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Christensen ASSOCIATES

2022 Load Impact Evaluation of Pacific Gas and Electric Company's Non-Residential Time-of-Use Rates: Ex-post and Ex-ante Report

CALMAC Study ID PGE0485

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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") non-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.

Decision 18-08-013 adopted new TOU periods and season definitions for all non-residential customer classes. The season definition changed from May through October to June through September; and the peak period changed from noon to 6:00 p.m. to 4:00 to 9:00 p.m. for commercial and industrial (C&I) customers and 5:00 to 8:00 p.m. for agricultural customers.

ES.1 Resources Covered

The C&I rates A-1, A-6, A-10, E-19, and E-20 are being phased out and replaced by rates B-1, B-6, B-10, B-19, and B-20. Similarly, the agricultural rates AG-1A, AG-1B, AG-4A, AG-4B, AG-4C, AG-5A, AG-5B, AG-5C, AG-VA, AG-VB, AG-RA, AG-RB are being phased out and replaced by AG-A1, AG-A2, AG-B, AG-C, AG-FA, AG-FB, and AG-FC. The new rates became available on a voluntary basis in November 2019 (C&I) and March 2020 (Ag). Customer transitions to the new rates began in March 2021, with November (C&I) and March (Ag) transitions occurring annually.

The following transitions are included[1]:

- Schedule A-1 TOU to B-1, Small (non-NEM and NEM)
- Schedule A-6 to B-6, Small (non-NEM and NEM)
- Schedule A-10 TOU to B-10, Medium (non-NEM and NEM)
- Schedule E-19 to B-19, Medium (non-NEM and NEM)
- Schedule E-20 to B-20, Large (non-NEM only)
- Schedule AG-4A to AG-A1, Small (non-NEM and NEM)
- Schedule AG-4B to AG-B, Medium (non-NEM and NEM)
- Schedule AG-5A to AG-A2, Small (non-NEM only)
- Schedule AG-5B to AG-C, Medium (non-NEM only)
- Schedule AG-5C to AG-C, Large (non-NEM only)

ES.2 Evaluation Methodologies

Various data issues prevent us from estimating reliable TOU load impacts. First, the COVID pandemic has caused usage to shift across years, which prevents us from estimating TOU load impacts by comparing treatment customer's pre- and post-rate-change load profiles. The shift in usage across years does not affect all hours equally and these (seemingly) pandemic-related load changes across years are large enough to mask any load changes due to changing TOU rates. If we were to estimate treatment-only

[1] Other size groups may have been present for a given rate transition, but we focus on the one with the highest number of customers.

models, any changes across years that aren't due to weather would be attributed to the TOU rate. We don't have information to insert into the model that quantifies a COVID effect that is distinct from a change due to any other non-weather factor that changes across years. As a result, we would falsely estimate TOU-related load decreases for most hours of the day if we used 2019 as the counterfactual year; and TOU-related load increases for most hours of the day if we used 2020 as the counterfactual year. The fact that pandemic-related load changes appear to differ by hour of day also prevents us from reliably estimating changes in shares of usage by TOU pricing period as customers change TOU rates.

A control group may be used to account for factors such as the pandemic, which in theory would allow us to isolate the effect of changing TOU rates on the customer's load profile. However, the customers available to be selected for the control groups are limited to solar legacy customers and structural non-benefiters. As a result, valid control groups are not available.

We limited the ex-ante impacts to the rates with the most expected customers in the large size category: Schedules B-10, B-19, B-20, and AG-C. We focus on the following rate transitions with the highest expected rate migrations:

- A-10 TOU to B-10
- E-19 to B-19
- E-20 to B-20
- AG-5B and AG-5C to AG-C

To develop the per-customer ex-ante reference loads, we estimate regression equations from historical data and use the resulting coefficients and ex-ante weather conditions (provided by PG&E) to simulate reference loads for the scenarios required by the Protocols. The models use hourly load data from the post-treatment period averaged across "cells" (e.g., for the average customer in each TOU rate).

The second component, the hourly load impacts, are simulated using the reference loads, tariff rates, and an assumed elasticity of demand. The tariff prices are first converted to an effective energy charge (EECs), which has two elements. The first element is simply the tariff's energy rates. The second element is a conversion of the tariff's demand rates into an energy rate, which is accomplished by dividing the demand rate by the number of hours in the month to which it applies. Loads on the new TOU rate are simulated by applying the assumed elasticity to the change in EECs on an hourly basis. The load impact is the difference between the simulated loads on the new and legacy TOU rates.

ES.3 Ex-Ante Load Impacts

The ex-ante load impacts were forecast for only the large (over 200kW) customers. Figure ES.1 summarizes the average impact during the Resource Adequacy (RA) window (4:00 to 9:00 p.m. normally, 5:00 to 10:00 p.m. for March and April) for each month of 2024, by rate. The values reflect PG&E 1-in-2 peak day weather conditions. A few things to note:

- Impacts are shown for 2024 rather than 2023 because new enrollments are not forecast to begin for commercial and industrial customers until November 2023.
- Incremental load impacts are low, largely due to small incremental enrollment.
- May and October load impacts represent a load *increase* relative to usage on the legacy TOU rate. This is due to the change in the summer definition from May through October to June through September. The two months that changed from summer to winter (May and October) have significantly lower effective energy charges during the RA window due to differences in both the energy and demand rates.

Figure ES.1: 2024 Monthly Average RA-Window Load Impacts

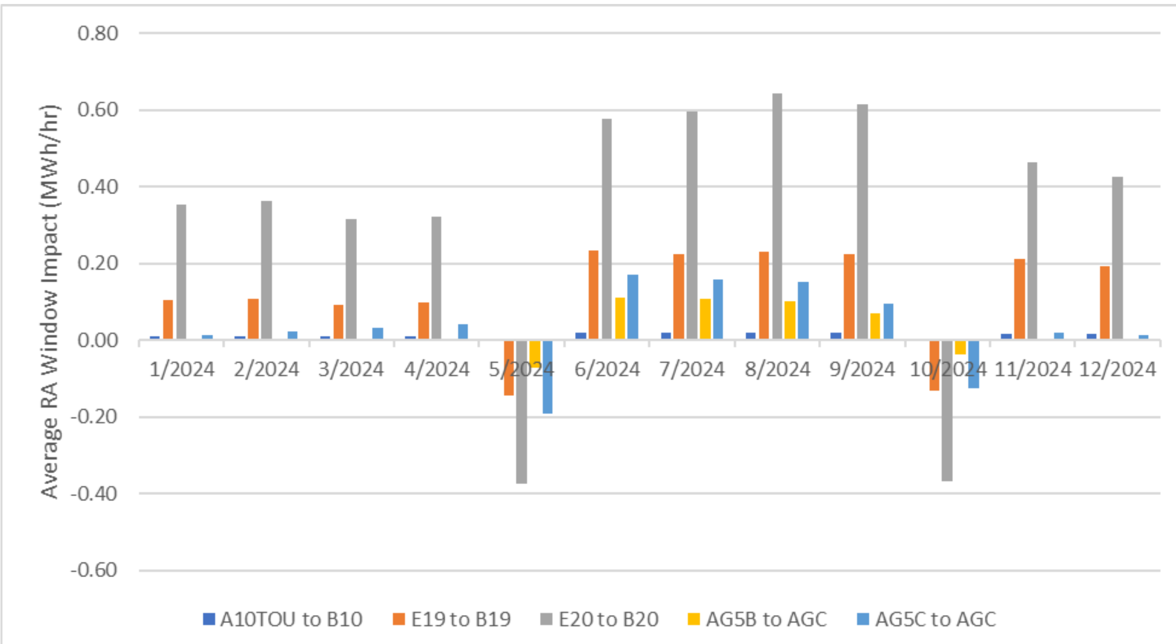
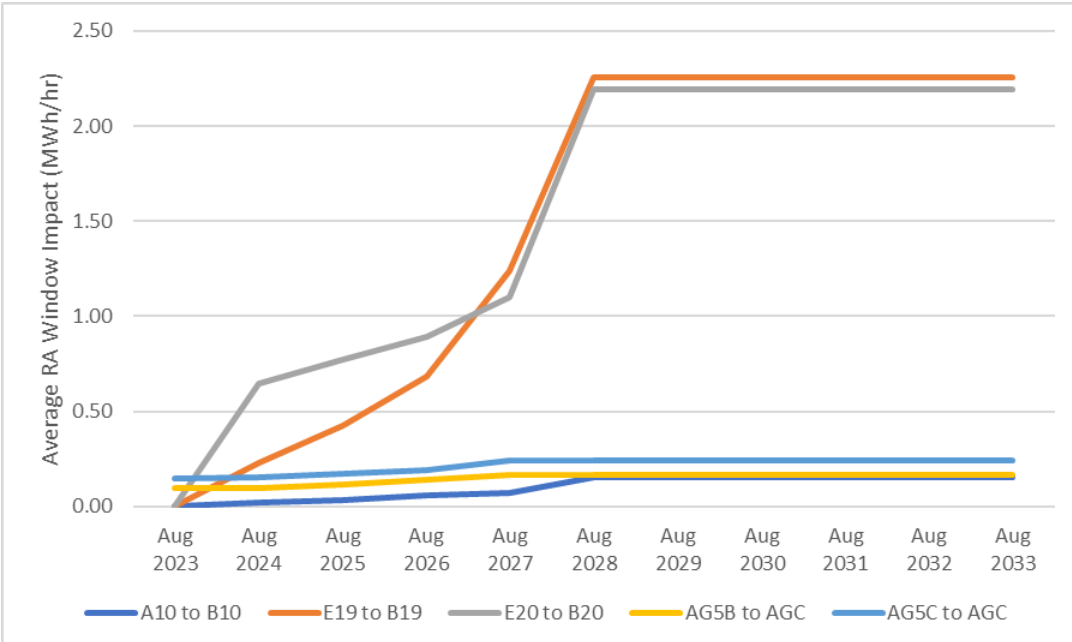


Figure ES.2 summarizes the forecast load impacts for each August during the forecast period. The values are the average load impacts during the RA window for the PG&E 1-in-2 peak day weather conditions. The load impact pattern across years closely resembles the corresponding enrollment pattern.

Figure ES.2: August Average RA-Window Load Impacts by Year



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") non-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.

Decision 18-08-013 adopted new TOU periods and season definitions for all non-residential customer classes. The season definition changed from May through October to June through September; and the peak period changed from noon to 6:00 p.m. to 4:00 to 9:00 p.m. for commercial and industrial (C&I) customers and 5:00 to 8:00 p.m. for agricultural customers.

Thus, the C&I rates A-1, A-6, A-10, E-19, and E-20 are being phased out and replaced by rates B-1, B-6, B-10, B-19, and B-20. Similarly, the agricultural rates AG-1A, AG-1B, AG-4A, AG-4B, AG-4C, AG-5A, AG-5B, AG-5C, AG-VA, AG-VB, AG-RA, AG-RB are being phased out and replaced by AG-A1, AG-A2, AG-B, AG-C, AG-FA, AG-FB, and AG-FC. The new rates became available on a voluntary basis in November 2019 (C&I) and March 2020 (Ag). Customer transitions to the new rates began in March 2021, with November (C&I) and March (Ag) transitions occurring annually.

The primary goals of the evaluation are the following:

1. Estimate ex-post load impacts for each rate for the 2022 program year;
2. Develop ex-ante load impact forecasts for the rates for the eleven years following the program year (e.g., 2023 through 2033).

A key difference between this evaluation and most other TOU evaluations is that it seeks to estimate a *change* in a TOU load impact rather than a *total* TOU load impact relative to a non-TOU rate. This does not present a novel methodological challenge – it simply alters the "base" rate used in the analysis.

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. Section 5 contains the ex-ante load impact forecasts. Section 6 provides a series of comparisons of ex-post and ex-ante results.

2. DESCRIPTION OF TIME-OF-USE RATES

The C&I rate schedules are largely differentiated by customer demand levels. Schedules B-1 and B-6 are non-demand rates applicable to customers with demand under 75 kW. Schedule B-6 differs from Schedule B-1 by removing the Summer Partial-Peak pricing period and increasing the Summer Peak to Off-Peak price ratio. The demand-based rates are applicable to the following demand ranges:

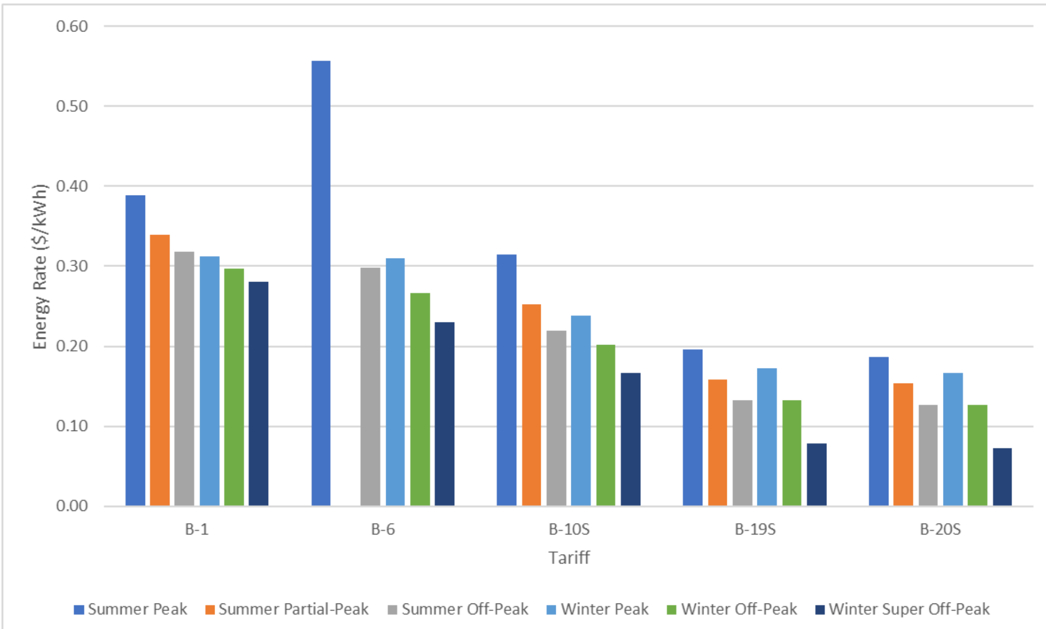
- Schedule B-10 = 75 to 499 kW;
- Schedule B-19 = 500 to 999 kW; and

- Schedule B-20 = over 999 kW.

All schedules except B-1 differentiate rates by service level (Secondary, Primary, and Transmission). For all C&I schedules, the Peak period is from 4 to 9 p.m. on all days. All but Schedule B-6 have a Partial-Peak period from 2 to 4 p.m. and 9 to 11 p.m. on all summer days. In March, April, and May there is a Super Off-Peak period from 9 a.m. to 2 p.m. The Off-Peak period covers all other hours.

Figure 2.1 illustrates the energy rates by pricing period and tariff. Note that Schedules B-19 and B-20 have demand charges that apply only to Peak-period demand, thus increasing the effective rate during those hours.

Figure 2.1: Energy Rates by Tariff and Pricing Period, C&I Rates



The agricultural rates are differentiated by customer demand levels, load factors[2], and desire for flexibility in selecting off-peak days.

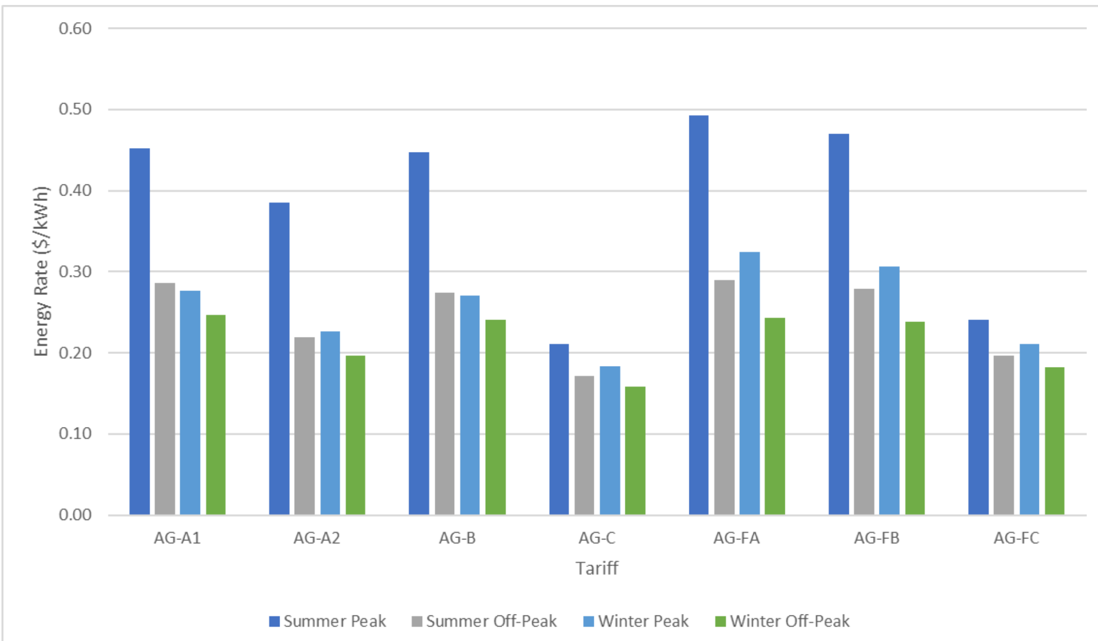
- Schedule AG-A1 is targeted to low load factor customers with demand less than 35 kW.
- Schedule AG-A2 is targeted to high load factor customers with demand less than 35 kW.[3]
- Schedule AG-B is targeted to medium load factor customers with demand over 35 kW.
- Schedule AG-C is targeted to high load factor customers with demand over 35 kW.

[2] Load factor is defined as the customer's average hourly usage divided by its maximum demand over a period of time (e.g., a billing month or year). Values approaching zero reflect customers with high peak demand relative to their typical hourly usage, whereas values approaching one reflect customers with loads that are constant across hours.
[3] The increased appeal to high load factor customers is due to the higher demand and lower energy rates vs. AG-A1.

- Schedules AG-FA, AG-FB, and AG-FC allow customers to choose two off days per week: Wednesday+Thursday, Saturday+Sunday, or Monday+Friday.
- Schedule AG-FA is targeted to customers with demand less than 35 kW.
- Schedules AG-FB and AG-FC are targeted to customers with demand over 35 kW with low and high load factors, respectively.

Figure 2.2 illustrates the energy rates by pricing period and tariff. Note that Schedules AG-C and AG-FC have demand charges that apply only to the summer Peak-period demand, thus increasing the effective rate during those hours.

Figure 2.2: Energy Rates by Tariff and Pricing Period, Ag Rates



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.

3.1 Ex-Post Load Impact Evaluation

In this section, we discuss the methods used to estimate the ex-post load impacts for PG&E's non-residential TOU rates. We begin with a discussion of the challenges present in the prior evaluation.

<u>Challenges in the PY2021 Evaluation</u>

In the previous evaluation (for Program Year 2021), we were unable to estimate reliable ex-post load impacts. There were two reasons for this:

1. The absence of a sufficient pool of eligible control-group customers.

2. Year-over-year changes in treatment customer load profiles due to the COVID-19 pandemic.

The lack of control-group customers occurred because most customers were transitioned at the same time (in March 2021). The remaining pool of eligible control-group customers consisted of those who were yet to be transitioned to the new TOU rates. That limited us to customers with the following characteristics:

- Solar legacy customers.

- Customers without hourly metering.

- Customers who were expected to have a significant negative bill impact (i.e., "structural non-benefiters").

- Customers with less than 12 months of interval data.

Because our methods require interval data from the pre-treatment and treatment periods, our control group pool was limited to the solar legacy customers and structural non-benefiters. Those customers are systematically different from the transitioned customers, preventing us from finding enough quality matches to form a valid control group.

In the absence of a control group, load impacts could be estimated by comparing pre- and post-TOU rate change load profiles for the treatment customers, controlling for weather conditions in the two years. This method requires an assumption that the non-weather differences in load shapes across years are attributable to the TOU rate change. In this case, a comparison of summer 2020 and summer 2021 loads was affected by pandemic effects on loads. There was no way for us to separate the TOU rate change effects from those of the pandemic (or any other changes that occurred across years except weather), thus preventing us from getting valid load impact estimates using this within-treatment methodology.

In the end, we concluded that none of the ex-post estimates were reliable. But we considered the difference-in-differences approach that employed the limited matched control group as provided the best available estimates, so we reported those as the PY2021 per-customer ex-post impacts.

<u>Implications for the Current Study</u>

The circumstances for this evaluation have not represented an improvement upon those of the previous evaluation. There are still no valid control-group customers available, so we did not request any data representing potential control-group customers. In addition, we did not anticipate the year-over-year within-treatment comparisons to produce reasonable TOU load impact estimates. Because of these conditions, PG&E suggested that we limit the scope of this year's study. In consultation with them, we decided on the following analysis path:

- Obtain updated data (from October 2021 through September 2022) for the treatment customers included in the PY2021 evaluation.

- Examine the data to determine whether within-treatment ex-post estimates of TOU load impacts are possible (which seems unlikely).

  - If so, we would conduct and summarize those analyses.

  - If not (which turned out to be the case, as discussed in Section 4 below), we would base this year's ex-post impacts on the PY2021 per-customer ex-post impacts, scaled to current enrollments.

- Use the updated data to produce ex-ante reference loads, under the assumption that these loads represent a "new normal" with no adjustment for pandemic effects required during the forecast period.

- Apply the same ex-ante load impact simulations used last year to the updated reference loads.

Ex-post load impacts are reported as follows:

- For the monthly system peak day and average weekday for each month of the calendar year.

- For weekends/holidays (as requested by PG&E).

- By Local Capacity Area (LCA).

- By industry group.

- By size group.

We report the same rate changes as we did in the PY2021 study:

- Schedule A-1 TOU to B-1, Small (non-NEM and NEM).

- Schedule A-6 to B-6, Small (non-NEM and NEM).

- Schedule A-10 TOU to B-10, Medium (non-NEM and NEM).

- Schedule E-19 to B-19, Medium (non-NEM and NEM).

- Schedule E-20 to B-20, Large (non-NEM only).

- Schedule AG-4A to AG-A1, Small (non-NEM and NEM).

- Schedule AG-4B to AG-B, Medium (non-NEM and NEM).

- Schedule AG-5A to AG-A2, Small (non-NEM only).

- Schedule AG-5B to AG-C, Medium (non-NEM only).

- Schedule AG-5C to AG-C, Large (non-NEM only).

In the list above, "Small" refers to customers under 20 kW; "Medium" refers to customers from 20 to 200 kW; and "Large" refers to customers over 200 kW.

Determining the Analyses to be Conducted

We use current-year billing data (October 2021 through September 2022) to identify customers who have remained on the new TOU rate they transitioned to in program year 2021 (e.g., from Schedule A-6 to B-6). After restricting the sample to customers enrolled during the entire analysis timeframe (from October 2019 through September 2022), we tabulate rate changes by month including the "from" rate and the "to" rate (e.g., from Schedule A-1 to B-1). As in the program year 2021 study, we focus on customers who were on a legacy TOU rate for the entire sample timeframe until they switched to a new TOU rate sometime during the program year. We then examine the data to determine whether it is possible to estimate improved within-treatment ex-post TOU load impacts, using either 2019 or 2020 loads as the pre-treatment period for the summer of 2022.

As we will discuss briefly in Section 4, changes in pandemic effects on load levels across years prevented us from estimating reliable TOU load impacts using treatment-only models.

3.2 Forecasting Ex-Ante Load Impacts

3.2.1 Objectives

The objective of the ex-ante forecast is to develop eleven-year forecasts of estimate program load impacts based on forecasts of per-customer load impacts 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 (1-in-2 and 1-in-10 weather years based on CAISO and PG&E conditions);
- The monthly system peak day in each month under the four weather scenarios.

3.2.2 Ex-ante evaluation approach

In a typical evaluation, ex-ante forecasts are based on ex-post load impact estimates. In this case, reliable ex-post estimates are not available, so we use a simulation-based method in which the assumed levels of demand response are informed by prior studies. From the 2014 through 2016 program years, we conducted evaluations of the TOU load impacts associated with small business, medium business, and agricultural customers being transitioned to mandatory TOU rates.[4] These studies tended to find load reductions across all pricing periods (i.e., akin to conservation) rather than a shift of usage from Peak to Off-Peak pricing periods. In addition, recent Statewide Critical Peak Pricing

[4] For example, the PY2015 study: "2015 Load Impact Evaluation of Pacific Gas and Electric Company's Mandatory Time-of-Use Rates for Small, Medium, and Agricultural Non-residential Customers: *Ex-post* and *Ex-ante* Report", CALMAC Study ID PGE0373.

evaluations have found very low load impacts for small- and medium-sized customers.[5] Based on this evidence, we determined that a reasonable and conservative estimate of the change in TOU impacts for the small- and medium-sized non-residential customers is zero, and we did not undertake further effort to simulate their load impacts.

There is some evidence that large customers have higher demand response, in part from the CPP study referenced above. The assumptions used in this study are consistent with those of a high-level study of the potential load impacts from offering new TOU rates for residential and non-residential customers requested by the Energy Division.[6] The remainder of this section describes how we developed the ex-ante forecast for the large C&I and agricultural customers.

As described above, the ex-ante forecast contains a range of day types and weather scenarios. For each of these, three components are required to complete the forecast:

- Per-customer reference loads associated with each customer type (e.g., Schedule B-19 customers in the Greater Bay Area);
- Hourly load impacts associated with each reference load profile; and
- Enrollment forecasts that scale the per-customer forecasts to represent the total rate-level forecast.

To develop the per-customer reference loads, we estimate regression equations from historical data and use the resulting coefficients and ex-ante weather conditions (provided by PG&E) as the baseline for simulating reference loads for the scenarios required by the Protocols. The models thus use hourly load data from the post-treatment period averaged across "cells" (e.g., for the average customer in each TOU rate).

Separate models are estimated by customer group (defined by rate and LCA) and season (summer and winter). The reference load regression model specification is the following:

$$Q_{i,t} = a + \sum_{i=2}^{24} \left(b_i^{Mean17} \times h_{i,t} \times Mean17_t\right) + \sum_{i=2}^{24} \left(b_i^{MON} \times h_{i,t} \times MON_t\right) + \sum_{i=2}^{24} \left(b_i^{FRI} \times h_{i,t} \times FRI_t\right) + \sum_{i=2}^{24} b_i^{h} \times h_{i,t} + \sum_{i=2}^{5} b_i^{DOW} \times DOW_{i,t} + \sum_{i=2}^{12} b_i^{MONTH} \times MONTH_{i,t} + e_{i,t}$$

The variables are explained in the table below.

[5] "Load Impact Evaluation of Non-Residential Critical Peak and Peak Day Pricing" by Applied Energy Group, as presented at the 2020 DRMEC Load Impact Workshop, May 1, 2020.
[6] "Statewide Time-of-Use Scenario Modeling for 2015 California Energy Commission Integrated Energy Policy Report", November 15, 2015.

Variable Name / Term	Variable / Term Description
$Q_{i,t}$	the group's average per-customer usage in hour *i* of day *t*
a and the various *b*'s	the estimated parameters
h_i	a dummy variable for hour *i*
$Mean17_t$	the average temperature during the first 17 hours of day *t*
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.

The model is estimated using the current-year load data (October 2021 through September 2022). We assume that these data represent a "new normal" and that no further adjustments are required to account for COVID-19 pandemic effects.

The second component of the ex-ante forecast, the hourly load impacts, are simulated using the reference loads, tariff rates, and an assumed elasticity of demand. The tariff prices are first converted to an effective energy charge (EEC), which has two elements. The first element is simply the tariff's energy rates. The second element is a conversion of the tariff's demand rates into an energy rate, which is accomplished by dividing the demand rate by the number of hours in the month to which it applies. For example, an all-hours $10 per kW month demand charge would be converted to an EEC by dividing $10 by 730 hours (the average number of hours in a month), or approximately 1.4 cents per kWh. The addition of the EECs is particularly important for rate schedules that incorporate a Peak-period demand charge, as this charge effectively increases the cost of Peak-period usage in a manner similar to the corresponding energy rate.

We assume an own-price elasticity of demand of -0.04. This is consistent with the elasticity of substitution assumed in the aforementioned Statewide TOU study.[7] Each hour's load on the new TOU rate is simulated as follows:

$$Q_{New} = \exp\{\ln(Q_{Old}) + \varepsilon_d \times \ln(P_{New} / P_{Old})\}$$

where,

- Q_{New} = usage on the new TOU rate;
- Q_{Old} = usage on the legacy TOU rate;
- P_{New} = EEC on the new TOU rate;
- P_{Old} = EEC on the legacy TOU rate;
- ε_d = elasticity of demand;

[7] We did not perform these simulations using an elasticity of substitution (as was done in the Statewide study) because of the high number of effective pricing periods. That is, the distinct pricing periods for simulation purposes are defined as all combinations of legacy and new TOU rate pricing periods (e.g., Off-Peak to Off-Peak, Off-Peak to Part-Peak, Off-Peak to Peak, etc.). A model that formally models substitutions across a high number of periods is difficult to derive, so we instead apply an own-price elasticity to each hour's price change. It can be shown that an own-price elasticity is approximately equal to an elasticity of substitution over relatively small changes in prices.

- exp = the exponential function; and
- ln = the natural log function.

The load impact is the difference between the simulated loads on the new and legacy TOU rates (Q_{New} and Q_{Old}, respectively).

We limited the ex-ante impacts to the rates with the most expected customers in the large size category: Schedules B-10, B-19, B-20, and AG-C. We focus on the following rate transitions, which have the highest number of large customer rate transitions:

- A-10 TOU to B-10
- E-19 to B-19
- E-20 to B-20
- AG-5B and AG-5C to AG-C

To develop uncertainty-adjusted load impacts, we assume a 0.005 standard deviation around our assumed elasticity of demand. Scenario-specific percentage load impacts are then simulated for the 10th, 30th, 50th, 70th, and 90th percentile load changes using the resulting distribution of load impacts.

4. EX-POST LOAD IMPACT STUDY FINDINGS

This section reports ex-post peak load impact findings for the customers who voluntarily migrated from a legacy TOU rate to one of the new TOU rates. The following transitions are under examination, along with the size group and whether we include both NEM and non-NEM customers[8]:

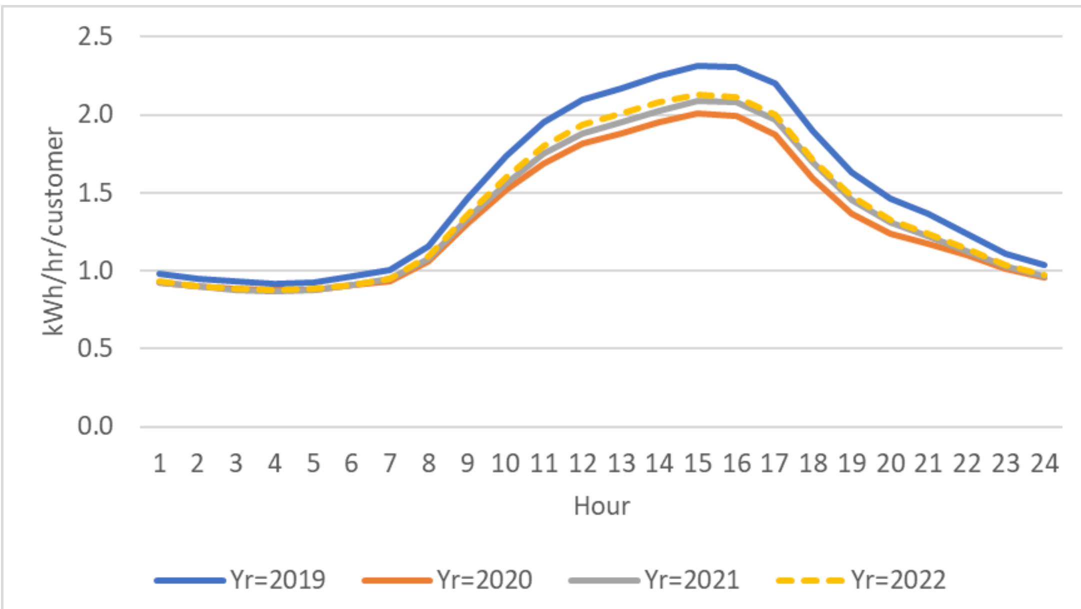
- Schedule A-1 TOU to B-1, Small (non-NEM and NEM)
- Schedule A-6 to B-6, Small (non-NEM and NEM)
- Schedule A-10 TOU to B-10, Medium (non-NEM and NEM)
- Schedule E-19 to B-19, Medium (non-NEM and NEM)
- Schedule E-20 to B-20, Large (non-NEM only)
- Schedule AG-4A to AG-A1, Small (non-NEM and NEM)
- Schedule AG-4B to AG-B, Medium (non-NEM and NEM)
- Schedule AG-5A to AG-A2, Small (non-NEM only)
- Schedule AG-5B to AG-C, Medium (non-NEM only)
- Schedule AG-5C to AG-C, Large (non-NEM only)

As described in Section 3.1, various data issues prevent us from estimating reliable TOU load impacts. First, the COVID pandemic has caused usage to shift across years, which prevents us from estimating TOU load impacts by comparing treatment customer's pre- and post-rate-change load profiles. Figure 4.1 provides an example, showing average hourly usage on summer non-holiday weekdays for small non-NEM customers who changed from Schedule A-1 TOU to Schedule B-1. Notice that the pre-pandemic usage in

[8] Other size groups may have been present for a given rate transition, but we focus on the one with the highest number of customers.

2019 is much higher than usage in any of the following years. Usage levels dropped the furthest in 2020, rebounding somewhat in 2021 and 2022.[9] The shift in usage across years does not affect all hours equally. The post-2019 load levels are virtually the same at the beginning and end of the day, but 2022 loads are 7.7 percent higher than 2020 loads in HE19. These (seemingly) pandemic-related load changes across years are large enough to mask any load changes due to changing TOU rates. When we estimate treatment-only models, any changes across years that aren't due to weather are attributed to the TOU rate. We don't have information to insert into the model that quantifies a COVID effect that is distinct from a change due to any other non-weather factor that changes across years. As a result, we would falsely estimate TOU-related load decreases for most hours of the day if we used 2019 as the counterfactual year; and TOU-related load increases for most hours of the day if we used 2020 as the counterfactual year. The fact that pandemic-related load changes appear to differ by hour of day also prevents us from reliably estimating changes in shares of usage by TOU pricing period as customers change TOU rates.

Figure 4.1: Summer Average Non-Holiday Weekday Usage by Year, A-1 TOU to B-1



Though the corresponding figures for other rate transitions differ in their details, they generally support the same conclusion that pandemic-related load changes differ by hour of day, whether 2019 or 2020 is taken as the counterfactual year. Appendix E includes the figure above as well as the corresponding figure for the other examined rates.

[9] The average temperature in 2020 was approximately the same as in 2019 but slightly higher than in 2021, so temperature differences cannot explain the load level difference among the three earlier years. The average temperature in 2022, however, was slightly higher than in these preceding years, which could potentially explain the increase between 2021 and 2022.

5. EX-ANTE LOAD IMPACTS

5.1 Overview and Enrollment Forecasts

As described in Section 3.2, the ex-ante load impacts were forecast for only the large (over 200kW) customers. The following rate transitions are included in the forecast:

- A-10 TOU to B-10
- E-19 to B-19
- E-20 to B-20
- AG-5B to AG-C
- AG-5C to AG-C

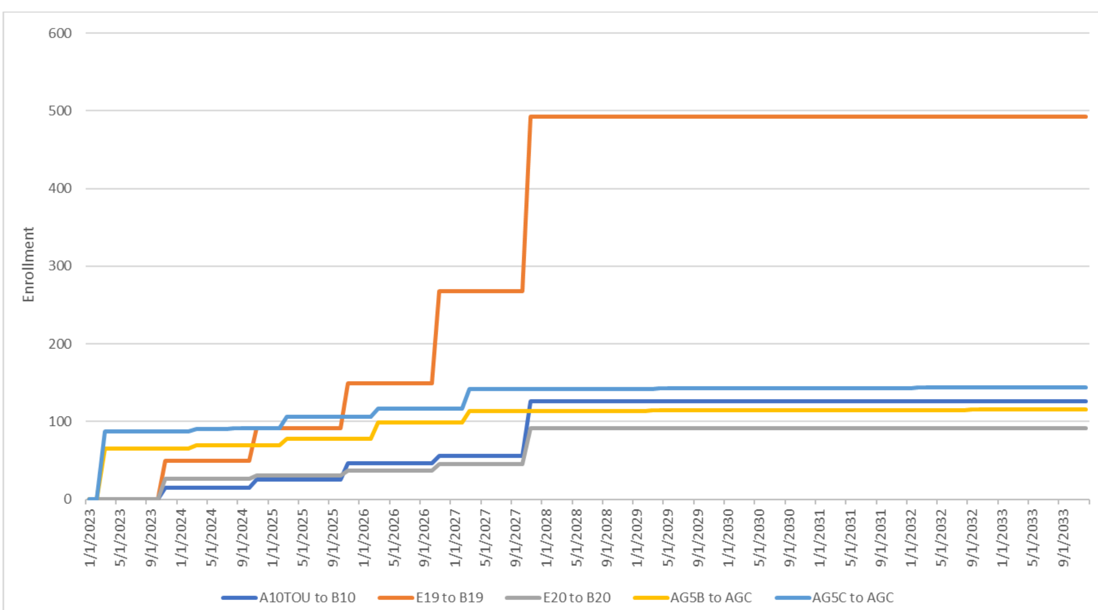
As with all ex-ante studies, we develop four sets of results associated with distinct weather scenarios, which are distinguished by:

- 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 monthly enrollments by rate for the forecast period. The incremental TOU enrollments begin in March 2023 for agricultural customers and November 2023 for commercial and industrial customers. Additional enrollment continues through 2027 with enrollment remining flat from 2028 through 2033.

Figure 5.1: Ex-Ante Enrollment Forecast by Rate



5.2 Ex-Ante Load Impact Results

The following sub-sections present the ex-ante forecasts for each of the forecast rate transitions.

Figure 5.2 summarizes the average impact during the Resource Adequacy (RA) window (4:00 to 9:00 p.m. normally, 5:00 to 10:00 p.m. for March and April) for each month of 2023, by rate. The values reflect PG&E 1-in-2 peak day weather conditions.

Figure 5.2: 2023 Monthly Average RA-Window Load Impacts

Figure 5.3 shows the same information as Figure 5.2 for the 2024 forecast year.

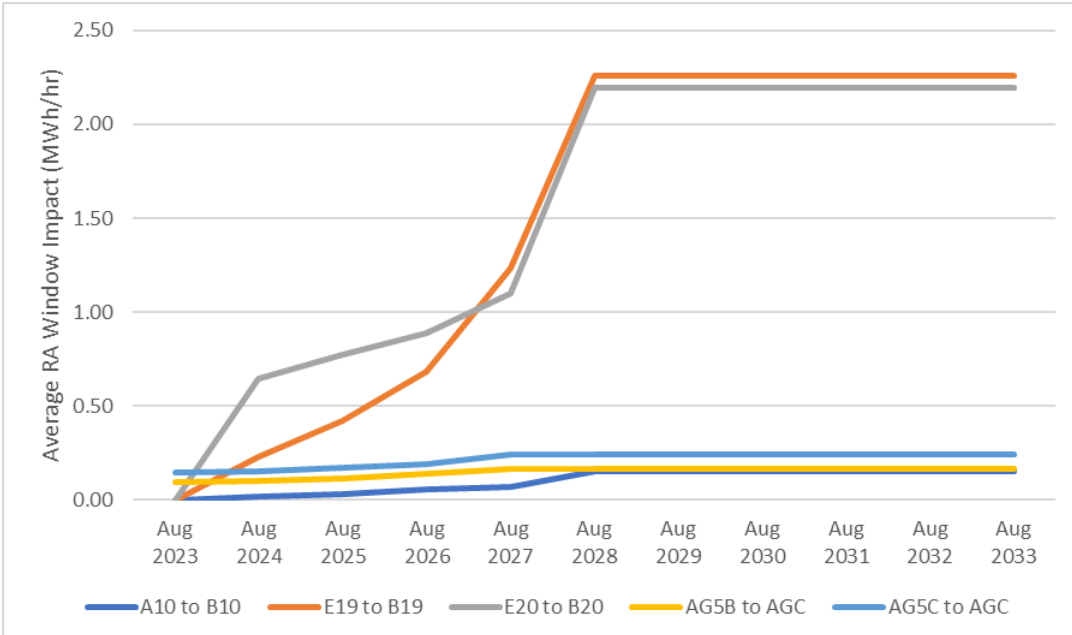
Figure 5.3: 2024 Monthly Average RA-Window Load Impacts

A few things to note:

- There are no impacts in January and February 2023 because new enrollments begin in March, with commercial and industrial enrollments not beginning until November 2023.
- Incremental load impacts are low, largely due to small incremental enrollment.
- May and October load impacts represent a load *increase* relative to usage on the legacy TOU rate. This is due to the change in the summer definition from May through October to June through September. The two months that changed from summer to winter (May and October) have significantly lower effective energy charges during the RA window due to differences in both the energy and demand rates.

Figure 5.4 summarizes the forecast load impacts for each August during the forecast period. The values are the average load impacts during the RA window for the PG&E 1-in-2 weather conditions. The load impact pattern across years closely resembles the corresponding enrollment pattern, as shown in Figure 5.1.

Figure 5.4: August Average RA-Window Load Impacts by Year



The following sub-sections provide additional summaries of the 2024 load impacts associated with each included rate transition. Impacts are shown for 2024 rather than 2023 because incremental enrollments are forecast to be zero for commercial and industrial customers through October 2023.

5.2.1 Ex-ante load impacts for A-10 TOU to B-10 customers

Table 5.1 shows the A-10 TOU to B-10 load impacts, averaged during the Resource Adequacy window. The tables show monthly load impacts in 2024 associated with each of the four weather scenarios. The blue highlighting represents the winter months. There is little variation in the load impact across weather scenarios. The load impact is highest during the summer months (with the apparent similarity in November and December impacts due to an additional increase in forecast enrollment in November). The table shows the May and October load increases described in the context of Figure 5.3 above.

Table 5.1: A-10 TOU to B-10 Ex-Ante Load Impacts, 2024 Monthly Peak Day during RA Window (MWh/hr)

Month	CAISO 1-in-10	CAISO 1-in-2	PG&E 1-in-10	PG&E 1-in-2
January	0.009	0.010	0.010	0.010
February	0.010	0.010	0.010	0.010
March	0.009	0.008	0.008	0.009
April	0.009	0.009	0.010	0.009
May	-0.004	-0.004	-0.004	-0.004
June	0.019	0.019	0.020	0.019
July	0.018	0.019	0.019	0.019
August	0.021	0.020	0.020	0.019
September	0.022	0.019	0.022	0.020
October	-0.004	-0.004	-0.004	-0.004
November	0.018	0.018	0.017	0.017
December	0.016	0.016	0.016	0.016

Figures 5.5 and 5.6 show the August and December 2024 hourly loads and load impacts associated with the PG&E 1-in-2 weather scenario, respectively. The load impacts tend to be small, peaking at 0.8 percent in August and 0.6 percent in December.

Figure 5.5: A-10 TOU to B-10 Hourly Ex-Ante Load Impacts, 2024 August PG&E 1-in-2 Peak Day

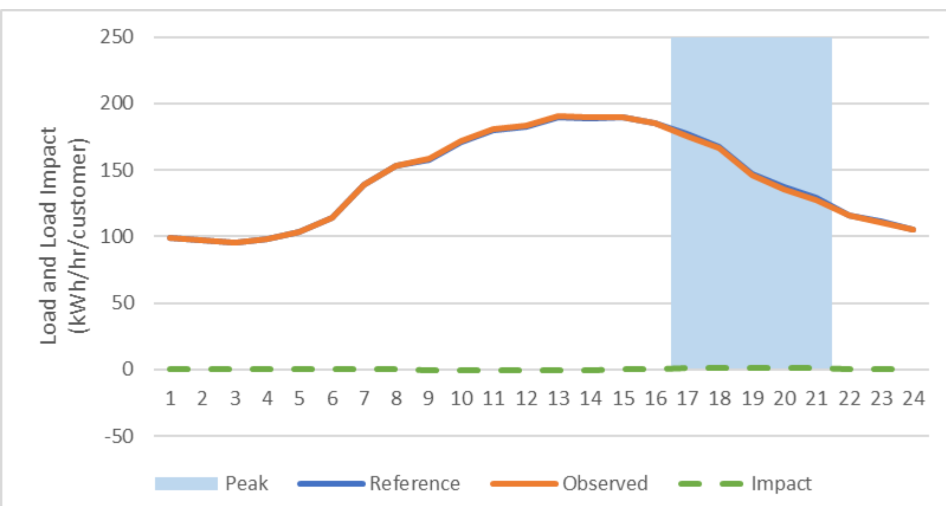
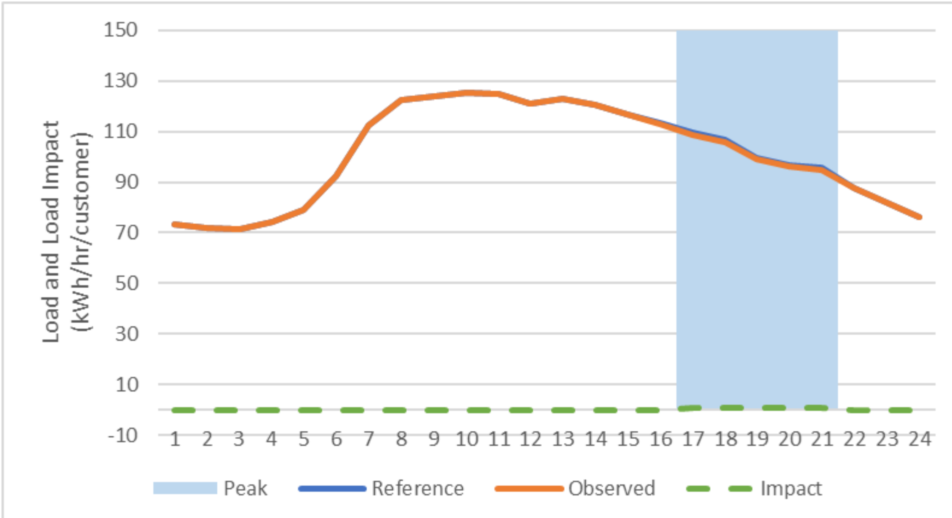


Figure 5.6: A-10 TOU to B-10 Hourly Ex-Ante Load Impacts, 2024 December PG&E 1-in-2 Peak Day



5.2.2 Ex-ante load impacts for E-19 to B-19 customers

Table 5.2 shows the E-19 to B-19 load impacts, averaged during the Resource Adequacy window. The tables show monthly load impacts in 2024 associated with each of the four weather scenarios. The blue highlighting represents the winter months. There is very little variation in the load impact across weather scenarios. The load impact is highest during the summer months (with the apparent similarity in November and December impacts due to an additional increase in forecast enrollment in November). The table shows the May and October load increases described in the context of Figure 5.3 above.

Table 5.2: E-19 to B-19 Ex-Ante Load Impacts, 2024 Monthly Peak Day during RA Window (MWh/hr)

Month	CAISO 1-in-10	CAISO 1-in-2	PG&E 1-in-10	PG&E 1-in-2
January	0.10	0.11	0.10	0.10
February	0.11	0.11	0.11	0.11
March	0.09	0.08	0.08	0.09
April	0.10	0.09	0.10	0.10
May	-0.15	-0.14	-0.15	-0.14
June	0.23	0.24	0.24	0.23
July	0.22	0.22	0.23	0.22
August	0.24	0.23	0.24	0.23
September	0.24	0.21	0.24	0.22
October	-0.14	-0.13	-0.14	-0.13
November	0.22	0.22	0.20	0.21
December	0.19	0.19	0.19	0.19

Figures 5.7 and 5.8 show the August and December 2024 hourly loads and load impacts associated with the PG&E 1-in-2 weather scenario, respectively. The August load impacts range from increases of 2.5 percent to decreases of 1.9 percent. In December, the range is smaller, from increases of 0.1 percent to 1.0 percent load decreases.

Figure 5.7: E-19 to B-19 Hourly Ex-Ante Load Impacts, 2024 August PG&E 1-in-2 Peak Day

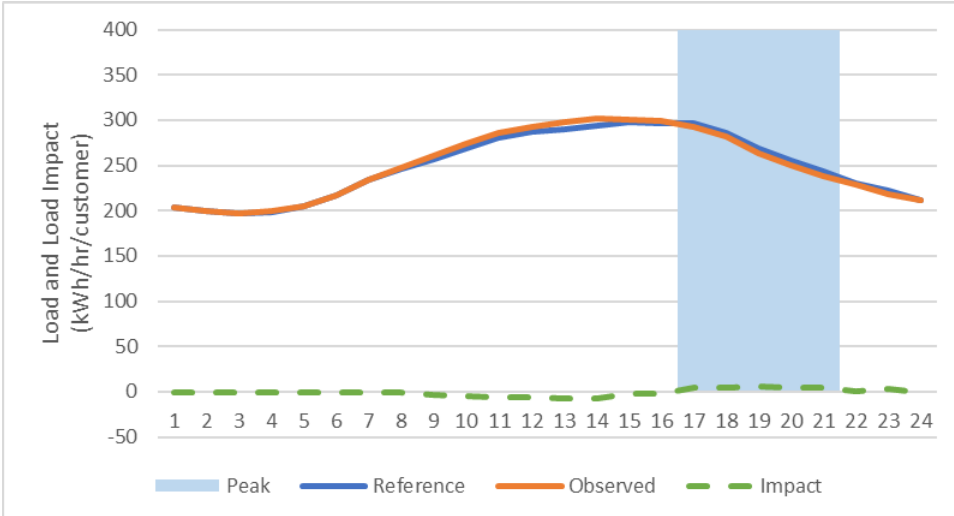
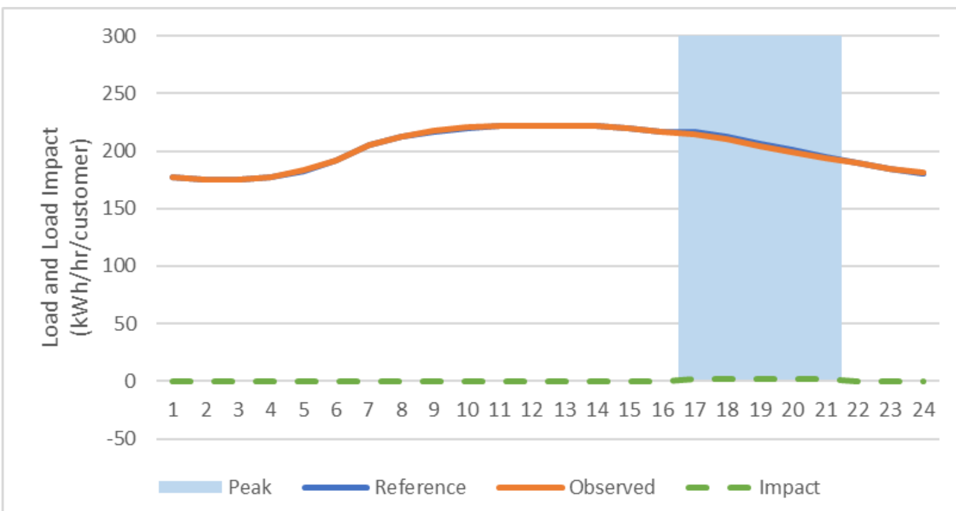


Figure 5.8: E-19 to B-19 Hourly Ex-Ante Load Impacts, 2024 December PG&E 1-in-2 Peak Day



5.2.3 Ex-ante load impacts for E-20 to B-20 customers

Table 5.3 shows the E-20 to B-20 load impacts, averaged during the Resource Adequacy window. The tables show monthly load impacts in 2024 associated with each of the four weather scenarios. The blue highlighting represents the winter months. There is very little variation in the load impact across weather scenarios. The load impact is highest during the summer months. The table shows the May and October load increases described in the context of Figure 5.3 above.

Table 5.3: E-20 to B-20 Ex-Ante Load Impacts, 2024 Monthly Peak Day during RA Window (MWh/hr)

Month	CAISO 1-in-10	CAISO 1-in-2	PG&E 1-in-10	PG&E 1-in-2
January	0.34	0.35	0.35	0.35
February	0.36	0.36	0.36	0.36
March	0.32	0.30	0.29	0.32
April	0.32	0.31	0.33	0.32
May	-0.38	-0.38	-0.38	-0.37
June	0.58	0.58	0.59	0.58
July	0.59	0.59	0.60	0.59
August	0.66	0.65	0.65	0.64
September	0.63	0.61	0.63	0.61
October	-0.37	-0.37	-0.38	-0.37
November	0.48	0.47	0.45	0.46
December	0.42	0.43	0.42	0.43

Figures 5.9 and 5.10 show the August and December 2024 hourly loads and load impacts associated with the PG&E 1-in-2 weather scenario, respectively. The August load impacts range from increases of 2.5 percent to decreases of 1.8 percent. In December, the range is smaller, from 0.0 percent to 1.1 percent load decreases.

Figure 5.9: E-20 to B-20 Hourly Ex-Ante Load Impacts, 2024 August PG&E 1-in-2 Peak Day

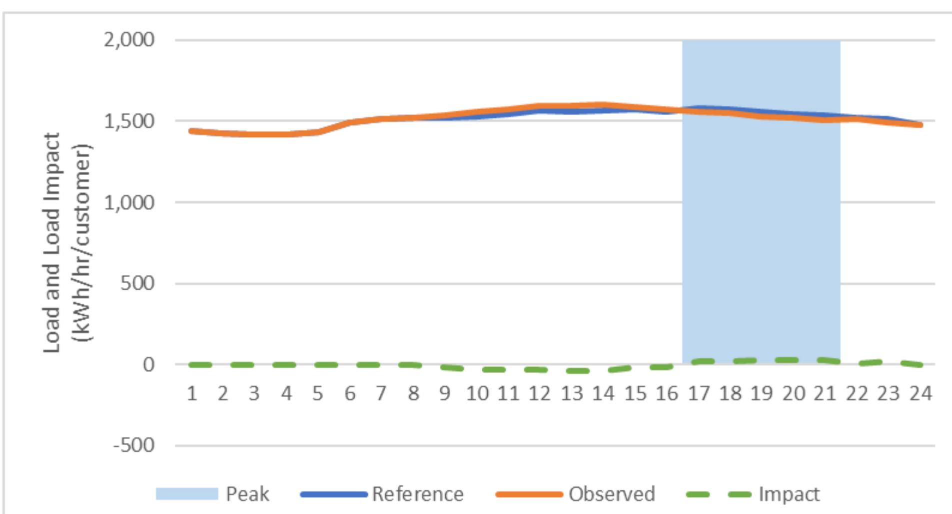
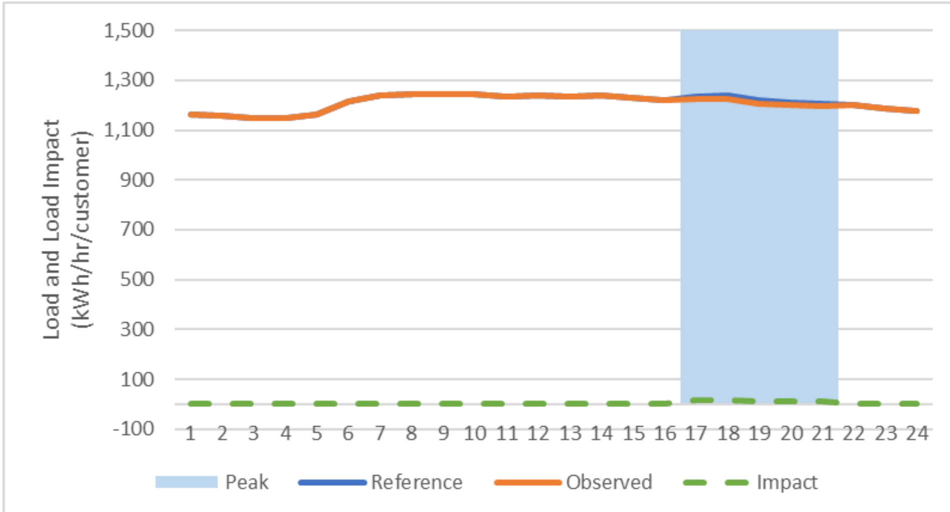


Figure 5.10: E-20 to B-20 Hourly Ex-Ante Load Impacts, 2024 December PG&E 1-in-2 Peak Day



5.2.4 Ex-ante load impacts for AG-5B to AG-C customers

Table 5.4 shows the AG-5B to AG-C load impacts, averaged during the Resource Adequacy window. The tables show monthly load impacts in 2024 associated with each of the four weather scenarios. The blue highlighting represents the winter months. There is very little variation in the load impact across weather scenarios. The load impact is highest during the summer months. The table shows the May and October load increases described in the context of Figure 5.2 above.

Table 5.4: AG-5B to AG-C Ex-Ante Load Impacts, 2024 Monthly Peak Day during RA Window (MWh/hr)

Month	CAISO 1-in-10	CAISO 1-in-2	PG&E 1-in-10	PG&E 1-in-2
January	0.00	0.00	0.00	0.00
February	0.00	0.00	0.00	0.00
March	0.00	0.00	0.00	0.00
April	0.00	0.00	0.00	0.00
May	-0.07	-0.07	-0.07	-0.07
June	0.11	0.11	0.11	0.11
July	0.11	0.11	0.11	0.11
August	0.10	0.10	0.10	0.10
September	0.07	0.07	0.08	0.07
October	-0.04	-0.04	-0.04	-0.04
November	0.00	0.00	0.00	0.00
December	0.00	0.00	0.00	0.00

Figures 5.11 and 5.12 show the August and December 2024 hourly loads and load impacts associated with the PG&E 1-in-2 weather scenario, respectively. The August load impacts range from increases of 1.8 percent to decreases of 3.2 percent. In December, the range is smaller, from 0.0 to 0.2 percent load increases.

Figure 5.11: AG-5B to AG-C Hourly Ex-Ante Load Impacts, 2024 August PG&E 1-in-2 Peak Day

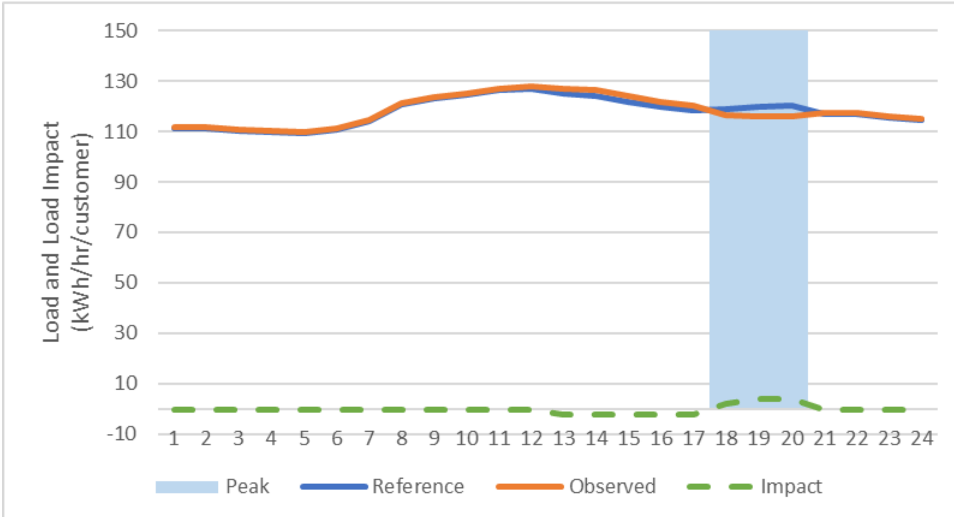
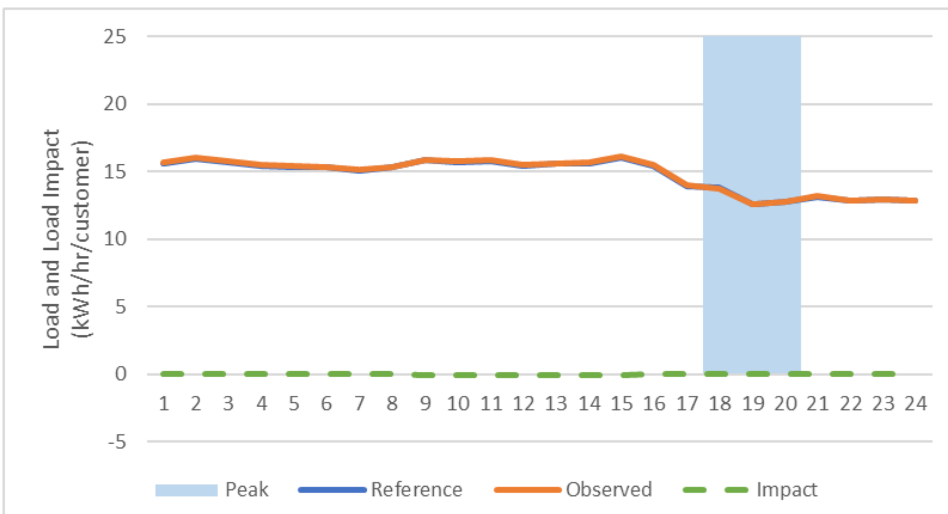


Figure 5.12: AG-5B to AG-C Hourly Ex-Ante Load Impacts, 2024 December PG&E 1-in-2 Peak Day



5.2.5 Ex-ante load impacts for AG-5C to AG-C customers

Table 5.5 shows the AG-5C to AG-C load impacts, averaged during the Resource Adequacy window. The tables show monthly load impacts in 2024 associated with each of the four weather scenarios. The blue highlighting represents the winter months. There is very little variation in the load impact across weather scenarios. The load decreases are highest during the summer months. The table shows the May and October load increases described in the context of Figure 5.2 above.

Table 5.5: AG-5C to AG-C Ex-Ante Load Impacts, 2024 Monthly Peak Day during RA Window (MWh/hr)

Month	CAISO 1-in-10	CAISO 1-in-2	PG&E 1-in-10	PG&E 1-in-2
January	0.01	0.01	0.01	0.01
February	0.02	0.02	0.02	0.02
March	0.03	0.03	0.03	0.03
April	0.04	0.04	0.04	0.04
May	-0.20	-0.19	-0.19	-0.19
June	0.17	0.17	0.17	0.17
July	0.16	0.16	0.16	0.16
August	0.15	0.15	0.15	0.15
September	0.10	0.10	0.10	0.10
October	-0.13	-0.13	-0.14	-0.13
November	0.02	0.02	0.02	0.02
December	0.01	0.01	0.01	0.01

Figures 5.13 and 5.14 show the August and December 2024 hourly loads and load impacts associated with the PG&E 1-in-2 weather scenario, respectively. The August load impacts range from increases of 1.7 percent to decreases of 2.8 percent. In December, the range is smaller, from 0.0 to 0.5 percent load decreases.

Figure 5.13: AG-5C to AG-C Hourly Ex-Ante Load Impacts, 2024 August PG&E 1-in-2 Peak Day

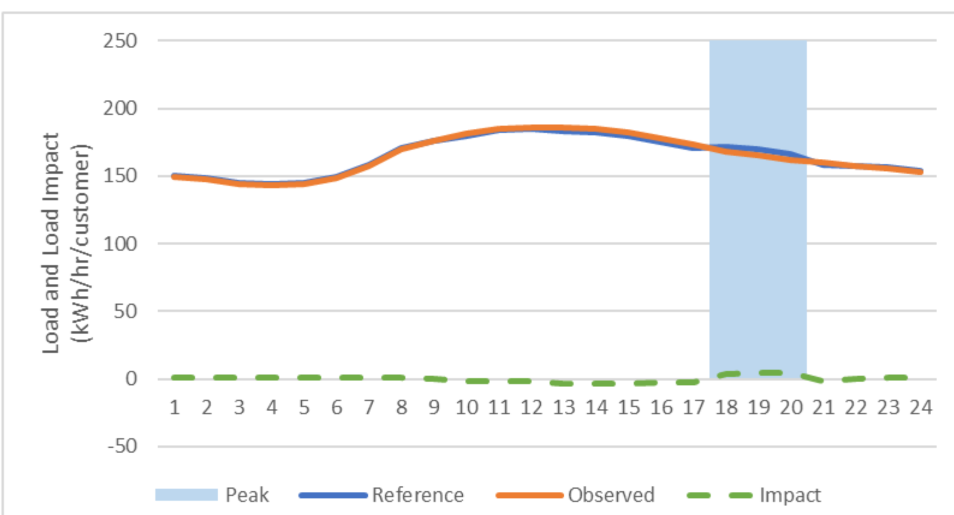
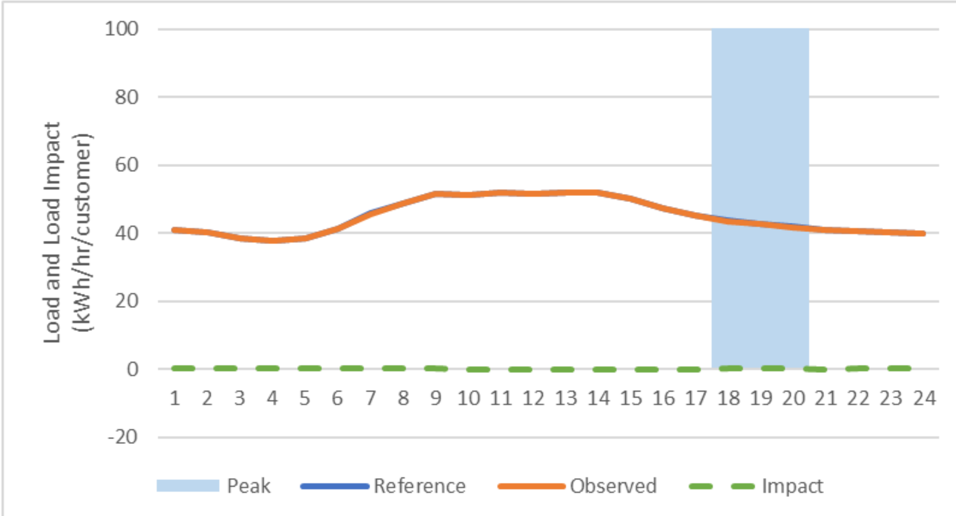


Figure 5.14: AG-5C to AG-C Hourly Ex-Ante Load Impacts, 2024 December PG&E 1-in-2 Peak Day



6. COMPARISONS OF RESULTS

In an effort to clarify the relationships between ex-post and ex-ante results, the annual load impact evaluations typically include comparisons of 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.

In this case, the current ex-post load impacts are not reliable, so we limit our comparisons to the current and previous ex-ante load impacts.

In each of the tables below, we compare the ex-ante forecasts from the previous and current studies, focusing on the August 2024 average weekday under PG&E 1-in-2 weather conditions. The top panel of each table shows the aggregate results while the bottom panel shows per-customer results.

The two forecasts used a common framework, though the inputs have been updated. The reference loads are produced using the current load data, and the enrollments have been updated. The TOU rates that are an input to the load impact simulations have also been updated, which leads to somewhat different percentage load impacts.

Table 6.1 provides the ex-ante comparison for the A-10 to B-10 customers. Total load impacts are the same in the current study. The per-customer load impacts are lower due to a lower percentage load impact but this is offset by a slightly higher forecast enrollment.

Table 6.1 Comparison of Current and Previous Ex-Ante Load Impacts, A-10 to B-10

Level	Outcome	Previous Ex-Ante	Current Ex-Ante
Total	# SAIDs	14	15
	Reference (MW)	1.89	2.14
	Load Impact (MW)	0.018	0.018
	Avg. Temp.	74.8	79.0
Per SAID	Reference (kW)	134.9	143.0
	Load Impact (kW)	1.29	1.20
	% Load Impact	1.0%	0.8%

Table 6.2 provides the ex-ante comparison for the E-19 to B-19 customers. Total load impacts approximately the same in the current study. The per-customer load impacts are slightly lower in the current study, resulting from a lower per-customer reference load, but this is offset by a slightly higher forecast enrollment.

Table 6.2 Comparison of Current and Previous Ex-Ante Load Impacts, E-19 to B-19

Level	Outcome	Previous Ex-Ante	Current Ex-Ante
Total	# SAIDs	47	50
	Reference (MW)	12.43	12.99
	Load Impact (MW)	0.21	0.22
	Avg. Temp.	76.6	76.6
Per SAID	Reference (kW)	264.5	259.9
	Load Impact (kW)	4.52	4.44
	% Load Impact	1.7%	1.7%

Table 6.3 provides the ex-ante comparison for the E-20 to B-20 customers. Enrollments are forecast higher in the current study, leading to higher total load impacts. The per-customer load impacts are slightly higher in the current study, due to higher per-customer reference loads offset by slightly lower percentage load impacts.

Table 6.3 Comparison of Current and Previous Ex-Ante Load Impacts, E-20 to B-20

Level	Outcome	Previous Ex-Ante	Current Ex-Ante
Total	# SAIDs	8	26
	Reference (MW)	10.77	39.83
	Load Impact (MW)	0.19	0.63
	Avg. Temp.	77.3	83.2
Per SAID	Reference (kW)	1,346.7	1,532.0
	Load Impact (kW)	23.2	24.4
	% Load Impact	1.7%	1.6%

Table 6.4 provides the ex-ante comparison for the AG-5B to AG-C customers. Enrollments are much higher in the current study, leading to higher total load impacts. Also contributing are the higher per-customer load impacts in the current study (3.16 vs. 1.52 kWh/hour/customer), which result from higher reference loads.

Table 6.4 Comparison of Current and Previous Ex-Ante Load Impacts, AG-5B to AG-C

Level	Outcome	Previous Ex-Ante	Current Ex-Ante
Total	# SAIDs	14	69
	Reference (MW)	0.78	7.92
	Load Impact (MW)	0.02	0.22
	Avg. Temp.	92.6	95.9
Per SAID	Reference (kW)	55.6	114.8
	Load Impact (kW)	1.52	3.16
	% Load Impact	2.7%	2.8%

Table 6.5 provides the ex-ante comparison for the AG-5C to AG-C customers. Total load impacts in the current study are slightly higher. A lower forecast enrollment is offset by the higher per-customer load impacts in the current study (4.11 vs. 3.20 kWh/hour/customer) due to higher reference loads.

Table 6.5 Comparison of Current and Previous Ex-Ante Load Impacts, AG-5C to AG-C

Level	Outcome	Previous Ex-Ante	Current Ex-Ante
Total	# SAIDs	108	90
	Reference (MW)	13.39	14.85
	Load Impact (MW)	0.35	0.37
	Avg. Temp.	79.8	91.9
Per SAID	Reference (kW)	123.9	164.9
	Load Impact (kW)	3.20	4.11
	% Load Impact	2.6%	2.5%

APPENDICES

Appendix A Non-NEM Ex-Post Load Impact Tables:

7a. PGE_2022_NonRes_TOU_NonNEM _Ex_Post_CONFIDENTIAL.xlsx

7a. PGE_2022_NonRes_TOU_NonNEM _Ex_Post_PUBLIC.xlsx

Appendix B NEM Ex-Post Load Impact Tables:

7b. PGE_2022_NonRes_TOU_NEM_Ex_Post_CONFIDENTIAL.xlsx

7b. PGE_2022_NonRes_TOU_NEM_Ex_Post_PUBLIC.xlsx

Appendix C Agricultural Ex-Ante Load Impact Tables:

7c. PGE_2022_NonRes_TOU_Ag_Ex_Ante_CONFIDENTIAL.xlsx

7c. PGE_2022_NonRes_TOU_Ag_Ex_Ante_PUBLIC.xlsx

Appendix D C&I Ex-Ante Load Impact Tables:

7d. PGE_2022_NonRes_TOU_CI _Ex_Post_CONFIDENTIAL.xlsx

7d. PGE_2022_NonRes_TOU_CI _Ex_Post_PUBLIC.xlsx

Appendix E Ex-Post Analysis: Summer Average Usage by Year

APPENDIX E. SUMMER AVERAGE USAGE BY YEAR

This appendix presents the summaries of our examination of the potential for within-treatment ex-post load impact estimates. Figures E.1 through E.16 illustrate the average hourly usage on summer non-holiday weekdays, by year, for the various rate changes. The figures show that pandemic-related load changes differ by hour of day, whether 2019 or 2020 is taken as the counterfactual year, preventing us from reliably distinguishing the ex-post load impact from pandemic-related load changes.

Figure E.1: Summer Average Non-Holiday Weekday Usage by Year, A-1 TOU to B-1 Non-NEM

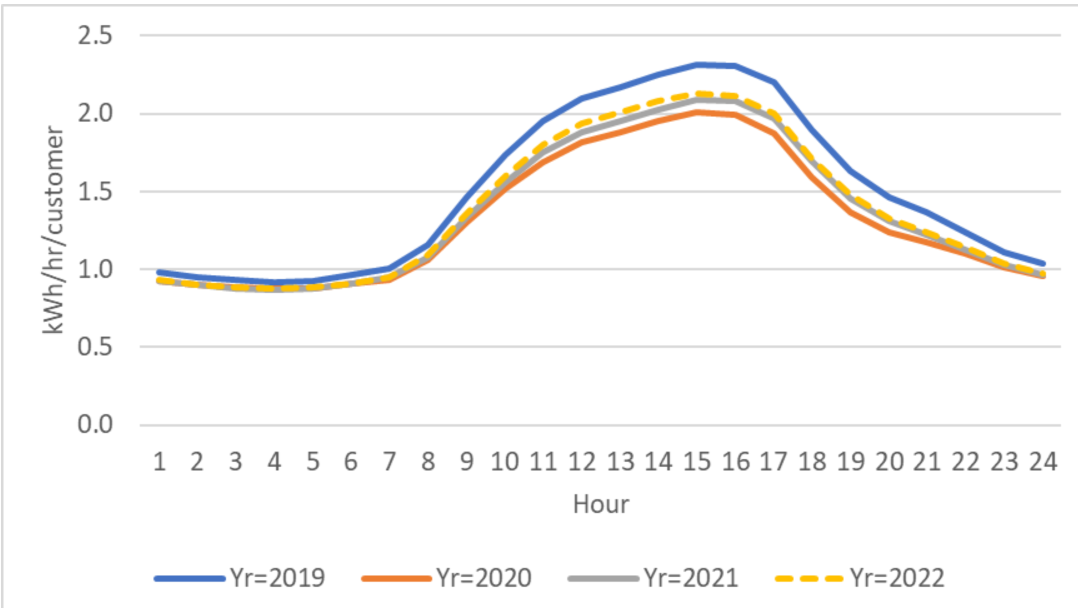


Figure E.2: Summer Average Non-Holiday Weekday Usage by Year, A-6 to B-6 Non-NEM

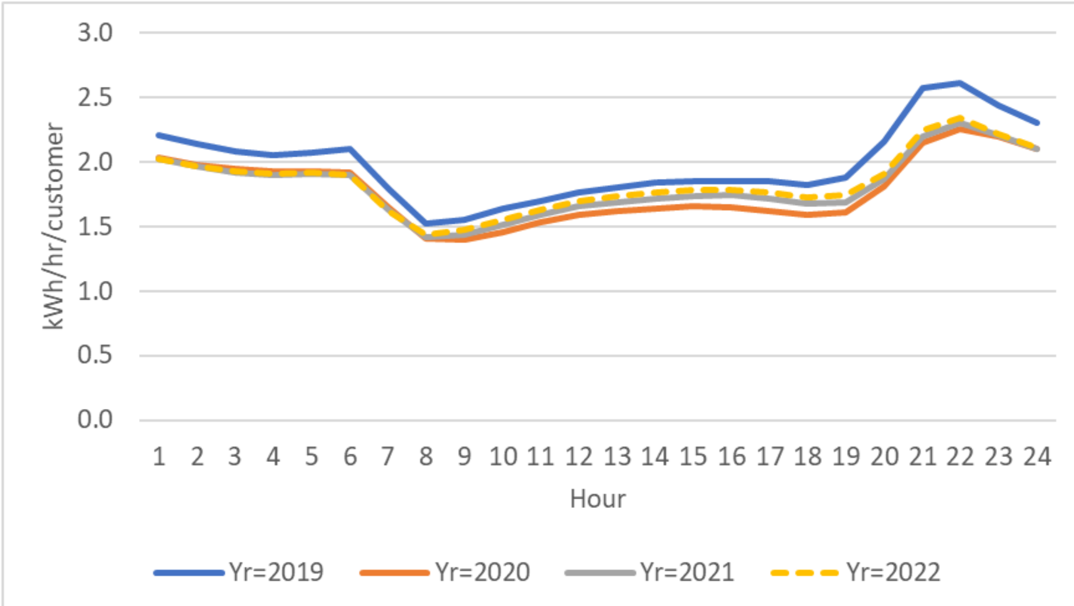


Figure E.3: Summer Average Non-Holiday Weekday Usage by Year, A-10 TOU to B-10 Non-NEM

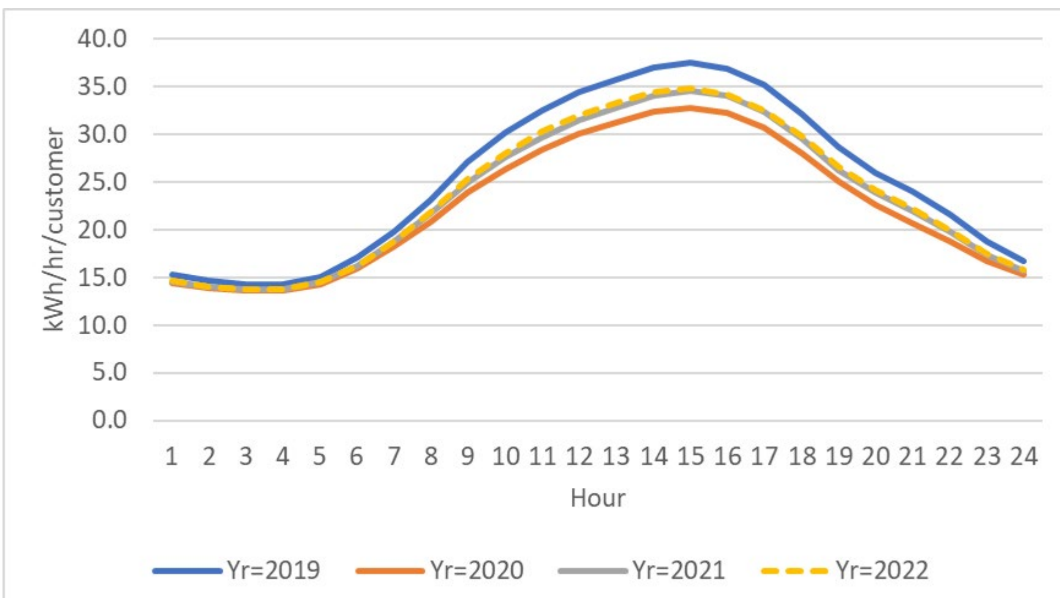


Figure E.4: Summer Average Non-Holiday Weekday Usage by Year, E-19 to B-19 Non-NEM

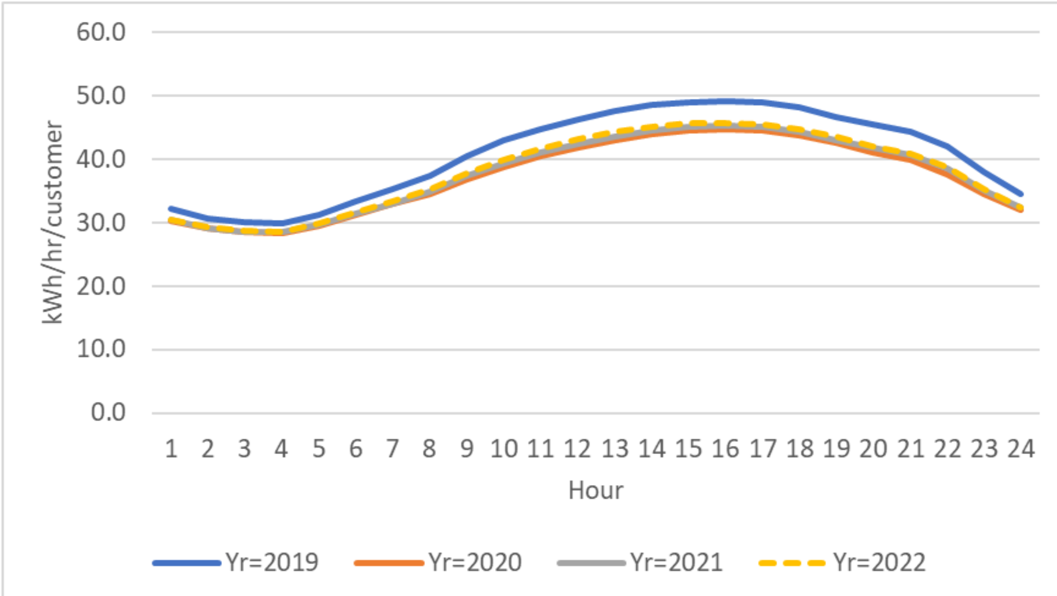


Figure E.5: Summer Average Non-Holiday Weekday Usage by Year, E-20 to B-20 Non-NEM

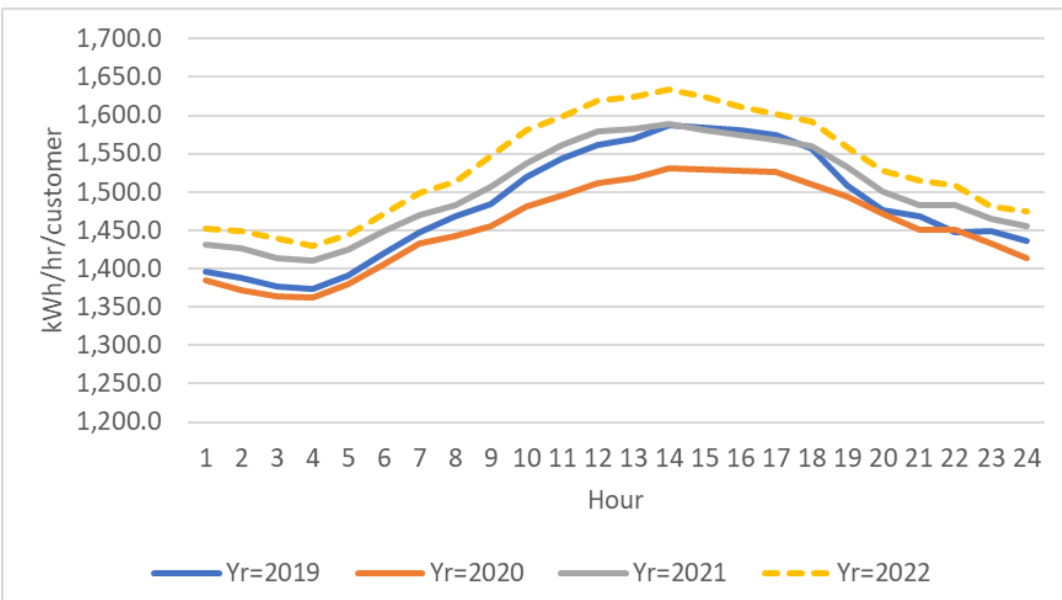


Figure E.6: Summer Average Non-Holiday Weekday Usage by Year, AG-4A to AG-A1 Non-NEM

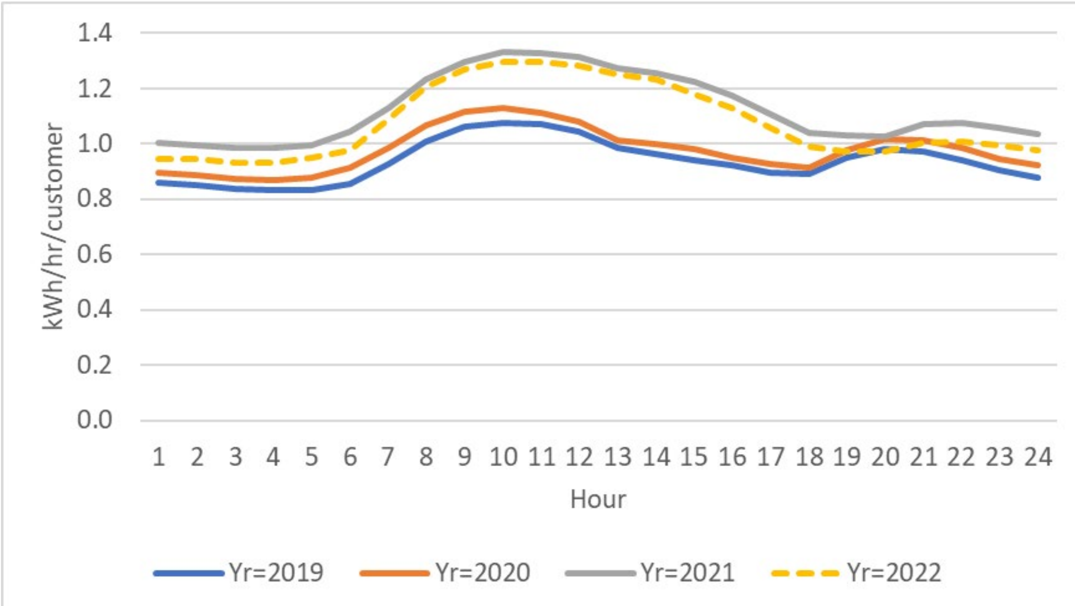


Figure E.7: Summer Average Non-Holiday Weekday Usage by Year, AG-4B to AG-B Non-NEM

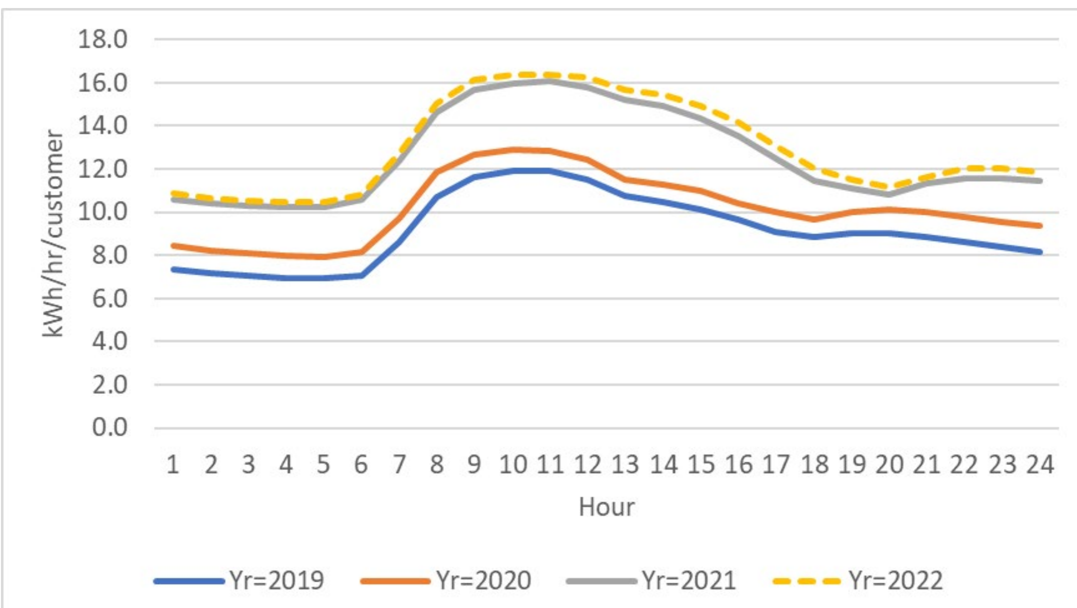


Figure E.8: Summer Average Non-Holiday Weekday Usage by Year, AG-5A to AG-A2 Non-NEM

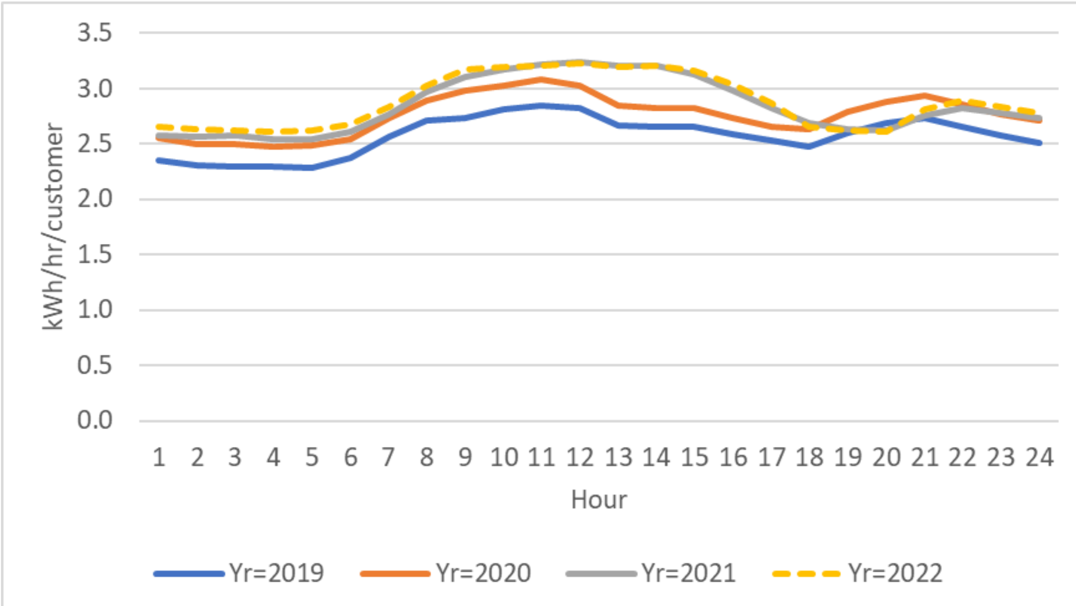


Figure E.9: Summer Average Non-Holiday Weekday Usage by Year, AG-5B to AG-C Non-NEM

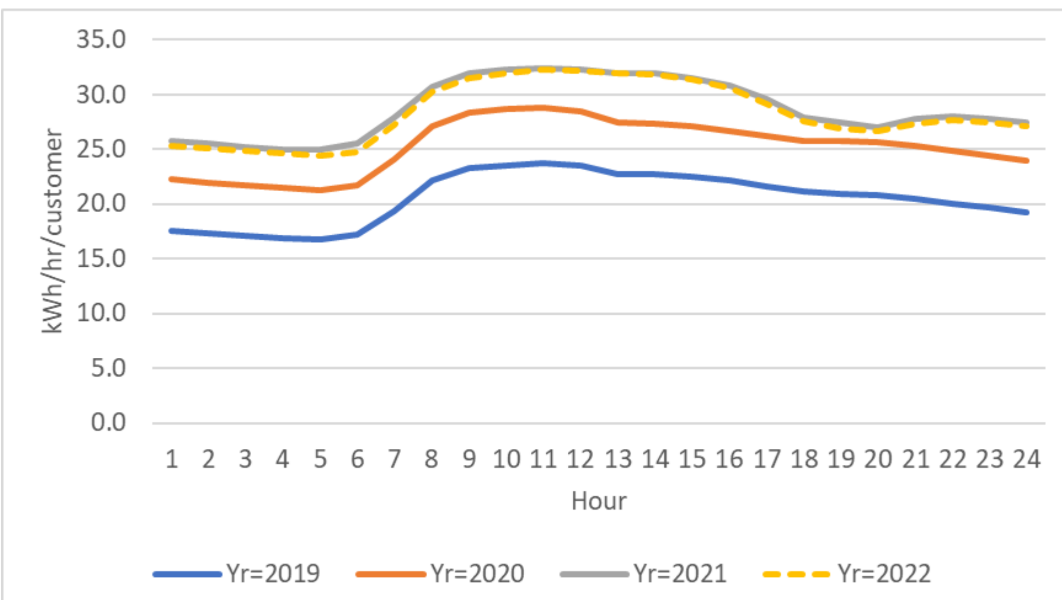


Figure E.10: Summer Average Non-Holiday Weekday Usage by Year, AG-5C to AG-C Non-NEM

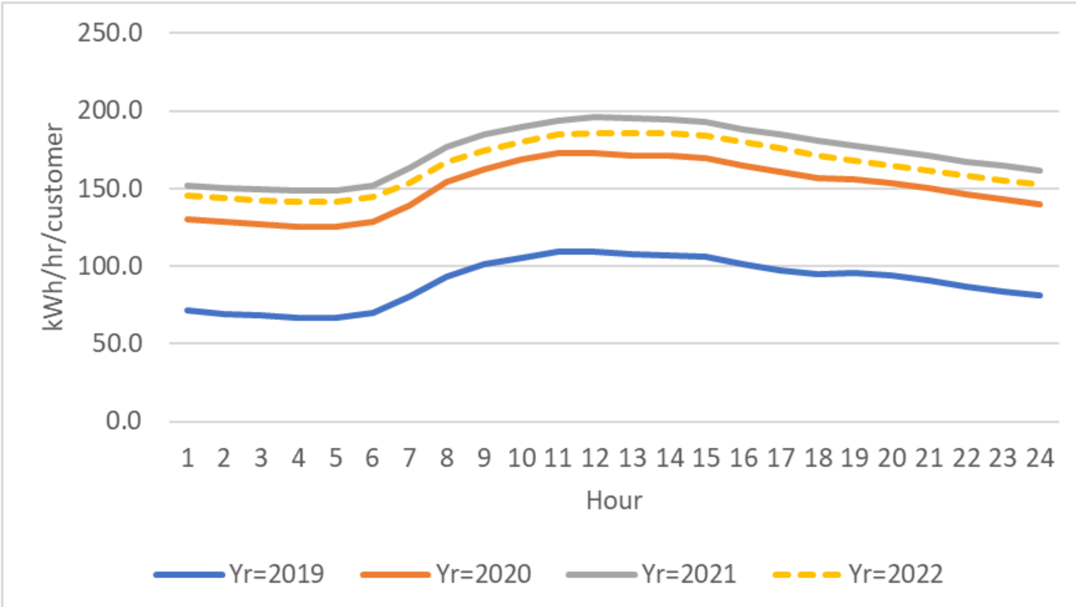


Figure E.11: Summer Average Non-Holiday Weekday Usage by Year, A1 TOU to B-1 NEM

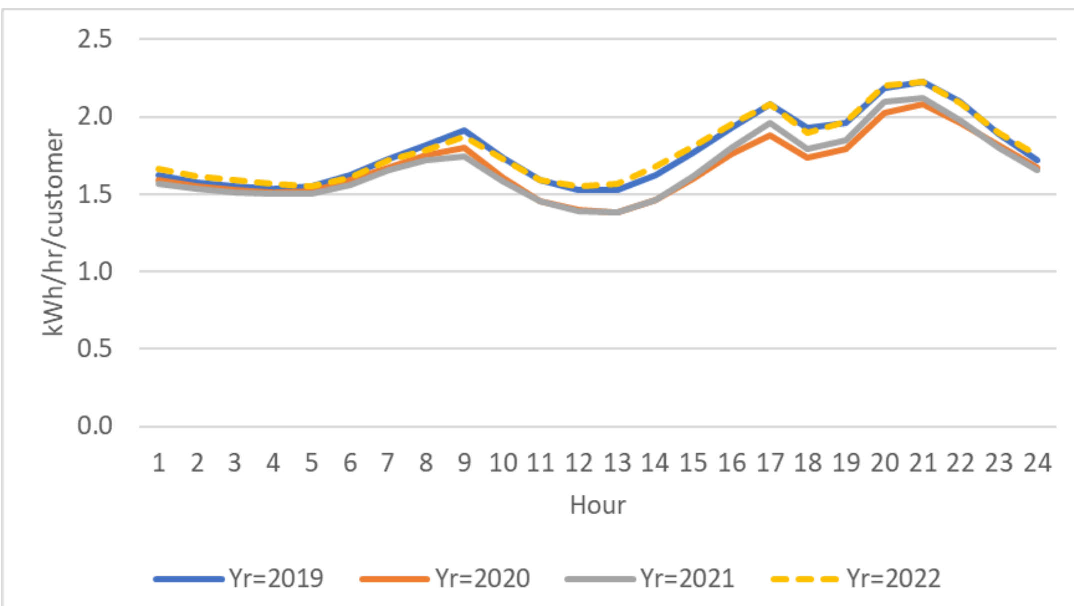


Figure E.12: Summer Average Non-Holiday Weekday Usage by Year, A-6 to B-6 NEM

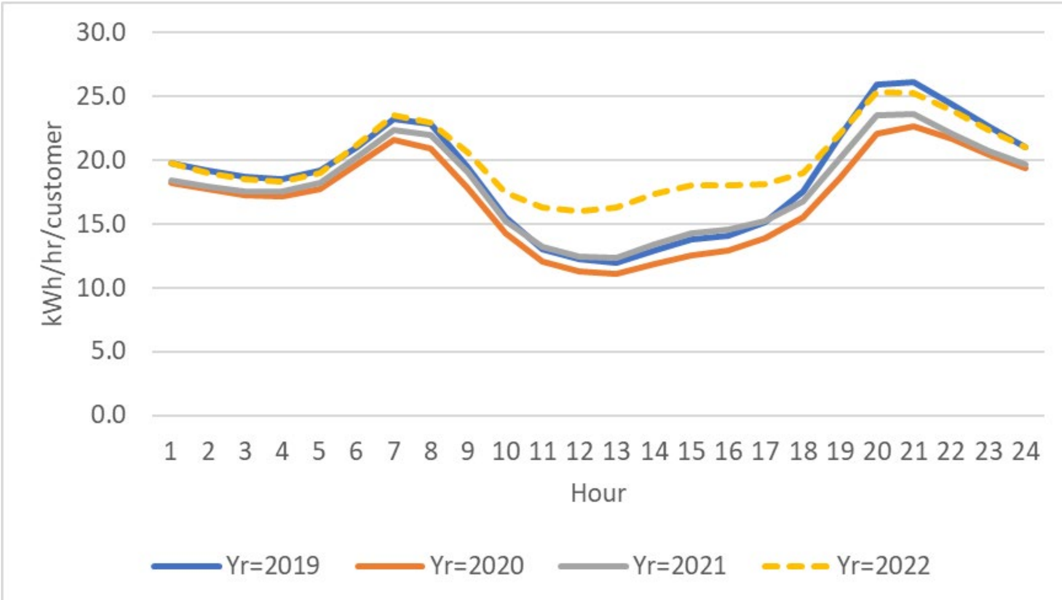


Figure E.13: Summer Average Non-Holiday Weekday Usage by Year, A-10 TOU to B-10 NEM

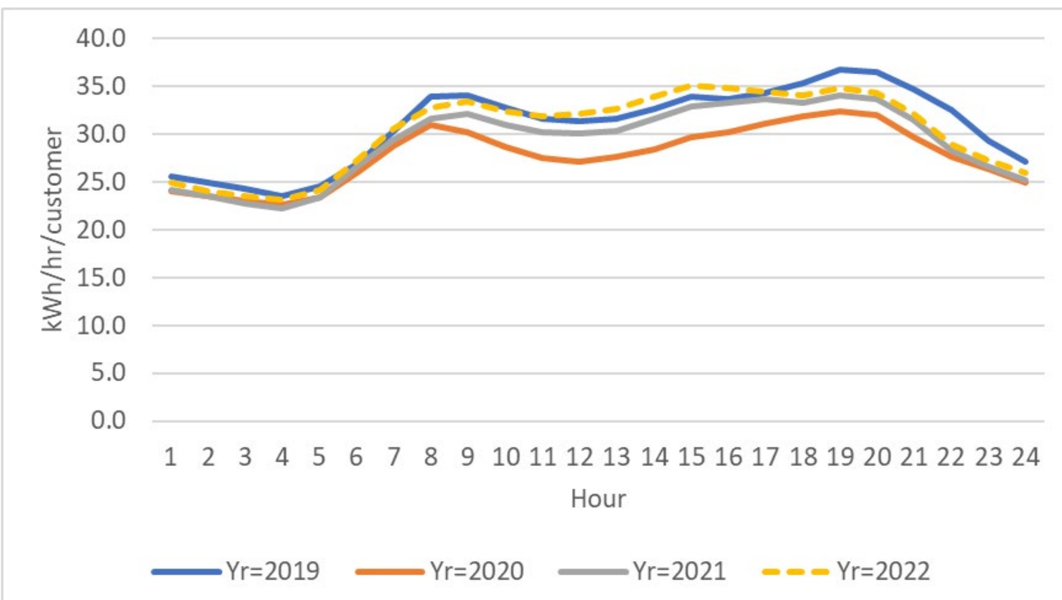


Figure E.14: Summer Average Non-Holiday Weekday Usage by Year, E-19 to B-19 NEM

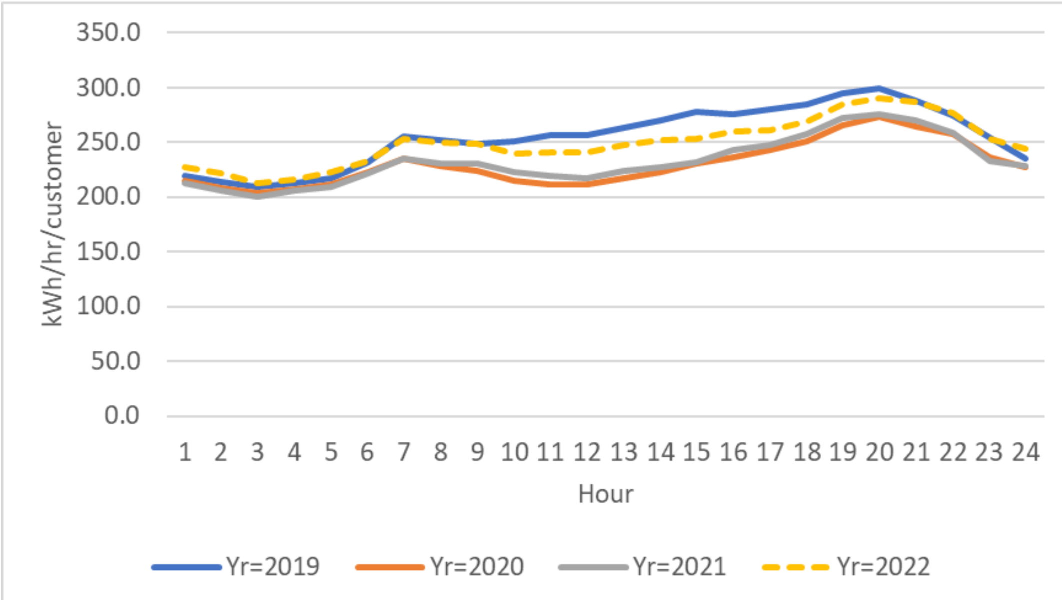


Figure E.15: Summer Average Non-Holiday Weekday Usage by Year, AG-4A to AG-A1 NEM

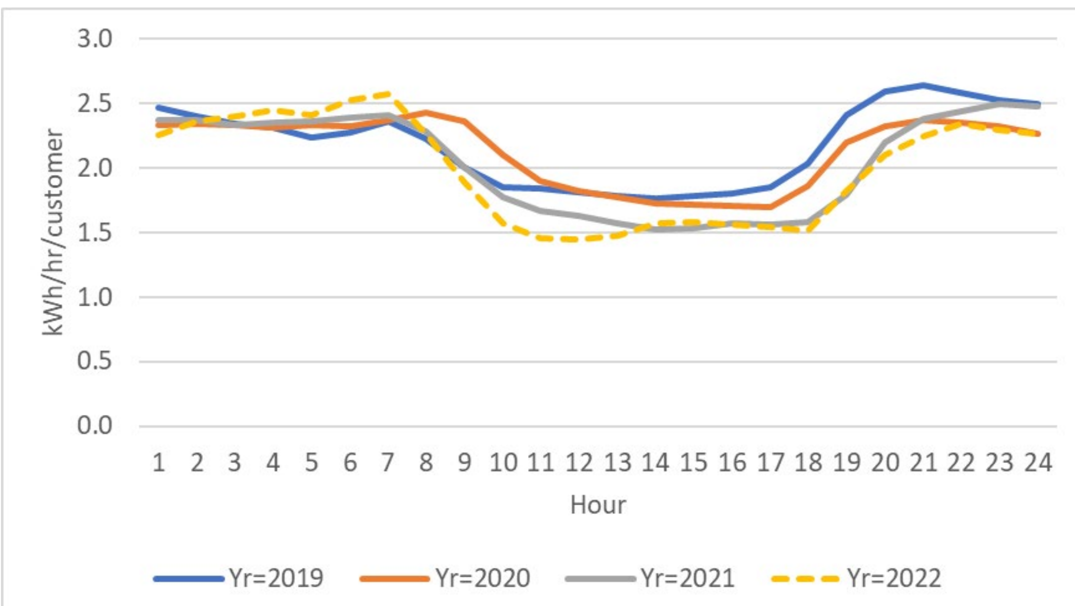


Figure E.16: Summer Average Non-Holiday Weekday Usage by Year, AG-4B to AG-B NEM