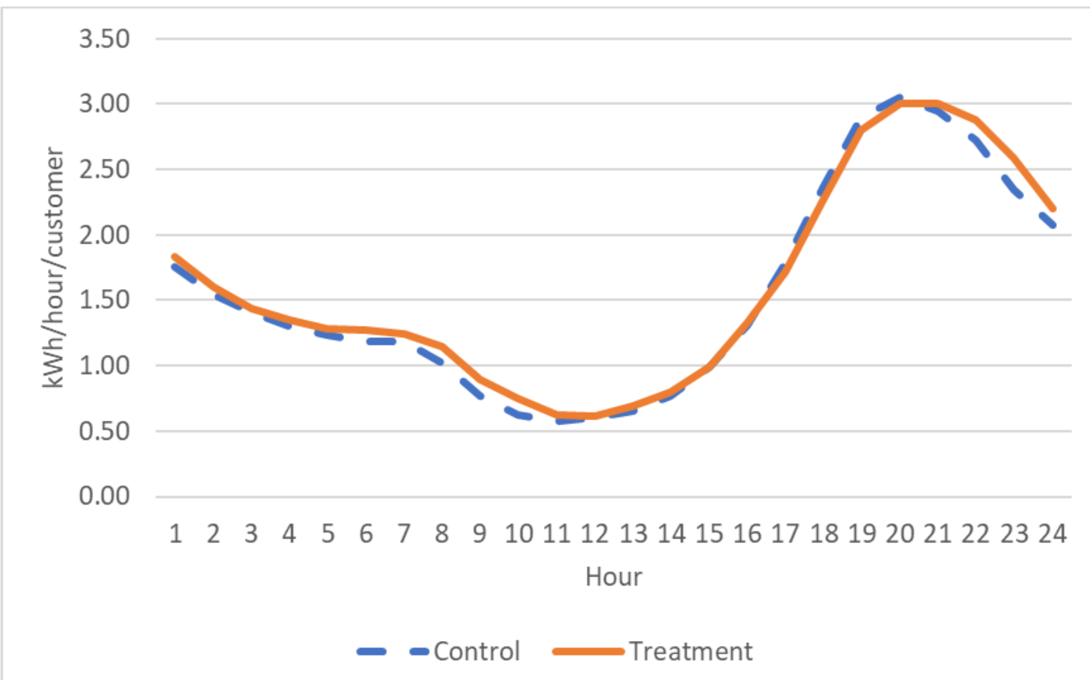


Figure F.8: E-TOU-D NEM Winter Match Quality

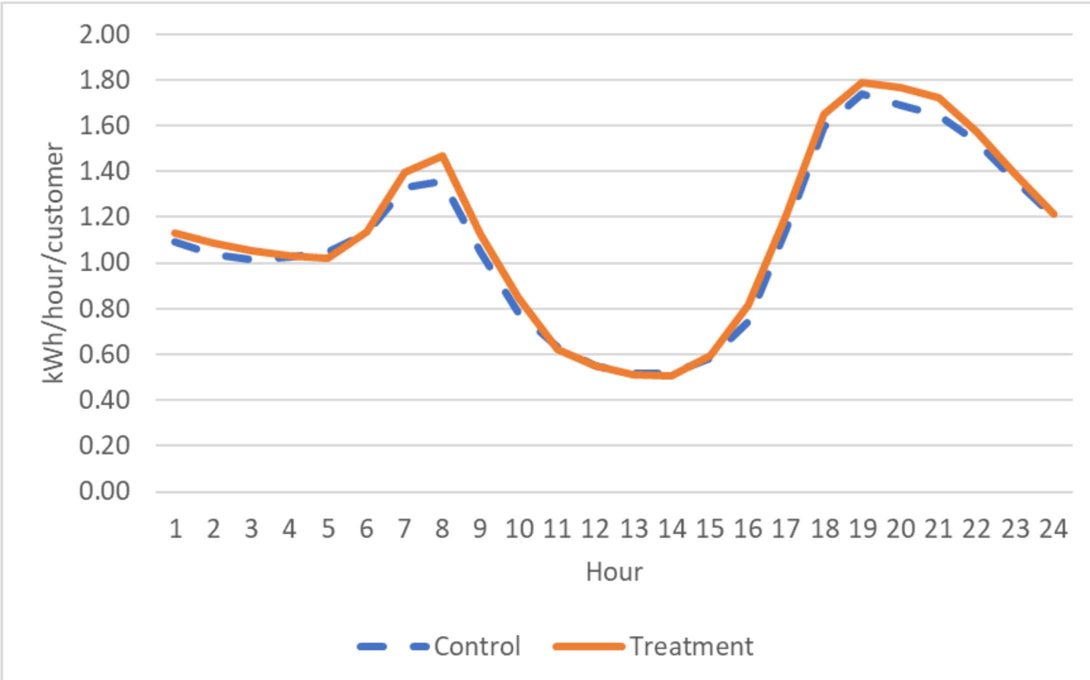


Table F.1 contains the MPE and MAPE values calculated across all 24 hours and the peak pricing period of the load profiles shown in the figures above. MPE provides an indicator of bias in the matches, while MAPE provides a measure of accuracy.

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

Season	Rate	All Hours		Peak Period	
		MPE	MAPE	MPE	MAPE
Summer	E-TOU-C	-0.9%	1.8%	1.2%	1.2%
	E-TOU-C NEM	1.4%	5.2%	3.1%	3.1%
	E-TOU-D	-2.8%	3.1%	0.9%	0.9%
	E-TOU-D NEM	-4.2%	5.4%	3.2%	3.2%
Winter	E-TOU-C	0.8%	1.8%	1.3%	1.3%
	E-TOU-C NEM	-0.6%	2.6%	-2.3%	2.3%
	E-TOU-D	-2.7%	3.1%	-3.3%	3.3%
	E-TOU-D NEM	-2.9%	3.5%	-3.5%	3.5%

APPENDIX G. REGRESSION SAMPLE SIZES

This appendix presents the number of treatment customers represented in the ex-post impacts presented in Section 4. Table G.1 shows the number of enrolled treatment customers by rate in February and August. The E-ELEC enrollment levels are particularly low in February because the rate only opened to enrollment in the prior December.

Table G.1: Sample Sizes for Load Impacts by Rate and Season

Adopted TOU Rate	Sample Size	
	February	August
E-TOU-C	2,276	5,093
E-TOU-D	1,412	2,282
EV2-A	1,030	2,243
E-ELEC	71	933

Table G.2 shows the various screens applied to arrive at the customer samples used in the regression models.[28] 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. Column B shows the total enrollment levels used to scale our estimated per-customer load impacts. It represents all customers who changed to a residential TOU rate during PY2023. At the far right of the table (column G), we show the number of enrolled treatment customers that are included in the regression models. The exclusions to get from column B to column G are as follows:

- Exclude customers with less than four months of pre-treatment data (column C);
- Exclude customers who had multiple rate changes during the sample timeframe (column D);
- Exclude customers enrolled in a demand response (DR) program (column E);
- Exclude customers with incomplete interval data, characteristics data, as well as any E-ELEC NEM customers (column F); and
- Exclude customers with poor match quality (in the E-TOU-C and E-TOU-D transitions that use a control group); or who have a structural break in their load levels during the sample timeframe (in the EV2-A and E-ELEC transitions that do not employ a control group).

[28] Note that the values in Table G.2 are higher than corresponding values in Table G.1 because Table G.2 represents treatment customers enrolled at any point in the program year, while Table G.1 represents treatment customers enrolled in specific months.

Table G.2: Sample Exclusions to Develop Regression Data Sets

(A)	(B)	(C)	(D)	(E)	(F)	(G)
Rate Transition	Adopted a TOU Rate during PY2023	Exclude if insufficient pre-treatment data	Exclude if multiple rate changes	Exclude DR enrolled	Exclude for incomplete data + E-ELEC NEM	Exclude if poor match quality or structural break
E-1 to E-TOU-C	54,952	11,574	11,306	6,925	5,732	5,647
E-1 to E-TOU-C NEM	3,253	2,793	2,701	1,631	1,528	1,244
E-1 to E-TOU-D	14,863	6,075	5,930	3,207	2,859	2,812
E-1 to E-TOU-D NEM	1,008	771	747	514	488	389
E-1 to EV2-A	6,708	4,859	4,725	3,428	3,219	744
E-TOU-C to EV2-A	14,658	8,800	8,615	6,470	6,396	1,469
E-TOU-D to EV2-A	2,861	1,405	1,342	1,030	1,013	278
E-1 to E-ELEC	2,145	1,577	1,550	978	944	322
E-TOU-C to E-ELEC	2,607	1,404	1,371	971	939	319
E-TOU-D to E-ELEC	1,156	500	487	359	352	145
EV2-A to E-ELEC	1,690	915	913	663	654	362

APPENDIX H. COMPARISONS OF RESULTS BY RATE TRANSITION

This appendix presents the results comparisons from Section 6 summarized by rate transition rather than by the adopted TOU rate. The four tables below correspond to Tables 6.1 through 6.4.

Table H.1: Comparison of Average August Weekday Peak-period Ex-Post Impacts Across Studies

Rate Transition	Previous Ex-Post					Current Ex-Post				
	Enrolled	PC Impact (kW/cust)	Agg Impact (MW)	% Impact	Peak Temp.	Enrolled	PC Impact (kW/cust)	Agg Impact (MW)	% Impact	Peak Temp.
E-1 to E-TOU-C	1,265,748	0.029	36.93	3.2%	78.2	45,191	0.058	2.64	6.3%	81.4
E-1 to E-TOU-C NEM	21,845	0.030	0.65	1.8%	87.9	3,065	0.137	0.42	7.2%	87.1
E-1 to E-TOU-D	20,882	0.110	2.29	4.2%	88.1	12,721	0.141	1.80	6.1%	84.9
E-1 to E-TOU-D NEM	1,288	0.268	0.35	8.7%	90.4	914	0.145	0.13	5.0%	86.3
E-1 to EV2-A						6,195	0.244	1.51	15.3%	79.7
E-TOU-C to EV2-A	2,747	0.085	0.23	8.2%	76.5	13,528	0.107	1.44	9.0%	78.2
E-TOU-D to EV2-A						2,630	0.149	0.39	7.5%	80.4
E-1 to E-ELEC						1,997	0.177	0.35	8.2%	82.7
E-TOU-C to E-ELEC						2,386	0.066	0.16	4.4%	76.3
E-TOU-D to E-ELEC						1,062	0.131	0.14	4.5%	78.6
EV2-A to E-ELEC						1,552	0.077	0.12	3.7%	77.6

Table H.2: Comparison of Average August 2024 Weekday Peak-period Ex-Ante Impacts in the Previous and Current Studies[29]

Rate Transition	Previous Ex-Ante					Current Ex-Ante				
	Enrolled	PC Impact (kW/cust)	Agg Impact (MW)	% Impact	Peak Temp.	Enrolled	PC Impact (kW/cust)	Agg Impact (MW)	% Impact	Peak Temp.
E-1 to E-TOU-C	11,745	0.027	0.32	3.1%	77.6	12,440	0.042	0.53	5.3%	79.2
E-1 to E-TOU-C NEM	0	N/A	0.0	N/A	N/A	3,130	0.091	0.28	5.1%	86.6
E-1 to E-TOU-D	1,019	0.088	0.09	4.1%	83.6	1,626	0.125	0.20	6.3%	82.7
E-1 to E-TOU-D NEM	0	N/A	0.0	N/A	N/A	987	0.114	0.11	4.1%	89.3
E-1 to EV2-A						5,728	0.218	1.25	17.5%	77.3
E-TOU-C to EV2-A	20,712	0.085	1.76	8.1%	76.8	6,468	0.096	0.62	9.7%	76.3
E-TOU-D to EV2-A						1,106	0.156	0.17	9.4%	78.2
E-1 to E-ELEC[30]	16,471	0.028	0.45	1.7%	87.1	1,813	0.187	0.34	9.9%	79.3
E-TOU-C to E-ELEC						2,107	0.084	0.18	5.0%	77.0
E-TOU-D to E-ELEC						756	0.110	0.08	4.6%	75.7
EV2-A to E-ELEC						1,176	0.069	0.08	3.8%	74.7

Table H.3 Comparison of Previous Ex-Ante and Current Ex-Post Impacts

Rate Transition	Previous Ex-Ante					Current Ex-Post				
	Enrolled	PC Impact (kW/cust)	Agg Impact (MW)	% Impact	Peak Temp.	Enrolled	PC Impact (kW/cust)	Agg Impact (MW)	% Impact	Peak Temp.
E-1 to E-TOU-C	10,278	0.027	0.28	3.1%	77.6	45,191	0.058	2.64	6.3%	81.4
E-1 to E-TOU-C NEM	11,768	0.027	0.32	1.7%	86.8	3,065	0.137	0.42	7.2%	87.1
E-1 to E-TOU-D	893	0.088	0.08	4.1%	83.5	12,721	0.141	1.80	6.1%	84.9
E-1 to E-TOU-D NEM	2,643	0.248	0.66	8.7%	88.7	914	0.145	0.13	5.0%	86.3
E-TOU-C to EV2-A	19,634	0.085	1.67	8.1%	76.8	13,528	0.107	1.44	9.0%	78.2
E-1 to E-ELEC[31]	18,529	0.028	0.51	1.7%	87.2	1,997	0.177	0.35	8.2%	82.7

[29] The "Previous Ex-Ante" results are based on the difference between enrollments in August 2024 and December 2023. (In contrast, the filed PY2022 study contains an ex-ante forecast with incremental enrollments relative to 2022.) This "re-basing" improves comparability to the "Current Ex-Ante" results, which represent load impacts incremental to 2023. Note that the E-1 to E-TOU-C NEM and E-1 to E-TOU-D NEM transitions were modeled in the previous study but did not have any incremental enrollments during the time period examined.

[30] The "Previous Ex-Ante" result reflects August 2024 because August 2023 had no forecast enrollment.

[31] The "Previous Ex-Ante" result reflects August 2024 because August 2023 had no forecast enrollment.

Table H.4 Comparison of Current Ex-Post and Ex-Ante Load Impacts

Rate Transition	Current Ex-Post					Current Ex-Ante				
	Enrolled	PC Impact (kW/cust)	Agg Impact (MW)	% Impact	Peak Temp.	Enrolled	PC Impact (kW/cust)	Agg Impact (MW)	% Impact	Peak Temp.
E-1 to E-TOU-C	45,191	0.058	2.64	6.3%	81.4	12,440	0.042	0.53	5.3%	79.2
E-1 to E-TOU-C NEM	3,065	0.137	0.42	7.2%	87.1	3,130	0.091	0.28	5.1%	86.6
E-1 to E-TOU-D	12,721	0.141	1.80	6.1%	84.9	1,626	0.125	0.20	6.3%	82.7
E-1 to E-TOU-D NEM	914	0.145	0.13	5.0%	86.3	987	0.114	0.11	4.1%	89.3
E-1 to EV2-A	6,195	0.244	1.51	15.3%	79.7	5,728	0.218	1.25	17.5%	77.3
E-TOU-C to EV2-A	13,528	0.107	1.44	9.0%	78.2	6,468	0.096	0.62	9.7%	76.3
E-TOU-D to EV2-A	2,630	0.149	0.39	7.5%	80.4	1,106	0.156	0.17	9.4%	78.2
E-1 to E-ELEC	1,997	0.177	0.35	8.2%	82.7	1,813	0.187	0.34	9.9%	79.3
E-TOU-C to E-ELEC	2,386	0.066	0.16	4.4%	76.3	2,107	0.084	0.18	5.0%	77.0
E-TOU-D to E-ELEC	1,062	0.131	0.14	4.5%	78.6	756	0.110	0.08	4.6%	75.7
EV2-A to E-ELEC	1,552	0.077	0.12	3.7%	77.6	1,176	0.069	0.08	3.8%	74.7