TECH POPULATION-BASED PATHWAY IMPACT REPORT

FINAL REPORT

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I. EXECUTIVE SUMMARY

Building energy consumption is responsible for a quarter of California's greenhouse gas (GHG) emissions. To address these emissions, the California Legislature passed Senate Bill (SB) 1477, which calls on the California Public Utilities Commission (CPUC) to develop the Technology and Equipment for Clean Heating (TECH) Initiative. The TECH Initiative is designed to accelerate market adoption of low-emissions space conditioning and water heating technologies for existing single and multifamily residential homes across California. Given the potential of heat pump technologies to reduce GHG emissions, the CPUC envisions them as part of the state's strategy for achieving carbon neutrality by 2045. The TECH Initiative is designed to reduce market barriers and accelerate the long-term adoption of high-efficiency heat-pump technologies while transforming the market and achieving cost-effectiveness and regulatory simplicity.

The $120 million TECH Initiative was launched in December of 2021, and most incentives were subscribed to by early summer 2022. The initial $120 million was funded by Cap-and-Trade gas utility auction proceeds. The California Energy Trailer Bill, released on August 31, 2022, allocated an additional $50 million for TECH in 2023 from the California general fund. In the 2023-24 state budget, an additional $95 million for TECH was budgeted from the California Greenhouse Gas Reduction Fund (GGRF) state auction proceeds.[1]

Market transformation of residential space and water heating is expected to have significant impacts on energy consumption, customer energy bills, and greenhouse gas emissions in California.[2] As such, SB 1477 requires that TECH Initiative metrics include projected utility bill savings and the cost per metric ton of avoided greenhouse gas (GHG) emissions. The study team addressed the following research questions to quantify and contextualize these and related impacts among participants in the TECH Initiative:

- What are the GHG emissions reductions and cost per metric ton (MT) of avoided GHG associated with the TECH Initiative?
- What are the electric and gas energy impacts associated with the TECH Initiative? What are the impacts associated with customer segments including by climate zone and among customers that are net-metered, low-income, live in a disadvantaged community, or are on a time-of-use rate?
- With what degree of certainty can whole house meter data produce electric energy impact results? What project features produce high degrees of uncertainty?
- What are the average changes in energy costs for TECH Initiative participants? What are the average changes in energy costs for subgroups of interest (e.g., low-income customers, participants in DACs)?

Opinion Dynamics (the study team) is the independent third-party evaluator of the TECH Initiative, researching program impacts, market effects, policy developments, and technology advances. This study evaluates the impacts of the TECH Initiative for the first phase of projects funded by Cap-and-Trade gas utility auction proceeds (July 2021-July 2023) and for participants receiving electric service from PG&E, SCE, or SMUD and gas service from PG&E or SoCalGas.[3] The study

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[1] Please note that throughout this evaluation report, we refer to "Cap-and-Trade" funds. These references refer specifically to the initial $120 million of funding associated with the Cap-and-Trade gas utility auction proceeds. GGRF funds are also associated with cap-and-trade, but with cap-and-trade activities of the whole GHG-emitting market, not just those of the gas utilities.

[2] See Synapse Energy Economics, 2018. Decarbonization of Heating Energy Use in California Buildings: Technology, Markets, Impacts, and Policy Solutions. Prepared for the Natural Resources Defense Council. https://www.synapse-energy.com/sites/default/files/Decarbonization-Heating-CA-Buildings-17-092-1.pdf. Also, see E3, 2019. Residential Building Electrification in California: Consumer Economics, Greenhouse Gases, and Grid Impacts. Prepared for SCE, LADWP, and SMUD. https://www.ethree.com/wp-content/uploads/2019/07/CA_Res_Building_Electrification_Final_Presentation.pdf

[3] SDG&E and LADWP are excluded from the study scope due to unavailable or unreliable consumption data as discussed further in the Methods section.

team collected customer advanced metering infrastructure (AMI) interval consumption data and monthly billing gas consumption data for TECH participants and a comparison group of matched nonparticipants from the California Energy Commission (CEC) Snowflake Database. Using two-way fixed-effect, difference-in-differences (D-in-D) panel regression models,[4] we estimated the average per-participant electricity and natural gas energy impacts, electricity load shape impacts, and peak electricity demand impacts of participation in the TECH Initiative. Impacts were also estimated by measure type and climate zone, and for key customer segments including net metered customers, CARE/FERA-enrolled customers, and time-of-use (TOU) rate customers. Based on the energy impact estimates, we also derived the average GHG emissions and customer bill impacts of TECH participation.

1.1 KEY FINDINGS

Between July 2021 and July 2023, over 10,000 TECH participants completed projects supported by Cap-and-Trade funds. Most participants installed a central heat pump (58% of sites). About one in four participants (26%) installed a ductless heat pump, and one in five (21%) installed an HPWH.[5] Throughout the report, we refer to these three specific measures when reporting results. We use the term "heat pump" to mean generic heat pump technology and "heat pump HVAC" when referring to both central and ductless heat pumps. The reported program-level impacts represent the mix of measures installed during the evaluation period, however, these measures produce unique energy and demand impacts, and we recommend readers review the measure-level results to understand this variation.

Based on the projects completed during the evaluation period, the TECH Initiative achieves a net reduction in GHG emissions from space and water heating and a negligible decrease in customer energy bills. In a normal weather year (i.e., under typical weather conditions as defined by the California Measurement Advisory Council rather than the actual weather during the evaluation period), an average TECH participant reduces emissions by 0.73 metric tons of CO_2-e (17%), which is the equivalent of 81 gallons of gasoline consumed.[6],[7] Across all participants in the evaluation period, the TECH Initiative achieves over 7,000 avoided metric tons of CO_2-e per year which is equivalent to 832,925 gallons of gas consumed. To put it into further perspective, the annual GHG emissions reduction across all TECH participants is equivalent to taking about 1,700 gasoline-powered passenger vehicles off the road for the year.[8] Based on a review of program administration costs in 2022 and incentives paid to participants, the program achieved a cost per unit of avoided emissions of $268 per metric ton of avoided CO_2-e. The average TECH participant experiences a $11 decrease in annual energy bills, but the annual change in bills is not statistically different from zero. Based on the confidence interval, there is a 95% likelihood that the average utility bill change for a TECH participant is between a $37 decrease and a $15 increase each year. Across all participants in the study population, the TECH Initiative results in about $100,000 of utility bill reductions per year (Figure 1).

[4] The two-way fixed-effect D-in-D regression model is the standard approach for estimating energy impacts when the timing of intervention varies between participants. See Bertand, Marianne, Esther Duflo, and Sendhil Mullainanthan 2004. "How Much Should We Trust Difference-in-Differences Estimates?" The Quarterly Journal of Economics 119: 249-275. "Two-way" refers to the inclusion of customer and time-period fixed effects in the model.

[5] Values sum to over 100% because a small number of participants received a ductless and central heat pump or a heat pump HVAC and a HPWH.

[6] The results of an "average TECH participant" reflect the mix of measures adopted during the evaluation period, as well as the mix of participant and housing characteristics such as baseline equipment, housing stock, climate zone and corresponding heating and cooling needs, and incidence of net metered participants.

[7] The estimate that each gallon of gasoline emits about 8.89 kg of CO_2 is sourced from the U.S. Environmental Protection Agency (EPA). This value is detailed in the EPA's Greenhouse Gas Equivalencies Calculator: Greenhouse Gas Equivalencies Calculator | US EPA and the GHG Emission Factors Hub: GHG Emission Factors Hub | US EPA.

[8] The EPA estimates that a typical gasoline-powered passenger vehicle emits 4.2 metric tons of CO_2-e per year. https://www.epa.gov/energy/greenhouse-gases-equivalencies-calculator-calculations-and-references

Figure 1. Annual TECH Initiative GHG and Bill Impacts

Metric	Average Per Participant	Total All Participants
GHG Emissions (MT CO_2-e)	- 0.73* (- 17.2%)	- 7,478
Customer Net Energy Bills ($)	- $11	- $116,083

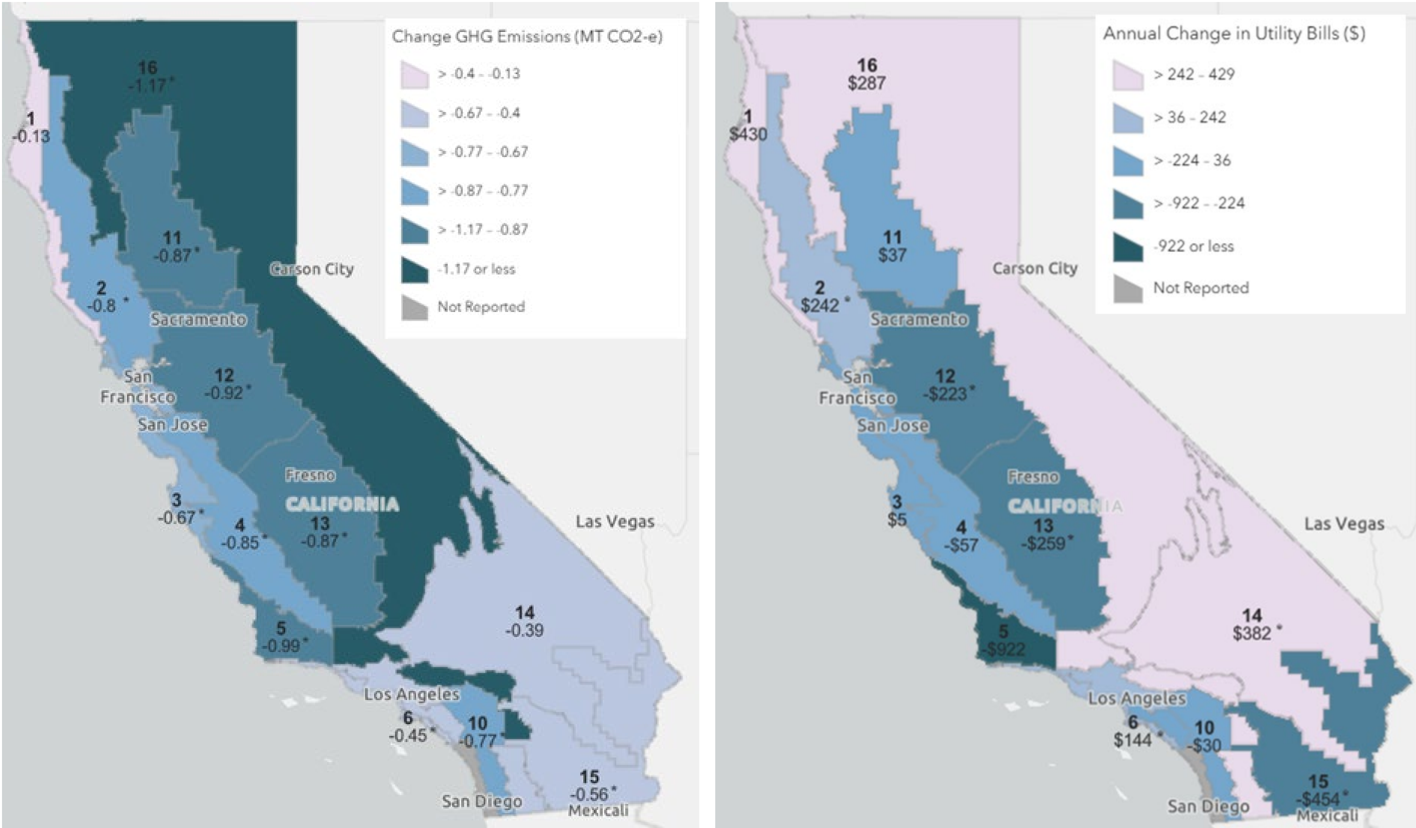
*Results are statistically significant at 95% confidence level.

Note: All estimates are for a normal weather year (CZ2022). Annual customer utility bill impacts are not statistically different from zero.

Participant GHG impacts vary by customer subsegment and climate zone. In all climate zones, there is a net reduction in GHG emissions, but the magnitude varies. Climate zones in northern and central California with higher space heating energy consumption tend to achieve greater GHG emissions reductions than those in southern and coastal California, where heating energy consumption is lower (Figure 2).

Participant energy bill impacts also vary widely by climate zone, with the average TECH participant experiencing a decrease in their annual energy bills in some climate zones and an increase in others. Bill increases tend to be greatest in northern climate zones and inland climate zones throughout the state, whereas customers in the southern-most and central climate zones tend to save on their energy bills. The variation in customer energy bill impacts across the state is a function not only of variable energy impacts but also due to differences in energy prices. For example, there are differences in rate structures and pricing between utility territories and differences in the relative number of participants that are net metered or receive a low-income discount on their bill (both of which can mitigate bill increases from electrification) in each climate zone (Figure 2).

Figure 2. Average Annual Per-Participant GHG and Bill Impacts by Climate Zone

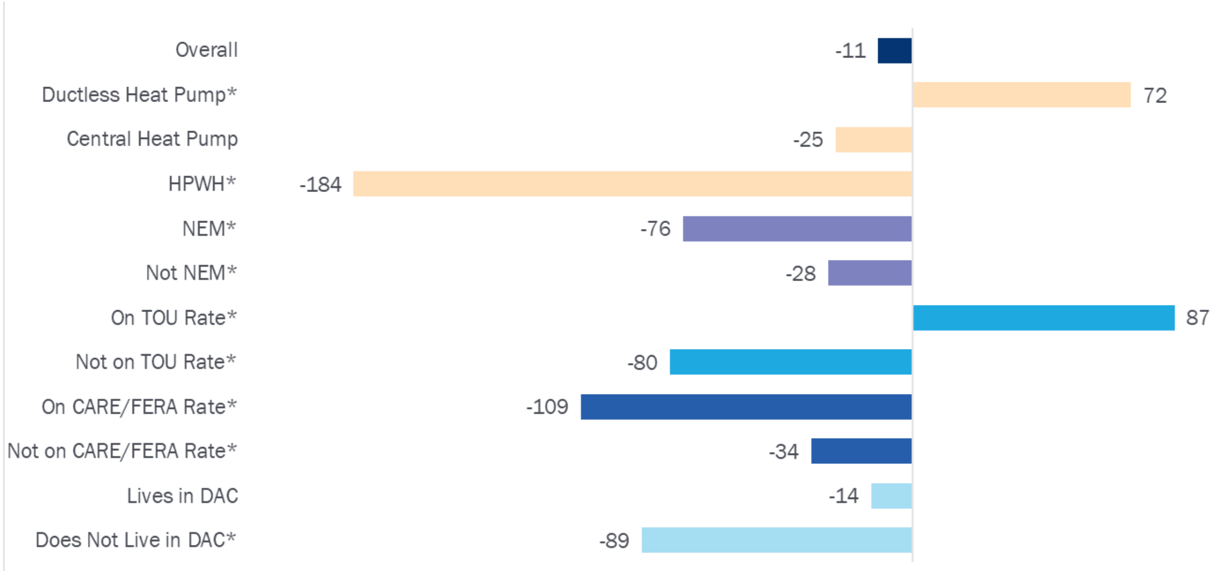


*Results are statistically significant at 95% confidence level.

Note: Impacts are estimated for the CZ2022 normal weather year. The following climate zones overlap with the service territory of utilities excluded from the analysis sample due to missing or unreliable data. SDG&E: CZ6, CZ7, CZ8, CZ10, CZ14, and CZ15. LADWP: CZ6, CZ8, and CZ9.

Participant energy bill impacts differ based on the measure received and customer segment. Participants receiving a HPWH experience the largest annual bill savings ($184 per year) while those receiving a ductless heat pump experience a bill increase of $72 per year, on average. Central heat pump participants may experience a modest decrease in annual utility bills ($25 on average), but these are not statistically different from zero, suggesting that in general the bill impacts for this measure are negligible. The average TECH participant receiving a low-income bill discount saves about $109 in annual utility bills, while the average net-metered participant experiences a $76 annual reduction in utility bills. Participants on TOU rates tend to experience large bill increases compared to other segments analyzed. Figure 3 summarizes bill impacts by measure and customer segment.

Figure 3. Average Annual Per-Participant Net Energy Bill Impact ($) by Measure and Segment



*Results are statistically significant at 95% confidence level.

Note: TOU/Non-TOU and NEM/Non-NEM gas bill impacts represent an average across all participants, as these impacts could not be separately calculated for gas. Segment-level bill impacts reflect the mix of rate codes and proportion of participants receiving a CARE/FERA discount within that segment.

The changes in GHG emissions and customer energy bills are due to TECH's significant effects on yearly electricity and natural gas consumption. In a normal weather year, electricity consumption per TECH participant increases by an average of 1,451 kWh, or 17%. Natural gas consumption falls by an average of 165 therms, or 38%.[9] The average net change in energy consumption across fuels per participant is -11.6 MMBtu or -16%. Most of the increase in electricity consumption and the decrease in gas consumption occur during the winter and shoulder seasons. During the summer resource adequacy (RA) window hours, demand decreases by 0.07 kW or 4% for the average TECH participant. Figure 4 summarizes the annual TECH Initiative electric and natural gas consumption and peak electric demand impacts.

[9] All impacts were adjusted to reflect a normal weather year. The study team leveraged CALMAC's CZ2022 weather files as the typical weather year. If for a given site, the typical weather year file was unavailable for the closest weather station from which historical actual weather data were derived, the study team leveraged CZ2018 data.

Figure 4. Annual TECH Initiative Impacts

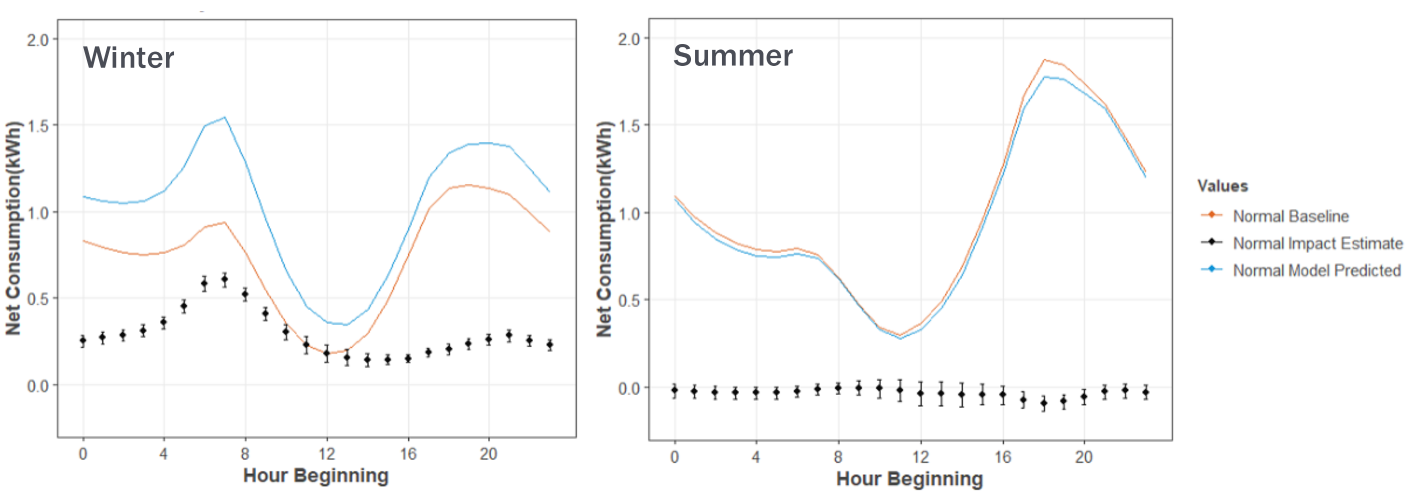
Metric	Average Per Participant	Total All Participants
Electric Consumption (kWh)	1,451* (17.2%)	14,796,760
Gas Consumption (therms)	- 165* (- 38.2%)	- 1,683,471
Energy Consumption (MMBtu)	- 11.55* (- 16.1%)	- 117,818
Summer Electric Peak Demand (kW)	- 0.07* (- 4.4%)	- 749

*Results are statistically significant at 95% confidence level.

Note: All estimates are for a normal weather year (CZ2022). The change in electric peak demand refers to the change in average hourly consumption during the RA window, between 4:00 p.m. – 9:00 p.m. on summer weekdays. Impacts are provided as a percentage of baseline in parentheses.

Electrification of space and water heating also changes when electricity is consumed during the day (Figure 5). In the winter, TECH participation results in a shift of daily peak electricity demand from afternoon to morning. TECH participation increases the existing peak in electricity demand on weekday afternoons but also causes a new daily mid-morning peak. In the summer, TECH participation results in a small average decrease in electricity consumption per participant across most weekday hours. However, summer impacts vary across climate zones. In climate zones with a high penetration of central air conditioning prior to heat pump adoption, TECH participation decreases electricity consumption in most hours. TECH increases hourly electricity consumption in climate zones where central air conditioning is less common.

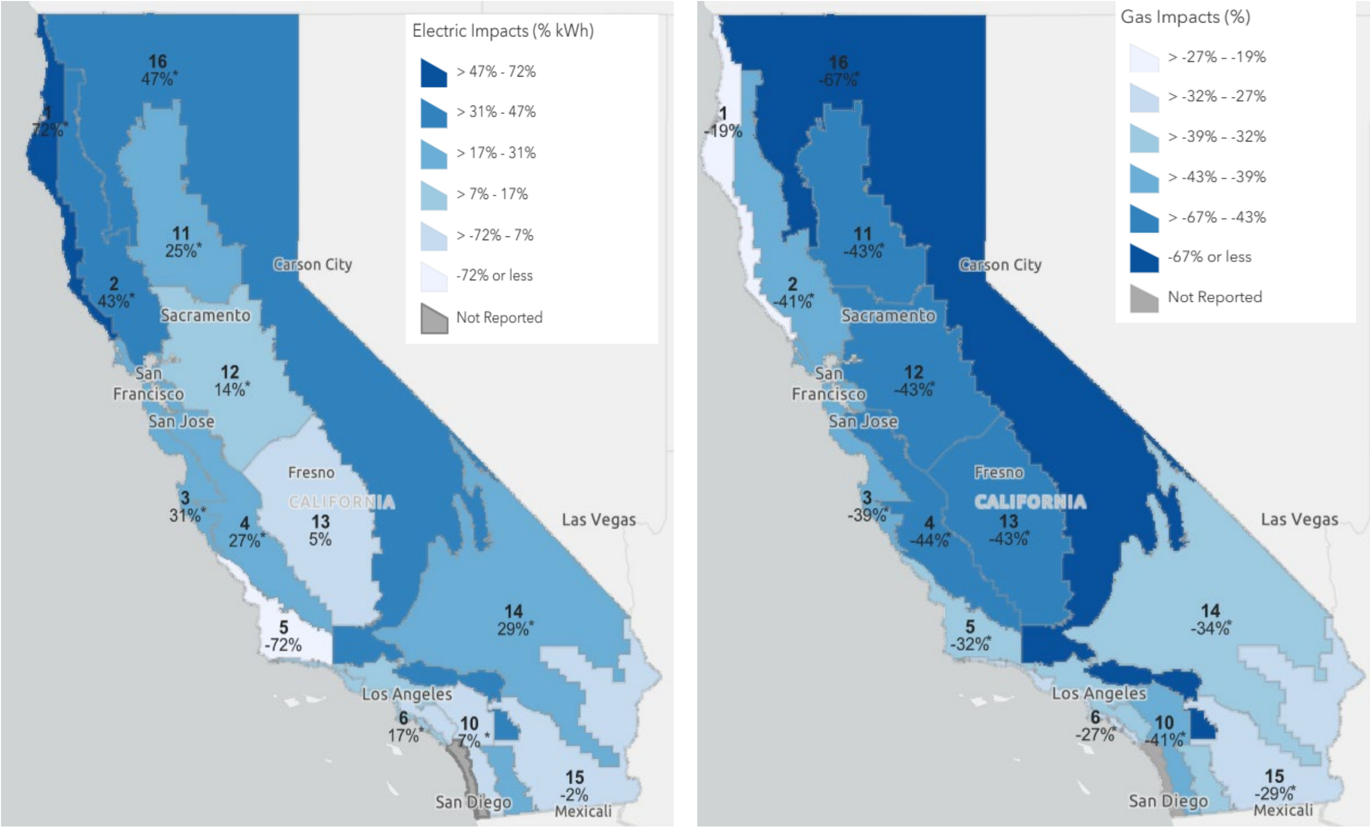
Figure 5. Average Winter and Summer Weekday Electric Load Shapes and Impacts



Note: Normal weather estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant interval electricity consumption data. Error bars show 95% confidence intervals. Estimates are defined as follows: (1) Normal baseline: Weather-normalized modeled baseline, or normal weather electricity consumption that would have happened in the absence of the TECH Initiative; (2) Normal impact estimate: Weather-normalized estimate of energy impacts due to TECH participation. (3) Normal model predicted: Weather-normalized modeled consumption following TECH participation.

Figure 6 illustrates the variation in energy impacts across the state. On average, the TECH Initiative increases electric energy consumption in cooler climate zones, which have greater heating needs and in which a greater share of participants add summer cooling load upon installation of their heat pump. In warmer climate zones, the increases in electric consumption are more modest, and in some climate zones, overall electric energy consumption decreases. Likewise, the decrease in natural gas consumption is larger in cooler climate zones and smaller in warmer climate zones (Figure 6).

Figure 6. Average Annual Energy Impact Per Participant by Climate Zone



*Results are statistically significant at 95% confidence level.

Note: Impacts are estimated for the CZ2022 normal weather year. The following climate zones overlap with the service territory of utilities excluded from the analysis sample due to missing or unreliable data. SDG&E: CZ6, CZ7, CZ8, CZ10, CZ14, and CZ15. LADWP: CZ6, CZ8, and CZ9.

The changes in energy consumption produced by the TECH Initiative depend largely on the measure installed. Ductless heat pumps produce the greatest increase in electric energy consumption and the largest decrease in gas consumption, whereas central heat pumps produce the smallest change in energy consumption for both fuels. The measures also have different impacts on when energy is consumed. HPWHs have a negligible impact on peak demand during the RA window, whereas for central heat pumps there is a reduction in peak demand in this period. This is likely because many central heat pump participants replaced an existing, less efficient central cooling system (Figure 7).

Figure 7. Annual TECH Initiative Impacts by Measure

Metric	Central Heat Pump	Ductless Heat Pump	HPWH
Electric Consumption (kWh)	1,064* (11.2%)	2,123* (28.7%%)	1,845* (27.6%)
Gas Consumption (therms)	- 154* (- 36.6%)	- 180* (- 41.4%)	- 164* (- 35.1%)
Energy Consumption (MMBtu)	- 11.81*	-10.72*	-10.05*
Summer Electric Peak Demand (kW)	- 0.16* (- 7.5%)	0.06* (5.6%)	- 0.01* (- 0.9%)

*Results are statistically significant at 95% confidence level.

Note: All estimates are for a normal weather year (CZ2022). The change in electric peak demand refers to the change in average hourly consumption during the RA window, between 4:00 p.m. – 9:00 p.m. on summer weekdays. Impacts are provided as a percentage of baseline in parentheses.

Many TECH participants (27% compared to an estimated 10% of customers statewide) are net-metered.[10] These participants have different energy consumption patterns and impacts than participants without solar PV because their solar production partially offsets the increased electric energy consumption from electrifying their space or water heating. Figure 8 compares the electric energy impacts of NEM participants and non-NEM participants. NEM participants tend to experience a smaller increase in electric consumption, but this increase represents a larger proportion of their baseline net consumption than for non-NEM participants. During the summer peak period, NEM participants tend to experience a 14% reduction in electric demand whereas the change for the typical non-NEM participant is negligible.

[10] Throughout the report, the study team refers to NEM participants when discussing TECH participants with solar PV. These participants were identified based on their net metering status with their electric utility. The study team has no way to identify non-net-metered customers with solar PV and understands this would be rare among residential customers in the study period.

Figure 8. Annual TECH Initiative Electric Impacts for NEM vs. Non-NEM Participants

Metric	NEM	Non-NEM
Electric Consumption (kWh)	1,081* (26.5%)	1,544* (14.9%)
Summer Electric Peak Demand (kW)	- 0.21* (- 14.1%)	- 0.02* (- 1.0%)

*Results are statistically significant at 95% confidence level.

Note: All estimates are for a normal weather year (CZ2022). The change in electric peak demand refers to the change in average hourly consumption during the RA window, between 4:00 p.m. – 9:00 p.m. on summer weekdays. Impacts are provided as a percentage of baseline in parentheses.

1.2 CONCLUSIONS AND RECOMMENDATIONS

Based on our findings, the study team offers the following conclusions and recommendations.

Overall Impacts

- **Conclusion:** The energy impacts of the TECH Initiative lead to a substantial net reduction in GHG emissions statewide (17%) and in all climate zones annually. The avoided GHG emissions from reduced natural gas consumption are nearly four times the new GHG emissions from increased electric energy consumption annually.
- **Conclusion:** There is not a statistically significant change in net energy bills for the average participant. However, customers in some climate zones, particularly the southern-most and central climate zones, experience bill savings on an annual basis. Participants on a TOU rate at the time of their TECH participation experience an increase in their energy bills ($87 per year on average), whereas those not on a TOU rate experience savings ($80 per year on average). All bill impacts reflect the CARE/FERA discount that would be received by eligible customers within a given segment.
  - **Recommendation:** Electric utilities should encourage TECH TOU rate participants, particularly those who install central or ducted heat pumps, to switch to a TOU rate designed for electrification customers to minimize the bill impacts of electrification. TECH participants on a standard TOU rate pay a high price for electricity consumed at peak times and now use electricity for space heating instead of cheaper natural gas.
  - **Recommendation:** Participation in demand response programs may also help TECH participants to manage their bills (i.e., in the case of daily load shifting programs) or to offset some of the bill increases from electrification (i.e., for programs with annual or seasonal participation incentives).
- **Conclusion:** On average, participation in the TECH Initiative leads to substantial reductions in natural gas energy consumption while increasing electric energy consumption. The typical TECH participant experiences a 38% reduction in their natural gas consumption and a 17% increase in their electric consumption annually.
- **Conclusion:** The increase in electric energy consumption is mostly driven by increases in space heating in the winter and, to a lesser extent, the shoulder season. Summer electric energy impacts are small on average but vary widely between customer segments as discussed further below. The impact of heat pump technology on summer electricity consumption is highly sensitive to whether participants replace an existing central cooling system or add a new cooling load.

Impacts by Measure

- **Conclusion:** Participants adopting central and ductless heat pumps have different energy impacts. Central heat pump participants experience the smallest annual electric consumption increase, whereas ductless heat pump participants experience the largest annual electric consumption increase, and this is largely attributable to differences in their baseline space conditioning equipment. Winter impacts are similar for central and ductless heat pumps for both electricity and gas. However, due to the differences in summer electric energy impacts, central heat pump participants tend to experience a modest reduction in their energy bills, whereas ductless heat pump participants experience an increase.
  - **Recommendation:** In future studies, consider separately estimating energy impacts as a function of the participant's pre-existing air conditioning to disentangle summer electricity efficiency savings from electric load growth due to adding space cooling. This would allow for better planning of the impact of the TECH Initiative if the levels of pre-existing air conditioning penetration among future participants differ from the current evaluated population.[11]
- **Conclusion:** The adoption of heat pump technology, particularly heat pump HVACs, impacts electricity demand during peak and off-peak periods. During the RA window, the average participant experiences a reduction in demand of about four percent. The reduction tends to be greater in warm climate zones where participants are more likely to have air conditioning before TECH participation. In cooler climate zones with lower baseline space conditioning, there tends to be an increase in demand during the RA window. In the winter months, TECH participation leads to a new morning electric peak due to the use of heat pump HVACs for space heating, which is greater than the afternoon winter peak, although still smaller than the summer peak in most cases.
  - **Recommendation:** As more customers electrify their homes with central and ductless heat pumps, grid planners should prepare for increased summer electric load in regions that previously had lower air conditioning penetration and for new morning peaks in daily winter load due to space heating electrification.
  - **Recommendation:** The Program administrator should continue and expand efforts to pair heat pump technology installations with smart thermostat controls and incentivize TECH participants to enroll in demand response and other load flexibility offerings to help manage the growth in heating and cooling loads.
- **Conclusion:** HPWHs have less impact on peak demand than heat pump HVAC measures, but still lead to substantial increases in energy consumption that are spread more evenly throughout the day and the year. In fact, on average, HPWH participants experience a 27% increase in electric energy consumption annually, only slightly less than ductless heat pump participants and substantially more than participants receiving a central heat pump.
  - **Recommendation:** Continue targeting and enrolling HPWH participants in HPWH-focused DR programs for daily load shifting away from peak periods such as the PG&E WatterSaver and SCE SmartShift Rewards programs.

Key Customer Segments

The study team estimated impacts by climate zone and among customers that are net-metered, low-income, live in a disadvantaged community, or are on a time-of-use rate.

- **Conclusion:** The TECH Initiative energy impacts, GHG emissions, and bill impacts vary between climate zones, measures, and customer segments such as customers on CARE or FERA and TOU rates. The impacts are also sensitive to baseline home attributes such as existing central air conditioning and net metering. In addition, the

[11] This analysis was not pursued during the current evaluation period due to incomplete information on baseline space conditioning equipment in the tracking data when the evaluation was initiated. This issue has since been resolved, and we expect these data to be readily available for future evaluations.

GHG impacts depend on the forecasted GHG emission intensity of the electric grid in each region, and the bill impacts depend on current electricity and natural gas tariffs.

- **Recommendation:** When designing future electrification policies and programs, California policymakers should consider that there is significant variation in energy, GHG, and bill impacts of residential space and water electrification. The impacts for some subpopulations as defined by climate zone or other customer attributes may be very different from the population mean impact.
- **Recommendation:** TECH Initiative program administrator and policymakers should be cautious about assuming that future program impacts will be the same as those observed during this evaluation. Changes in the composition of the participant population or utility tariffs could lead to different impacts.

- **Conclusion:** A disproportionate share of TECH participants (27% vs. approximately 10% statewide) are net-metered, which often makes residential electrification more financially attractive. The evaluation period generally precedes the NEM 3.0 tariff, so net-metered TECH participants in this study were subject to NEM 1.0 or NEM 2.0 tariffs, in which the net metering credit is equal to the per-kWh cost of electricity.
  - **Recommendation:** Solar panels can be a catalyst for customer interest in heat pump technology, as the two systems are complementary. As resources allow, the program administrator should continue to explore collaboration opportunities with solar companies to leverage existing customer relationships and streamline outreach efforts, potentially increasing adoption rates. Additionally, bundling incentives or providing joint educational resources could enhance the value proposition, making the transition to an all-electric home more attractive.
- **Conclusion:** The TECH Initiative projects funded by Cap-and-Trade gas utility auction proceeds and represented in this report were primarily composed of market rate single family incentives, and as such reached a limited number of low-income customers and customers living in disadvantaged communities (DACs).[12] Although the TECH Initiative reached a limited number of low-income participants during the evaluation period, on average, those that participated experienced bill savings and their gas and electric energy consumption impacts were more modest than those customers that do not receive a CARE or FERA discount. However, DAC participants experienced energy impacts similar to those outside DACs, and their net bill decreases were less than those outside DACs.
  - **Recommendation:** Continue to monitor the TECH participation impacts on energy consumption and net energy bills for participants residing in DACs to avoid burdening customers in these areas with unaffordable energy bills. Consider whether differences in housing stock in some DACs (i.e., a disproportionate presence of older homes) might cause these participants to benefit from weatherization or other services as part of their TECH participation.[13] If results from the ongoing TECH LI Pilot show participants avoid unaffordable energy bills, it might be possible for the LI TECH Pilot to reach more participants by working with the Energy Savings Assistance (ESA) Program for weatherization.[14]

[12] Disadvantaged communities refers to those communities and geographic areas identified as such by the California Environmental Protection Agency in accordance with California Senate Bill 535. We include DACs identified under both CalEnviroScreen 3.0 and CalEnviroScreen 4.0. Low income customers and those living in DACs were a focus of TECH Initiative multifamily efforts and collaborations with existing low-income direct install programs that primarily occurred after the evaluation period and are not represented in these impacts.

[13] For more details on this see: Bastian, H. and C. Cohn, October 2022. "Ready to Upgrade: Barriers and Strategies for Residential Electrification." American Council for an Energy-Efficient Economy.

[14] The TECH Low-Income Heat Pump Adoption Pilot ("TECH LI Pilot") was designed to complement existing low-income programs, including the Energy Savings Assistance (ESA) program and San Joaquin Valley Disadvantaged Community Pilot. The TECH LI Pilot fills the gap between what is needed to install a heat pump—such as electrical panel upgrades and relocations, removing old HVAC systems, sealing leaks in ducts, walls, and roofs, and building outdoor enclosures for HPWHs—and what is paid by TECH's incentives for heat pump equipment and installation. In coordination with ESA, the TECH LI Pilot may help customers avoid unaffordable electric bills by reducing energy consumption via weatherization before adding heat pumps. Effective weatherization also has the potential to reduce the price of the heat pump purchase because homes with tighter envelopes have lower heating and cooling loads that can be served by smaller heat pumps.

Data and Measurement

- **Conclusion:** The CEC Snowflake Database is an important resource designed to enable timely and innovative studies to advance climate and energy initiatives across California. The study team benefited from the ability to access this resource but was unable to estimate the impact of TECH Initiative participation for customers in some utility service territories due to missing or incomplete data.
  - **Recommendation:** Continue to build out the CEC Snowflake Database and ensure timely and complete access to data across utilities to realize the potential for efficiencies and insights from the database.
- **Conclusion:** A substantial number of project claims were excluded from the analysis due to missing or inaccurate utility identifiers needed to connect project information to meter data for one or both fuels. Twelve percent of claims could not be associated with an electric premise and 16% could not be associated with a gas premise.
  - **Recommendation:** To ensure estimates of future TECH impacts are as representative as possible, consider recording each participant's utility and premise identifier for both fuels as part of the program tracking data. This would help to increase the number of participants included in the sample frame in future evaluations and can also facilitate a better understanding of cross-fuel impacts. For example, NEM status is typically only associated with the electric account. By consistently tracking both the gas and electric premise identifiers for a given participant, future evaluations could separately estimate the gas energy impacts of NEM participants.
- **Conclusion:** Due to data limitations, the analysis did not include an assessment of or accounting for cross-participation of TECH participants in other utility programs during the evaluation period. As a result, if participants took part in other decarbonization or energy efficiency programs at a different rate than similar nonparticipants, the impact of these interventions is not reflected in the TECH Initiative impacts.
  - **Recommendation:** The evaluator and the program administrator continue efforts to compile information on other program participation among TECH participants that can be readily connected to TECH participant tracking data. Tracking this information will enable deeper insights into the heat pump market, support assessment of incentive layering, and position future impact evaluations to assess how exogenous increases or decreases in energy consumption due to participation in other programs affect TECH Initiative impacts.
- **Conclusion:** Understanding how often and which customers retain their natural gas service following TECH participation could enhance the rigor of the impact analysis and support policy and planning efforts by contextualizing the findings.
  - **Recommendation:** For future studies, consider collecting data on whether customers go "all-electric" due to their TECH participation and/or conducting additional analysis to identify customers that closed their gas accounts following TECH participation. Including time-varying information in the CEC Snowflake database on individual customer baseline allowances (i.e., all-electric baselines, SCE's HPWH baseline adjustment) could facilitate this analysis. By differentiating between customers with missing gas consumption data versus inactive gas service, future studies would be able to estimate separate gas consumption baselines and bill impacts for these customers. These data will also allow stakeholders to monitor the market transformation and differences between participants who retain and those who close their gas service following TECH Initiative participation.
- **Conclusion:** The study team separately estimated electric energy impacts for net-metered participants using net energy consumption data and a matched comparison group of similar customers. The study team found that TECH net-metered participants experienced a smaller average increase in annual electricity consumption and saved more on their utility bills than non-net-metered participants. We also tested a custom modeling approach that controlled for variation in solar PV production (i.e., due to the local solar irradiance at a given point in time). We found that, with a robust comparison group, we measured approximately equal electricity impacts with or without using solar irradiance data in our models.

- **Recommendation:** For pooled models with a high-quality comparison group, energy and load impacts for net-metered customers can be calculated without including solar irradiance data. Including solar irradiance data might be more important for site-level modeling, especially when those models lack an hourly baseline constructed to include a comparison group.

2. INTRODUCTION

Building energy consumption is responsible for a quarter of California's GHG emissions. To address these emissions, the California Legislature passed Senate Bill (SB) 1477, which calls on the California Public Utilities Commission (CPUC) to develop the TECH Initiative. The TECH Initiative is designed to accelerate market adoption of low-emissions space conditioning and water heating technologies for existing single family and multifamily residential housing units across California. Given the potential of heat pump technologies to reduce GHG emissions, the CPUC envisions them as a key element to meeting the State's mission to achieve carbon neutrality by 2045. The TECH Initiative is designed to address and reduce market barriers to accelerate the longer-term adoption of low-emission space and water heating technology and transform the market over time while striving for cost-effectiveness and regulatory simplicity.

The $120 million TECH Initiative was launched in December of 2021, and the majority of incentives were subscribed to by early summer 2022. The initial $120 million was funded by Cap-and-Trade gas utility auction proceeds. The California Energy Trailer Bill, released on August 31, 2022, allocated an additional $50 million for TECH in 2023 from the California general fund. In the 2023–24 state budget, an additional $95 million for TECH was budgeted from the California Greenhouse Gas Reduction Fund (GGRF) state auction proceeds. This study focuses on the impact of projects funded by Cap-and-Trade Natural Gas Allowance Allocation proceeds.[15]

2.1 RESEARCH OBJECTIVES

The study addresses the following underlying research questions:

- What are the GHG emissions reductions and cost per metric ton of avoided GHG associated with the TECH Initiative?
- What are the electric and gas energy impacts associated with the TECH Initiative? What are the impacts associated with customer segments including by climate zone and among customers that are net-metered, low-income, live in a disadvantaged community, or are on a time-of-use rate?
- With what degree of certainty can whole house meter data produce electric energy impact results? What project features produce high degrees of uncertainty?
- What are the average changes in energy costs for TECH Initiative participants? What are the average changes in energy costs for subgroups of interest (e.g., low-income customers, participants in DACs)?

[15] We refer to these as Cap-and-Trade projects throughout the report but acknowledge that GGRF is also funded by the Cap-and-Trade program.

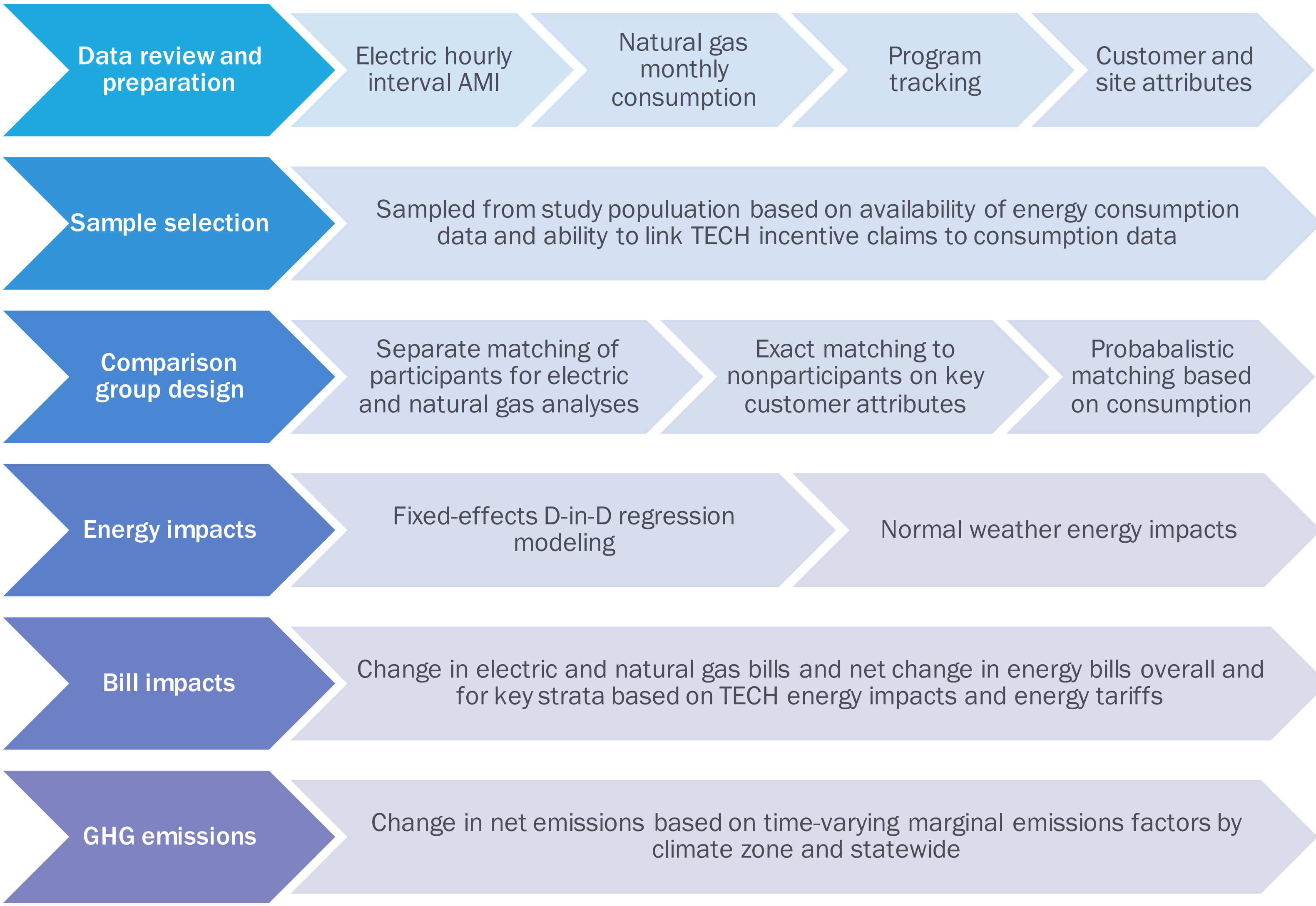
3. METHODS

This section provides an overview of the methods used for this study. As summarized in Figure 9, the key elements of the study approach include the following:

- Calculation of net GHG emissions impacts using climate-zone electricity generation marginal emissions factors and calculation of customer net bill impacts using electric and gas utility tariffs for TECH participants and nonparticipants.
- Analysis of AMI meter hour-interval electricity consumption data and monthly billing gas consumption data.
- Exact matching of TECH participants to nonparticipants based on characteristics such as climate zone location, net metering status, TOU rate, CARE discount, and DAC status; and probabilistic matching of TECH participants to nonparticipants within the same exact matching stratum based on baseline energy consumption.
- Two-way fixed-effect D-in-D panel regression analysis of customer electricity and gas consumption data.
- Estimation of TECH normal-weather average electricity and gas impacts per participant. Electricity consumption impacts are estimated by season, day type (i.e., weekday and weekend), and hour of the day. Gas consumption impacts are estimated by month of the year.

Our approach was informed by guidance about data collection and preparation, baseline construction, modeling, and model validation in the CPUC NMEC Rulebook, CalTRACK, Lawrence Berkely National Laboratory (LBNL) NMEC Technical Guidance, and industry and academic research. All methods are described in more detail in Appendix A.

Figure 9. Population-Based Pathway Analysis Steps



3.1 DATA REVIEW AND PREPARATION

The study team collected data from a variety of sources, as summarized in Table 1, to undertake the TECH Initiative impact analysis. All data were reviewed for reasonableness and sufficiency prior to inclusion in the analysis.

Table 1 . TECH Initiative Program Evaluation Data Streams

Data Inputs	Data Source
TECH program participation information ▪ Measure(s) installed ▪ Date of installation ▪ Climate zone ▪ DAC indicator[a] ▪ Incentives provided to customers	TECH program tracking data
TECH program cost information	▪ TECH program tracking data ▪ CARB reporting data
Electric interval usage	California Energy Commission (CEC) Snowflake Database
Gas monthly usage and associated metadata	CEC Snowflake Database
Customer information ▪ Rate code ▪ Net metering status[b] ▪ Utility ▪ Address ▪ Unique identifiers	CEC Snowflake Database
Marginal hourly avoided cost and GHG system hourly emissions rate	CEC[c]
Weather data ▪ Historical temperature ▪ Historical irradiance ▪ Normal weather	▪ National Centers for Environmental Information (NCEI) ▪ Solcast ▪ CALMAC[d]
Rate schedules	Utility-published tariffs

[a] Disadvantaged communities refers to those communities and geographic areas identified as such by the California Environmental Protection Agency in accordance with California Senate Bill 535. We include DACs identified under both CalEnviroScreen 3.0 and CalEnviroScreen 4.0.
[b] The study team did not have information on the prevalence of TECH participants that pair their solar with a storage system or the timing of the storage system adoption in relation to their TECH participation.
[c] California Energy Commission. "Final 2022 TDV Methodology Report." Docket 19-BSTD-03. January 18, 2022.
[d] California weather files for typical/normal years are maintained at https://www.calmac.org/weather.asp

The study team obtained customer and energy consumption data from the CEC's Snowflake Database. The data included AMI meter electricity consumption data and monthly gas consumption billing data. To connect TECH participant project data to the energy consumption data in the CEC Snowflake Database, the study team leveraged prior work completed by the implementation team.

Notably, due to data limitations, the analysis did not include an assessment of or accounting for cross-participation of TECH participants in other utility programs during the evaluation period. As a result, if participants took part in other decarbonization or energy efficiency programs at a different rate than similar nonparticipants, the impact of these interventions would be absorbed into the impact of TECH participation.

3.2 SAMPLE SELECTION

This study estimates the GHG, energy, electricity demand, and bill impacts of TECH participants with projects funded by Cap-and-Trade between July 2021 and July 2023. In this timeframe, there were 14,686 TECH Incentive claims associated with over 10,000 residential premises. In this study, the unit of analysis is a utility customer-premise where a TECH-funded project was undertaken.[16]

The study team developed separate electricity and natural gas analysis samples. Each sample includes residential utility customer premises that could be matched with consumption data in the CEC Snowflake Database. There were 10,523 TECH claims associated with premises receiving electric service in the CEC Snowflake Database and 10,014 TECH claims associated with premises receiving gas service (Table 3). We linked TECH claims to energy consumption in the CEC Snowflake Database based on the utility premise identifier.

Although there are many reasons why a TECH incentive claim may not be linked with the CEC Snowflake Database, an important reason was the database's incompleteness at the time of this analysis. The unavailability of consumption data in the CEC Snowflake Database for some utilities prevented some TECH projects from being included in the analysis sample. Furthermore, there were meter or billing consumption data quality issues for participants in some utility service territories that required excluding these data from the analysis. Table 2 summarizes these data limitations and how they impacted the study.

Table 2. CEC Snowflake Data Availability by Utility

Utility	Included Fuel(s)		Data Availability	Study Implications
	Electric	Gas		
LADWP	N	N/A	No interval data available	Excluded from analysis sample
PG&E	Y	Y	Available for study timeframe	N/A
SCE	Y	N/A	Available for study timeframe	N/A
SoCalGas	N/A	Y	Available except for May–October 2022 due to poor quality in Snowflake	Adjustments to gas impact estimation approach for SoCalGas projects
SDG&E	N	N	Unavailable for study timeframe	Excluded from analysis sample
SMUD	Y	N/A	Available for study timeframe	N/A

The TECH projects included in the final analysis sample met the following criteria.

Project Factors

- The project(s) was completed between December 2021 and December 2022.[17]

[16] The utility customer-premise is defined as all meters at a premise for a period of time where the same account is associated with the premise. If the account changes, this would become a new utility customer-premise.

[17] The analysis sample was limited to projects completed in this period to facilitate the construction of a comparison group and the modeling. The analysis results were extended to all projects completed between July 2021 and July 2023.

- The project was completed for those participants receiving electricity service from Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), or Sacramento Municipal Utility District (SMUD) and gas service from PG&E or Southern California Gas (SoCalGas) for the reasons outlined in Table 2.[18]
- The project was funded by Cap-and-Trade gas utility auction proceeds.
- The TECH Incentive claim(s) for the project(s) could be linked to a utility customer-premise.
- A small number of premises that received both HPWH and HVAC incentives were excluded from the analysis to allow the study team to isolate the effect of individual measures.
- While the vast majority of projects involved natural gas-to-electric conversions, we include a small number of electric-to-electric projects, representing 1.3% of premises. Projects involving propane-to-electric conversions were excluded due to unavailable data, although this was very rare.

Consumption Data Criteria

- The utility premise could be linked to electric AMI meter or natural gas monthly billing consumption data.
- The premise must have been individually metered. Participants in master-metered multifamily buildings were excluded from the analysis sample, but individually metered multifamily premises were included.
- The premise had sufficient consumption data before and after participation in TECH after conducting data cleaning to address missing, outlier, duplicate, and overlapping consumption readings and other meter or billing data issues. Each utility customer-premise in the gas analysis sample and the electric analysis sample required a minimum of nine months of consumption data in the year immediately preceding participation and nine months of consumption data in the year immediately following participation.

Premise and Customer Attributes

- There must have been continuous residency by the utility customer at the premise in the baseline and reporting periods. We identified likely residency changes through changes in the customer billing account associated with the premise.
- The premise did not experience a change in net metering status during the baseline or reporting period.
- Customer and premise data required for matching and estimation were available. The customer segmentation data included climate zone, CARE or FERA status, DAC residency status, NEM status, and TOU rate status.
- The TECH participant was matched to a similar nonparticipant. This process is discussed further in the next section. Participants that could not be matched to a suitable nonparticipant were excluded from the analysis.

Overall, after completion of data cleaning, sample selection, and matching steps, there were 4,129 electric utility customer premises (representing 50% of sites in the study frame) in the electricity consumption analysis sample and 3,684 gas utility customer premises (43% of sites in the study frame) in the natural gas consumption analysis. The study team compared the sampled sites to participants in the study population on known attributes including measure received, electric and gas utility, climate zone, NEM status, housing type, low-income status based on receipt of a CARE or FERA discount, whether or not they are on a TOU rate, whether or not they live in a DAC, and whether or not they had air conditioning prior to TECH participation, and determined that the sampled sites are reasonably similar to the participants to which the analysis results will be extrapolated. The results of this comparison are presented in more detail in Appendix A.

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[18] As a result of data limitations, the evaluated participants do not align with the program funding structure or service utilities of all participants during the evaluation period. To comply with CARB rules regarding Cap-and-Trade funds, the percentage allocation for pilot program spending in each gas corporation service territory shall be consistent with each gas corporation's allocation of Cap-and-Trade allowances: SoCalGas: 49.26% PG&E: 42.34% SDG&E: 6.77% Southwest Gas Corporation: 1.63%.

This study's per-participant impact estimates are based on participants in the analysis sample. Program-level impacts for the study population are obtained by multiplying the average impact per TECH participant in the analysis sample by the number of participants that completed a Cap-and-Trade–funded project between July 2021 and July 2023 and received electric service from PG&E, SCE, or SMUD and gas service from PG&E or SoCalGas.[19]

Table 3 summarizes the analysis sample selection process.

Table 3. Analysis Sample Selection and Extrapolation

Step	Count	
All Cap-and-Trade incentive claims	14,686	
	Electric	Natural Gas
Merge claims to utility meter data in the CEC Snowflake database by fuel	12,377	11,830
Convert claims to utility customer-premise	10,523	10,014
Limit to study population	8,250	8,545
Limit to analysis sample	4,129	3,684
Total study population customer-premises to extrapolate program impacts	10,197	

Note: Sites can be associated with more than one claim. This signifies that the site received multiple types of measures or submitted separate claims for multiple units of the same type of measure (which is possible but not required).

3.3 COMPARISON GROUP DESIGN

We developed a matched comparison group of nonparticipants to account for exogenous (i.e., non-TECH-Incentive-related) changes in energy consumption during the reporting period, such as those related to economic booms and recessions and any naturally occurring adoption of heat pump technology. The details of the matching are provided in Appendix A, but the key elements are as follows:

- We conducted separate matching of participants to nonparticipants for the impact analysis of each fuel.
- For each fuel, each TECH participant was matched to one nonparticipant through a multi-step matching process. A nonparticipant could be matched to more than one participant. In the impact analysis, these nonparticipants received a higher weight than nonparticipants matched to only one participant. Participants for whom a suitable match could not be identified were excluded from the modeling process. 598 electric and 549 gas sites were excluded from modeling for this reason.
- There were two steps to the matching process. In the first step, we did exact matching of each participant to multiple nonparticipants. For electricity, we exactly matched participants to nonparticipants on customer characteristics, including climate zone, TOU rate status, NEM status, CARE or FERA discount status, and whether they reside in a DAC. Thus, a TECH participant was only matched to nonparticipants with these same characteristics. For natural gas, we exactly matched participants to nonparticipants on climate zone, CARE discount, and DAC status.
- Starting from the pool of nonparticipants identified for each TECH participant in step one, we used propensity score matching to match each TECH participant to the most similar nonparticipant based on their baseline energy consumption, including, for electricity, consumption disaggregated into heating and cooling loads.[20] We

[19] The study team estimated this value from the claim-level participant tracking data using the ratio of the number of claims per site for those projects that could be associated to a utility premise (as some sites had more than one claim) and by filtering to the utility assigned to the claim by the implementation team.

[20] Propensity score matching involved estimating a probability model of a customer participating in TECH as a function of baseline period energy consumption characteristics. Then the model was used to generate a prediction or score for each customer of the probability of participating in TECH. Finally, each participant was matched to one nonparticipant based on the closeness of the scores.

used heating and cooling energy consumption to match each participant to a nonparticipant with the same heating fuel and similar air conditioning use. Given that our goal is to measure the impacts of electrifying gas end uses, it is important that the study team match participants to nonparticipants with the same baseline heating fuel and air conditioning use.[21]

- We validated the matches in two ways. We compared the energy consumption of participants and matched nonparticipants during the baseline period and tested for statistically significant differences. Also, as the time of TECH treatment varied across the analysis sample, we conducted an event study that tested for TECH impacts on energy consumption before TECH participation occurred. We do not observe any energy impacts before treatment, strongly suggesting the models are correctly specified and that the reporting period TECH impact estimates are accurate. Appendix A includes the results of these tests and suggests that nonparticipants provide a valid baseline for TECH participants.

3.4 CONSUMPTION ANALYSIS

The study team estimated the average electric and natural gas impacts per TECH participant. The consumption regression models were estimated with data for TECH participants and matched nonparticipants, and the impact estimates were weather-normalized using CZ2022 normal weather data.[22] We estimated electric impacts for a normal weather year and by season, day type, and hour of the day. We estimated gas impacts for a normal weather year and by month and season. We also estimated impacts by TECH measure and for customer segments, including TOU rate, NEM, CARE or FERA discount, DAC customers, and for each climate zone.

Electric Model

For electric energy impacts, we estimated two-way, fixed-effect D-in-D models of hourly electricity consumption (kWh_{it}), where i indexes the customer and t the hour of sample.[23] For each customer segment, we estimated a separate model for each season (summer, shoulder, winter) and day type (weekday and weekend).[24] Equation 1 shows the winter season model. It includes customer (α_i) and hour-of-sample fixed effects (τ_t) and allows the impact of weather as represented by heating degree hour (HDH) on consumption and savings to depend on hour of the day. We do this by interacting HDHs with hour-of-the-day fixed effects ($HourofDay_j$, j=1, 2, …24).

Equation 1. Electric Energy Model Specification (Winter Model with HDH terms only)

$$kWh_{it} = \alpha_i + \tau_t + \sum_{j=1}^{24} \theta_{HDH,j} HDH_{it}\, x\, HourofDay_j + \sum_{j=1}^{24} (\gamma_j TECH_{it} x HourofDay_j + \gamma_{HDH,j} TECH_{it} x HDH_{it} x HourofDay_j) + \varepsilon_{it}$$

[21] In creating the comparison group for estimating electric impacts, this step utilized granular consumption values that would also account for customer EV charging behavior. For example, a participant with high electric energy consumption in the overnight hours that indicates at-home EV charging would likely be matched with a nonparticipant with similar overnight energy consumption.

[22] The study team leveraged CALMAC's CZ2022 weather files as the typical weather year. If the typical weather year file was unavailable for the closest weather station from which historical actual weather data were derived for a given site, the study team leveraged CZ2018 data.

[23] The two-way fixed-effect D-in-D regression model is the standard approach for estimating energy impacts when the timing of intervention varies between participants. See Bertand, Marianne, Esther Duflo, and Sendhil Mullainanthan 2004. "How Much Should We Trust Difference-in-Differences Estimates?" The Quarterly Journal of Economics 119: 249-275. "Two-way" refers to the inclusion of customer and time-period fixed effects in the model.

[24] Throughout the report, summer is defined as June through September, winter as December through March, and the shoulder season includes April, May, October, and November.

Equation 1 assumes TECH program participation denoted by $TECH_{it}$ (=1 if customer i was treated on or before hour-of-sample t, =0, otherwise) could have non-weather sensitive impacts (γ_j) and weather-sensitive impacts ($\gamma_{HDH,j}$) on consumption that vary by hour of the day *j*.

In winter, the normal-weather average hourly electricity kWh impact per TECH participant for hour of day j equals:

$$\gamma_j + \gamma_{HDH,j}\overline{HDH}_j$$

where $\overline{HDH}_j$ are the normal weather average heating degree hours for hour-of-day j, γ_j is the coefficient on the stand-alone hour-of-day j indicator variable, and $\gamma_{HDH,j}$ is the coefficient on the interaction between the hour-of-the-day j indicator variable and $\overline{HDH}_j$.

The summer season and shoulder season consumption models have the same basic structures as Equation 1. The only differences are that the summer model allows consumption and savings to depend on cooling degree hours (CDH), and the shoulder season models allow consumption and savings to depend on CDH and HDH. For some climate zone models, particularly for the shoulder season, it was necessary to modify Equation 1 by replacing the interactions between hour of the day and weather with standalone CDH or HDH variables due to the absence of cooling or heating degrees in some hours and to avoid collinearity.[25] By specifying separate models for each season and day type, incorporating customer and time-period fixed effects, and allowing the impact of weather to depend on hour of the day, our modeling approach enabled us to flexibly model electric energy consumption and obtain precisely estimated and accurate TECH program impacts.[26]

We estimated the electricity consumption models by ordinary least squares with data for TECH participants and matched nonparticipants in the nine to twelve months immediately preceding and following TECH participation. The regression standard errors were clustered on the customer and time period (the hour of sample). We then used the estimates of the coefficients in Equation 1 to estimate the TECH program normal weather electricity impacts.

Gas Model

For gas energy impacts, the study team estimated a two-way fixed-effect panel regression model of utility customer monthly gas consumption. As Equation 2 shows, the dependent variable is average daily therm consumption (for customer i in month-year of sample t), and the model includes month-year of sample (τ_t) and customer fixed effects (α_i). The model only includes average daily heating degree days (HDD_{it}) since natural gas is not used in cooling homes.

Equation 2. Gas Energy Impacts Model Specification

$$therm_{it} = \alpha_i + \tau_t + \sum_j \theta_j HDD_{it} x\, CZ_{ij} + \beta_1 TECH_{it} + \beta_2 TECH_{it} x HDD_{it} + \varepsilon_{it}$$

We estimated the normal weather natural gas energy impacts for participants overall and by measure type, climate zone, whether the customer receives a low-income CARE discount, and whether the customer resides in a DAC. The normal weather average daily gas impact per participant for calendar month k, k=1 , 2, ... , 12 equals:

$$\beta_1 + \beta_2\overline{HDD}_k$$

[25] Collinearity occurs when two model independent variables are highly correlated and it is not possible to separately estimate their effects on the dependent variable. There are formal tests for detecting collinearity, but a reliable sign is inflated standard errors.

[26] The study team also tested models for NEM customers that included historical and normal irradiance values to control for variation in net energy consumption due to solar generation.

where $\overline{HDD}_k$ is normal weather heating degrees for month k, β_1 is the coefficient on the standalone TECH indicator variable, and β_2 is the coefficient on the interaction between the TECH indicator variable and HDD. The β_1 coefficient captures TECH impacts on baseload consumption and β_2 captures impacts on weather-sensitive consumption.

We estimated the electricity and gas consumption models by ordinary least squares and clustered the standard errors on the customer and time period (the month-year of sample). The models were estimated with monthly billing consumption data for TECH participants and matched nonparticipants in the years immediately preceding and following TECH participation.

3.5 PEAK DEMAND IMPACTS

The introduction of widespread heating electrification across the state will likely affect both winter and summer peak demand. Electrification can increase current peaks and create new ones. To better understand this important issue, the study team estimated changes in peak demand from TECH participation using three different peak demand period definitions.

- **Resource Adequacy Window:** The study team estimated the average impact of TECH participation on electricity demand on summer weekdays between 4:00 p.m. and 9:00 p.m. We evaluated the Resource Adequacy Window impacts using the estimates from Equation 1.
- **DEER Definition:** The study team estimated the impact of TECH participation on peak demand using the peak demand definition from the Database for Energy Efficient Resources (DEER). The peak demand days and hours are from 4:00 p.m. to 9:00 p.m. on three consecutive summer heat wave days. The heat wave days differ between climate zones based on CZ2022 weather normal values. This DEER peak day approach is the methodology used for estimating peak demand impacts in energy efficiency evaluations. We evaluated the DEER peak demand impacts using the estimates from Equation 1.
- **Daily Peak Demand by Season, Day Type, and Hour:** The study team identified the season, day type, and hour of the day (e.g., summer weekday 5:00 p.m.) when demand was highest on average before and after electrification. We report the difference in demand and whether there is a change in the season, day type, and hour of peak demand. This analysis will give resource planners information about changes in the timing of when load tends to typically peak following electrification.

3.6 GHG EMISSIONS

We calculated the TECH GHG emissions impacts by fuel and combined these to estimate net GHG emissions impacts. The study team relied on electric and natural gas long run marginal emissions factors (EFs) from the Time Dependent Valuation (TDV) of Energy for Developing Building Efficiency Standards report.[27] To estimate GHG emissions from increased electricity consumption, the study team applied marginal EFs defined by Title 24 climate zone and hour of the year to the estimated hourly climate zone electricity impact estimates. Using climate zone-specific, 8,760-hourly marginal EFs means the estimated TECH emissions impacts account for variation in emissions across hours of the year and climate zones and depend on the emissions of the marginal generating unit in each hour. [28] For natural gas, we applied a static GHG emission factor to the natural gas impact estimates. These

[27] Final 2022 TDV Methodology Report. CEC Docket 19-BSTD-03. June 5, 2020.

[28] The CPUC expressed a preference for GHG impacts to be measured consistently for TECH and BUILD. The TDV 8760-hour EFs are defined by Title 24 climate zone and hour of the year for electricity and are the EFs inherently used for BUILD because they are built into the California Building Energy Code Compliance (CBECC) tool. Therefore, we apply TDV EFs to calculate the GHG impacts for the electricity impacts for both

EFs account for upstream methane leakage and refrigerant leakage. After aggregating the gas and electric emissions across climate zones to the program level, the study team converted the annual GHG emissions impacts into lifetime impacts, assuming a 23-year effective useful life (EUL) for heat pump HVAC measures and a 20-year EUL for HPWHs.[29] We estimated the cost per metric ton of avoided GHG emissions at the program level based on the lifetime avoided GHG emissions combined with program and project costs.

3.7 BILL IMPACTS

We calculated electric and gas average bill impacts per participant by multiplying the average energy baseline and modeled post-participation usage within each customer segment by the respective average cost of energy. As many electricity customers are on TOU rates, we calculated an average electricity cost by season, day type, and hour of the day. In addition, because customers within each segment may have a different likelihood of being on a TOU rate or may be served by different utilities, we calculated the average energy costs separately by customer segment. Net bill impacts were calculated by adding together the bill impacts from each fuel type. We gathered data on hourly electricity costs based on the participant's rate at the time of TECH participation and utility tariffs as of January 2022.[30] The electricity and gas rate codes used in calculating the average rate are summarized in Appendix A.

The net bill impact estimates provide the change in energy usage costs following TECH participation, accounting for TOU rates, tiered fee structures, natural gas space heating fees, baseline allowances, and discounted utility rates for low-income customers. As the analysis sample is limited to TECH participants who retained gas service after participation, there are no changes in customer fixed charges from discontinuing gas service, and our estimates do not adjust for any changes except in the all-electric bill impact estimates (Section 5.13.1). The all-electric bill impacts assume that the gas baseline is equal to the gas energy impacts observed among the evaluated TECH participants, that gas bills are $0 following TECH participation, and incorporates flat fees into the baseline bill amount.

The evaluation team developed bill impacts by climate zone, for DAC and non-DAC customers, customers receiving a CARE or FERA discount, NEM customers, and TOU rate customers. We used each segment's electricity and gas impact estimates to calculate these bill impacts. We aggregated customer gas and electric bill impacts to the program level by multiplying the estimated average bill impact per participant by the number of participants.

For additional details on the bill impact methodology and assumptions, see Appendix A.

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programs. This approach has been reviewed and accepted by the California Air Resource Board (CARB) as in compliance with CARB funding requirements for these programs.

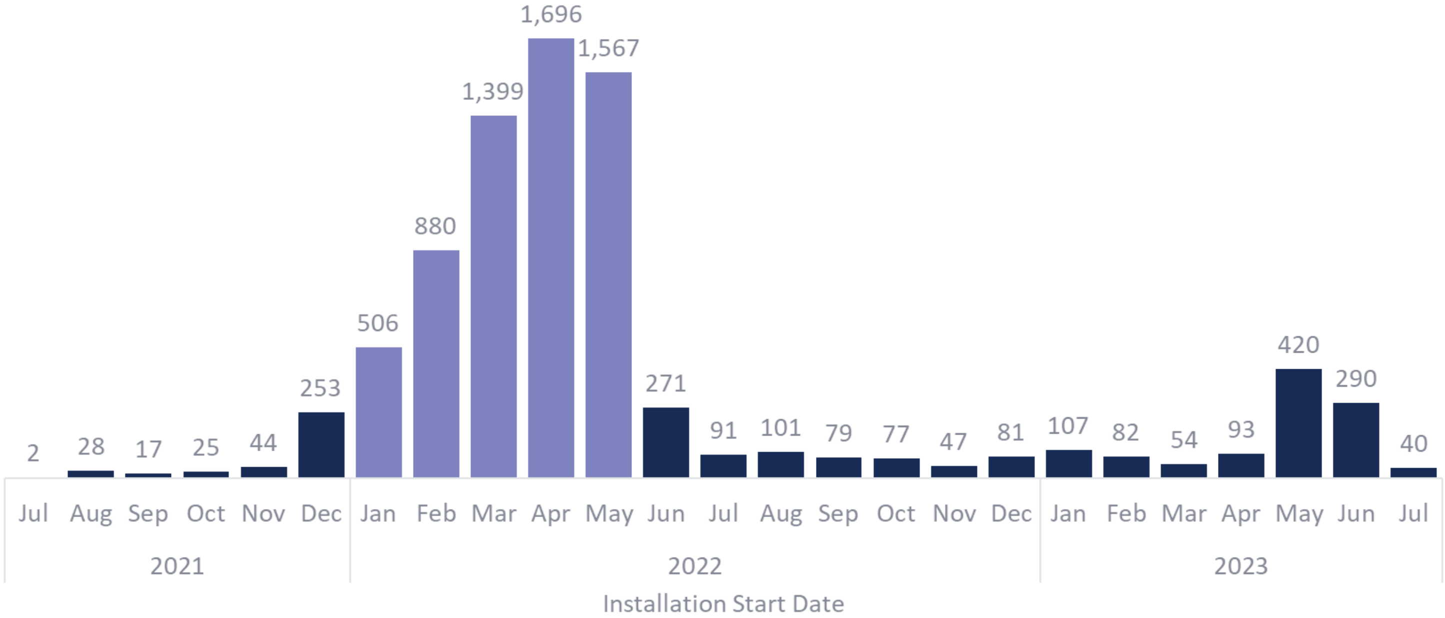
[29] These EUL values align with DEER 2026 guidelines and with the assumptions of the TECH implementation team.

[30] The study team referenced historic tariffs as close to January 2022 as publicly available for calculating the price of energy on each rate.

4. PARTICIPATION SUMMARY

The participation analysis summarizes Cap-and-Trade–funded projects completed in the study population.[31] The evaluated projects occurred between July 2021 and July 2023, with nearly three-quarters of projects beginning between January and May 2022 (Figure 10).[32] Projects in the study population occurred at utility customer premises receiving electricity service from PG&E, SCE, or SMUD and gas service from PG&E or SoCalGas.

Figure 10. Project Installation Start Dates (n=8,250)

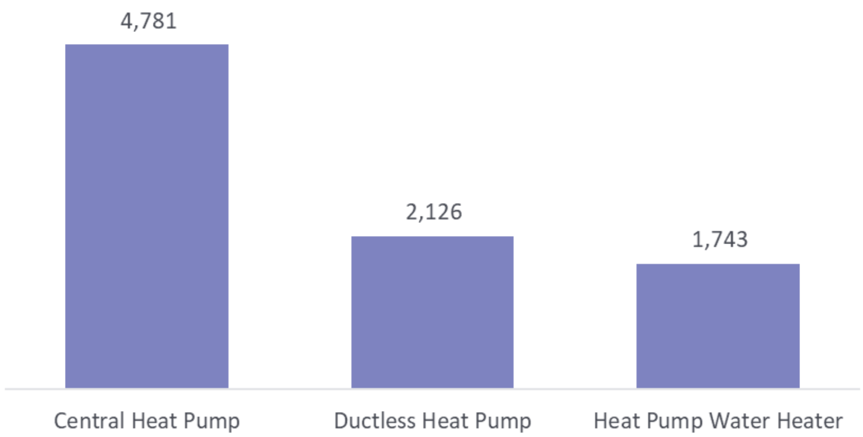


This study evaluates impacts from incented TECH measures: central heat pumps, ductless heat pumps, and HPWHs. The vast majority (95%) of TECH participants during the study timeframe installed only one measure type, while the remainder installed multiple measure types (i.e., a heat pump HVAC and HPWH or, in rare instances, a ductless and central heat pump). The majority (84%) of participants replaced their HVAC, with only 21% receiving an HPWH either on its own or in combination with another measure. The most common measure was a central heat pump, which 58% of sites received (Figure 11). Appendix B includes a summary by customer segment (e.g., NEM, DAC, TOU rate) of the measures received by participants during the evaluation period.

31 Participants with insufficient consumption data to be included in the sample analysis frame are still included in the participant analysis if their data could be identified in the CEC Snowflake Database. Participants from utilities excluded from the evaluation are omitted from the participant analysis (n=522 LADWP, n=1,740 SDG&E electric, n=1,469 SDG&E natural gas).

32 The sudden and brief surge in projects in the spring of 2022 is discussed further in an earlier report: Opinion Dynamics. "Interim Process Evaluation: Technology and Equipment for Clean Heating (TECH) Initiative." November 7, 2022. (p.26). https://techcleanca.com/documents/991/TECH_Interim_Process_Evaluation_Final_Report.pdf.

Figure 11. Number of Participants by Incented Measure Type (n=8,250)



Note: The sum of the sites receiving each measure will not equal the total number of treated sites, as some received multiple measures.

The study team assessed the baseline air conditioning equipment of sites receiving a central or ductless heat pump, which affects baseline energy consumption and the expected energy impacts. As Table 4 shows, over half of sites where a central heat pump was installed had a central or ducted air conditioning unit previously, whereas a similar proportion of sites receiving a ductless heat pump had no air conditioning prior to participation. This means that many participants that installed ductless heat pumps were adding air conditioning as part of that installation. Appendix B includes a summary of the baseline air conditioning equipment by customer segment.

Table 4. Existing Space Conditioning by HVAC Measure Type

Existing Air Conditioning	Central Heat Pump		Ductless Heat Pump	
	Count of Sites	Percent of Sites	Count of Sites	Percent of Sites
Central or Ducted	2,894	61%	624	29%
Room, Window, or Wall Unit	32	1%	73	3%
None	1,817	38%	1,339	63%
Unknown [1]	40	1%	90	4%
Total	**4,783**	**100%**	**2,126**	**100%**

Note: 49 sites received both central and ductless heat pump measures. Rows do not sum to 100% due to rounding.

[1] An unknown status indicates that this information was not collected by the contractor and/or was not recorded in the program tracking data.

Most sites that received HVAC measures had their natural gas furnace fully decommissioned after the heat pump HVAC measure(s) was installed. This outcome was similar for participants who received a central heat pump and ductless heat pump (Table 5).

Table 5. Furnace Status After Install by HVAC Measure Type

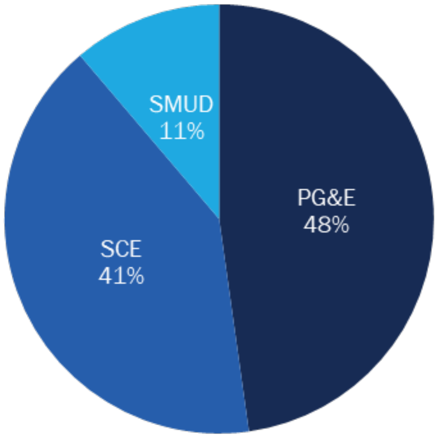
Status of Baseline Furnace Following TECH Participation	Central Heat Pump		Ductless Heat Pump	
	Count of Sites	Percent of Sites	Count of Sites	Percent of Sites
Fully Decommissioned	4,216	88%	1,854	87%
Run in Emergency Service Only	445	9%	167	8%
Use the Blower Only	32	1%	19	1%
Unknown [1]	88	2%	86	4%
Total	**4,781**	**100%**	**2,126**	**100%**

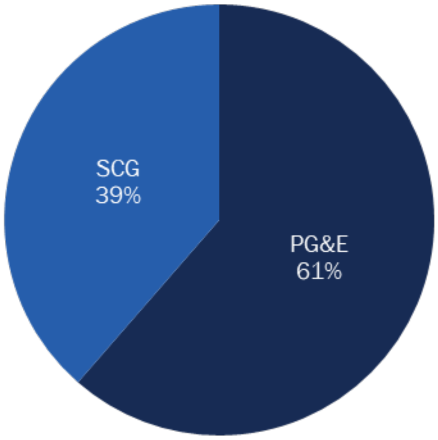
Note: 49 sites received both central and ductless heat pump measures.

[1] An unknown status indicates that this information was not collected by the contractor and/or was not recorded in the program tracking data.

TECH participants are served by many utilities from across the state. Most have PG&E (48%) or SCE (41%) as their electric utility, and the majority (61%) receive natural gas service from PG&E (Figure 12).[33]

Figure 12. Electric (n=8,250) and Natural Gas (n=8,545) Utilities of TECH Participants



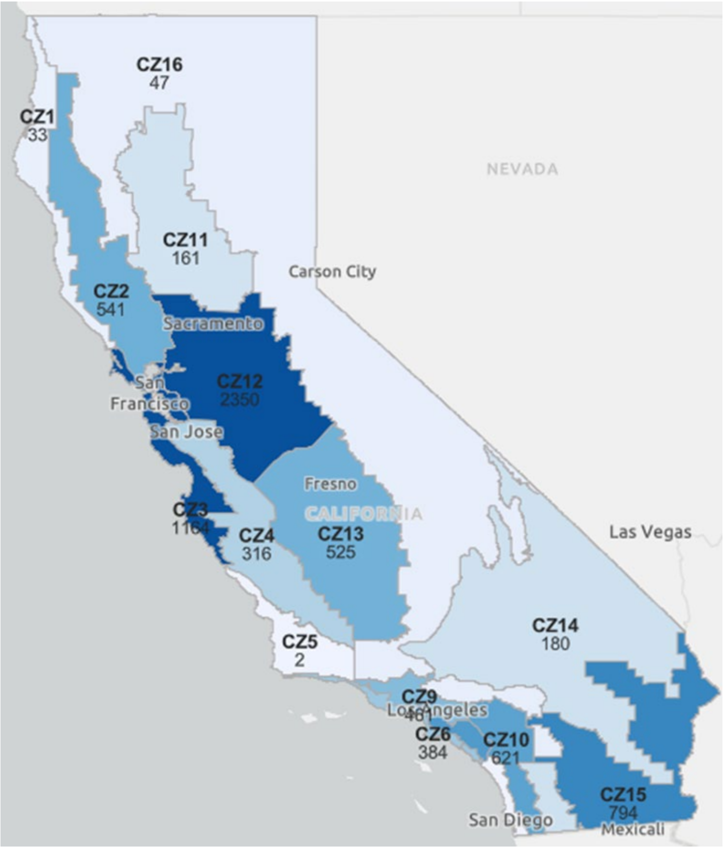


TECH participants also live in a variety of climate zones (CZs), most commonly CZ12 (28% of participants) and CZ3 (14% of participants) CZ1, CZ5, and CZ16 had a small number of participants, comprising fewer than 1% of the sites each.[34] Figure 13 depicts the number of participant sites in each climate zone.

[33] SDG&E was excluded from the analysis due to missing data.

[34] CZ7 was excluded from the analysis as it is served by SDG&E for both natural gas and electric service. The study team was not able to access SDG&E data through the CEC Snowflake Database.

Figure 13. Climate Zone and Number of TECH Sites



Note: n=8,248. Excludes one site in CZ7 and one site with no CZ recorded.
Sourced from TECH program tracking data; CZs were verified for modeled sites.

Table 6 summarizes demographic and housing attributes of TECH participants compared to all Californians. TECH participants were much more likely than the general population to be net-metered and live in a single-family home.[35] Both of these outcomes are expected. The presence of net metering can make electrifying more financially attractive to residential customers, and the TECH Initiative was not focused on reaching multifamily customers during the study period. TECH participants were slightly more likely than average to live in a DAC and similarly likely to receive a CARE or FERA discount on their utility bills compared to a typical utility customer in California. TECH participants were more likely than the general population to be on a TOU rate, although only about 59% were at the time of their participation.

35 This may be a slight underestimate of multifamily participation. It is possible that the process of identifying the participating site(s) was less successful for multifamily than for single family projects, since the fuzzy address matching process may be less successful in these cases. Further, this figure is based on participating sites, not claims or measures. Some multifamily sites receive multiple measures.

Table 6. Key Demographic and Housing Attributes

Attribute		TECH Participants		Estimated Percent of All Californians
		Count of Sites	Percent of Sites	
	Net Metered[1]	**1,886**	**27%**	**10%**
	Housing Type[2]			
	Single Family	8,029	97%	65%
	Multifamily	218	3%	32%
	Resides in a DAC[3]	2,118	26%	24%
	Receives a CARE or FERA Discount[4]	758	11%	27%
	On a TOU Rate[5]	4,132	59%	40%

Note: Values may not sum to 100% due to rounding.

[1] Sources: CEC Snowflake database; CA DGStats Interconnection Dataset

[2] Sources: TECH program tracking data; American Community Survey 2022 5 Year Housing Unit Estimates (Table B25024).

[3] Sources: TECH program tracking data; CalEnviroScreen 4.0

[4] Sources: Estimate of participants and customers receiving CARE/FERA discounts via CEC Snowflake Data Warehouse.

[5] Sources: Estimate of participants and customers on a TOU rate via CEC Snowflake Data Warehouse.

5. FINDINGS

5.1 CROSS-FUEL ENERGY IMPACTS SUMMARY

The average TECH participant increases their electric energy consumption and decreases their natural gas consumption, leading to an overall reduction in energy use of 11.6 MMBtu (16%) per year. The fuel substitution and change[36] in energy use also corresponds with a reduction in GHG emissions of 0.73 metric tons of CO_2-e (17%) per year. The increase in electric energy consumption and reduction in gas consumption occur primarily during the winter months. The winter electric energy impacts make up 84% of the change in electric energy consumption from the TECH Initiative and 61% of the change in gas consumption. The smallest changes occur in the summer months. On average there is a small reduction in electric energy consumption in the summer months as some TECH participants replace their existing space conditioning systems with a more efficient alternative. Despite the 17% overall increase in electric consumption, total energy consumption decreases. The 38% reduction in gas consumption more than offsets the electricity consumption increase. Across seasons and fuels, TECH participants reduce their total energy consumption by 16%. This suggests that the heat pump technology adopted by participants is also more efficient than the gas baseline systems they replace (Table 7).

Table 7. Cross-Fuel Energy Annual Energy Impacts by Season

Season	Electric Impacts			Gas Impacts			Total Energy Impacts		
	Baseline (kWh)	Average Impact (kWh)	% Impact	Baseline (therms)	Average Impact (therms)	% Impact	Baseline (MMBtu)	Average Impact (MMBtu)	% Impact
Summer	3,398	-100*	-2.9%	65	-17*	-25.6%	18.10	-2.00*	-11.1%
Winter	2,917	1,215*	41.6%	246	-101*	-41.2%	34.55	-5.98*	-17.3%
Shoulder	2,106	336*	15.9%	121	-47*	-39.1%	19.26	-3.57*	-18.5%
Overall	**8,421**	**1,451***	**17.2%**	**432**	**-165***	**-38.2%**	**71.90**	**-11.55***	**-16.1%**

*Results are statistically significant at 95% confidence level.

Note: Weather-normalized impact estimates based on fixed-effects D-in-D panel regression analysis of TECH participants and matched nonparticipant monthly gas and interval electricity consumption data. Summer is defined as June through September, winter as December through March, and shoulder as April, May, October, and November.

5.2 CROSS-FUEL ENERGY IMPACTS BY MEASURE

The TECH energy impacts also vary by measure. Table 8 summarizes the energy impact by season for central heat pumps, ductless heat pumps, and HPWHs. Central heat pumps produce large increases in energy consumption in the winter and shoulder season, but also produce large decreases in electric energy consumption in the summer. They also lead to decreases in gas consumption in all seasons, but especially the winter. Compared to central heat pumps, ductless heat pumps produce similar gas impacts, and similar electric impacts in the winter and shoulder seasons. However, in summer, ductless heat pump participants experience an increase in electric energy consumption of 14% relative to baseline. This is likely because a larger share of ductless than central heat pump participants are adopting air conditioning as part of their heat pump HVAC installation. As a result, ductless heat pump participants increase their electric consumption by 29% on an annual basis, compared to by only about 11% for central heat pump participants. The electric and gas energy impacts of an HPWH participant fall in between the impacts for a central and ductless heat pump. These participants reduce their gas usage by about 35% and increase

[36] The results of an “average TECH participant” reflect the mix of measures adopted during the evaluation period, as well as the mix of participant and housing characteristics such as baseline equipment, housing stock, climate zone and corresponding heating and cooling needs, and incidence of net metered participants.

electric consumption by about 28%. These impacts are more evenly spread throughout the year than they are for heat pump HVACs but are still the largest in the winter and the smallest in the summer. The overall change in energy consumption ranges from a 10.1 MMBtu (14.5%) reduction for HPWHs to a 11.8 MMBtu (15.8%) reduction for central heat pumps.

Table 8. Cross-Fuel Energy Annual Energy Impacts by Measure and Season

Season	Electric Impacts			Gas Impacts			Total Energy Impacts		
	Baseline (kWh)	Average Impact (kWh)	% Impact	Baseline (therms)	Average Impact (therms)	% Impact	Baseline (MMBtu)	Average Impact (MMBtu)	% Impact
Central Heat Pump									
Summer	4,330	-404*	-9.3%	62	-8*	-13.4%	20.93	-2.20*	-10.5%
Winter	2,891	1,226*	42.4%	242	-105*	-43.4%	34.06	-6.31*	-18.5%
Shoulder	2,259	242*	10.7%	118	-41*	-34.9%	19.52	-3.29*	-16.9%
Overall	**9,480**	**1,064***	**11.2%**	**422**	**-154***	**-36.6%**	**74.51**	**-11.81**	**-15.8%**
Ductless Heat Pump									
Summer	2,314	314*	13.6%	63	-8*	-12.0%	14.20	0.31	2.2%
Winter	3,094	1,232*	39.8%	247	-120*	-48.7%	35.30	-7.83*	-22.2%
Shoulder	1,984	576*	29.0%	123	-52*	-42.0%	19.05	-3.19*	-16.8%
Overall	**7,392**	**2,123***	**28.7%**	**433**	**-180***	**-41.4%**	**68.55**	**-10.72***	**-15.6%**
HPWH									
Summer	2,150	332*	15.4%	74	-48*	-64.9%	14.75	-3.68*	-24.9%
Winter	2,807	996*	35.5%	268	-62*	-23.0%	36.40	-2.77*	-7.6%
Shoulder	1,724	517*	30.0%	123	-54*	-43.6%	18.18	-3.60*	-19.8%
Overall	**6,681**	**1,845***	**27.6%**	**466**	**-164***	**-35.1%**	**69.34**	**-10.05***	**-14.5%**

*Results are statistically significant at 95% confidence level.

Note: Weather-normalized impact estimates based on fixed-effects D-in-D panel regression analysis of TECH participants and matched nonparticipant monthly gas and interval electricity consumption data. Summer is defined as June through September, winter as December through March, and shoulder as April, May, October, and November.

5.3 ELECTRIC ENERGY IMPACTS SUMMARY

TECH participants increase their electricity consumption by 17% or an average of 1,451 kWh in a normal weather year. Across all TECH participants, total electric energy consumption increases by 14,797 MWh per year (Table 9).

Table 9. Annual Electric Energy Impacts

Metric	Value
Average Impact per Participant (kWh)	1,451
% Impact	17.2%
Participants	10,197
Total Impact (MWh)	14,797

Note: Weather-normalized impact estimates based on fixed-effects D-in-D panel regression analysis of TECH participants and matched nonparticipant interval electricity consumption data.

The large increase in average annual electricity consumption obscures substantial variation in impacts across seasons. As Table 10 shows, the average participant experiences a slight *decrease* in energy consumption of 2.9% (100 kWh) during the summer season and an *increase* of 41.6% (1,215 kWh) during the winter season, with a more modest increase during the shoulder seasons.

Table 10. Per-Participant Seasonal Electric Energy Impacts

Season	Baseline (kWh)	Average Impact (kWh)	% Impact	Lower CI	Upper CI
Winter	2,917	1,215*	41.6%	1,130	1,300
Summer	3,398	-100*	-2.9%	-190	-9
Shoulder	2,106	336*	15.9%	281	391
Overall	**8,421**	**1,451***	**17.2%**	**1,315**	**1,587**

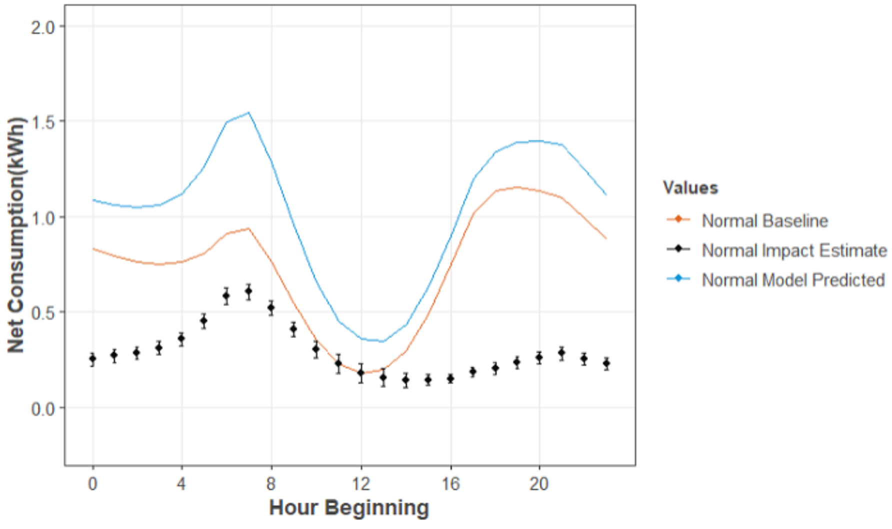
*Results are statistically significant at 95% confidence level.

Note: Weather-normalized impact estimates based on fixed-effects D-in-D panel regression analysis of TECH participants and matched nonparticipant interval electricity consumption data. Summer is defined as June through September, winter as December through March, and shoulder as April, May, October, and November.

As the California grid has periods of under- or over-supply of electricity due to high levels of variable renewable resources and other periods when it is capacity constrained in meeting peak demand, the TECH Initiative hourly electricity impacts are as important as the overall energy impact.

Given the increase in heating load associated with the adoption of heat pump technology, there is a statistically significant increase in energy consumption across all hours on a typical winter weekday. The absolute impact is greatest during the morning heating hours between 3:00 a.m. and 10:00 a.m., with impacts greater than 0.5 kWh between 6:00 a.m. and 8:00 a.m. Between 3:00 a.m. and 10:00 a.m., the average participant increased electric consumption by 62% over the baseline. This growth in electric energy consumption creates a new morning peak for TECH participants, which is greater than the afternoon peak in the baseline period (Figure 14).

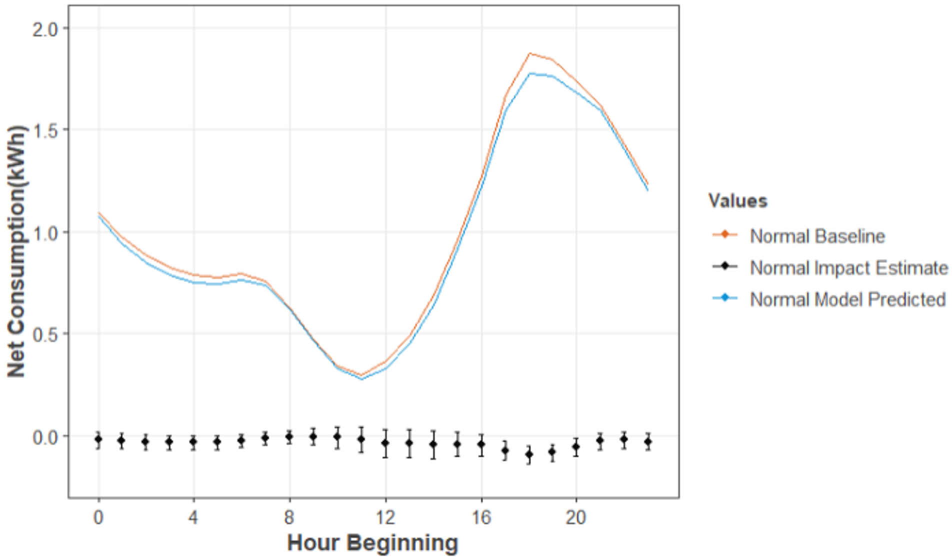
Figure 14. Average Winter Weekday Electric Load Shape and Impacts



Note: Normal weather estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant interval electricity consumption data. Error bars show 95% confidence intervals.

Across participants, on a typical summer weekday, the largest and statistically significant differences in energy consumption occur between 5:00 p.m. and 8:00 p.m., with no significant difference for the remaining hours (Figure 15). During this period, electricity consumption is 0.08 kWh per hour (4.4%) lower after electrification. According to program tracking data, about half (51%) of sites that received a ductless or central heat pump had an existing central cooling system. This suggests that the efficiency gains for sites with existing cooling offsets the additional cooling load for homes with window or room units or no preexisting space cooling before their TECH participation. The impact on peak demand will be discussed further in Section 5.6.[37]

Figure 15. Average Summer Weekday Electric Load Shape and Impacts



Note: Normal weather estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant interval electricity consumption data. Error bars show 95% confidence intervals.

5.4 ELECTRIC ENERGY IMPACTS BY MEASURE

The annual and seasonal electric energy impacts vary by TECH measure adopted. Ductless heat pumps have the greatest annual impact, meaning they add the most electric load, followed by HPWHs (87% of ductless heat pump impact) and central heat pumps (50% of ductless heat pump impact; Table 11).

Central heat pumps have the smallest impacts, even though these sites have the greatest average baseline electric usage. A closer look at the seasonal results can help us to understand why the central heat pump impacts are so different from those of ductless heat pumps. Central heat pumps cause reduced energy usage in the summer months, while ductless heat pumps cause an increase in energy consumption in the summer months. This is likely because 61% of central heat pump sites had existing central cooling, whereas only 29% of ductless heat pump sites did. The shoulder season impacts for ductless systems are almost double that of central systems, potentially because these systems tend to be installed in colder climates that require more heating during the shoulder season and where pre-existing air conditioning systems are less common. In the winter, electric energy impacts are similar for central and ductless heat pumps. HPWHs produce less varied electric energy impacts throughout the year than HVAC heat pumps, with the greatest electric energy impact in the winter, followed by the shoulder season (Table 11).

Table 11. Measure-Level Seasonal and Annual Electric Energy Impacts

Season	Baseline (kWh)	Average Impact (kWh)	% Impact	Lower CI	Upper CI
Central Heat Pump					
Winter	2,891	1,226*	42.4%	1,124	1,327

[37] For brevity, the study team elected to present only weekday summer and weekday winter load shapes in the body of the report. Hourly point estimates and standard errors as well as weekend and shoulder season load shapes are provided via Appendix B.

Summer	4,330	-404*	-9.3%	-532	-276
Shoulder	2,259	242*	10.7%	173	311
Overall	**9,480**	**1,064***	**11.2%**	**886**	**1,241**
Ductless Heat Pump					
Winter	3,094	1,232*	39.8%	1,008	1,456
Summer	2,314	314*	13.6%	141	487
Shoulder	1,984	576*	29.0%	447	705
Overall	**7,392**	**2,123***	**28.7%**	**1,812**	**2,433**
HPWH					
Winter	2,807	996*	35.5%	807	1,185
Summer	2,150	332*	15.4%	153	511
Shoulder	1,724	517*	30.0%	389	645
Overall	**6,681**	**1,845***	**27.6%**	**1,555**	**2,135**

*Results are statistically significant at 95% confidence level.

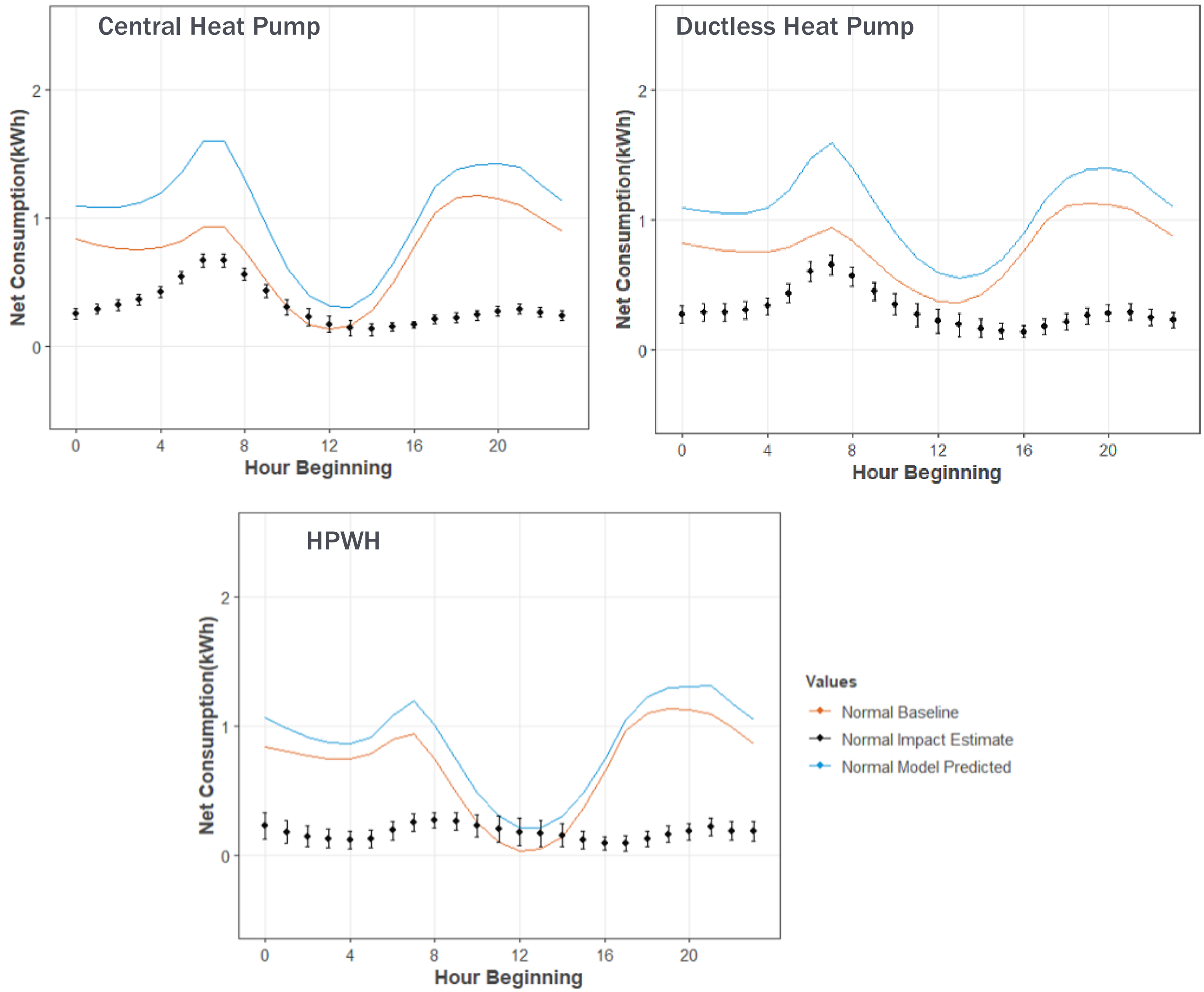
Note: Sites receiving multiple measures were excluded from the measure-level impact estimates. Weather-normalized impact estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant interval electricity consumption data. Summer is defined as June through September, winter as December through March, and shoulder as April, May, October, and November.

Figure 16 and Figure 17 illustrate the hourly load shapes and load impacts by season and measure adopted.[38] In winter, adopters of any TECH measure show a large and statistically significant change in electric energy consumption across all hours on winter weekdays. Central and ductless heat pumps produce similar load impacts on winter weekdays. Both measures also produce a higher peak in the morning than in the afternoon, which is a change from the baseline period. Sites adopting an HPWH use more energy on winter weekday mornings than before TECH participation, but their peak remains in the afternoon (Figure 16).

On summer weekdays, central heat pumps produce a small but statistically significant decrease in energy consumption across all hours of the day, representing a decrease of 0.10 kWh (9.6%) on average. Ductless heat pumps produce a similarly sized *increase* in energy consumption (0.11 kWh), but only in the daytime hours of 8:00 a.m. through 4:00 p.m. Due to the lower baseline usage of ductless heat pump sites in the summer, this change also represents a much larger (55%) increase from the baseline consumption. On summer weekdays, HPWHs cause a statistically significant change in energy consumption only during the morning hours between 7:00 a.m. and 10:00 a.m., when hot water usage peaks (Figure 17).

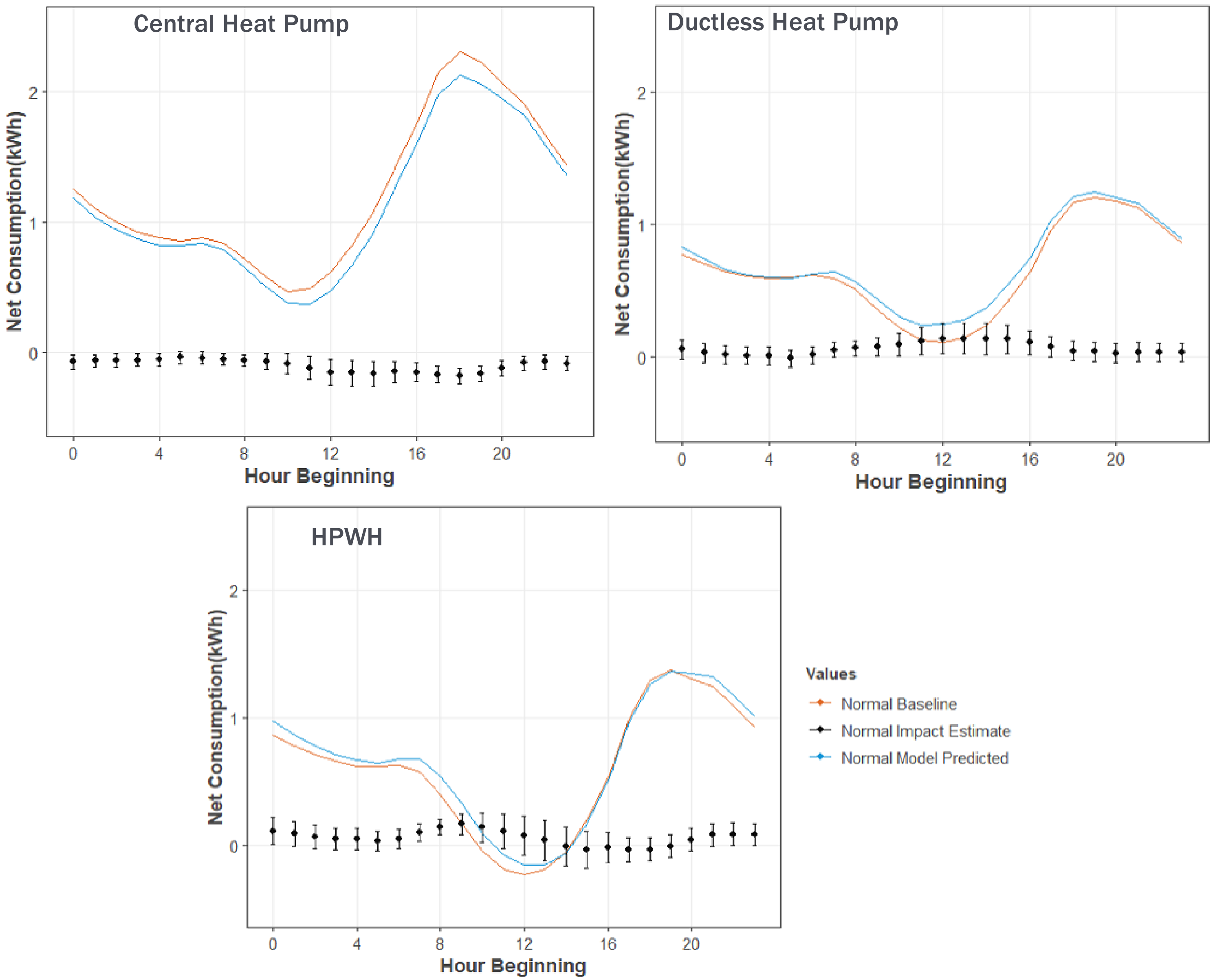
[38] For brevity, the study team elected to present only weekday summer and weekday winter load shapes in the body of the report. Hourly point estimates and standard errors as well as weekend and shoulder season load shapes are provided via Appendix B.

Figure 16. Average Winter Weekday Electric Load Shape and Impacts by Measure



Note: Normal weather estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant interval electricity consumption data. Error bars show 95% confidence intervals.

Figure 17. Average Summer Weekday Electric Load Shape and Impacts by Measure

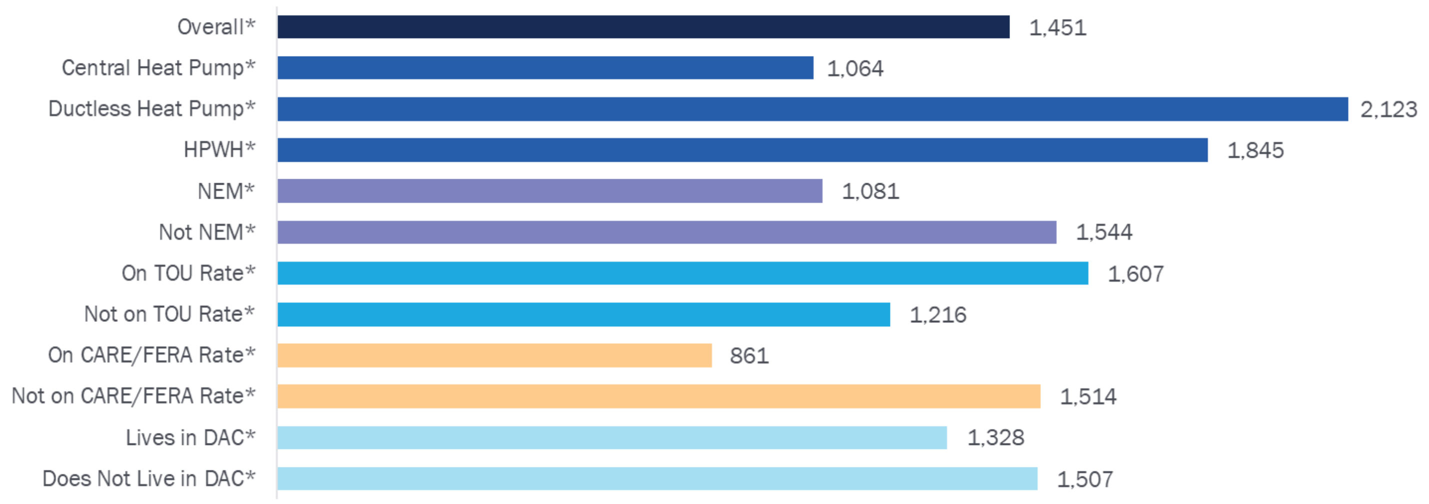


Note: Normal weather estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant interval electricity consumption data. Error bars show 95% confidence intervals.

5.5 ELECTRIC ENERGY IMPACTS BY SEGMENT

The following sections present average electric energy impacts for each customer segment. The study team observed substantial variation in annual energy impacts across segments, as displayed in Figure 18. For example, sites receiving ductless heat pumps had greater overall impacts than those receiving other measures. NEM participants had smaller impacts than non-NEM participants, and low-income participants experienced smaller impacts than customers that do not receive a CARE or FERA discount. These differences and the seasonal patterns within each segment are described in the following sections.

Figure 18. Average Annual Per-Participant Electric Energy Impacts (kWh) by Measure and Segment



*Results are statistically significant at 95% confidence level.

5.5.1 CLIMATE ZONE

There is substantial variation in electric energy impacts between climate zones due to the different climates, measures adopted, baseline home appliances, and demographic characteristics. However, the impacts are not statistically different from zero in all climate zones. The insignificance of some impact estimates may be due to small customer counts, which, all else equal, will increase the uncertainty of the point estimates. Among climate zones with more than 30 modeled sites and results that are statistically different from zero (shaded blue in Table 12), the electricity consumption impacts range from 7% for CZ10 to 43% for CZ2.

Table 12. Climate Zone Annual Electric Energy Impacts

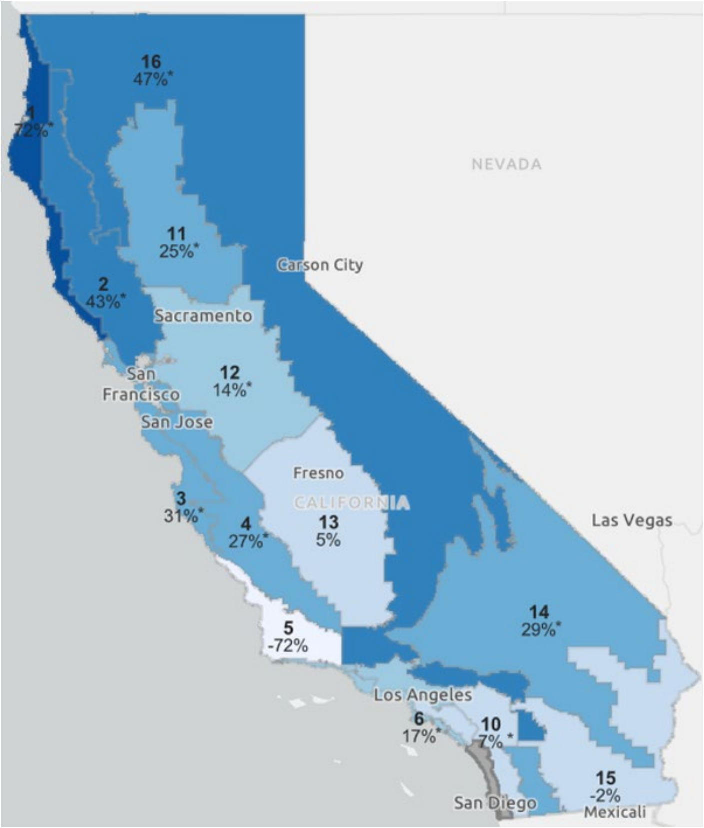
Climate Zone	Modeled Sites	Average Baseline (kWh)	Average Impact (kWh)	% Impact	Lower CI	Upper CI
1	22	4,958	3,588*	72.4%	2,308	4,868
2	235	6,509	2,769*	42.5%	2,334	3,204
3	493	5,331	1,640*	30.8%	1,364	1,916
4	154	5,797	1,583*	27.3%	987	2,178
5	2	2,368	-1,702	-71.9%	-6,144	2,739
6	234	9,303	1,615*	17.4%	1,075	2,154
7						
8	423	8,792	656*	7.5%	348	963
9	251	9,327	1,631*	17.5%	1,096	2,166
10	340	9,045	619*	6.8%	201	1,036
11	89	8,865	2,257*	25.5%	624	3,890
12	1,069	8,678	1,230*	14.2%	1,001	1,458
13	298	9,182	481	5.2%	-49	1,012
14	60	8,833	2,562*	29.0%	1,445	3,679
15	437	12,772	-310	-2.4%	-875	256
16	22	6,855	3,210*	46.8%	1,608	4,812

*Results are statistically significant at 95% confidence level.

Note: Weather-normalized impact estimates based on fixed-effects D-in-D panel regression analysis of TECH participants and matched nonparticipant interval electricity consumption data. Due to unavailable data for some utilities, the study team was unable to estimate electric energy impacts for CZ7. The following climate zones overlap with the service territory of utilities excluded from the analysis sample due to missing or unreliable data. SDG&E: CZ6, CZ7, CZ8, CZ10, CZ14, and CZ15. LADWP: CZ6, CZ8, and CZ9.

The regions with greater impacts as a percentage of baseline electric consumption are located in northern and central California and tend to have high heating load combined with a greater proportion of participants adopting central cooling for the first time upon adopting a heat pump HVAC. Climate zones in southern California experience smaller per-participant impacts. For example, in CZ2 and CZ16, electric energy consumption increases by nearly half (43% and 47%, respectively) over baseline following TECH participation. Meanwhile, in CZ6 and CZ10, the increases are much more modest (7% and 17%, respectively; Figure 19).

Figure 19. Change in Annual Electric Energy Consumption by Climate Zone



*Results are statistically significant at 95% confidence level.

Note: The following climate zones overlap with the service territory of utilities excluded from the analysis sample due to missing or unreliable data. SDG&E: CZ6, CZ7, CZ8, CZ10, CZ14, and CZ15. LADWP: CZ6, CZ8, and CZ9.

Table 13 illustrates how the summer and winter electricity consumption impacts vary across climate zones. In the winter, all climate zones except CZ5 have a statistically significant increase in electric energy consumption. Unsurprisingly, colder climate zones have larger electric energy impacts in the winter than warmer climate zones. The largest increases are in CZ2 and CZ16, while the smallest increases are in CZ6 and CZ8.

In summer, there are statistically insignificant electric energy impacts in six climate zones. While this outcome is partially attributable to the low numbers of sites in some climate zones, it is also driven by variations in energy impacts between sites. Some sites adopted central air conditioning only upon adopting a heat pump HVAC, leading to a large increase in cooling load in the summer. In contrast, in other climate zones, a greater share of participants might be replacing an inefficient central cooling system or widespread window air conditioning usage with a more efficient heat pump solution. Several climate zones in southern and central California, including CZ10, CZ12, CZ13, and CZ15, had a decrease in electric energy consumption in the summer (Table 13).

Table 13. Climate Zone Seasonal Electric Energy Impacts

Climate Zone	Winter					Summer				
	Average Baseline (kWh)	Average Baseline (kWh)	Average Baseline (kWh)	Average Baseline (kWh)	Average Baseline (kWh)	Average Baseline (kWh)	Average Impact (kWh)	% Impact	Lower CI	Upper CI
1	1,024	1,024	1,024	1,024	1,024	1,138	1,075*	94.50%	296	1,855
2	3,188	3,188	3,188	3,188	3,188	1,541	649*	42.10%	439	860
3	2,696	2,696	2,696	2,696	2,696	1,103	321*	29.10%	180	462
4	2,558	2,558	2,558	2,558	2,558	1,815	-11	-0.60%	-396	374
5	658	658	658	658	658	253	-1,877	-740.90%	-5,201	1,447
6	3,542	3,542	3,542	3,542	3,542	3,184	459*	14.40%	64	854
7										
8	2,940	2,940	2,940	2,940	2,940	3,589	-180	-5.00%	-402	43
9	3,056	3,056	3,056	3,056	3,056	4,025	-96	-2.40%	-461	270
10	2,616	2,616	2,616	2,616	2,616	4,611	-714*	-15.50%	-1,028	-400
11	3,665	3,665	3,665	3,665	3,665	3,250	145	4.50%	-772	1,062
12	3,014	3,014	3,014	3,014	3,014	3,428	-168*	-4.90%	-325	-11
13	2,669	2,669	2,669	2,669	2,669	5,079	-1,279*	-25.20%	-1,648	-911
14	2,796	2,796	2,796	2,796	2,796	3,939	829*	21.00%	6	1,652
15	2,390	2,390	2,390	2,390	2,390	7,154	-983*	-13.70%	-1,462	-504
16	2,594	2,594	2,594	2,594	2,594	2,554	952	37.30%	-273	2,178

*Results are statistically significant for designated climate zone and season at 95% confidence level.

Note: Weather-normalized impact estimates based on fixed-effects D-in-D panel regression analysis of TECH participants and matched nonparticipant interval electricity consumption data. Summer is defined as June through September, winter as December through March, and shoulder as April, May, October, and November. Due to unavailable data for some utilities, the study team was unable to estimate electric energy impacts for CZ7. The following climate zones overlap with the service territory of utilities excluded from the analysis sample due to missing or unreliable data. SDG&E: CZ6, CZ7, CZ8, CZ10, CZ14, and CZ15. LADWP: CZ6, CZ8, and CZ9.

5.5.2 NEM STATUS

Table 14 contains the annual and seasonal electric energy impacts for NEM compared to non-NEM participants.[39] The impacts reported for NEM participants come from the same model specification as non-NEM participants. The study team also tested models containing solar irradiance data but did not find statistically different results. This is discussed further in Appendix A.

NEM participants experience a smaller increase in annual energy consumption than non-NEM participants, although this increase represents a higher percentage of their baseline net energy consumption. The baseline energy consumption of NEM sites is less than half that of non-NEM sites based on net energy consumption. Winter season impacts are similar between NEM and non-NEM sites, although again, these represent a higher percentage of the net usage baseline of NEM than non-NEM sites. In the summer, NEM participants experience a reduction in energy consumption, whereas the impacts for non-NEM participants are close to and not statistically different from zero. In the shoulder season, TECH participation causes NEM customers to approximately double their net electricity usage, whereas the energy consumption of non-NEM sites only increases by about 10% (Table 14).

Table 14. NEM and Non-NEM Seasonal Electric Energy Impacts

NEM Status	Baseline (kWh)	Average Impact (kWh)	% Impact	Lower CI	Upper CI
NEM					
Winter	2,040	1,200*	58.8%	1,017	1,382
Summer	1,654	-510*	-30.8%	-708	-312
Shoulder	385	391*	101.7%	260	522
Overall	**4,079**	**1,081***	**26.5%**	**782**	**1,380**
Non-NEM					
Winter	3,279	1,204*	36.7%	1,115	1,294
Summer	4,185	59	1.4%	-37	155
Shoulder	2,875	281*	9.8%	228	333
Overall	**10,340**	**1,544***	**14.9%**	**1,403**	**1,685**

*Results are statistically significant at 95% confidence level.

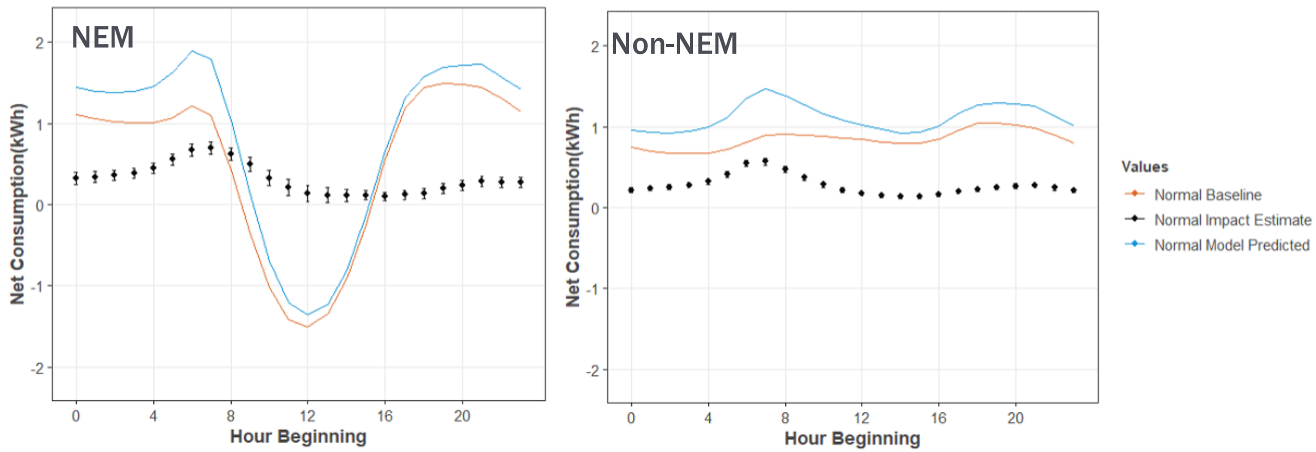
Note: Weather-normalized impact estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant interval electricity consumption data. Summer is defined as June through September, winter as December through March, and shoulder as April, May, October, and November.

Both NEM and non-NEM sites exhibit a large and statistically significant increase in energy consumption across all hours of the day on winter weekdays and a new morning peak in demand following TECH participation. On winter weekdays, the increase in net electric energy consumption tends to be greater for NEM sites during the non-solar production hours and greater for non-NEM sites during peak solar production hours. The typical NEM TECH participant uses less electricity on a summer day than before TECH participation, resulting in smaller net energy usage (i.e., more excess energy is sent back to the grid during solar production hours than would have been otherwise). Among NEM participants, there is a statistically significant decrease of 73% in energy consumption for all hours from noon through 10:00 p.m.. While this change is large when considered as a percentage of the baseline net consumption of NEM participants, the magnitude of the change remains small. On summer weekdays, the average non-NEM participant

[39] Throughout the report, the study team refers to NEM participants when discussing TECH participants with solar PV. These participants were identified based on their net metering (NEM) status with their electric utility. The study team has no way to identify non-net-metered customers with solar PV and understands this would be rare among residential customers in the study period.

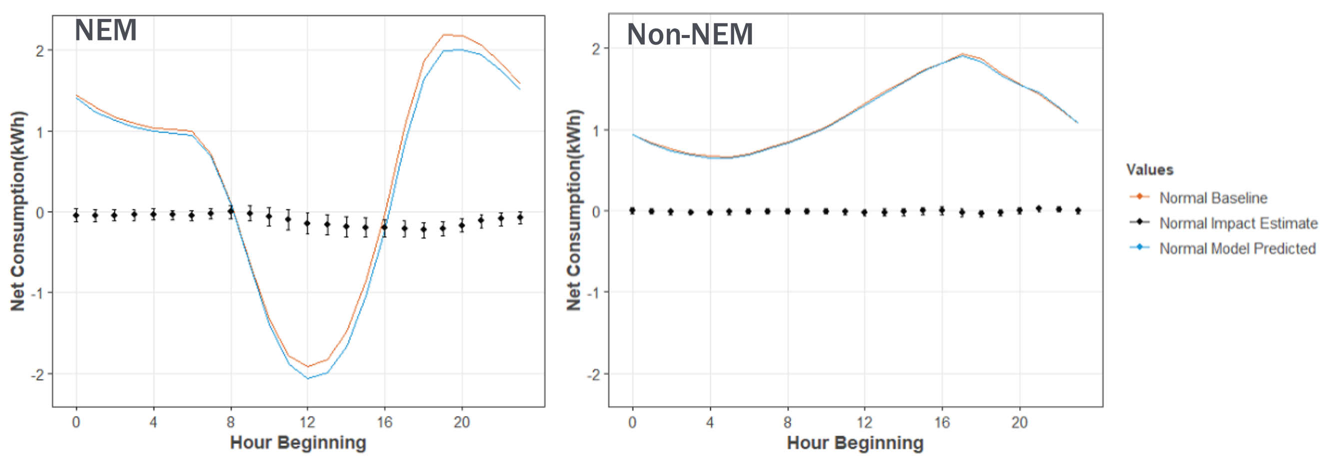
experiences no change in how energy is used across the hours of a typical day following TECH participation (Figure 20 and Figure 21).

Figure 20. NEM and Non-NEM Average Winter Weekday Electric Load Shape and Impacts



Note: Estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant interval electricity consumption data. Error bars show 95% confidence intervals.

Figure 21. NEM and Non-NEM Average Summer Weekday Electric Load Shape and Impacts



Note: Estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant interval electricity consumption data. Error bars show 95% confidence intervals.

5.5.3 TIME-OF-USE RATE

TOU rate participants experience a 25% greater increase in electric energy consumption than participants on a non-TOU rate. Their energy impacts are higher than those of non-TOU rate participants despite having lower baseline consumption.[40] While in summer TOU rate participants have no change in consumption on average, non-TOU participants experience a 5% decrease in energy consumption, likely because more non-TOU participants had pre-existing central air conditioning than did TOU participants (53% vs. 48%). The winter season impacts are similar between the groups, while the shoulder season impacts are larger for TOU participants. This is likely because a higher proportion of participants on a TOU rate than a standard rate adopted HPWHs (19% vs. 9%), which has higher shoulder season impacts than HVAC measures (Table 15).

Table 15. TOU and Non-TOU Rate Seasonal Electric Energy Impacts

Time-of-Use Rate	Baseline (kWh)	Average Impact (kWh)	% Impact	Lower CI	Upper CI
On TOU Rate					
Winter	2,989	1,241*	41.5%	1,114	1,368
Summer	3,005	-35	-1.2%	-161	92
Shoulder	1,969	400*	20.3%	319	482
Overall	**7,963**	**1,607***	**20.2%**	**1,410**	**1,804**
Not on TOU Rate					
Winter	2,797	1,165*	41.7%	1,059	1,272
Summer	4,039	-179*	-4.4%	-299	-58
Shoulder	2,303	229*	9.9%	160	298
Overall	**9,140**	**1,216***	**13.3%**	**1,041**	**1,390**

*Results are statistically significant at 95% confidence level.

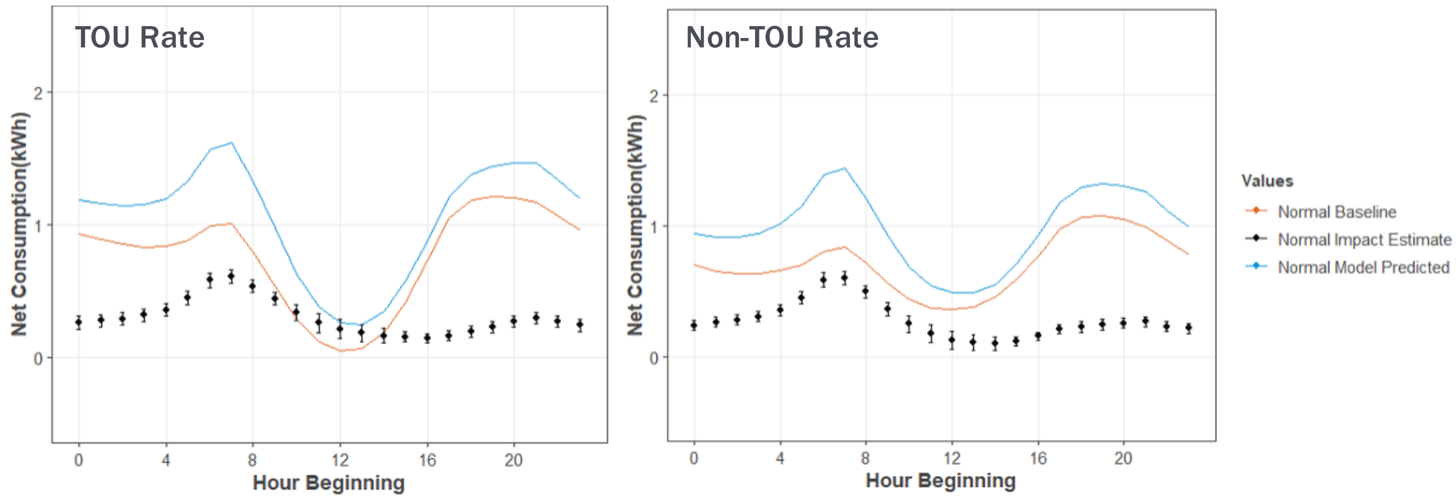
Note: Weather-normalized impact estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant interval electricity consumption data. Summer is defined as June through September, winter as December through March, and shoulder as April, May, October, and November.

Both TOU and non-TOU rate participants experience statistically significant increases in electric energy consumption across all winter weekday hours and display prominent morning and afternoon peaks, with the morning peak higher than the afternoon. In the winter, the increase in energy consumption is greater for TOU than non-TOU rate participants in the midday hours from 9:00 a.m. through 3:00 p.m. and in the 10:00 p.m. hour. The only hour energy consumption increases more for non-TOU rate participants than for TOU rate participants is the 5:00 p.m. hour (Figure 22).

TECH participants on a TOU rate experience a statistically significant decrease in energy consumption on summer weekdays between 5:00 p.m. and 7:00 p.m., which represents about 5% of the baseline usage in those hours. Participants on a non-TOU rate experience a decrease in most hours on summer weekdays, and the decrease is higher than for TOU participants (6.7% on average in hours with a reduction; Figure 23).

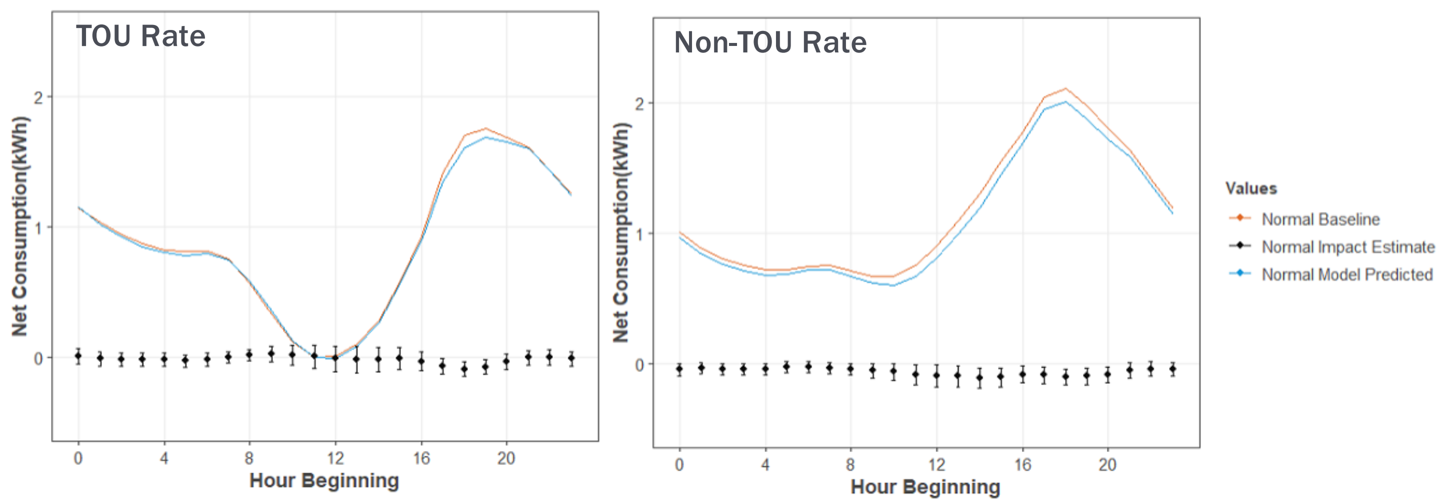
[40] This analysis grouped customers based on their rate code type when they installed their TECH equipment and does not account for rate changes following equipment installation.

Figure 22. TOU and Non-TOU Rate Average Winter Weekday Electric Load Shape and Impacts



Note: Estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant interval electricity consumption data. Error bars show 95% confidence intervals.

Figure 23. TOU and Non-TOU Rate Average Summer Weekday Electric Load Shape and Impacts



Note: Estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant interval electricity consumption data. Error bars show 95% confidence intervals.

5.5.4 LOW-INCOME CUSTOMERS

The electric energy impacts of customers receiving a CARE or FERA discount on their electric service are shown in Table 16. TECH participants on CARE or FERA increase their annual consumption by about 861 kWh or 9.2%. The increase in annual consumption for CARE and FERA participants was about half as much as for non-CARE or FERA TECH participants, despite CARE and FERA participants having a higher baseline. The biggest difference in impacts between CARE or FERA and non-CARE or FERA customers occurs in the winter and shoulder seasons. In both seasons, the increase in consumption is much higher (1.7 to 2.3 times higher) for customers not receiving a CARE or FERA discount.

Table 16. CARE or FERA and Non-CARE or FERA Seasonal Electric Energy Impacts

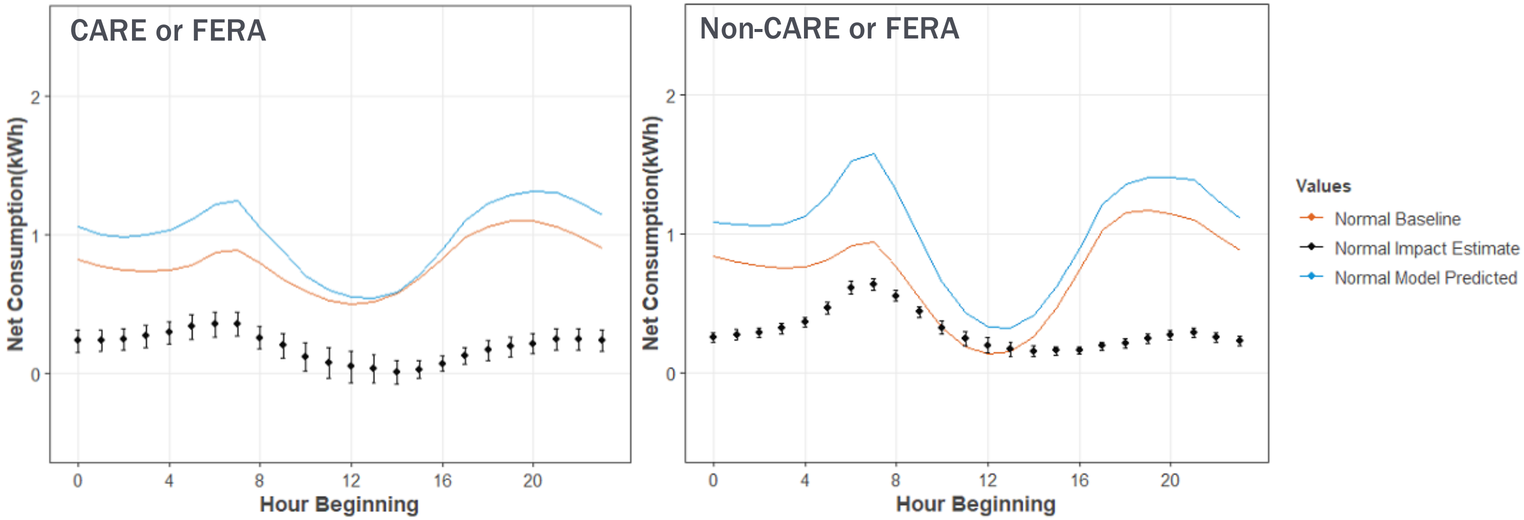
Low-Income Status	Baseline (kWh)	Average Impact (kWh)	% Impact	Lower CI	Upper CI
CARE or FERA					
Winter	3,004	756*	25.2%	484	1,028
Summer	4,067	-47	-1.2%	-309	214
Shoulder	2,338	153*	6.5%	-14	320
Overall	**9,409**	**861***	**9.2%**	**449**	**1,274**
Non-CARE or FERA					
Winter	2,892	1,261*	43.6%	1,173	1,349
Summer	3,321	-103*	-3.1%	-199	-7
Shoulder	2,069	356*	17.2%	298	415
Overall	**8,281**	**1,514***	**18.3%**	**1,371**	**1,657**

*Results are statistically significant at 95% confidence level.

Note: Weather-normalized impact estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant interval electricity consumption data. Summer is defined as June through September, winter as December through March, and shoulder as April, May, October, and November.

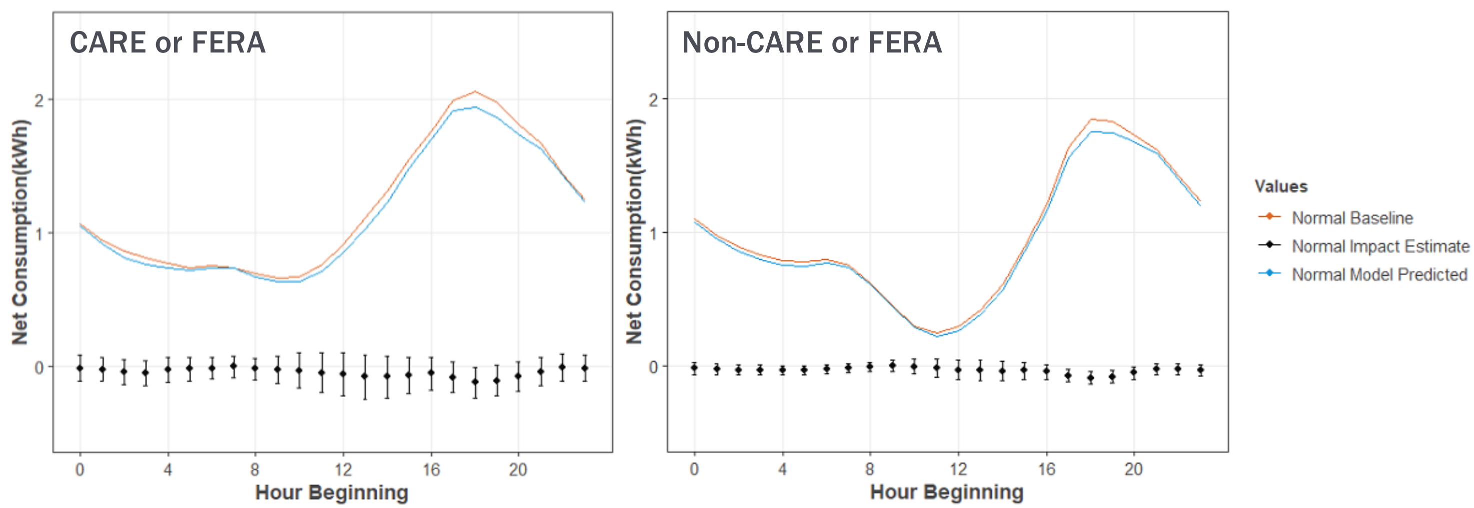
In winter, CARE and FERA TECH participants experience increases in consumption between 12:00 a.m. and 10:00 a.m. and after 4:00 p.m. Although the increase in consumption is greater in the morning hours, electricity demand still peaks in the afternoon. Meanwhile, in winter, Non-CARE or FERA customers experience statistically significant increases in energy consumption across all weekday hours. Consumption increases the most between 5:00 a.m. and 8:00 a.m. Demand now peaks in the morning, and the afternoon peak is also greater than before (Figure 24). In the summer, CARE and FERA participants exhibit small (4.4%) and marginally statistically significant decreases in consumption on weekdays between 5:00 p.m. and 9:00 p.m. The energy impacts are not statistically significant in other weekday hours (Figure 25).

Figure 24. CARE or FERA and Non-CARE or FERA Average Winter Weekday Electric Load Shape and Impacts



Note: Estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant interval electricity consumption data. Error bars show 95% confidence intervals.

Figure 25. CARE or FERA and Non-CARE or FERA Average Summer Weekday Electric Load Shape and Impacts



Note: Estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant interval electricity consumption data. Error bars show 95% confidence intervals.

5.5.5 DISADVANTAGED COMMUNITIES

Table 17 summarizes the annual and seasonal electric energy impacts of participants residing within and outside DACs. Overall, participants living in DACs have slightly smaller electric energy impacts than customers living outside DACs. Their overall increase in electric energy consumption is 88% of a customer not living in a DAC. In the winter, participants living in DACs have a more modest (26% smaller) increase in electric energy consumption than those living outside DACs. The summer energy impacts of participants in DACs are not different from zero. In contrast, the typical TECH participant living outside a DAC experiences a slight decrease (3.3%) in electric energy consumption in the summer.

Table 17. DAC and Non-DAC Seasonal Electric Energy Impacts

DAC Status	Baseline (kWh)	Average Impact (kWh)	% Impact	Lower CI	Upper CI
Lives in a DAC					
Winter	2,758	960*	34.8%	809	1,111
Summer	3,468	-28	-0.8%	-192	137
Shoulder	1,937	396*	20.4%	298	494
Overall	**8,162**	**1,328***	**16.3%**	**1,084**	**1,572**
Does Not Live in a DAC					
Winter	2,941	1,294*	44.0%	1,193	1,394
Summer	3,384	-112*	-3.3%	-219	-5
Shoulder	2,170	326*	15.0%	259	392
Overall	**8,495**	**1,507***	**17.7%**	**1,346**	**1,668**

*Results are statistically significant at 95% confidence level.

Note: Weather-normalized impact estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant interval electricity consumption data. Summer is defined as June through September, winter as December through March, and shoulder as April, May, October, and November.

Load shapes for the DAC and non-DAC segments are similar and are provided in Appendix B.

5.6 ELECTRIC PEAK DEMAND IMPACTS

Widespread electrification is likely to affect electricity demand during peak hours. The study team estimated the peak demand impacts using several peak period definitions.

5.6.1 RESOURCE ADEQUACY WINDOW

The study team assessed the change in average hourly demand during the resource adequacy (RA) window from 4:00 p.m. to 9:00 p.m. on summer weekdays. Among all participants, there is a slight decrease in demand of 4.4% during the RA window. Participants installing central heat pumps exhibit a decrease in demand of 7.5%. In contrast, ductless heat pump participants increase demand during the RA window by 5.6%. This variation likely reflects differences in the prevalence of baseline period air conditioning equipment. Across the other segments, the biggest difference is between NEM and non-NEM participants. NEM participants experience a 14% decrease in RA window demand, while non-NEM participants experience a 1% decrease. This is likely due to the correspondence of the RA window with solar production hours (Table 18).

Table 18 . Change in Average Electric Demand During RA Window by Segment

Segment	Baseline Period (kW)	Reporting Period (kW)	Change (kW)	% Change
Overall	**1.68**	**1.61**	**-0.07**	**-4.4%**
Measure Type				
Central HP	2.10	1.94	-0.16	-7.5%
Ductless HP	1.03	1.09	0.06	5.6%
HPWH	1.10	1.09	-0.01	-0.9%
NEM Status				
NEM	1.46	1.25	-0.21	-14.1%
Not NEM	1.77	1.75	-0.02	-1.0%
Time-of-Use Rate				
TOU	1.50	1.44	-0.06	-4.1%
Not TOU	1.94	1.85	-0.09	-4.8%
Low-Income Customers				
CARE/FERA	1.92	1.83	-0.09	-4.7%
Not CARE/FERA	1.65	1.58	-0.07	-4.3%
Disadvantaged Communities				
DAC	1.75	1.68	-0.06	-3.6%
Not DAC	1.66	1.58	-0.07	-4.5%

Note: Results are derived from summer weekday 4:00 p.m. to 9:00 p.m. weather-normalized impact estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant interval electricity consumption data.

Table 19 presents the average demand impacts during the RA window by climate zone. These results for some climate zones should be interpreted cautiously, as their impacts are estimated with a small number of participants and, therefore, imprecisely estimated. There is a range of climate zone RA demand impacts, with some zones experiencing demand increases and others experiencing demand decreases. Eight of 15 climate zones experience increased demand during the RA window. The largest increases tend to occur in cooler climate zones such as CZ1, CZ2, and CZ16 with lower baseline air conditioning penetration. Seven climate zones experience a decrease in RA window demand. Most experience a decrease of between 10% and 15%. In these climate zones, program tracking data suggests that TECH participants were more likely to replace less efficient central cooling systems with heat pump HVACs.

Table 19. Change in Average Electric Demand During RA Window by Climate Zone

Climate Zone	Modeled Sites	Baseline Period (kW)	Reporting Period (kW)	Change (kW)	% Change	Statistically Significant
1	22	0.37	0.57	0.21	56.7%	Yes
2	235	0.68	0.90	0.22	32.3%	Yes
3	493	0.44	0.50	0.05	12.2%	Yes
4	154	0.86	0.85	-0.01	-1.1%	Yes
5	2	0.32	-1.17	-1.49	-459.8%	No
6	234	1.25	1.39	0.14	10.9%	Yes
7						
8	423	1.58	1.63	0.04	2.6%	Yes
9	251	1.87	1.92	0.04	2.3%	Yes
10	340	2.51	2.26	-0.25	-9.8%	Yes
11	89	2.10	1.80	-0.30	-14.3%	Yes
12	1,069	1.76	1.60	-0.16	-9.1%	Yes
13	298	2.68	2.28	-0.40	-14.9%	No
14	60	1.78	2.16	0.38	21.4%	Yes
15	437	3.14	2.87	-0.27	-8.6%	No
16	22	1.50	1.87	0.36	24.1%	Yes

Note: Results are derived from summer weekday 4:00 p.m. to 9:00 p.m. weather-normalized impact estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant interval electricity consumption data. Due to unavailable data for some utilities, the study team was unable to estimate electric energy impacts for CZ7. The following climate zones overlap with the service territory of utilities excluded from the analysis sample due to missing or unreliable data. SDG&E: CZ6, CZ7, CZ8, CZ10, CZ14, and CZ15. LADWP: CZ6, CZ8, and CZ9. Final column indicates whether results were significant at 95% confidence level for overall summer weekday models from which RA results were derived. Results from climate zones with insignificant results should be interpreted with caution.

5.6.2 DEER DEFINITION

The DEER peak demand hours occur on three successive weekdays from 4:00 p.m. to 9:00 p.m., with the peak weekdays varying between climate zones based on CZ2022 weather normal values.

Across climate zones, there is a range of DEER peak demand impacts, with some climate zones experiencing increased demand and others experiencing decreases. This variation may be due to differences in baseline air conditioning systems, with some sites previously without central air conditioning adding cooling load and other sites replacing existing air conditioning systems with more efficient heat pump HVACs. Many of the climate zone DEER peak impact estimates are imprecisely estimated and not statistically different from zero. For some climate zones, this reflects a small sample size. For other climate zones, it reflects true impacts equal or close to zero. Only a few climate zones experience statistically significant changes in peak demand during the DEER peak period (shaded blue in Table 20). CZ2, a northern coastal climate zone with low levels of central air conditioning, experiences an increase in peak demand for participants. CZ12 and CZ13, in southern California, where central air conditioning is more prevalent, experience decreases in peak demand (Table 20).

Table 20. Climate Zone Change in DEER Peak Electric Demand

Climate Zone	Modeled Sites	Average Impact (kW)	Lower CI	Upper CI
1	22	0.21	-0.04	0.45
2	235	0.18*	0.05	0.30
3	493	0.05	-0.02	0.12
4	154	0.01	-0.23	0.24
5	2	-1.49	-4.10	1.12
6	234	0.05	-0.08	0.17
7				
8	423	0.02	-0.10	0.14
9	251	0.02	-0.20	0.24
10	340	-0.09	-0.27	0.09
11	89	-0.12	-0.51	0.28
12	1,069	-0.13*	-0.23	-0.03
13	298	-0.20*	-0.37	-0.04
14	60	0.22	-0.19	0.63
15	437	-0.15	-0.37	0.06
16	22	0.08	-0.61	0.78

*Results are statistically significant at 95% confidence level.

Note: Weather-normalized impact estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant interval electricity consumption data for DEER peak periods. Due to unavailable data for some utilities, the study team was unable to estimate electric energy impacts for CZ7. The following climate zones overlap with the service territory of utilities excluded from the analysis sample due to missing or unreliable data. SDG&E: CZ6, CZ7, CZ8, CZ10, CZ14, and CZ15. LADWP: CZ6, CZ8, and CZ9.

5.6.3 TIMING OF TYPICAL PEAK DEMAND

For each segment and the sample overall, the study team assessed the impact of TECH participation on peak electricity demand by season, day type (i.e., weekday vs. weekend), and hour of the day and whether there was change in when demand typically peaks (e.g., a switch from summer weekdays at 6:00 p.m. to summer weekdays at 8:00 p.m.). The study team assessed the change in the time when demand typically peaks using the reporting-period, weather-normalized baseline and predicted load shapes.

Across all TECH participants, there is a change in the peak day type from a summer weekend to a summer weekday, although the peak hour remains at 6:00 p.m. Among the segments displayed in Table 21, over one-third (36%) experience a change in the peak hour, season, and/or day type after TECH participation. In most cases, the change is minor. For example, in many cases, the peak hour remains in the summer but shifts one hour later or earlier or between a weekday and a weekend. However, in rare cases, the change is more pronounced. For example, among ductless heat pump sites, the peak hour shifts from 7:00 p.m. on a summer weekday to 7:00 a.m. on a winter weekday.

Table 21. Change in Peak Day Type, Season, and Hour Between Baseline and Reporting Periods

Legend	Day Type		Season		Hour	
	Weekday	Weekend	Summer	Winter	Baseline Period	Reporting Period

Segment	Overall Change?	Day Type		Season		Hour				
						7 a.m.	5 p.m.	6 p.m.	7 p.m.	8 p.m.
Overall	Yes									
Measure Type										
Central HP	No									
Ductless HP	Yes									
HPWH	No									
NEM Status										
NEM	Yes									
Not NEM	No									
Time-of-Use Rate										
TOU	No									
Not TOU	No									
Low-Income Customers										
CARE/FERA	No									
Not CARE/FERA	Yes									
Disadvantaged Communities										
DAC	Yes									
Not DAC	No									

Note: Results are derived from weather-normalized impact estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant interval electricity consumption data.

The study team also considered the magnitude and direction of change in the average per-participant demand in the peak hour of the baseline period compared to the reporting period. Across all TECH participants, there is a decrease in demand of 0.10 kW, which is a five percent reduction relative to baseline peak demand. In ten of eleven segments, TECH participants experience a decrease in peak hour demand, whether the peak hour changes. The change in peak demand is typically modest—between 3 and 9%. Ductless heat pump sites are the exception. Ductless heat pump participants experience an increase in peak demand and a shift to a winter peak. On average, a ductless heat pump participant increases demand by 0.39 kW, a 32% increase over the baseline peak demand value (Table 22).

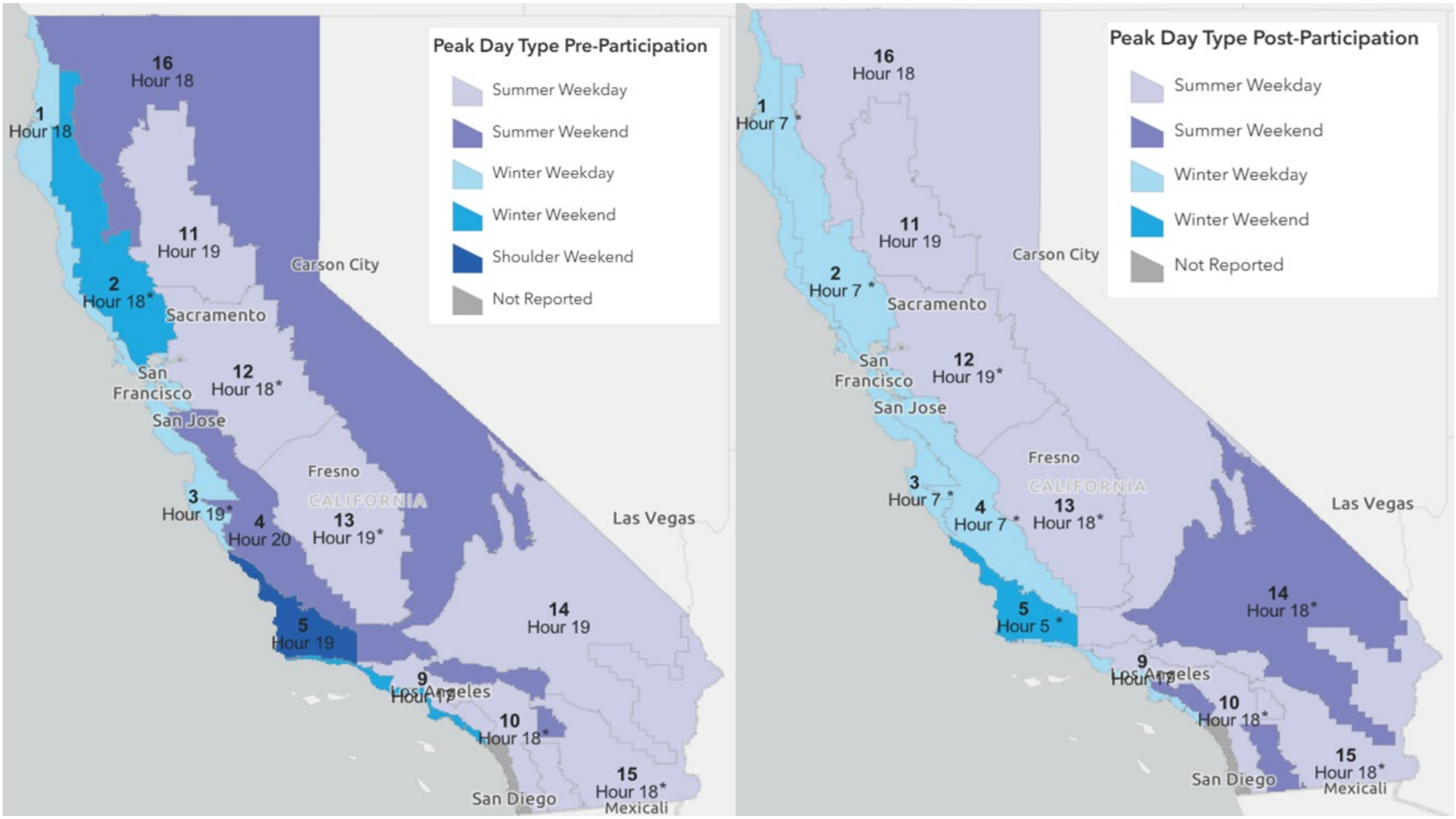
Table 22. Change in Average Peak Electric Demand by Segment

Segment	Change in Peak Hour and Day Type?	Baseline Period (kW)	Reporting Period (kW)	Change (kW)
Overall	**Yes**	**1.88**	**1.78**	**-0.10**
Measure Type				
Central HP	No	2.31	2.13	-0.18
Ductless HP	Yes	1.20	1.59	0.39
HPWH	No	1.37	1.36	-0.01
NEM Status				
NEM	Yes	2.20	2.00	-0.19
Not NEM	No	1.97	1.92	-0.06
Time-of-Use Rate				
TOU	No	1.76	1.68	-0.07
Not TOU	No	2.11	2.01	-0.10
Low-Income Customers				
CARE/FERA	No	2.06	1.94	-0.12
Not CARE/FERA	Yes	1.86	1.76	-0.10
Disadvantaged Communities				
DAC	Yes	1.92	1.84	-0.08
Not DAC	No	1.86	1.76	-0.10

Note: Results are derived from weather-normalized impact estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant interval electricity consumption data.

To inform regional grid planning given widespread electrification, policymakers will want to consider how the magnitude and timing of peak demand changes for TECH participants in different climate zones. These results should be interpreted with caution, as the hourly modeled results from which these impacts were derived are not statistically significant for all climate zones due to small sample sizes. Nevertheless, most climate zones (73%) experience a change in the peak hour, day type, and/or season. Most of the time, this shift is between weekdays and weekends or a shift of one hour earlier or later. However, there are a couple of more dramatic shifts. In CZ4, the peak hour among TECH participants shifts from 8:00 p.m. on a summer weekend to 7:00 a.m. on a winter weekday. For some cooler climate zones, including CZ2 and CZ3, the peak hour shifts from a winter evening hour to a winter morning hour (Figure 26).

Figure 26. Change in Average Peak Electric Demand Amount by Climate Zone



*Results are statistically significant at 95% confidence level.

Note: The following climate zones overlap with the service territory of utilities excluded from the analysis sample due to missing or unreliable data. SDG&E: CZ6, CZ7, CZ8, CZ10, CZ14, and CZ15. LADWP: CZ6, CZ8, and CZ9.

The magnitude of the change in peak demand among TECH participants also varies by climate zone. About two-thirds (67%) of climate zones exhibit an increase in peak demand for TECH participants. Among climate zones with at least 30 modeled sites, those with the largest increase in peak demand are CZ2, CZ3, and CZ4, and those with the largest decrease are CZ13 and CZ15 (Table 23).

Table 23. Change in Average Peak Electric Demand by Climate Zone

Climate Zone	Modeled Sites	Change in Peak Hour and Day Type?	Baseline Period (kW)	Reporting Period (kW)	Change (kW)
1	22	Yes	1.85	2.45	0.60
2	235	Yes	1.20	1.92	0.72
3	493	Yes	1.09	1.51	0.42
4	154	Yes	1.21	1.61	0.40
5	2	Yes	1.28	2.47	1.19
6	234	Yes	1.35	1.61	0.26
7					
8	423	Yes	1.69	1.73	0.03
9	251	No	2.02	2.04	0.02
10	340	No	2.72	2.45	-0.27
11	89	No	2.42	2.13	-0.28
12	1,069	Yes	2.00	1.78	-0.22
13	298	Yes	2.98	2.59	-0.39
14	60	Yes	2.05	2.39	0.34
15	437	No	3.36	3.08	-0.29
16	22	Yes	1.86	2.06	0.20

Note: Results are derived from weather-normalized impact estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant interval electricity consumption data. Due to unavailable data for some utilities, the study team was unable to estimate electric energy impacts for CZ7.

5.7 GAS ENERGY IMPACTS SUMMARY

TECH participants decrease their gas consumption by an average of 165 therms or -38% in a normal weather year. Across all participants, this equates to 1,683,471 therms per year (Table 24).

Table 24. Annual Gas Energy Impacts

Metric	Value
Average Impact (therms)	-165
% Impact	-38%
Participants	10,197
Total Impact (therms)	-1,683,471

Note: Weather-normalized impact estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant monthly natural gas consumption data.

As natural gas was the primary heating fuel for the majority of TECH participants, the gas energy impacts are concentrated in the winter season (-101 therms, -41%) and shoulder season (-47 therms, -39%). As Table 25 shows, the impact was smallest in summer (-17 therms, -26%).

Table 25. Seasonal Gas Energy Impacts

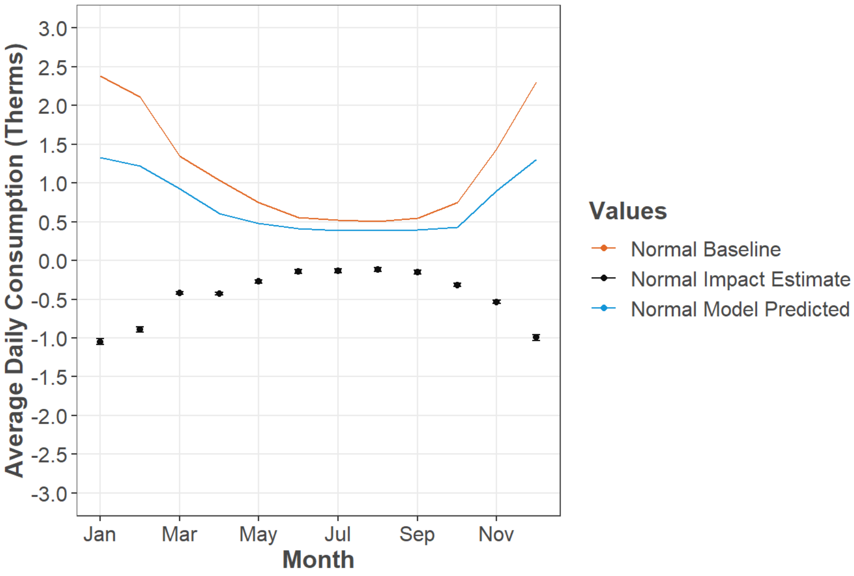
Season	Baseline (therms)	Average Impact (therms)	% Impact	Lower CI	Upper CI
Winter	246	-101*	-41.2%	-105	-98
Summer	65	-17*	-25.6%	-20	-13
Shoulder	121	-47*	-39.1%	-51	-44
Overall	**432**	**-165***	**-38.2%**	**-172**	**-158**

*Results are statistically significant at 95% confidence level.

Note: Weather-normalized impact estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant monthly natural gas consumption data. Summer is defined as June through September, winter as December through March, and shoulder as April, May, October, and November.

Average gas consumption per participant decreases in every month following installation of the heat pump technology. The impacts are greater in the winter, which reflects the electrification of gas space heating systems. The summer impacts are smaller and mainly driven by HPWH measures, which are less commonly adopted than HVAC measures (Figure 27).

Figure 27. Monthly Gas Consumption Shapes and Impacts



Note: Normal weather estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant monthly natural gas consumption data. Error bars show 95% confidence intervals.

5.8 GAS ENERGY IMPACTS BY MEASURE

For all measures and seasons, there are statistically significant reductions in gas consumption. However, the annual and seasonal impacts vary by measure. Ductless heat pump participants have the largest average annual reduction in gas consumption, 180 therms, compared to central heat pump participants, 154 therms, a difference statistically significant at the 5% level. The difference in impact is not attributable to a difference in baseline consumption. Among participants receiving an HVAC measure, ductless heat pump participants exhibit the largest winter and shoulder season reductions in gas consumption. HPWH participants also show large reductions in average annual gas consumption per participant of 164 therms or 35%. However, as hot water demand is less sensitive to weather, the impacts are distributed more evenly across seasons (Table 26).

Table 26. Measure-Level Seasonal Gas Energy Impacts

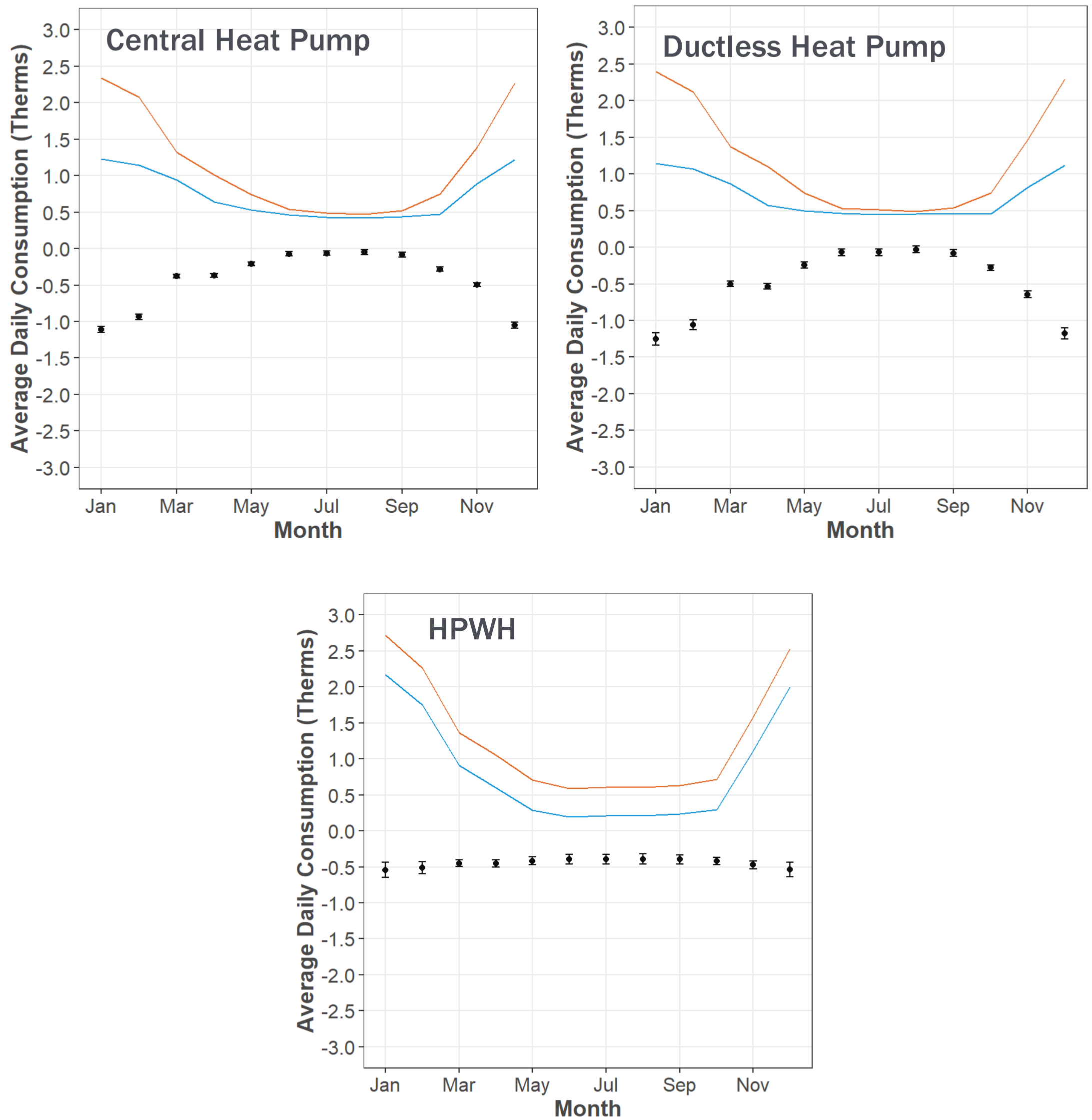
Season	Baseline (therms)	Average Impact (therms)	% Impact	Lower CI	Upper CI
Central Heat Pump					
Winter	242	-105*	-43.4%	-109	-101
Summer	62	-8*	-13.4%	-12	-4
Shoulder	118	-41*	-34.9%	-45	-37
Overall	**422**	**-154***	**-36.6%**	**-163**	**-145**
Ductless Heat Pump					
Winter	247	-120*	-48.7%	-127	-114
Summer	63	-8*	-12.0%	-14	-1
Shoulder	123	-52*	-42.0%	-58	-45
Overall	**433**	**-180***	**-41.4%**	**-194**	**-165**
HPWH					
Winter	268	-62*	-23.0%	-71	-53
Summer	74	-48*	-64.9%	-57	-39
Shoulder	123	-54*	-43.6%	-63	-45
Overall	**466**	**-164***	**-35.1%**	**-181**	**-146**

*Results are statistically significant at 95% confidence level.

Note: Sites receiving multiple measures were excluded from the measure-level impact estimates. Weather-normalized impact estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant monthly natural gas consumption data. Summer is defined as June through September, winter as December through March, and shoulder as April, May, October, and November.

The monthly impact estimates (in average daily therms per participant) by heat pump measure type underscore the strong seasonality of the gas impacts for central heat pump and ductless heat pump customers. The reductions in gas consumption are close to zero in summer, between 0 and 0.5 therms in the shoulder months, and reach a maximum in winter of about 1.0 therms per participant per day. The impact estimate for HPWHs is close to -0.5 therms per participant per day in each month of the year. The impact is slightly lower in summer and higher in winter (Figure 28).

Figure 28. Monthly Gas Consumption Shapes and Impacts by Measure

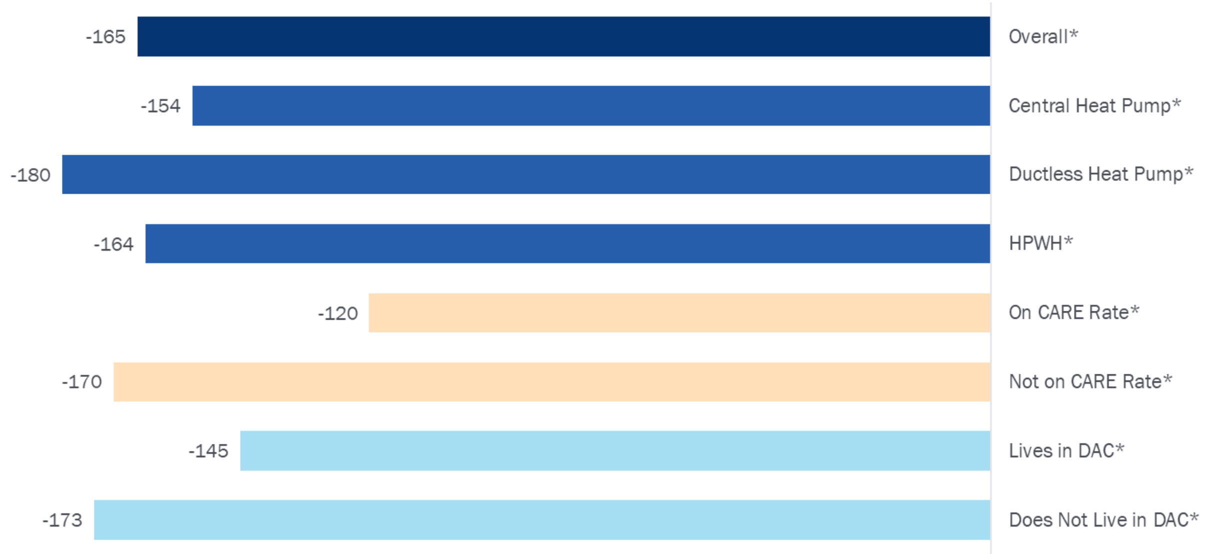


Note: Normal weather estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant monthly natural gas consumption data. Error bars show 95% confidence intervals.

5.9 GAS ENERGY IMPACTS BY SEGMENT

Gas energy impacts were also estimated by climate zone, DAC status, and enrollment in CARE (Figure 29). Sites receiving ductless heat pumps have greater annual impacts than those receiving other measures. Customers receiving a CARE discount or living in a DAC have smaller reductions than customers not receiving a CARE discount or not living in a DAC, respectively. These differences and the seasonal patterns within each segment are described in the sections that follow.

Figure 29. Average Annual Per-Participant Natural Gas Energy Impacts (therms) by Measure and Segment



*Results are statistically significant at 95% confidence level.

5.9.1 CLIMATE ZONE

Due to different climates, measures adopted, baseline energy systems, and customer attributes, gas impacts vary between climate zones. All climate zones exhibit a decrease in normal-weather annual gas consumption due to TECH participation; however, the impacts are not statistically significant in all zones due to small customer counts. Of the climate zones with statistically significant impacts and sample sizes greater than 30 (shaded blue in Table 27), the impacts ranged from about -27% (CZ6) to about -45% (CZ4), with most zones having average reductions between 30% and 45%.

Table 27. Climate Zone Annual Gas Energy Impacts

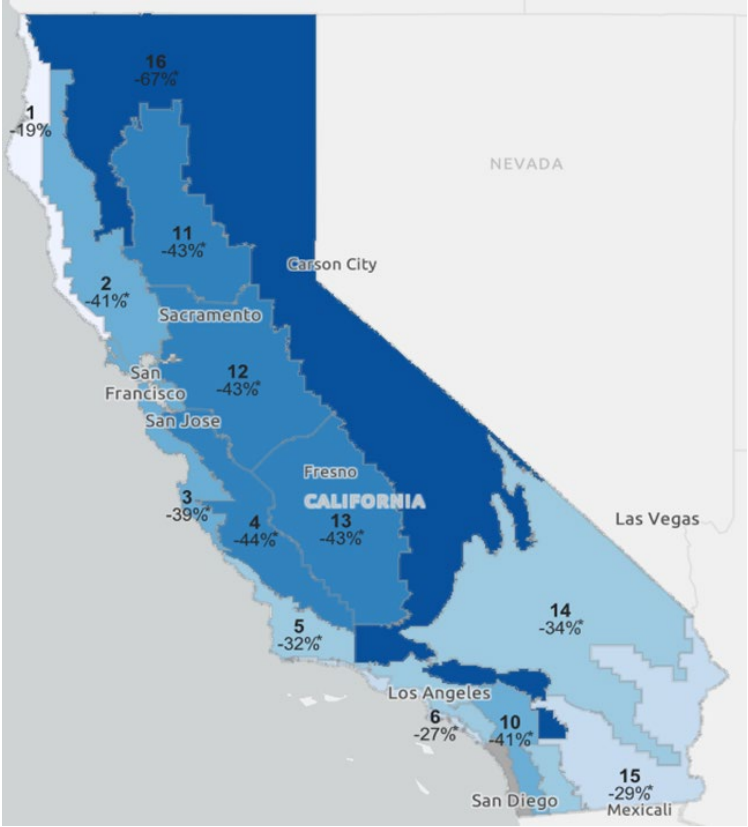
Climate Zone	Modeled Sites	Average Baseline (therms)	Average Impact (therms)	% Impact	Lower CI	Upper CI
1	5	511	-97	-19.0%	-249	54
2	205	506*	-210	-41.5%	-239	-180
3	377	421*	-165	-39.1%	-184	-146
4	120	452*	-201	-44.5%	-237	-164
5	9	671*	-216	-32.1%	-229	-202
6	249	499*	-133	-26.7%	-148	-119
7						
8	298	374*	-122	-32.6%	-137	-107
9	279	441*	-145	-32.9%	-159	-131
10	250	424*	-172	-40.6%	-185	-159
11	88	491*	-214	-43.5%	-248	-179
12	891	460*	-196	-42.7%	-208	-184
13	213	441*	-189	-42.9%	-214	-164
14	35	410*	-141	-34.4%	-211	-71
15	657	350*	-101	-29.0%	-117	-86
16	8	431*	-287	-66.7%	-304	-270

*Results are statistically significant at 95% confidence level.

Note: Weather-normalized impact estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant monthly natural gas consumption data. Summer is defined as June through September, winter as December through March, and shoulder as April, May, October, and November. The following climate zones overlap with the service territory of utilities excluded from the analysis sample due to missing or unreliable data. SDG&E: CZ6, CZ7, CZ8, CZ10, CZ14, and CZ15. LADWP: CZ6, CZ8, and CZ9.

The regions with greater impacts as a percentage of baseline gas consumption are located in northern and central California and tend to have greater heating needs. Climate zones in southern California experience smaller per-participant impacts (Figure 30).

Figure 30. Change in Annual Natural Gas Energy Consumption by Climate Zone



*Results are statistically significant at 95% confidence level.

Note: The following climate zones overlap with the service territory of utilities excluded from the analysis sample due to missing or unreliable data. SDG&E: CZ6, CZ7, CZ8, CZ10, CZ14, and CZ15. LADWP: CZ6, CZ8, and CZ9.

5.9.2 LOW-INCOME CUSTOMERS

The main findings from the gas impact analysis for low-income participants are depicted in in Table 28 and Figure 31. Both CARE discount participants and on-CARE discount participants experience large and statistically significant decreases in average annual and seasonal gas energy consumption. However, Non-CARE participants reduce their gas consumption by more than CARE discount participants. The difference in annual consumption is 50 therms, or 42% greater. However, Non-CARE participants have much higher baseline energy consumption. As a percentage of baseline usage, the impacts for Non-CARE participants are only slightly larger than those of CARE participants. Both CARE and Non-CARE participants experience larger reductions in consumption in winter than in summer and shoulder months due to the installation of central heat pumps or ductless heat pumps by most participants. Non-CARE participants show bigger decreases in the shoulder and winter months due to their higher baseline consumption.

Table 28. CARE and Non-CARE Seasonal Gas Impacts

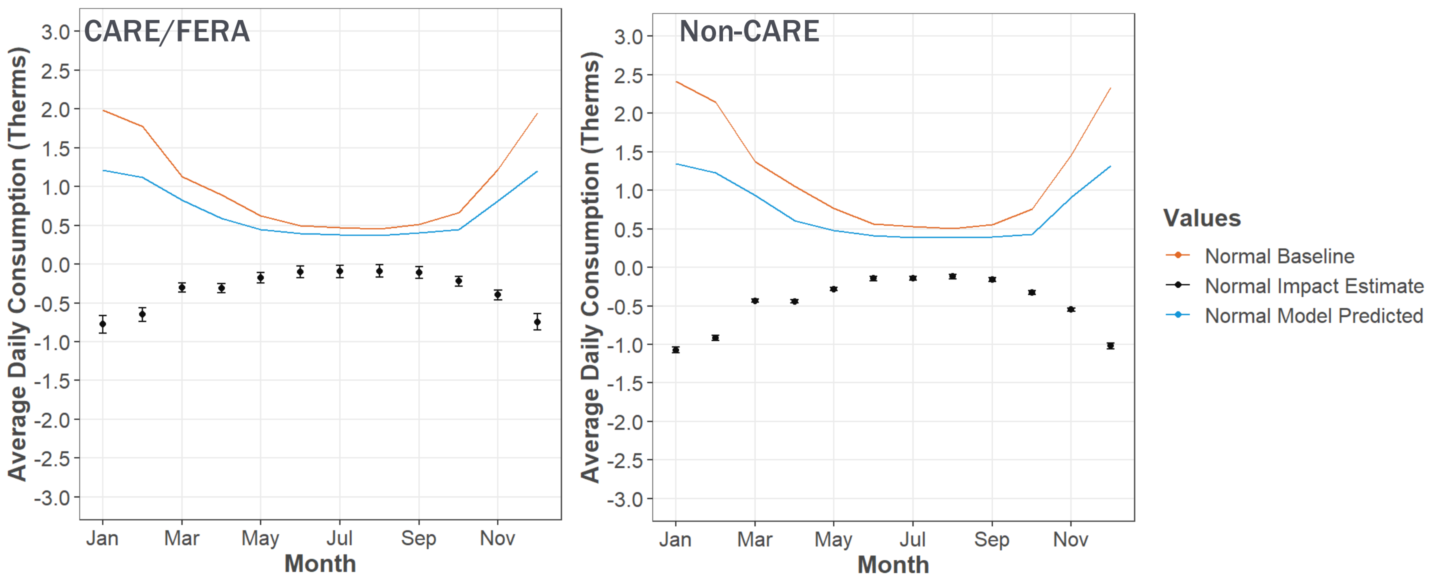
Low-Income Status	Baseline (therms)	Average Impact (therms)	% Impact	Lower CI	Upper CI
CARE					
Winter	207	-75*	-36.2%	-84	-65
Summer	59	-12*	-20.3%	-22	-2
Shoulder	103	-34*	-32.4%	-43	-24
Overall	**369**	**-120***	**-32.6%**	**-142**	**-99**

Low-Income Status	Baseline (therms)	Average Impact (therms)	% Impact	Lower CI	Upper CI
Non-CARE					
Winter	250	-104*	-41.6%	-107	-100
Summer	66	-17*	-26.2%	-21	-14
Shoulder	123	-49*	-39.7%	-52	-45
Overall	**438**	**-170***	**-38.7%**	**-177**	**-162**

*Results are statistically significant at 95% confidence level.

Note: Sites receiving multiple measures were excluded from the measure-level impact estimates. Weather-normalized impact estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant monthly natural gas consumption data. Summer is defined as June through September, winter as December through March, and shoulder as April, May, October, and November.

Figure 31. CARE and Non-CARE Monthly Gas Consumption Shapes and Impacts



Note: Normal weather estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant monthly natural gas consumption data. Error bars show 95% confidence intervals.

5.9.3 DISADVANTAGED COMMUNITIES

Table 29 summarizes the annual and seasonal results for DACs and Figure 32 depicts the monthly impacts. The average annual gas consumption impact per TECH participant is lower for participants in a DAC than those who do not reside in a DAC. On average, DAC participants experience a reduced gas consumption of about 145 therms, about 30 therms less than non-DAC participants. However, DAC and non-DAC participants experience similar percentages of decreases in gas consumption after participating in the TECH Initiative (~38%). Non-DAC participants decrease their gas consumption by more than DAC participants in the summer and shoulder seasons, while the impacts are similar in winter. This is likely explained by the higher proportion of non-DAC sites that installed HPWHs. The gas reductions are larger on average for DAC participants than CARE participants since DACs include a mix of low-income and non-low-income customers.

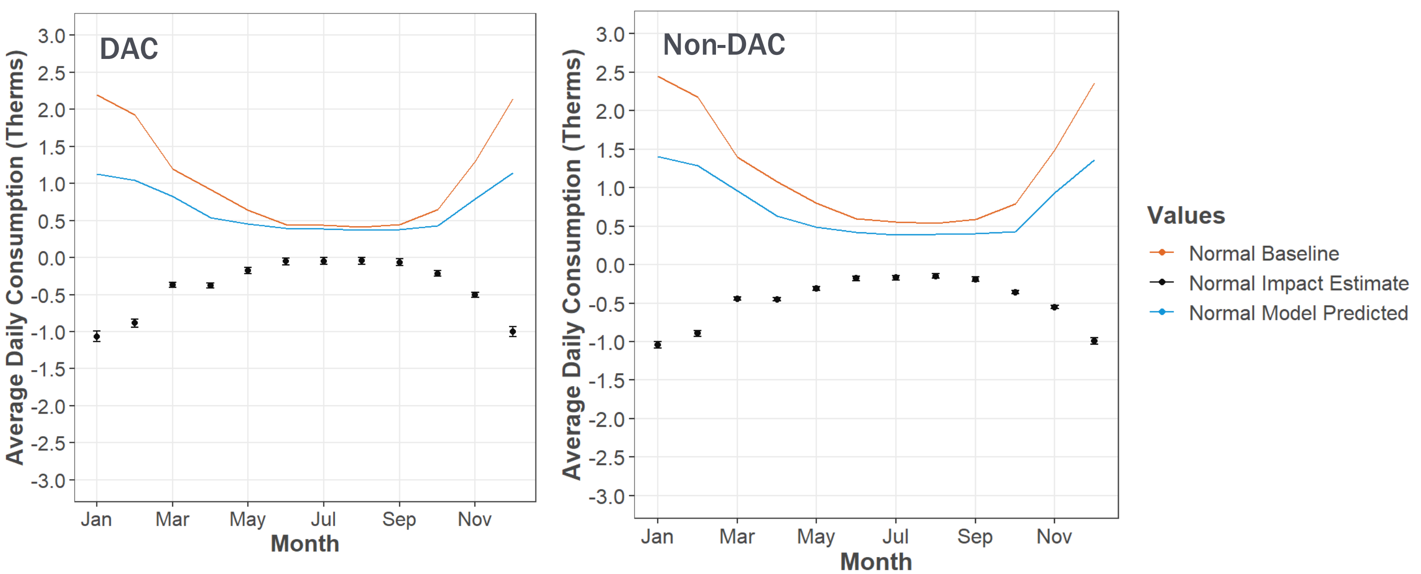
Table 29. DAC and Non-DAC Seasonal Gas Energy Impacts

DAC Status	Baseline (therms)	Average Impact (therms)	% Impact	Lower CI	Upper CI
Lives in DAC					
Winter	225	-100*	-44.5%	-106	-94
Summer	53	-6*	-12.0%	-12	-0.5
Shoulder	106	-39*	-36.4%	-45	-33
Overall	**385**	**-145***	**-37.7%**	**-158**	**-133**
Does Not Live in DAC					
Winter	253	-102*	-40.2%	-106	-98
Summer	70	-21*	-30.0%	-25	-17
Shoulder	126	-51*	-40.1%	-55	-47
Overall	**450**	**-173***	**-38.6%**	**-182**	**-165**

*Results are statistically significant at 95% confidence level.

Note: Sites receiving multiple measures were excluded from the measure-level impact estimates. Weather-normalized impact estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant monthly natural gas consumption data. Summer is defined as June through September, winter as December through March, and shoulder as April, May, October, and November.

Figure 32. DAC and Non-DAC Monthly Gas Consumption Shapes and Impacts



Note: Normal weather estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant monthly natural gas consumption data. Error bars show 95% confidence intervals.

5.10 GHG IMPACTS

5.10.1 SUMMARY IMPACTS

The change in GHG emissions from TECH participation was estimated as a function of the normal-weather gas consumption and electricity consumption impact estimates and GHG emissions factors for both fuels. The electricity emissions are calculated using hourly electricity emissions factors specific to each climate zone and for each hour of the year.

Following the adoption of a heat pump measure, the average TECH participant reduces GHG emissions by 0.73 metric tons of CO_2-e per year, a 17% reduction from the baseline. Although the average participant increases emissions from electricity consumption by an average of 0.25 metric tons per year, the decrease in emissions from reducing natural gas use by 0.99 metric tons per year more than offsets the increase.[41] To put this reduction in perspective, the EPA estimates that a typical gasoline-powered passenger vehicle emits 4.2 metric tons of CO_2-e per year.[42] This annual reduction in emissions equates to 16.42 metric tons CO_2-e across the measure lifetime.[43]

Across all TECH participants, over 7,000 metric tons CO_2-e are avoided each year, and over 167,000 metric tons CO_2-e across the measure lifetime due to fuel substitution through the TECH Initiative (Table 30). The annual GHG emissions reduction is equivalent to taking about 1,700 gasoline-powered passenger vehicles off the road for the year in total across the 10,197 sites in the study population.

Table 30. Program-Level Annual GHG Emissions Impacts

Fuel	Per-Participant (MT CO_2-e)				Total (MT CO_2-e)	
	Average Annual	Lower CI	Upper CI	Lifetime	Annual	Lifetime
Electric	0.25			5.69	2,591	58,021
Natural Gas	-0.99			-22.11	-10,069	-225,497
Total	**-0.73**	**-0.77**	**-0.69**	**-16.42**	**-7,478**	**-167,476**

Note: Normal weather estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant monthly natural gas consumption data and interval electricity consumption data, combined with emissions factors. See report footnote for additional details on lifetime assumptions.

5.10.2 CLIMATE ZONE IMPACTS

Table 31 reports estimates of the annual GHG emissions impacts per TECH participant for California's climate zones. In every climate zone, there is an average net reduction in annual GHG emissions per participant. The avoided GHG emissions from reducing natural gas usage offsets the increase in GHG emissions from increased electric consumption. Annual GHG emissions impacts vary between climate zones due to differences in the TECH energy impacts and the emissions intensities of California's regional grids. Among climate zones with more than 30 participants and statistically significant results (shaded blue in Table 31), the impacts range from a low of about 0.5 metric tons CO_2-e per year in CZ6 and CZ8 to a high of almost 0.9 metric tons per year in CZ11, CZ12, and CZ13. As a percentage of the baseline emissions, the largest statistically significant changes are in CZ16, and the smallest are in CZ6. These results are also depicted visually in Figure 33.

[41] Carbon dioxide equivalent (CO_2-e) is a metric used to compare the climate impact of different GHGs by converting them to the equivalent carbon dioxide (CO_2).

[42] https://www.epa.gov/energy/greenhouse-gases-equivalencies-calculator-calculations-and-references

[43] The measure lifetime is based on DEER 2026 guidelines that indicate a 20-year effective useful life for a HPWH and a 23-year effective useful life for heat pump HVAC measures. The measure life applied in the analysis is a weighted average based on the percentage of participants adopting HPWHs and heat pumps HVACs. Note this may be an overestimate of lifetime gas impacts as it assumes the measure would have achieved the same gas energy impacts for each year of the electric measure life as it did in the first year (i.e., the lifetime impacts assume an existing conditions baseline for the full 20- or 23-year measure life, regardless of site- or project-specific information).

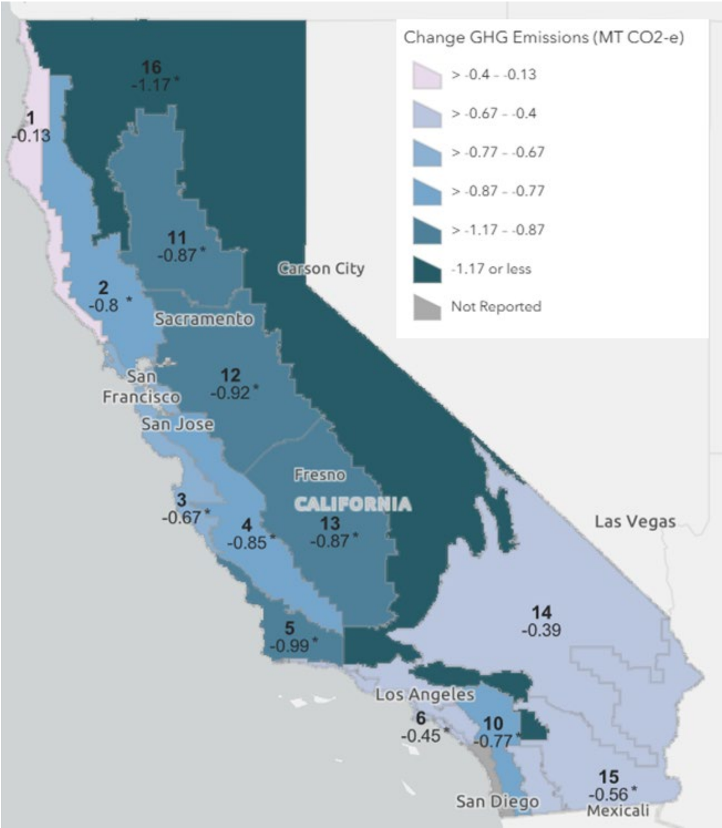
Table 31. Climate Zone Per Participant Average Annual GHG Emissions Impacts

Climate Zone	Electric		Natural Gas		Net Change GHG				
	Modeled Sites	Impact Estimate	Modeled Sites	Impact Estimate	Baseline	Impact Estimate	Lower CI	Upper CI	% Change
1	22	0.44	5	-0.57	4.59	-0.13	-1.03	0.78	-2.8%
2	235	0.42	205	-1.23	4.31	-0.80*	-0.99	-0.62	-18.7%
3	493	0.30	377	-0.96	3.71	-0.67*	-0.78	-0.55	-18.0%
4	154	0.33	120	-1.18	4.04	-0.85*	-1.07	-0.62	-21.0%
5	2	0.27	9	-1.26	4.69	-0.99*	-1.41	-0.57	-21.1%
6	234	0.33	249	-0.78	4.58	-0.45*	-0.55	-0.35	-9.8%
7									
8	423	0.20	298	-0.71	3.76	-0.51*	-0.61	-0.42	-13.6%
9	251	0.29	279	-0.85	4.26	-0.55*	-0.66	-0.45	-13.0%
10	340	0.24	250	-1.01	4.42	-0.77*	-0.86	-0.67	-17.3%
11	89	0.38	88	-1.25	4.76	-0.87*	-1.17	-0.57	-18.2%
12	1069	0.23	891	-1.15	4.45	-0.92*	-0.99	-0.84	-20.6%
13	298	0.24	213	-1.11	4.75	-0.87*	-1.03	-0.70	-18.2%
14	60	0.43	35	-0.82	4.22	-0.39	-0.83	0.05	-9.3%
15	437	0.04	657	-0.59	4.28	-0.56*	-0.67	-0.44	-13.0%
16	22	0.51	8	-1.68	3.97	-1.17*	-1.41	-0.93	-29.4%
Average		**0.25**		**-0.99**	**4.26**	**-0.73**	**-0.77**	**-0.69**	**-17.2%**

*Results are statistically significant at 95% confidence level.

Note: Fuel-specific values may not sum exactly to net values due to rounding. Normal weather estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant monthly natural gas consumption data and interval electricity consumption data, combined with emissions factors. Due to unavailable data for some utilities, the study team was unable to estimate electric energy impacts for CZ7. The following climate zones overlap with the service territory of utilities excluded from the analysis sample due to missing or unreliable data. SDG&E: CZ6, CZ7, CZ8, CZ10, CZ14, and CZ15. LADWP: CZ6, CZ8, and CZ9.

Figure 33. Per-Participant Annual GHG Emissions Impacts by Climate Zone



*Results are statistically significant at 95% confidence level.

Note: The following climate zones overlap with the service territory of utilities excluded from the analysis sample due to missing or unreliable data. SDG&E: CZ6, CZ7, CZ8, CZ10, CZ14, and CZ15. LADWP: CZ6, CZ8, and CZ9.

Table 32 shows the TECH Initiative's annual GHG emissions impacts in a normal-weather year by climate zone. The GHG emissions impacts are mainly driven by the participant counts in each climate zone. The climate zones with the greatest participants had the biggest impacts (see Table 31). Accounting for 34% of the overall emissions reductions, CZ12 achieved the largest GHG emissions reductions from the TECH Initiative. Other climate zones that contributed a high proportion of GHG emissions reductions include CZ3 (12%), CZ10 (8%), and CZ2, CZ13, and CZ15 (7% each, Table 32).

Table 32. Climate Zone Annual Net GHG Emissions Impact

Climate Zone	Total Annual (MT CO_2-e)				
	Electric Impact	Natural Gas Impact	Baseline	Net Change	% Net Change
1	18	-23	188	-5	-3%
2	258	-749	2,637	-492*	-19%
3	402	-1,309	5,040	-907*	-18%
4	120	-430	1,477	-310*	-21%
5	8	-35	132	-28*	-21%
6	211	-496	2,911	-286*	-10%
7					
8	171	-609	3,214	-438*	-14%
9	206	-594	2,982	-388*	-13%
10	186	-775	3,400	-589*	-17%

11	121	-396	1,510	-275*	-18%
12	627	-3,129	12,128	-2,501*	-21%
13	144	-666	2,858	-521*	-18%
14	91	-173	888	-83	-9%
15	33	-535	3,862	-502*	-13%
16	32	-105	248	-73*	-29%

*Results are statistically significant at 95% confidence level.

Note: Normal weather estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant monthly natural gas consumption data and interval electricity consumption data, combined with emissions factors. GHG impacts are not estimated for CZ7 as this climate zone was excluded from the impact analysis. The following climate zones overlap with the service territory of utilities excluded from the analysis sample due to missing or unreliable data. SDG&E: CZ6, CZ7, CZ8, CZ10, CZ14, and CZ15. LADWP: CZ6, CZ8, and CZ9. Program-level estimates assume average GHG impacts for the small number of projects in CZ7.

5.10.3 COSTS

SB 1477, the enabling legislation which created both the BUILD and TECH programs, requires each program to be evaluated based on, in part, the cost per metric ton of GHG reduction. This metric directly assesses the program's ability to reduce GHG emissions efficiently and facilitates a ready comparison to other decarbonization programs or initiatives California legislators and regulators may be considering to address climate change, both inside and outside of the consumer-facing energy program space. Further, the metric can be compared to marginal damage estimates of GHG emissions, such as the EPA's social cost of carbon. In this section, we provide three separate estimates of the cost per avoided metric tons CO_2-e.

The first estimate (CE1) is based on the inclusion of all program administration costs, incentives, and program spending on market support activities such as the pilots and quick start programs and workforce development and training activities (including both administrative and disbursements to grantees).[44] Although not a cost-effectiveness test, the included costs in this scenario are most aligned conceptually with that of the CPUC's Program Administrator Cost test.[45] In this estimate, the estimated average cost to the TECH Initiative per participating site is $4,396, including all program administration and TECH incentive costs. Based on the estimated avoided GHG emissions associated with TECH participation, this results in an average cost of $268 per avoided metric ton CO_2-e.

In the second estimate (CE2), we remove administrative and incentive costs related to both pilots and quick start grants and workforce training and development activities. As approved by the CPUC, the TECH Initiative is a market transformation pilot program designed to build workforce capacity and educate customers in addition to installing heat pumps. As the CPUC noted in the Building Decarbonization Phase IV scoping memo, "[a]s these pilot programs mature and show progress toward the objectives that were set for them, the Commission must think about *strategic scalability* of building decarbonization."[46] Therefore, CE2 represents what a streamlined implementation of the program might achieve in terms of cost per avoided metric ton CO_2-e, although, it should be noted, in an implementation of TECH that is strategically locationally targeted, we would expect the average GHG savings per site might be higher than the current estimate. In this scenario, the average cost per site is estimated to be $3,942, which translates to $240 per avoided

[44] Given that the program is ongoing and the analysis timeframe for used in the population pathway consumption analysis does not align neatly with calendar years, to calculate the cost per ton of avoided CO_2-e, program administration costs and incentive costs are estimated from separate datasets, normalized to a per-site basis, and extrapolated to the study population of sites.

[45] California Public Utilities Commission (CPUC) Standard Practice Manual. October 2001.

[46] CPUC Amended Scoping Memo and Ruling (Phase 4 Scoping Memo). Order Instituting Rulemaking Regarding Building Decarbonization. Rulemaking 19-01-011. July 1, 2024.

metric ton CO_2-e. Again, the costs included in this scenario are most aligned with that of the CPUC's Program Administrator Cost test.

The final metric (CE3) provides an estimate of the cost per metric ton of CO_2-e when accounting for the additional equipment and installation costs to the participant (which includes both out-of-pocket costs and any non-TECH incentives they received, such as through an energy efficiency program administered by BayREN or PG&E) in addition to all costs included in CE1. Although not a cost effectiveness test, the costs included in this scenario are most aligned with that of the CPUC's Total Resource Cost test. In this scenario, the average cost per site increases to $20,123 and translates to $1,225 per avoided metric ton CO_2-e. We provide CE3 for informational purposes, however, we believe it is appropriate for the cost-efficiency metric to account for only program implementation costs (including incentives) and to exclude customer contributions to equipment. This approach increases the comparability of the metric to non-customer-facing programs and avoids the asymmetry of including all participant costs while excluding some participant benefits.

All three scenarios are shown in Table 33 below. As a point of comparison, the EPA estimates the social cost of CO_2 emissions is $190 per MT using a discount rate of 2.0% and $340 per MT ton using a discount rate of 1.5% (damages in 2020 dollars).

Table 33. Cost Per Avoided MT CO_2-e

Metric	CE1	CE2	CE3
	Program Costs Only	*Program Cost - Streamlined*	*Program Costs + Non-Program Costs*
Average Cost Per Site ($)	$4,396	$3,942	$20,123
Average Lifetime Avoided GHG Emissions (MT CO_2-e)	-16.42	-16.42	-16.42
Cost Per Unit of Avoided Emissions ($)	$268	$240	$1,225

5.11 BILL IMPACTS SUMMARY

The impact of TECH Initiative participation on customer utility bills was estimated as a function of the normal-weather gas consumption and electricity consumption impact estimates, participant rate plans at the time of TECH participation, and utility rates in effect as of January 2022. The bill impact represents the net change in the sum of the customer's electricity and gas utility bills in 2022 dollars in a normal weather year. Since the analysis sample does not include participants who discontinued utility gas service and went "all electric," the net bill impacts only reflect changes in volumetric energy charges, not changes in bill fixed charges, unless otherwise noted.

The average TECH participant experiences a small net decrease of $11 in annual energy (natural gas and electricity) bills in a normal-weather year, although this difference is not statistically different from zero. The average participant experiences a reduction of $344 in natural gas charges and a slightly more than offsetting increase of $333 in charges for electricity.[47] Over the lifetime of the TECH measure, the average participant will experience a $351 reduction in energy bills. Each year, energy bills decrease by about $116,000 across all TECH participants in the study population (Table 34).[48]

[47] These estimates take into consideration CARE/FERA discounts for electricity consumption and CARE discount for gas consumption, depending on the proportion of customers eligible and enrolled in CARE/FERA and CARE discount rates. The bill impacts assume that participants are on NEM 1.0 or NEM 2.0 (i.e., the net metering credit is equal to the per-kWh cost of electricity).

[48] The measure lifetime is based on DEER 2026 guidelines that indicate a 20-year effective useful life for a HPWH and a 23-year effective useful life for heat pump HVAC measures. The measure life applied in the analysis is a weighted average based on the percentage of participants adopting HPWHs and heat pumps HVACs. Lifetime impacts were estimated with a discount rate of 2.5% and assuming that utility rates would increase according to the historical average annual rate of increase of utility household energy costs between 2013 and 2023 (CPI All Urban Consumers Household Energy for LA-Long Beach-Anaheim area and San Francisco-Oakland-Hayward.

Table 34. Annual and Lifetime Energy Bill Impacts

Fuel	Per-Participant		Total	
	Average Annual ($)	Lifetime ($)	Average Annual ($)	Lifetime ($)
Electric	$333	$10,276	$3,395,000	$104,785,504
Natural Gas	-$344	-$10,628	-$3,511,083	-$108,368,368
Total	**-$11**	**-$351**	**-$116,083**	**-$3,582,864**

Note: Normal weather estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant monthly natural gas consumption data and interval electricity consumption data, combined with utility rates. See report footnote for additional details on lifetime assumptions.

The modest decrease in annual energy bills masks substantial variation in bill impacts across seasons. The average participant experiences energy bill savings of $56 in summer and $49 during the shoulder season, and a more substantial bill increase of $94 in winter. Although the change in utility bills is statistically significant for each individual season, the annual change is not. The study team is 95% confident that the overall utility bill increase of an individual TECH participant like the participants included in this evaluation is no larger than $15 per year (Table 35).

Table 35. Per-Participant Seasonal Bill Impacts

Season	Electric Estimate	Natural Gas Estimate	Net Change		
			Annual Net Change	Lower CI	Upper CI
Winter	$316	-$222	$94*	$79	$108
Summer	-$33	-$24	-$56*	-$74	-$39
Shoulder	$50	-$99	-$49*	-$62	-$36
Overall	**$333**	**-$344**	**-$11**	**-$37**	**$15**

*Results are statistically significant at 95% confidence level.

Note: Normal weather estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant monthly natural gas consumption data and interval electricity consumption data, combined with utility rates. Summer is defined as June through September, winter as December through March, and shoulder as April, May, October, and November.

5.12 BILL IMPACTS BY MEASURE

Participant utility bill impacts vary by the measure adopted. Participants receiving HPWHs experience annual average net bill savings of $184, with all typical participants expected to achieve net bill savings. The reduction in energy bills due to gains in energy efficiency outweighs any increase due to the higher unit price of energy (from heating with more costly electricity rather than natural gas) and any increase in electric energy consumption for water heating. In contrast, TECH participants receiving ductless heat pumps experience an average annual net bill increase of $72. These impacts are statistically significant and positive, meaning that we would expect the vast majority of participants receiving this measure to experience energy bill increases. Ductless heat pump participants have the largest natural gas bill savings but also experience the largest electric bill increases, leading to a significant net increase in bills. The heat pump technology's efficiency gains are not large enough to outweigh the higher cost of electricity and any increases in utilization from, for example, the absence of central air conditioning prior to TECH participation. Central heat pump participants have the smallest overall change in bills. On average, they experience a $25 annual reduction in energy bills, but this change is not statistically significant, suggesting that some participants experience a modest bill increase while others experience a decrease or a negligible change (Table 36).

Table 36. Measure-Level Bill Impacts

Measure	Electric Estimate	Natural Gas Estimate	Net Change		
			Annual Net Change	Lower CI	Upper CI
Central Heat Pump	$289	-$314	-$25	-$67	$16
Ductless Heat Pump	$459	-$387	$72*	$15	$130
HPWH	$177	-$362	-$184*	-$242	-$127

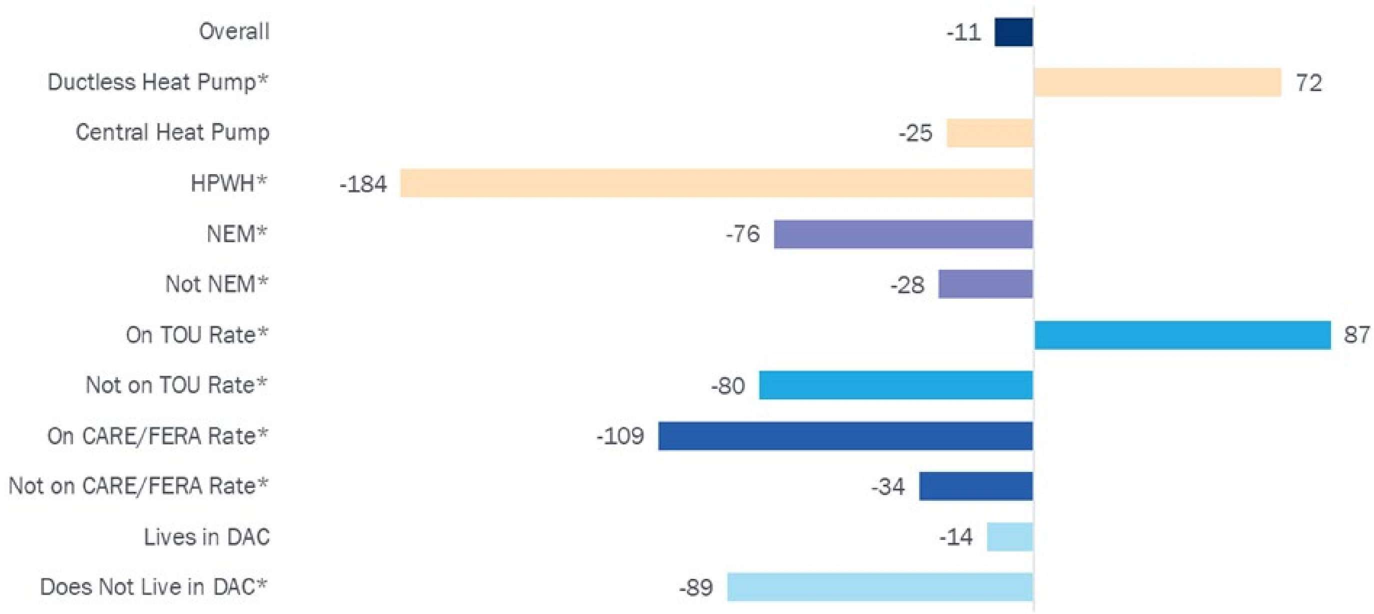
*Results are statistically significant at 95% confidence level.

Note: Normal weather estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant monthly natural gas consumption data and interval electricity consumption data, combined with utility rates.

5.13 BILL IMPACTS BY SEGMENT

The TECH net bill impacts vary significantly across customer segments (Figure 34). NEM participants save about 2.7 times that of non-NEM participants. Participants on a TOU rate tend to experience a net increase in their energy bills, whereas those not on TOU tend to experience a net decrease. Those TECH participants receiving a CARE or FERA discount experience average net bill savings of about $109 per year, compared to $34 per year for participants not receiving a CARE or FERA discount. Participants who live in DACs experience bill savings of $14 per year, while those living outside a DAC experience almost six times higher savings.[49]

Figure 34. Average Annual Per-Participant Net Energy Bill Impact ($) by Measure and Segment



*Results are statistically significant at 95% confidence level.

Note: TOU/Non-TOU and NEM/Non-NEM gas bill impacts represent an average across all participants, as these impacts could not be separately calculated for gas.

49 The bill impacts within each segment are inclusive of the mix of customers in that segment. For example, bill impacts of TOU participants reflect the proportion of TOU participants that receive a CARE or FERA discount and climate zone bill impacts reflect the proportion of NEM and TOU participants in each climate zone.

CLIMATE ZONE

There is substantial variation in net bill impacts across climate zones. Among climate zones with a minimum of 30 participants in the analysis sample and statistically significant results (shaded blue in Table 37), CZ12, CZ13, and CZ15, have average annual net bill savings per TECH participant of at least $200. The bill savings are likely due to the efficiency gains of central and ducted heat pumps. In contrast, CZ2, CZ6, CZ9, and CZ14 have average annual net bill increases of at least $100. While multiple factors affect the variation in energy bill impacts across the state, in general, participants in climate zones where energy consumption for space heating is lower and energy consumption for space cooling is higher tend to save on their bills while participants in climate zones where energy consumption for space heating is higher and energy consumption for space cooling is lower tend to experience bill increases (Table 37).

Table 37. Climate Zone Per-Participant Annual Bill Impacts

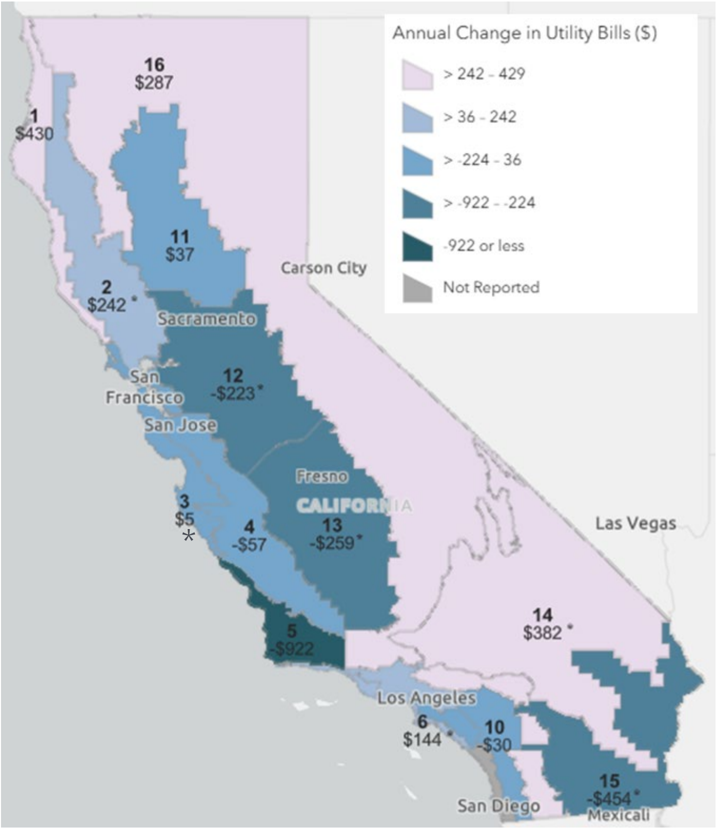
Climate Zone	Modeled Sites	Electric Estimate	Natural Gas Estimate	Net Change		
				Annual Net Change	Lower CI	Upper CI
1	22	$656	-$226	$430	-$4	$864
2	235	$718	-$476	$242*	$139	$345
3	493	$376	-$371	$5	-$62	$71
4	154	$396	-$453	-$57	-$223	$110
5	2	-$507	-$416	-$922	-$1,957	$113
6	234	$436	-$292	$144*	$46	$242
7						
8	423	$211	-$269	-$57	-$118	$3
9	251	$432	-$312	$120*	$17	$224
10	340	$324	-$354	-$30	-$111	$51
11	89	$513	-$476	$37	-$314	$387
12	1069	$216	-$439	-$223*	-$274	-$173
13	298	$145	-$404	-$259*	-$501	-$17
14	60	$685	-$303	$382*	$133	$631
15	437	-$224	-$230	-$454*	-$561	-$348
16	22	$797	-$510	$287	-$91	$666

*Results are statistically significant at 95% confidence level.

Note: Normal weather estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant monthly natural gas consumption data and interval electricity consumption data, combined with utility rates. Due to unavailable data for some utilities, the study team was unable to estimate electric energy impacts for CZ7. The following climate zones overlap with the service territory of utilities excluded from the analysis sample due to missing or unreliable data. SDG&E: CZ6, CZ7, CZ8, CZ10, CZ14, and CZ15. LADWP: CZ6, CZ8, and CZ9.

Overall, customer utility bills tend to increase in cooler climate zones such as CZ2 and decrease in warmer climate zones such as CZ15. Participants in coastal regions tend to experience the most neutral bill impacts (Figure 35).

Figure 35. Per-Participant Annual Net Energy Bill Impacts by Climate Zone



*Results are statistically significant at 95% confidence level.

Note: The following climate zones overlap with the service territory of utilities excluded from the analysis sample due to missing or unreliable data. SDG&E: CZ6, CZ7, CZ8, CZ10, CZ14, and CZ15. LADWP: CZ6, CZ8, and CZ9.

NEM STATUS

NEM sites make up a disproportionate share of TECH participants as the ability to offset increased electric energy consumption and energy bills through solar production and the NEM billing mechanism can make the adoption of heat pump technology more attractive and more affordable than it would be otherwise.

NEM participants save $76 on average on their energy bills after TECH participation, a net bill decrease about three times that of non-NEM sites. NEM participants can offset some of their new electric energy usage through solar generation. These impacts are negative and statistically different from zero, suggesting that NEM participants are very likely to experience bill savings. Non-NEM participants also experience bill savings, but these are more modest. The average non-NEM participant saves $28 each year, and this difference is just statistically significant, suggesting that some participants experience bill impacts close to zero (Table 38).[50]

Table 38. NEM and Non-NEM Annual Bill Impacts

NEM Status	Electric Estimate	Natural Gas Estimate	Net Change		
			Annual Net Change	Lower CI	Upper CI

[50] The study team is unable to consistently link TECH sites across fuels, preventing the separate estimation of gas impacts for NEM and non-NEM participants. Therefore, we assume equivalent gas bill impacts for NEM and non-NEM sites.

NEM	$269	-$344	-$76	-$129*	-$22
Non-NEM	$317	-$344	-$28	-$55*	-$1

*Results are statistically significant at 95% confidence level.

Note: Due to data limitations, the study team assumes that the gas bill impacts are equivalent for NEM and non-NEM sites. Normal weather estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant monthly natural gas consumption data and interval electricity consumption data, combined with utility rates.

TIME-OF-USE RATE

Table 39 summarizes bill impacts for customers on a TOU rate and those not on a TOU rate at the time of their TECH participation.[51] The average TECH participant on a TOU rate experiences an increase in their annual net utility bills ($87 per year), while those on the standard residential rate experience bill savings of a similar magnitude ($80 per year). In both cases, these results are statistically different from zero, suggesting that participants on a TOU rate are very likely to experience bill increases and those not on TOU rates are very likely to experience bill savings. The bill increases for TECH participants on a TOU rate are at least partially driven by their larger increase in electric energy consumption compared to participants on a standard residential rate, which translates to a bill increase. In addition, TOU rate participants pay a high unit cost for electricity during on-peak periods, and they are now using electricity instead of natural gas for home space heating.

Table 39. TOU and Non-TOU Rate Annual Bill Impacts

Time-of-Use Rate	Electric Estimate	Natural Gas Estimate	Net Change		
			Annual Net Change	Lower CI	Upper CI
On TOU Rate	$431	-$344	$87	$48	$125
Not on TOU Rate	$264	-$344	-$80	-$114	-$46

*Results are statistically significant at 95% confidence level.

Note: Due to data limitations, the study team assumes that the gas bill impacts are equivalent for TOU and non-TOU participants. Normal weather estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant monthly natural gas consumption data and interval electricity consumption data, combined with utility rates.

LOW-INCOME CUSTOMERS

Table 40 summarizes bill impacts for TECH participants receiving a CARE or FERA discount and those not receiving a CARE or FERA discount. TECH participants not receiving a CARE or FERA discount experience a reduction in their overall energy bills by an average of $34 per year, while TECH participants receiving a CARE or FERA discount reduce their net energy bills by $109 per year. Participants receiving a CARE or FERA discount experience a decrease in their annual electric bills that is more than three times that of customers not receiving a CARE or FERA discount. This is driven by the bill discount and a smaller increase in electric energy consumption compared to Non-CARE or FERA participants.

Table 40. CARE or FERA and Non-CARE or FERA Annual Bill Impacts

Low-Income Status	Electric Estimate	Natural Gas Estimate	Net Change		
			Annual Net Change	Lower CI	Upper CI
CARE or FERA	$95	-$205	-$109	-$169	-$50

[51] As with NEM sites, the study team is unable to consistently link TECH sites across fuels, preventing the separate estimation of gas impacts for TOU rate and standard residential rate participants. Therefore, we assume equivalent gas bill impacts for TOU and non-TOU participants.

Non-CARE or FERA	$327	-$361	-$34	-$63	-$4

*Results are statistically significant at 95% confidence level.

Note: Normal weather estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant monthly natural gas consumption data and interval electricity consumption data, combined with utility rates.

DISADVANTAGED COMMUNITIES

Table 41 compares bill impacts for TECH participants residing in a DAC and those not in a DAC. Overall, participants living in a DAC experience a more modest reduction in their overall energy bills than non-DAC participants ($14 vs. $89 savings per participant). For DAC participants, these results are not statistically different from zero, suggesting that some customers in this group experience bill savings while others experience bill increases. For non-DAC participants, these results are statistically significant, suggesting that these customers are very likely to experience bill savings. TECH participants living in DACs experience a smaller decrease in their natural gas bills and a larger increase in their electricity bills than those not living in DACs. The increase in electricity *bills* is greater among DAC than non-DAC participants even though the increase in electricity *consumption* is smaller among DAC than non-DAC participants. This suggests that other contributors to electricity costs, such as utility territory and the timing of electricity use, are driving the greater electricity bill increases for DAC participants. Participants living in DACs are slightly less likely than those not living in DACs to be NEM or to receive an HPWH, which may also help to explain their bill outcomes. Participants that are NEM or receive a HPWH tend to achieve greater bill savings than their counterparts.

The bill impact patterns between customers living in DACs and non-DACs differ from the patterns between those participants that receive a CARE or FERA discount versus those not receiving a CARE or FERA discount. This is in part because only around 19% of participants living in DACs receive CARE or FERA discounts for electric consumption, and only 15% of participants living in DACs receive CARE discounts for natural gas consumption.

Table 41. DAC and Non-DAC Annual Bill Impacts

DAC Status	Electric Estimate	Natural Gas Estimate	Net Change		
			Annual Net Change	Lower CI	Upper CI
Lives in a DAC	$285	-$298	-$14	-$60	$33
Does Not Live in a DAC	$274	-$364	-$89	-$122	-$57

*Results are statistically significant at 95% confidence level.

Note: Normal weather estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant monthly natural gas consumption data and interval electricity consumption data, combined with utility rates.

5.13.1 ESTIMATED ALL-ELECTRIC BILL IMPACTS

The impact of TECH Initiative participation on customer utility bills was estimated as a function of the normal-weather gas consumption and electricity consumption impact estimates and the participant utility rates in effect as of January 2022. The bill impact represents the net change in the sum of the customer's electricity and gas utility bills. Since the analysis sample does not include participants who discontinued utility gas service (i.e., went "all electric"), the net bill impacts presented in section 5.11 reflect changes in variable energy charges, and exclude any changes in fixed charges. In this section, we present the estimated bill impacts for a hypothetical TECH participant that closes their gas service following TECH participation. As the study team was unable to identify which specific participants closed their gas service following TECH participation, the all-electric bill impact estimate is based on the energy impact estimates for participants who retained their gas service and some additional assumptions.

The all-electric bill impacts assume the following:

- Baseline bills include gas flat fees (daily charges) in addition to per-therm charges.
- The participant has zero gas usage ($0 in gas bills) following TECH participation.
- The baseline gas usage is equivalent to the gas impact (rather than the gas baseline as estimated in the remainder of the study), as the TECH measure is assumed to be the participants' last remaining gas end use.
- Participants that go all-electric are otherwise similar to other participants in their gas and electric use
- Any substitution of gas with electricity for other home energy end uses (e.g., gas cooking) undertaken by all electric homes but not by homes that retained gas service is not a TECH program effect and would have occurred in absence of the program.

For the average TECH participant, going all-electric would lead to a $66 reduction in annual energy (natural gas and electricity) bills in a normal-weather year, which is six times greater than the bill savings for a participant that retains their gas service. The average participant experiences a reduction of $399 in natural gas charges, which more than offsets the increase of $333 in charges for electricity.[52] Over the lifetime of the TECH measure, the average participant will experience a $2,039 reduction in energy bills (Table 42).[53]

Table 42. Annual and Lifetime Energy Bill Impacts (All-Electric)

Fuel	Per-Participant	
	Average Annual ($)	Lifetime ($)
Electric	$333	$10,276
Natural Gas	-$399	-$12,315
Total	**-$66**	**-$2,039**

Note: Normal weather estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant monthly natural gas consumption data and interval electricity consumption data, combined with utility rates. See report footnote for additional details on lifetime assumptions.

As with a participant that retains its gas service following TECH participation, the annual bill reduction is driven by reduced energy bills in the summer and shoulder seasons and increased energy bills in the winter. Unlike the participant that retains its gas service, a TECH participant that closes its gas service is expected to achieve statistically significant annual bill savings despite this seasonal variation (Table 43).

Table 43. Per-Participant Seasonal Bill Impacts (All-Electric)

Season	Electric Estimate	Natural Gas Estimate	Net Change		
			Annual Net Change	Lower CI	Upper CI
Winter	$316	-$232	$84*	$69	$98
Summer	-$33	-$49	-$82*	-$99	-$65
Shoulder	$50	-$118	-$68*	-$81	-$55
Overall	**$333**	**-$399**	**-$66***	**-$92**	**-$40**

*Results are statistically significant at 95% confidence level.

[52] These estimates take into consideration CARE/FERA discounts for electricity consumption and CARE discount for gas consumption, depending on the proportion of customers eligible and enrolled in CARE/FERA and CARE discount rates. The bill impacts assume that participants are on NEM 1.0 or NEM 2.0 (i.e., the net metering credit is equal to the per-kWh cost of electricity).

[53] The measure lifetime is based on DEER 2026 guidelines that indicate a 20-year effective useful life for a HPWH and a 23-year effective useful life for heat pump HVAC measures. The measure life applied in the analysis is a weighted average based on the percentage of participants adopting HPWHs and heat pumps HVACs. Lifetime impacts were estimated with a discount rate of 2.5% and assuming that utility rates would increase according to the historical average annual rate of increase of utility household energy costs between 2013 and 2023 (CPI All Urban Consumers Household Energy for LA-Long Beach-Anaheim area and San Francisco-Oakland-Hayward.

Note: Estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant monthly natural gas consumption data and interval electricity consumption data, combined with utility rates. Summer is defined as June through September, winter as December through March, and shoulder as April, May, October, and November.

5.13.2 ESTIMATED ALL-ELECTRIC BILL IMPACTS BY CLIMATE ZONE

There is substantial variation in net bill impacts across climate zones for a participant that ends its gas service. Among climate zones with a minimum of 30 participants in the analysis sample and statistically significant results (shaded blue in Table 44), participants in CZ8, CZ12, CZ13, and CZ15, where household energy consumption for air conditioning tends to be high, have average annual net bill savings of at least $100. The bill savings are likely due to the efficiency gains of central and ducted heat pumps. In contrast, participants in CZ2 and CZ14, where energy consumption for space heating tends to be high, still experience bill increases on average, even if they go all-electric. Many climate zones do not achieve statistically significant results, which in some cases is due to a small number of participants, but in many cases is due to bill impacts close to zero among participants (Table 44).

Table 44. Climate Zone Annual Bill Impacts (All-Electric)

Climate Zone	Modeled Sites	Electric Estimate	Natural Gas Estimate	Net Change		
				Annual Net Change	Lower CI	Upper CI
1	22	$656	-$264	$392	-$43	$828
2	235	$718	-$506	$212*	$108	$316
3	493	$376	-$406	-$30	-$97	$36
4	154	$396	-$488	-$91	-$258	$76
5	2	-$507	-$473	-$980	-$2,015	$55
6	234	$436	-$346	$90	-$8	$188
7						
8	423	$211	-$323	-$111*	-$172	-$51
9	251	$432	-$361	$71	-$32	$175
10	340	$324	-$404	-$80	-$161	$0
11	89	$513	-$508	$5	-$346	$356
12	1069	$216	-$471	-$255*	-$306	-$204
13	298	$145	-$442	-$297*	-$539	-$55
14	60	$685	-$349	$336*	$88	$584
15	437	-$224	-$285	-$510*	-$616	-$403
16	22	$797	-$543	$255	-$124	$633

*Results are statistically significant at 95% confidence level.

Note: Estimates based on fixed-effects D-in-D panel regression analysis of TECH participant and matched nonparticipant monthly natural gas consumption data and interval electricity consumption data, combined with utility rates. Due to unavailable data for some utilities, the study team was unable to estimate electric energy impacts for CZ7. The following climate zones overlap with the service territory of utilities excluded from the analysis sample due to missing or unreliable data. SDG&E: CZ6, CZ7, CZ8, CZ10, CZ14, and CZ15. LADWP: CZ6, CZ8, and CZ9.

5.14 CONCLUSIONS AND RECOMMENDATIONS

Based on our findings, the study team offers the following conclusions and recommendations.

Overall Impacts

- **Conclusion:** The energy impacts of the TECH Initiative lead to a substantial net reduction in GHG emissions statewide (17%) and in all climate zones annually. The avoided GHG emissions from reduced natural gas consumption are nearly four times the new GHG emissions from increased electric energy consumption annually.
- **Conclusion:** There is not a statistically significant change in net energy bills for the average participant. However, customers in some climate zones, particularly the southern-most and central climate zones, experience bill savings on an annual basis. Participants on a TOU rate at the time of their TECH participation experience an increase in their energy bills ($87 per year on average), whereas those not on a TOU rate experience savings ($80 per year on average). All bill impacts reflect the CARE/FERA discount that would be received by eligible customers within a given segment.
  - **Recommendation:** Electric utilities should encourage TECH TOU rate participants, particularly those who install central or ducted heat pumps, to switch to a TOU rate designed for electrification customers to minimize the bill impacts of electrification. TECH participants on a standard TOU rate pay a high price for electricity consumed at peak times and now use electricity for space heating instead of cheaper natural gas.
  - **Recommendation:** Participation in demand response programs may also help TECH participants to manage their bills (i.e., in the case of daily load shifting programs) or to offset some of the bill increases from electrification (i.e., for programs with annual or seasonal participation incentives).
- **Conclusion:** On average, participation in the TECH Initiative leads to substantial reductions in natural gas energy consumption while increasing electric energy consumption. The typical TECH participant experiences a 38% reduction in their natural gas consumption and a 17% increase in their electric consumption annually.
- **Conclusion:** The increase in electric energy consumption is mostly driven by increases in space heating in the winter and, to a lesser extent, the shoulder season. Summer electric energy impacts are small on average but vary widely between customer segments as discussed further below. The impact of heat pump technology on summer electricity consumption is highly sensitive to whether participants replace an existing central cooling system or add a new cooling load.

Impacts by Measure

- **Conclusion:** Participants adopting central and ductless heat pumps have different energy impacts. Central heat pump participants experience the smallest annual electric consumption increase, whereas ductless heat pump participants experience the largest annual electric consumption increase, and this is largely attributable to differences in their baseline space conditioning equipment. Winter impacts are similar for central and ductless heat pumps for both electricity and gas. However, due to the differences in summer electric energy impacts, central heat pump participants tend to experience a modest reduction in their energy bills, whereas ductless heat pump participants experience an increase.
  - **Recommendation:** In future studies, consider separately estimating energy impacts as a function of the participant's pre-existing air conditioning to disentangle summer electricity efficiency savings from electric load growth due to adding space cooling. This would allow for better planning of the impact of the TECH Initiative if

the levels of pre-existing air conditioning penetration among future participants differ from the current evaluated population.[54]

- **Conclusion:** The adoption of heat pump technology, particularly heat pump HVACs, impacts electricity demand during peak and off-peak periods. During the RA window, the average participant experiences a reduction in demand of about four percent. The reduction tends to be greater in warm climate zones where participants are more likely to have air conditioning before TECH participation. In cooler climate zones with lower baseline space conditioning, there tends to be an increase in demand during the RA window. In the winter months, TECH participation leads to a new morning electric peak due to the use of heat pump HVACs for space heating, which is greater than the afternoon winter peak, although still smaller than the summer peak in most cases.
  - **Recommendation:** As more customers electrify their homes with central and ductless heat pumps, grid planners should prepare for increased summer electric load in regions that previously had lower air conditioning penetration and for new morning peaks in daily winter load due to space heating electrification.
  - **Recommendation:** The Program administrator should continue and expand efforts to pair heat pump technology installations with smart thermostat controls and incentivize TECH participants to enroll in demand response and other load flexibility offerings to help manage the growth in heating and cooling loads.
- **Conclusion:** HPWHs have less impact on peak demand than heat pump HVAC measures, but still lead to substantial increases in energy consumption that are spread more evenly throughout the day and the year. In fact, on average, HPWH participants experience a 27% increase in electric energy consumption annually, only slightly less than ductless heat pump participants and substantially more than participants receiving a central heat pump.
  - **Recommendation:** Continue targeting and enrolling HPWH participants in HPWH-focused DR programs for daily load shifting away from peak periods such as the PG&E WatterSaver and SCE SmartShift Rewards programs.

Key Customer Segments

The study team estimated impacts by climate zone and among customers that are net-metered, low-income, live in a disadvantaged community, or are on a time-of-use rate.

- **Conclusion:** The TECH Initiative energy impacts, GHG emissions, and bill impacts vary between climate zones, measures, and customer segments such as customers on CARE or FERA and TOU rates. The impacts are also sensitive to baseline home attributes such as existing central air conditioning and net metering. In addition, the GHG impacts depend on the forecasted GHG emission intensity of the electric grid in each region, and the bill impacts depend on current electricity and natural gas tariffs.
  - **Recommendation:** When designing future electrification policies and programs, California policymakers should consider that there is significant variation in energy, GHG, and bill impacts of residential space and water electrification. The impacts for some subpopulations as defined by climate zone or other customer attributes may be very different from the population mean impact.
  - **Recommendation:** TECH Initiative program administrator and policymakers should be cautious about assuming that future program impacts will be the same as those observed during this evaluation. Changes in the composition of the participant population or utility tariffs could lead to different impacts.
- **Conclusion:** A disproportionate share of TECH participants (27% vs. approximately 10% statewide) are net-metered, which often makes residential electrification more financially attractive. The evaluation period generally

[54] This analysis was not pursued during the current evaluation period due to incomplete information on baseline space conditioning equipment in the tracking data when the evaluation was initiated. This issue has since been resolved, and we expect these data to be readily available for future evaluations.

precedes the NEM 3.0 tariff, so net-metered TECH participants in this study were subject to NEM 1.0 or NEM 2.0 tariffs, in which the net metering credit is equal to the per-kWh cost of electricity.

  - **Recommendation:** Solar panels can be a catalyst for customer interest in heat pump technology, as the two systems are complementary. As resources allow, the program administrator should continue to explore collaboration opportunities with solar companies to leverage existing customer relationships and streamline outreach efforts, potentially increasing adoption rates. Additionally, bundling incentives or providing joint educational resources could enhance the value proposition, making the transition to an all-electric home more attractive.

- **Conclusion:** The TECH Initiative projects funded by Cap-and-Trade gas utility auction proceeds and represented in this report were primarily composed of market rate single family incentives, and as such reached a limited number of low-income customers and customers living in disadvantaged communities (DACs).[55] Although the TECH Initiative reached a limited number of low-income participants during the evaluation period, on average, those that participated experienced bill savings and their gas and electric energy consumption impacts were more modest than those customers that do not receive a CARE or FERA discount. However, DAC participants experienced energy impacts similar to those outside DACs, and their net bill decreases were less than those outside DACs.

  - **Recommendation:** Continue to monitor the TECH participation impacts on energy consumption and net energy bills for participants residing in DACs to avoid burdening customers in these areas with unaffordable energy bills. Consider whether differences in housing stock in some DACs (i.e., a disproportionate presence of older homes) might cause these participants to benefit from weatherization or other services as part of their TECH participation.[56] If results from the ongoing TECH LI Pilot show participants avoid unaffordable energy bills, it might be possible for the LI TECH Pilot to reach more participants by working with the Energy Savings Assistance (ESA) Program for weatherization.[57]

Data and Measurement

- **Conclusion:** The CEC Snowflake Database is an important resource designed to enable timely and innovative studies to advance climate and energy initiatives across California. The study team benefited from the ability to access this resource but was unable to estimate the impact of TECH Initiative participation for customers in some utility service territories due to missing or incomplete data.

  - **Recommendation:** Continue to build out the CEC Snowflake Database and ensure timely and complete access to data across utilities to realize the potential for efficiencies and insights from the database.

- **Conclusion:** A substantial number of project claims were excluded from the analysis due to missing or inaccurate utility identifiers needed to connect project information to meter data for one or both fuels. Twelve percent of claims could not be associated with an electric premise and 16% could not be associated with a gas premise.

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[55] Disadvantaged communities refers to those communities and geographic areas identified as such by the California Environmental Protection Agency in accordance with California Senate Bill 535. We include DACs identified under both CalEnviroScreen 3.0 and CalEnviroScreen 4.0. Low income customers and those living in DACs were a focus of TECH Initiative multifamily efforts and collaborations with existing low-income direct install programs that primarily occurred after the evaluation period and are not represented in these impacts.

[56] For more details on this see: Bastian, H. and C. Cohn, October 2022. "Ready to Upgrade: Barriers and Strategies for Residential Electrification." American Council for an Energy-Efficient Economy.

[57] The TECH Low-Income Heat Pump Adoption Pilot ("TECH LI Pilot") was designed to complement existing low-income programs, including the Energy Savings Assistance (ESA) program and San Joaquin Valley Disadvantaged Community Pilot. The TECH LI Pilot fills the gap between what is needed to install a heat pump—such as electrical panel upgrades and relocations, removing old HVAC systems, sealing leaks in ducts, walls, and roofs, and building outdoor enclosures for HPWHs—and what is paid by TECH's incentives for heat pump equipment and installation. In coordination with ESA, the TECH LI Pilot may help customers avoid unaffordable electric bills by reducing energy consumption via weatherization before adding heat pumps. Effective weatherization also has the potential to reduce the price of the heat pump purchase because homes with tighter envelopes have lower heating and cooling loads that can be served by smaller heat pumps.

- **Recommendation:** To ensure estimates of future TECH impacts are as representative as possible, consider recording each participant's utility and premise identifier for both fuels as part of the program tracking data. This would help to increase the number of participants included in the sample frame in future evaluations and can also facilitate a better understanding of cross-fuel impacts. For example, NEM status is typically only associated with the electric account. By consistently tracking both the gas and electric premise identifiers for a given participant, future evaluations could separately estimate the gas energy impacts of NEM participants.

- **Conclusion:** Due to data limitations, the analysis did not include an assessment of or accounting for cross-participation of TECH participants in other utility programs during the evaluation period. As a result, if participants took part in other decarbonization or energy efficiency programs at a different rate than similar nonparticipants, the impact of these interventions is not reflected in the TECH Initiative impacts.
  - **Recommendation:** The evaluator and the program administrator continue efforts to compile information on other program participation among TECH participants that can be readily connected to TECH participant tracking data. Tracking this information will enable deeper insights into the heat pump market, support assessment of incentive layering, and position future impact evaluations to assess how exogenous increases or decreases in energy consumption due to participation in other programs affect TECH Initiative impacts.
- **Conclusion:** Understanding how often and which customers retain their natural gas service following TECH participation could enhance the rigor of the impact analysis and support policy and planning efforts by contextualizing the findings.
  - **Recommendation:** For future studies, consider collecting data on whether customers go "all-electric" due to their TECH participation and/or conducting additional analysis to identify customers that closed their gas accounts following TECH participation. Including time-varying information in the CEC Snowflake database on individual customer baseline allowances (i.e., all-electric baselines, SCE's HPWH baseline adjustment) could facilitate this analysis. By differentiating between customers with missing gas consumption data versus inactive gas service, future studies would be able to estimate separate gas consumption baselines and bill impacts for these customers. These data will also allow stakeholders to monitor the market transformation and differences between participants who retain and those who close their gas service following TECH Initiative participation.
- **Conclusion:** The study team separately estimated electric energy impacts for net-metered participants using net energy consumption data and a matched comparison group of similar customers. The study team found that TECH net-metered participants experienced a smaller average increase in annual electricity consumption and saved more on their utility bills than non-net-metered participants. We also tested a custom modeling approach that controlled for variation in solar PV production (i.e., due to the local solar irradiance at a given point in time). We found that, with a robust comparison group, we measured approximately equal electricity impacts with or without using solar irradiance data in our models.
  - **Recommendation:** For pooled models with a high-quality comparison group, energy and load impacts for net-metered customers can be calculated without including solar irradiance data. Including solar irradiance data might be more important for site-level modeling, especially when those models lack an hourly baseline constructed to include a comparison group.

APPENDIX A. IMPACT ANALYSIS METHODS

APPENDIX A.1. DATA COLLECTION, REVIEW, AND PREPARATION

The TECH Initiative population-based impact study collected and analyzed data from several sources, including program participant data, utility customer data, AMI meter interval electricity consumption data, natural gas monthly billing consumption data, weather data, and solar irradiance data. We cleaned and prepared each data set and merged them before undertaking the impact analysis.

PARTICIPANT DATA

DESCRIPTION

We identified TECH program participants using program tracking ("claims") data maintained by the implementation contractor. These data contain information about each project, including the measures received, measure installation date, baseline heating and cooling equipment, project location, electric and gas utility premise identifiers, and home characteristics such as the baseline heating fuel. We analyzed the claims data to understand the participant population composition and trends in participation, including the mix of measures installed, housing and demographic characteristics of participants, and geographic and temporal patterns in participation.

DATA CLEANING

We cleaned the participation data in two stages. The study team first performed cleaning at the claims level. We started with 14,686 claims and ended up with 12,377 (84%) associated with electric utility premises and 11,830 (80%) for gas utility premises. The final step—linking each participant premise to utility customer electricity and gas consumption data in the CEC Snowflake Database—was the biggest reason for attrition. This step was completed separately for each fuel type since the CEC Snowflake Database does not include a shared identifier to link a premise's electricity and gas consumption data. This approach also helped maximize the number of premises included in the analysis for each fuel. We identified the electric and natural gas utility premise associated with each claim in the CEC Snowflake Database based on a combination of the premise identifier and the customer utility as recorded in the tracking data (Table 45).

Table 45. Participant Data – Claims Level Data Cleaning

Reason	Total Claims Remaining	Percent Claims Remaining	Claims Dropped	Percent Claims Dropped
Initial count Cap-and-Trade claims	14,686	100%	26	
Claims with no utility premises associated	14,569	99.2%	117	0.8%
Missing installation date(s)	14,423	98.2%	146	1.0%
Previous fuel was propane (fuel switching)	14,291	97.3%	132	0.9%
No measure type recorded	14,219	96.8%	72	0.5%
Unable to identify associated premise in CEC Snowflake Database (fuel-specific step)				
Electric	12,377	84.3%	1,842	12.5%
Natural gas	11,830	80.6%	2,389	16.3%

Following the claims-level cleaning steps, the study team aggregated the claims to the utility premise level for each fuel, retaining a record of the number and types of measures received and other key details from the program tracking data. This resulted in 10,523 utility premises for electric (Table 46) and 10,014 utility premises for gas (Table 47).

We added key information from the CEC Snowflake Database, including rate code, CARE or FERA program participation, and NEM status. For each fuel and premise, the study team leveraged the customer service account identifier associated with the premise to confirm that the customer continuously resided at the premise for at least nine months in the baseline and reporting periods. This check increased our confidence that changes in energy consumption at the premise were due to the TECH Initiative and not due to changes in occupancy. The utility customer-premise was the unit of analysis for the study and is defined as all meters at a premise for a period of time where the same account is associated with the premise. If the account changes, this would become a new utility customer-premise.

We used TECH participation data to identify the installation start and completion dates for each project. For premises with multiple measures, the installation start date was the start date for the first measure, and the installation end date was the completion date for the final measure. We used the installation start and completion dates to define the participant's baseline and reporting periods. We defined a deadband period between the earliest installation start date and the latest installation end date at each premise and excluded consumption data during this period when matching participants to nonparticipants and modeling.

The study team completed additional cleaning of the electric utility customer-premise level data as summarized in Table 46. We started with 10,523 premises and retained 4,129 (39%) in the analysis. The main contributor to attrition was removing SDG&E and LADWP customer-premises due to unavailable data and consumption data cleaning.

Table 46. Electric Utility Customer-Premise Level Data Cleaning

Reason	Premises Remaining	Percent Remaining	Premises Dropped	Percent Dropped
Initial count	10,523	100.0%		
Earliest installation before December 2021 or after December 2022[a]	9,166	87.1%	1,357	12.9%
Master-metered premises and multi-family multi-metered premises	9,154	87.0%	12	0.1%
Multiple different measures at the same premise	8,808	83.7%	346	3.8%
Noncontinuous residency (account change)	8,134	77.3%	674	7.7%
Served by LADWP and SDG&E	6,192	58.8%	1,942	23.9%
Consumption data unavailable (initial check)	6,170	58.6%	22	0.4%
Missing data on one or more stratification criteria	6,014	57.2%	156	2.5%
Noncontinuous residency (account change), SMUD customers only[b]	5,906	56.1%	108	1.8%
Limit to premises successfully matched to a nonparticipant	5,308	50.4%	598	10.1%
Consumption data cleaning and addition of weather data	4,170	39.6%	1,138	21.8%
Nonparticipant pair dropped due to cleaning	4,129	39.2%	41	1.0%
Final analysis sample	**4,129**	**39.2%**		

[a] The analysis sample only includes utility customer-premises that completed installation of TECH measures between December 2021 and December 2022. However, in calculating program impacts, we extrapolate the results of the consumption analysis to all projects funded through Cap and Trade between July 2021 and July 2023.

[b] This step was completed later in the cleaning process for SMUD participants as the needed data were initially unavailable.

The study team completed additional cleaning of the gas utility customer-premise level data, as summarized in Table 47. We started with 10,014 premises and retained 3,684 (37%) in the analysis. The main contributor to attrition was consumption data cleaning.

Table 47. Gas Utility Customer-Premise Level Data Cleaning

Reason	Premises Remaining	Percent Remaining	Premises Dropped	Percent Dropped
Initial count	10,014	100.0%		
Earliest installation before December 2021 or after December 2022[a]	8,782	87.7%	1,232	12.3%
Master-metered premises and multi-family multi-metered premises	8,733	87.2%	49	0.6%
Multiple different measures at the same premise	8,389	83.8%	344	3.9%
Noncontinuous residency (account change)	7,187	71.8%	1,202	14.3%
Remove SDG&E	5,838	58.3%	1,349	18.8%
Consumption data unavailable (initial check)	5,837	58.3%	1	<0.1%
Missing data on one or more stratification criteria	5,652	56.4%	185	3.2%
Limit to premises successfully matched to a nonparticipant	5,652	56.4%	0	0%
Consumption data cleaning and addition of weather data	3,684	36.8%	1,747	34.2%
Nonparticipant pair dropped due to cleaning	3,684	36.8%	0	0%
Final analysis sample	**3,684**	**36.8%**		

[a] The analysis sample only includes utility customer premises that completed installation of TECH measures between December 2021 and December 2022. However, in calculating program impacts, we extrapolate the results of the consumption analysis to all projects funded through Cap-and-Trade between July 2021 and July 2023.

NONPARTICIPANT DATA

DESCRIPTION

We obtained data from the CEC Snowflake Database for the California residential utility premise population with active accounts during the evaluation period that did not participate in the TECH Initiative. These utility customer-premises were candidates for the matched nonparticipant comparison group, which was used to estimate the electricity and gas consumption baselines for TECH participants. We defined separate sample frames of nonparticipating customers for electricity and natural gas.

DATA CLEANING

For each nonparticipant utility premise, we collected data on customer attributes such as whether the premise was net-metered, the customer account rate schedule (to identify and remove master-metered premises and to identify TOU rate customers), and receipt of a CARE or FERA discount. Based on the premise zip code, the study team assigned the premise to a climate zone and determined whether the premise was in a DAC. We also conducted a continuous residency check to ensure that the same customer resided at the premise for at least nine months of the baseline and reporting periods.[58] We cleaned the nonparticipant population data separately for electric and gas premises.

[58] SMUD customers were excluded from the nonparticipant matched comparison group candidates due to the inability to establish continuous residency. Participants from SMUD territory were matched to PG&E customers residing in the same climate zone.

Table 48 summarizes the cleaning steps completed for the electric nonparticipant population. We retained 76% of the over 9 million electric premises identified. The main contributor to attrition was the continuous residency check. Out of these 7,171,959 premises, 5,308 nonparticipant premises matched to form the comparison group.

Table 48. Electric Utility Customer-Premise Nonparticipant Data – Population-Level Data Cleaning

Reason	Premises Remaining	Percent Remaining	Premises Dropped	Percent Dropped
Initial count	9,440,110	100.0%		
Premise with more than one meter	9,375,909	99.3%	64,201	0.7%
TECH participant	9,368,698	99.2%	7,211	0.1%
Continuous residency duration < 548 days [a]	7,466,048	79.1%	1,902,650	20.2%
Missing data on one or more stratification criteria	7,171,959	76.0%	294,089	3.1%
Final comparison group candidates	**7,171,959**	**76.0%**		

[a] 548 days represents 75% of the two-year data period required to include the customer in the analysis.

Table 49 summarizes the cleaning steps completed for the gas nonparticipant population. We retained 69% of the over 10 million gas premises identified. The main contributor to attrition was the continuous residency check. Out of these 7,409,893 premises, 4,793 nonparticipant premises matched to form the comparison group.

Table 49. Gas Nonparticipant Data – Population-Level Data Cleaning

Reason	Premises Remaining	Percent Remaining	Premises Dropped	Percent Dropped
Initial count	10,781,326	100.0%		
Premise with more than one meter	10,781,326	100.0%	0	0%
TECH participant	10,775,752	100.0%	5,574	<0.1%
Continuous residency duration < 548 days [a]	7,785,302	72.2%	2,990,450	27.7%
Missing data on one or more stratification criteria	7,409,893	68.7%	375,409	3.5%
Final comparison group candidates	**7,409,893**	**68.7%**		

[a] 548 days represents 75% of the two-year data period required to include the customer in the analysis.

ELECTRIC CONSUMPTION DATA

DESCRIPTION

We used AMI electric consumption data to select the comparison group and to model the TECH Initiative electric energy and demand impacts. The study team obtained interval electric consumption data from the CEC Snowflake Database. The consumption data include the following fields:

- Premise ID

- Meter ID
- Metered electricity in kWh delivered from the utility to the premise
- Metered electricity in kWh delivered from the premise to the utility (for net-metered premises)
- Indicators for estimated consumption values
- Ending date-time of interval
- Length of interval in minutes

We extracted the consumption data at the meter level using utility premise identifiers and aggregated the meter data to the premise level before analysis.

DATA CLEANING

We separately processed and cleaned the consumption data by utility and channel (i.e., returned vs. delivered) and separately for the participant and comparison groups. Our data cleaning addressed the following issues in the electric interval data:

- **Duplicate Values:** Duplicate readings for a customer premise and time interval were dropped.
- **Missing Values:** Records with null or blank usage, date, or timestamp values were dropped.
- **Unusually Large Values:** Outlier interval consumption values were excluded from the analysis.
  - Delivered channel outliers were considered at the premise level and defined as usage that was both five standard deviations above the mean for the premise and above 30 kWh.
  - For the returned channel, outliers were defined as excess PV generation three standard deviations above the mean based on the typical residential solar PV generation capacity range documented in the California Interconnection Project Premises dataset.[59]
- **Negative Usage Values:** Negative values in both the delivered and received channels were dropped.
- **Zero Usage Values:** Zero usage values for electric customers not enrolled in net metering were dropped for the delivered channel only.
- **Change in NEM Status:** If NEM status changed in the baseline period, the records before the change were excluded from the analysis. Likewise, if NEM status changed in the reporting period, the records after the change were excluded.
- **Overall Data Sufficiency:** Each participant was required to have between 9 and 12 months of consumption data prior to the installation start date (the baseline period) and between 9 and 12 months after the installation end date (the reporting period). For matched nonparticipants, the electric consumption data were required to contain between 9 and 12 months of the baseline period and between 9 and 12 months of the reporting period of the participant(s) to which they were matched.
- **Seasonal Data Sufficiency:** Premises without 75% of the baseline and reporting period hours, as well as 75% of the summer and winter days in both the baseline and reporting periods, were excluded from the analysis to ensure that there was sufficient data to estimate energy impacts including for the winter heating and summer cooling seasons.

[59] California Distributed Generation Statistics. Interconnected Project Premises Data Set. https://www.californiadgstats.ca.gov/downloads/

After cleaning the electric data, we combined the records from the delivered and returned channels for each utility customer-premise and interval. We calculated net usage by subtracting the cleaned returned value from the cleaned delivered value.

The data cleaning steps outlined in this section ultimately contribute to the utility customer-premise level attrition described in Table 46 and ensured that outliers and missing data did not affect the analysis. The most common reason for attrition at the customer-premise level was the utility customer-premise having less than 75% of the total expected hours during the evaluation period.

GAS CONSUMPTION DATA

DESCRIPTION

We used monthly gas billing consumption data to model the gas energy impacts and to select the comparison group. We extracted gas meter consumption data from the CEC Snowflake Database. The gas billing data included the following fields:

- Meter ID
- Bill start and end dates
- Consumption (in therms)
- Rate code

We observed that the CEC Snowflake Database contained incomplete and invalid data for SoCalGas customers at the time of the evaluation. The SoCalGas billing data had gas consumption data for fewer than half of its customers between May 2022 and October 2022. Additionally, the available consumption data for this period had higher-than-expected usage values, suggesting the data were not valid. We did not identify any systematic anomalies with the PG&E gas billing consumption data.

DATA CLEANING

We cleaned the consumption data for each utility separately. Our data cleaning addressed the following issues:

- **SoCalGas data quality:** Dropped consumption data for all SoCalGas customers between May 2022 and October 2022 from the analysis sample and based our data cleaning and analysis on the remaining months.
- **Duplicate records:** Removed duplicate readings for utility customer-premises and billing periods.
- **Unusual usage values:** Removed records with null, infinite, negative, or blank usage values. Identified and removed the top one percent of utility customer-premises by average consumption.
- **Short and long billing periods:** Removed bills that were less than ten days or greater than 90 days in duration.
- **Overlapping bills:** Dropped overlapping bills.
- **Estimated bills:** Excluded estimated bills and the subsequent bill.
- **Data sufficiency**: Each participant was required to have consumption data for 75% of the months for which data were available for their utility in both the baseline and reporting period. Participants with fewer than 75% of the available months from the baseline period or reporting period data were excluded from the analysis sample. For

matched nonparticipants, the gas consumption data were required to include at least 75% of the months for the baseline and reporting period of the participant(s) to which they were matched.[60]

The data cleaning steps outlined in this section ultimately contributed to the utility customer-premise level attrition described in Table 47 and ensured that outliers and missing data did not affect the analysis. For both the treatment and comparison groups, the largest drop in utility customer-premises occurred due to insufficient data for analysis.

Due to the significantly lower amount of data available for SoCalGas from May through October compared to PG&E, the study team implemented a final step in preparing the gas data for analysis. The study team accounted for the missing SoCalGas data by calculating the probability that a specific calendar month (e.g., July or December) was included in the analysis sample for both the baseline and reporting periods. The study team then weighted the data by the inverse of the probability of selection in the analysis sample when estimating gas impacts. For consistency across utilities, we also calculated inverse probability weights for PG&E gas customers; however, the weights had little effect since the missing data were distributed evenly across the calendar months of both the baseline and reporting periods.

WEATHER DATA

DESCRIPTION

We collected historical weather data (dry-bulb temperature) from the National Centers for Environmental Information (NCEI) Integrated Surface Database (ISD) for all participants and matched nonparticipants. Weather for each utility customer-premise was extracted at the hourly level from the weather station closest to each premise based on the customer's zip code and using the open source eeweather software package for consistency with the implementation team.[61]

We also downloaded California typical meteorological year weather data (CZ2022 and CZ2018), which was used to produce weather normal energy impacts.[62] We appended the normal weather data for each customer in the analysis to the same station as their historical weather data (USAF ID). For 30 locations for which CZ2022 weather data were unavailable, we collected CZ2018 weather data.

DATA PREPARATION

- **Electric Consumption Data:** As part of the data preparation for the actual and normal weather, we calculated cooling degree hours with an outdoor base temperature of 75°F for cooling degree hour (CDH) and 65°F for heating degree hour (HDH) calculation. We chose those temperature points as the base temperatures because they approximate the point at which customers start using their cooling systems in the summer and heating systems in the winter.
- **Gas Consumption Data:** To make the hourly weather data compatible with the monthly bill level of the gas consumption data, the data were rolled up to the daily level and averaged across the billing period for each bill in the dataset. First, to calculate the daily weather from hourly values, the hourly temperature values were averaged daily for each weather station. We ensured that the average daily temperature reflected complete data by replacing incomplete weather station days (days when a weather station had less than 24 hours of data) with a day from the nearest complete weather station. Once all the data were rolled up to the daily level, we used 65°F for the heating

[60] The threshold was set to 75% rather than a static number of months due to the lower number of available months for SoCalGas customers compared to PG&E customers.

[61] https://github.com/openeemeter/eemeter

[62] California Measurement Advisory Council. California Weather Files. https://www.calmac.org/weather.asp

degree day (HDD) calculation. Finally, the calculated HDD values were averaged across the billing periods to get the average weather for each bill.

IRRADIANCE DATA

DESCRIPTION

To support the accurate estimation of electric energy impacts for NEM premises in the absence of solar generation data, the evaluation team collected a variety of irradiance data measures from a third-party data provider.[63] Data were collected for each participant and matched nonparticipant premise with solar PV as identified by their NEM status. We obtained hourly data (based on each individual premise's latitude and longitude) covering the 24-month period to be included in energy impact modeling. The most important data point for the analysis was Global Horizontal Irradiance (GHI). This is the amount of solar radiation that reaches the earth's surface on a horizontal plane. GHI is measured in watts per square meter (W/m^2) and is available for each hour of the day.[64]

DATA PREPARATION AND MODELING

Before including the GHI data in the modeling of TECH electricity impacts, we de-duplicated the records at the hourly data level and reviewed the data coverage, only retaining premises with GHI that met our data sufficiency thresholds.

GHI entered the electric consumption model, as specified in Equation 3:

Equation 3. Electric Energy Model (Summer Model with CDH terms only) Specification with GHI

$$kWh_{it} = \alpha_i + \tau_t + \sum_{j=1}^{24} \theta_{HDH,j} CDH_{it}\, x\, HourofDay_j + \sum_{j=1}^{24} (\gamma_j TECH_{it} x HourofDay_j + \gamma_{HDH,j} TECH_{it} x CDH_{it} x HourofDay_j) + GHI_{it} + \varepsilon_{it}$$

Where:

- α_i = Utility customer-premise-specific intercept
- τ_t = Month-Year-specific intercept
- $TECH_{it}$= Indicator variable for treatment Premise-Utility *i* after their latest installation date at time *t*
- CDH_{it} = Cooling degree-hours by Premise-Utility *i*'s weather station for time-period *t* (base 75°F)
- GHI_{it} = Global horizontal irradiance by Premise-Utility for time period t
- ε_{it} = Error term

Ultimately, irradiance data were not used in the models from which electric energy impacts were reported. The inclusion of the GHI terms in our model did not lead to considerable differences in estimated impact for NEM premises, particularly during the hours with solar radiation, so the study team elected to report the results from the non-GHI models for consistency ().

Table 50).

[63] We sourced our data from Solcast as they are able to provide more recent and geographically precise irradiance measures than open-source data providers currently offer. https://solcast.com/

[64] GHI= DNI x cos(z)+DHI where z is the solar zenith

Table 50. NEM Segment Hour of the Day Normal Impacts for Summer Weekday

Hour	Impact with GHI (kWh)	Impact without GHI (kWh)
0	-0.05	-0.05
1	-0.05	-0.05
2	-0.05	-0.05
3	-0.04	-0.04
4	-0.03	-0.03
5	-0.05	-0.04
6	-0.05	-0.05
7	-0.03	-0.03
8	0.01	-0.01
9	-0.01	-0.02
10	-0.06	-0.06
11	-0.11	-0.11
12	-0.15	-0.15
13	-0.17	-0.16
14	-0.19	-0.19
15	-0.20	-0.20
16	-0.20	-0.20
17	-0.21	-0.21
18	-0.23	-0.23
19	-0.22	-0.21
20	-0.17	-0.17
21	-0.12	-0.12
22	-0.09	-0.09
23	-0.08	-0.07

APPENDIX A.2 COMPARISON GROUP DEVELOPMENT

We developed matched comparison groups for the electricity and natural gas consumption impact analyses. The matching process involved two main steps. First, we exactly matched TECH participants to nonparticipants based on customer attributes such as climate zone, receipt of a CARE or FERA discount, and residency in a DAC. Second, we used distance and propensity score matching to match each TECH participant to a nonparticipant in the same exact matching stratum with similar energy consumption patterns.

ELECTRIC COMPARISON GROUP

STAGE 1: EXACT MATCHING

We stratified the population of participants and nonparticipants by the combination of their climate zone, NEM status, TOU rate, CARE or FERA discount, and whether the premise is located in a DAC, resulting in 180 different sample strata. We randomly sampled without replacement 30 nonparticipants in the same stratum for each participant to ensure a large enough pool of nonparticipants for matching on consumption in the next stage. By grouping the most similar participants and nonparticipants together, our goal was to create an equivalent comparison group for each attribute (e.g., climate zone, NEM status) to enable us to model the impacts for each segment while maintaining equivalency.

STAGE 2: DISTANCE MATCHING ON DISAGGREGATED LOAD

The evaluation team disaggregated pre-installation participant and nonparticipant whole-home daily electricity loads into cooling, heating, and baseload. Within each exact matching stratum, we matched on disaggregated load to increase the likelihood that each TECH participant would be matched to a nonparticipant with the same space heating fuel and similar space cooling loads.

We conducted the load disaggregation analysis using the OpenEEmeter package.[65] Based on the disaggregation results, we generated estimates of each customer's electric cooling load, heating load, and baseload. We then conducted one-to-many matches within our exact matching strata to narrow the pool of potential matches for each participant to those with similar heating and space cooling loads. We did this by calculating Mahalanobis distances between the participants and nonparticipants to identify the 30 nonparticipants in the same exact matching stratum with similar baseload, heating load, and cooling load for each participant.

Stage 3: Probabilistic Matching on Whole-Home Consumption Patterns

In the next step, we matched participants to nonparticipants in the same matching stratum from Stage 2 based on hourly whole-home electricity consumption patterns during the baseline period. We developed a linear probability model to estimate the likelihood of receiving treatment as a function of pre-treatment consumption. The covariates were pre-treatment mean consumption for four-hour blocks of the day by season and day type (12:00 a.m.–3:00 a.m. weekday summer, 3:00 a.m.–6:00 a.m. weekday summer, …, 9:00 p.m.–12:00 a.m. weekend winter, etc.) We then predicted propensity scores for participants and nonparticipants and matched each participant to the closest nonparticipant in the same matching stratum from Stage 2.[66] To address the staggering of TECH treatment dates, we divided participants into 13 cohorts based on the month-year of TECH installation from December 2021 to December 2022, and for each cohort, we generated covariates for participants and nonparticipants for the same 12 months of the baseline period.

In the final matching stage, we matched with replacement, meaning that a comparison premise could be matched to more than one participant within the exact matching stratum and cohort. The maximum number of participant premises a single comparison premise was matched to was three.

Evaluating Match Quality

Overall Equivalency

To assess match quality for the electricity consumption analysis, we plotted the average net electricity consumption across 24 hours of the day for the participant and the matched comparison group for each season (summer, winter, and shoulder) and day type (weekday and weekend) during the baseline period. We also modeled differences in hour of the day consumption between participants and matched nonparticipants to check for statistically significant differences in their net consumption.

With few exceptions, there is good equivalency between the participant and matched comparison group. A statistically significant difference exists for an hour at the 5% significance level if the error bar showing the 95% confidence interval does not contain zero. For customer segments with statistically significant differences, it is usually attributable to small sample sizes. Figure 36, Figure 37, and Figure 38 illustrate that the summer, winter, and shoulder weekday and weekend hours exhibit good equivalency, respectively.

[65] LF Energy. OpenEEMeter. https://lfenergy.org/projects/openeemeter/

[66] With this approach, it is possible for the same nonparticipant to be matched to more than one participant across the cohorts. Additionally, there was a 14th cohort of participants and nonparticipants for which it was not possible to disaggregate the load in Stage 2A.

Figure 36. Electric Participant and Comparison Group Summer Weekday and Weekend Equivalency

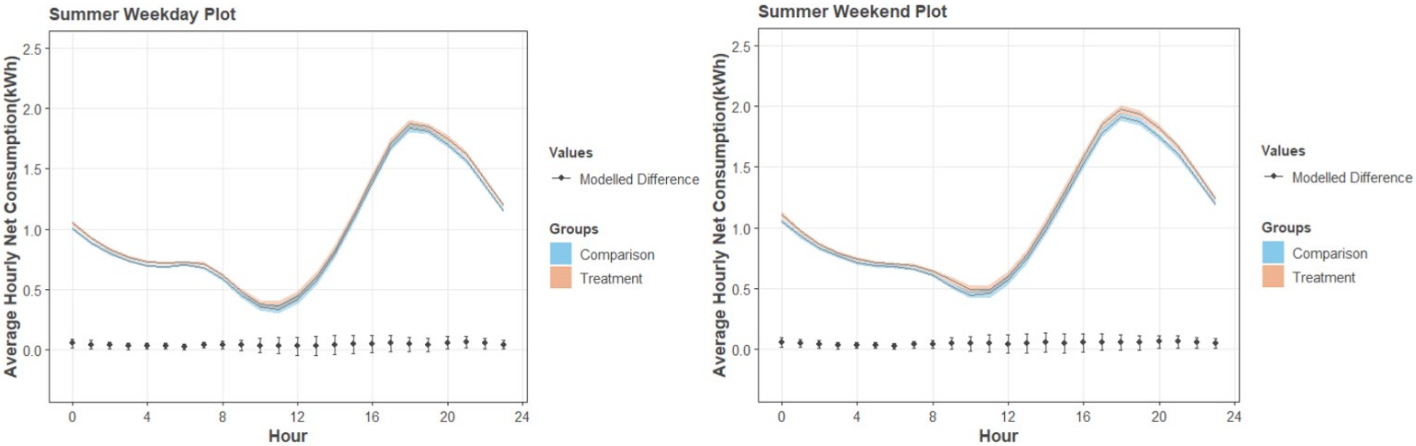


Figure 37. Electric Participant and Comparison Group Winter Weekday and Weekend Equivalency

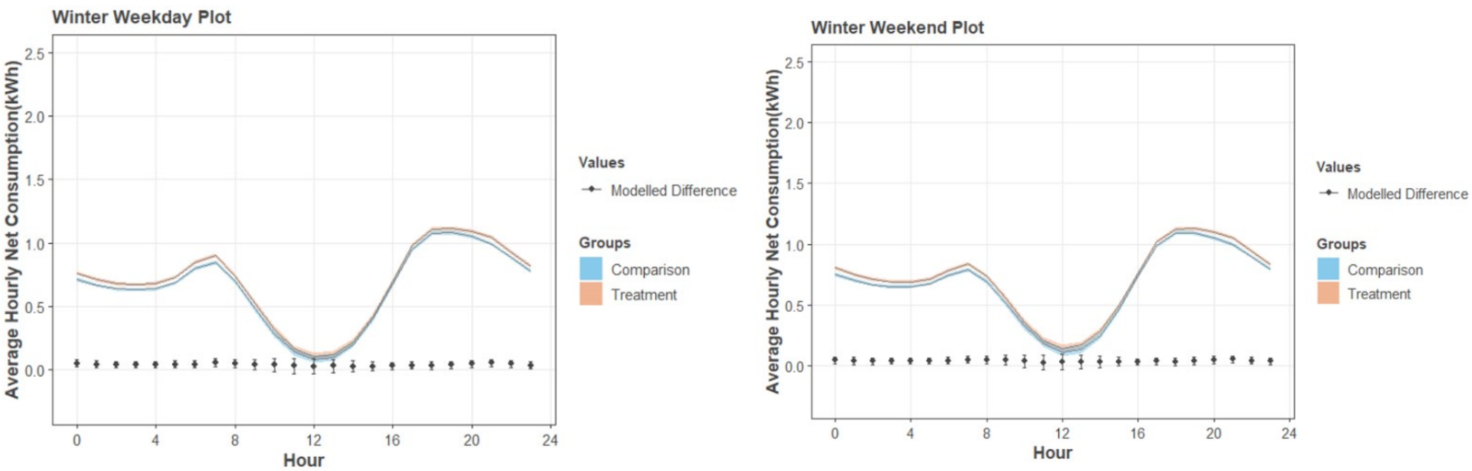
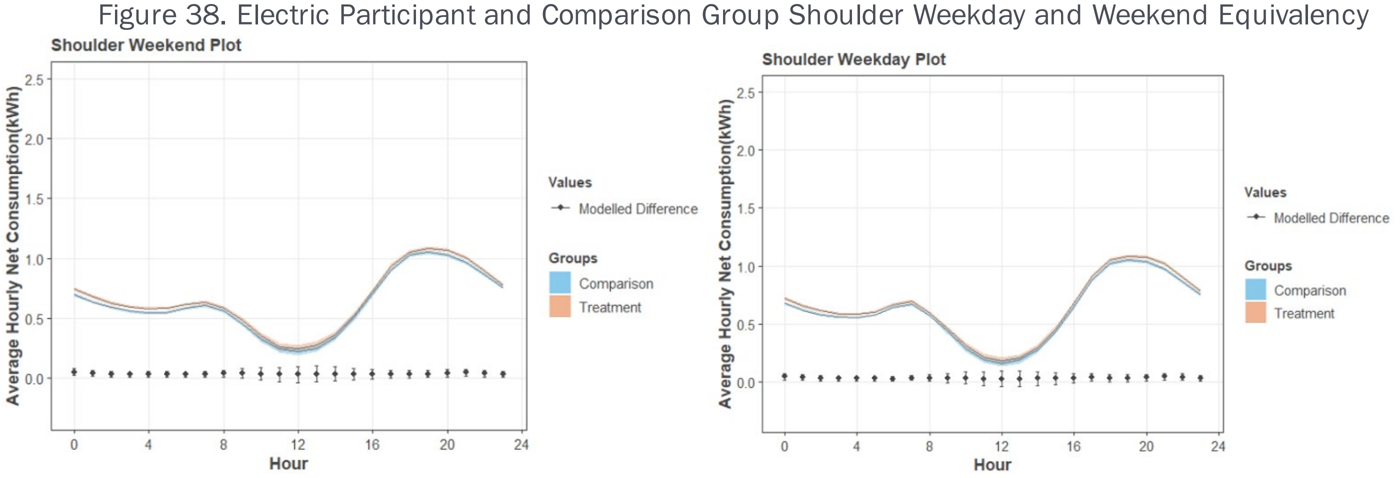
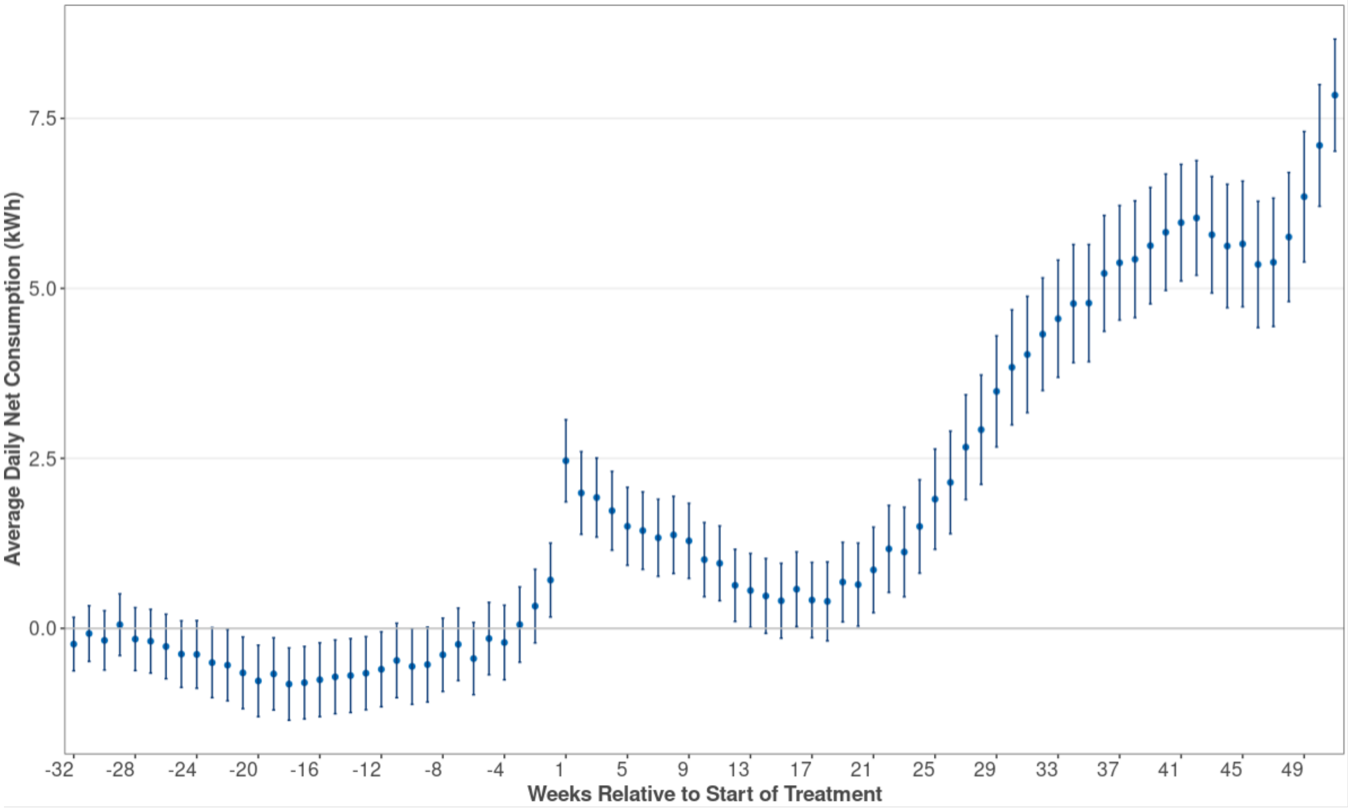


Figure 38. Electric Participant and Comparison Group Shoulder Weekday and Weekend Equivalency



To further assess the equivalency of the comparison group, we conducted an event study to check for differences in mean consumption before treatment. We modeled the differences in gas consumption between the two groups by the months relative to the start of treatment. This model included premise and month-year fixed effects as well as heating degree-days interacted with climate zone indicator variables. We modeled the differences in electric consumption by the week relative to the start of treatment. The model includes premise and week-of-sample fixed effects as well as heating degree-days and cooling degree-days interacted with climate zone indictor variables. For gas, we found small and statistically insignificant differences in consumption between the treatment and comparison groups during the baseline period. This suggests there were no pre-treatment consumption trends for either the treatment or comparison group that would violate the parallel trends assumption required for difference-in-differences estimation to produce an unbiased estimate of gas impacts (Figure 39). For electricity, we also find mostly small and mostly statistically insignificant effects on consumption before treatment and large and positive effects on consumption after treatment.

Figure 39. Overall Electric Premise Event Study



This

Segment Specific Equivalency

We also assessed the equivalency of matches for each segment or population stratum. Due to the volume of equivalency plots, we only include summer and winter weekdays here.

Climate Zone

In Figure 40 and Figure 41, except for climate zones five and one, which are some of the smallest climate zones in terms of participant size, all other climate zones exhibit good equivalency across summer weekday and winter weekday hours of the day.

Figure 40. Electric Participant and Comparison Group Summer Weekday Equivalency by Climate Zone

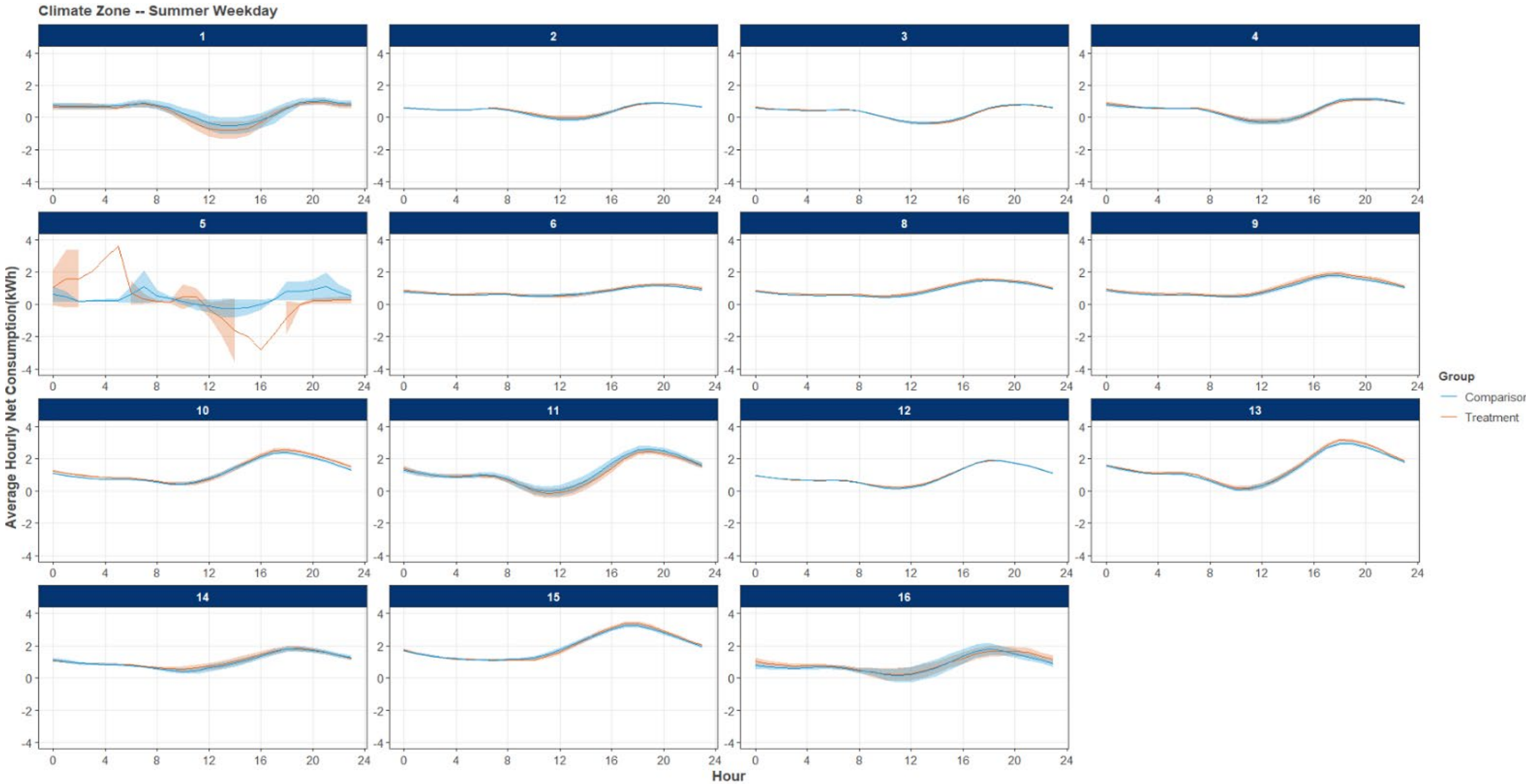
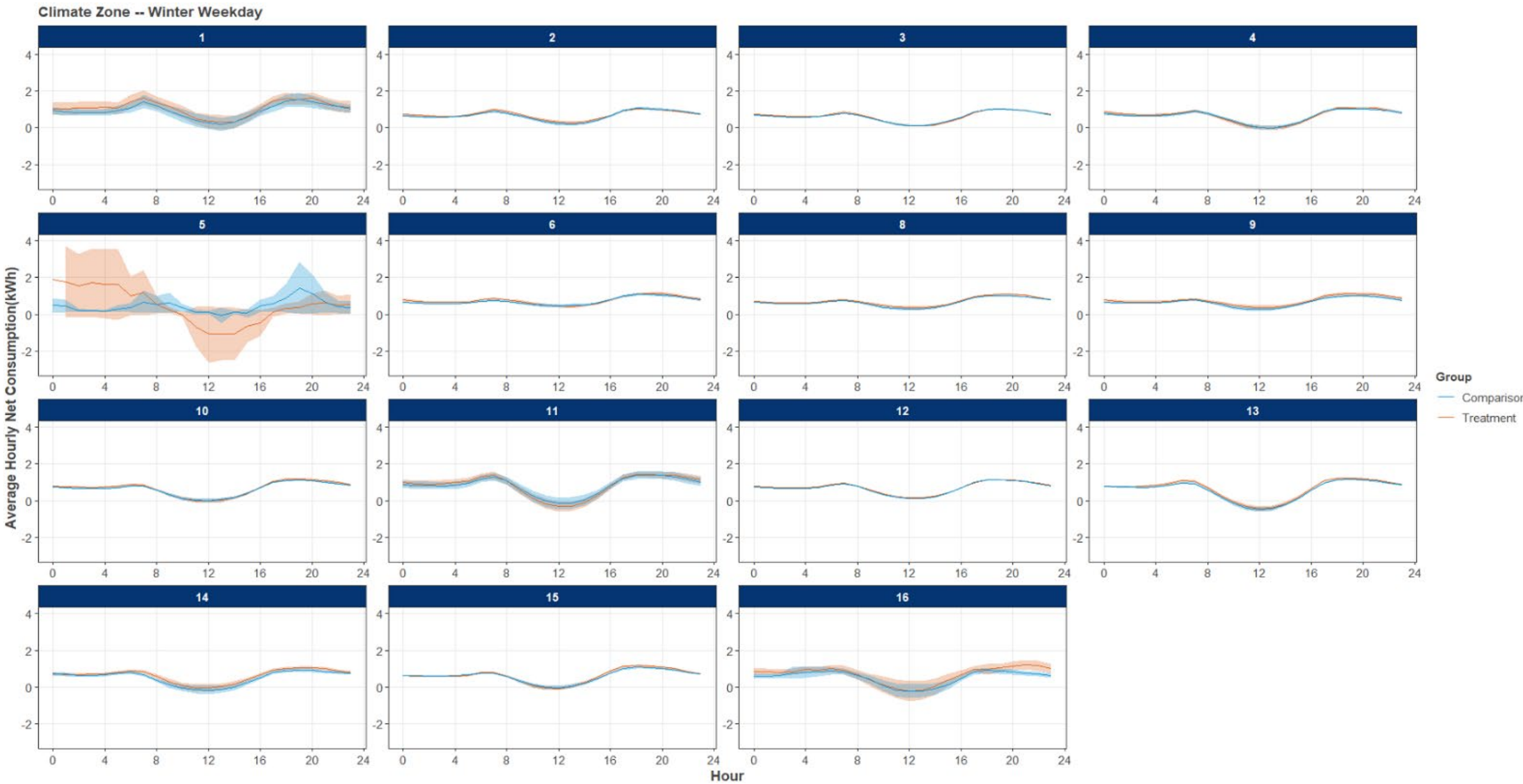


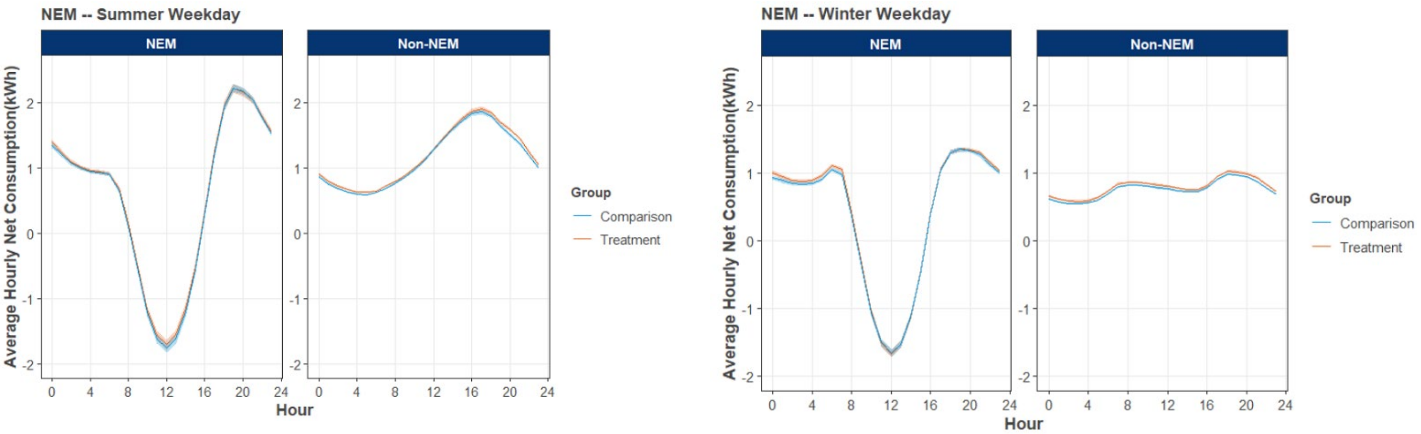
Figure 41. Electric Participant and Comparison Group Summer Weekday Equivalency by Climate Zone



NEM Status

There is good equivalency across almost all hours of the day for summer and winter weekdays for both NEM and Non-NEM segments, as shown in Figure 42. We found particularly good equivalency for NEM participants and nonparticipants.

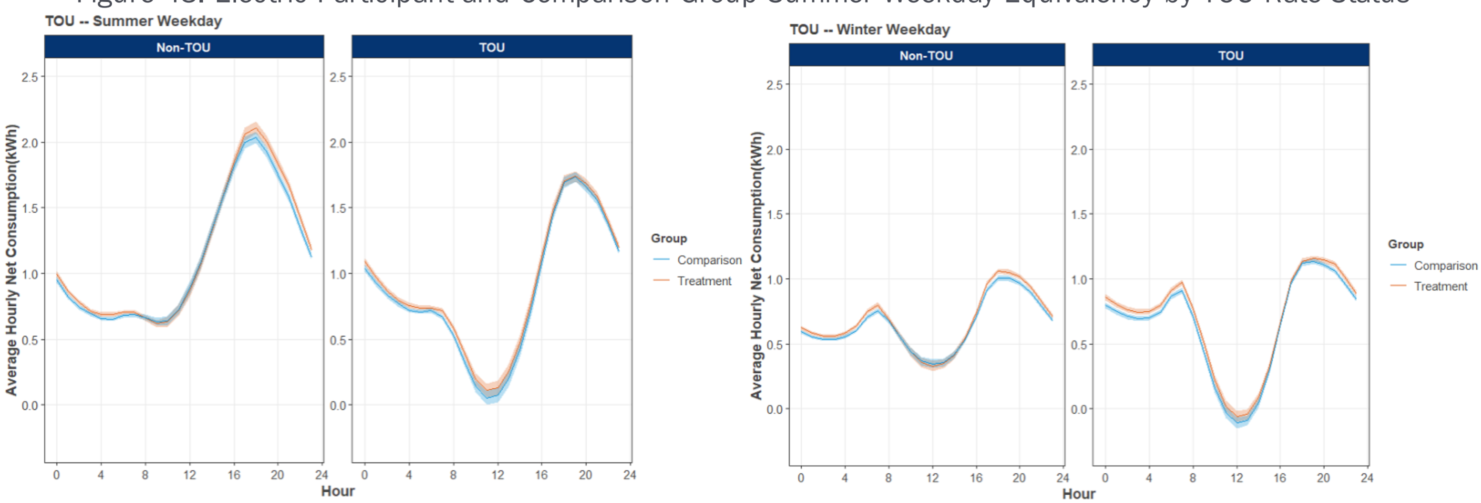
Figure 42. Electric Participant and Comparison Group Summer Weekday Equivalency by NEM Status



TOU Rate

Figure 43 shows that both TOU and non-TOU premises exhibit good equivalency.

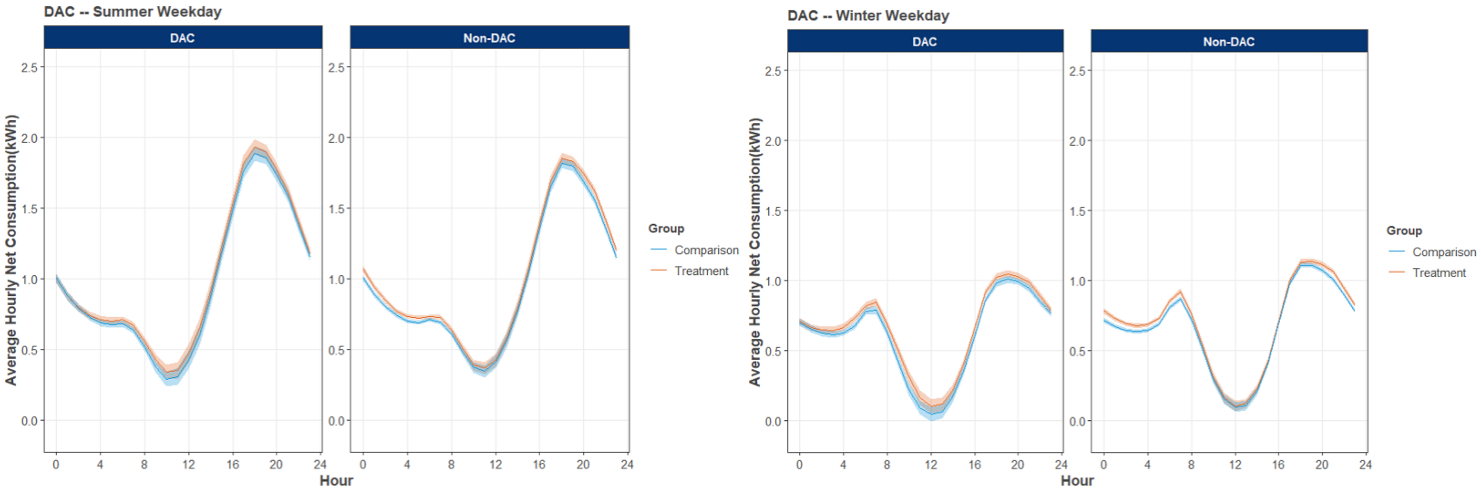
Figure 43. Electric Participant and Comparison Group Summer Weekday Equivalency by TOU Rate Status



Disadvantaged Communities

Figure 44 illustrates that both DAC and non-DAC premises have good equivalency in average net consumption between participants and the matched comparison group.

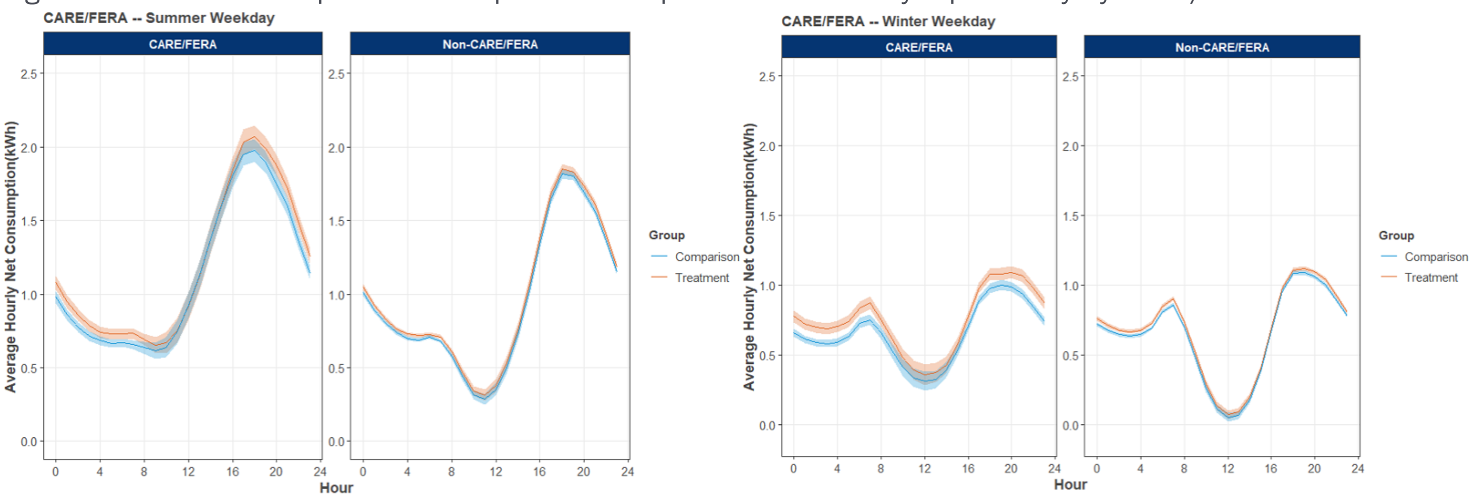
Figure 44. Electric Participant and Comparison Group Summer Weekday Equivalency by DAC



CARE/FERA Discount

Figure 45 shows that relative to treatment and comparison group premises not receiving a CARE or FERA discount, those on CARE or FERA have differences in average net consumption. This is particularly pronounced in the winter weekdays.

Figure 45. Electric Participant and Comparison Group Summer Weekday Equivalency by CARE/FERA Discount Status



GAS COMPARISON GROUP

We matched participants to nonparticipants for the gas consumption impact analysis using an approach similar to that used for electricity. We first conducted exact matching on variables defining key strata for which we would like to estimate impacts, including climate zone, CARE status, and DAC status. In the second step, we used propensity scoring to match participants to nonparticipants with similar monthly gas consumption in the baseline period. As a result of the unavailability of SoCalGas data for May 2022 to October 2022, we undertook separate matching of participants to nonparticipants by IOU (PG&E and SoCalGas).

STAGE I: EXACT MATCHING

First, we stratified gas account participants and nonparticipants by climate zone, CARE status, DAC status, and IOU. Within each matching stratum, we randomly sampled without replacement 30 nonparticipants for each participant.

Stage 2: Probabilistic Matching on Consumption

After the one-to-many exact matching of Stage 1, we matched participants to nonparticipants in each exact matching stratum based on their gas consumption. We generated the following covariates during the baseline period: average daily consumption in January, February, March, the shoulder months (April–May and October–November), the summer months (June–September), and December.

As with electricity, to account for the rolling TECH participation, we divided participants into cohorts by the month-year of the measure installation date and estimated a separate propensity model for each cohort model to predict the likelihood of TECH participation as a function of the consumption covariates. For each cohort, we calculated covariates for participants and nonparticipants using the same 12 months immediately preceding the start of participation. After generating a propensity score for each participant and nonparticipant, we matched each participant to a nonparticipant with the closest propensity score in the same exact matching stratum.

In the final matching stage, we matched without replacement, meaning a comparison premise could be matched to only one participant within the exact matching stratum and cohort. However, because a comparison premise could be matched to a participant in different cohorts, we allowed comparison premises to be matched one time per cohort or up to eight times in total. Matched comparison premises were matched to an average of 1.01 treatment premises, meaning very few were matched more than once.

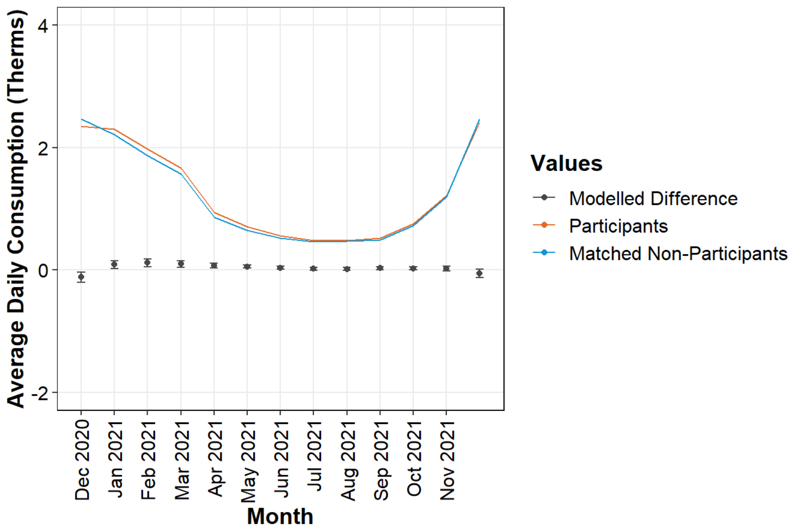
Evaluating Match Quality

Overall Equivalency

To assess the quality of the matches, we plotted the average daily consumption of the participant and matched comparison group from December 2020 to November 2021, the latest common 12 months of the baseline period for all participants. We also modeled differences in monthly consumption between participants and matched nonparticipants to check for statistically significant differences in their consumption.

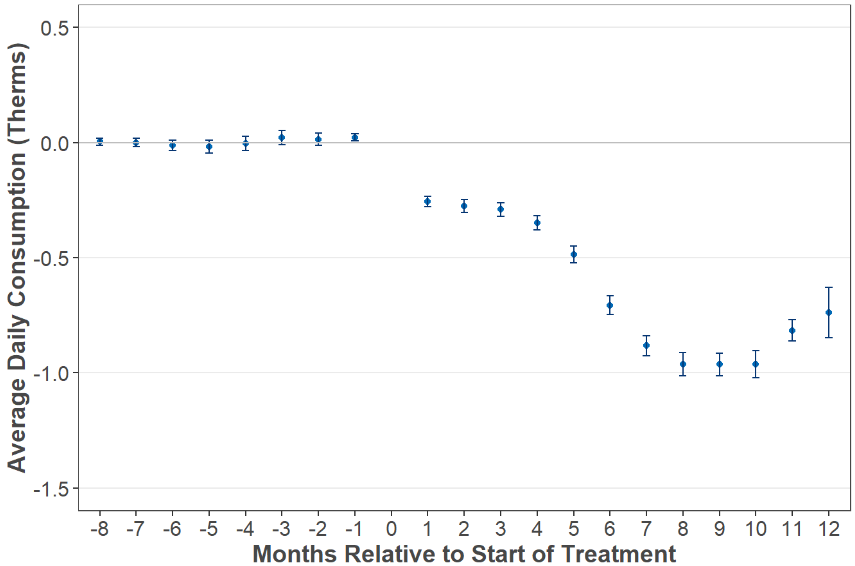
Figure 46 shows the average daily gas consumption of participants and matched nonparticipants in each month of the baseline period. The comparison group had higher consumption from December 2020 through February 2021, but the consumption of the two groups was close for the rest of the period and did not have statistically significant differences. The consumption differences between December 2020 and February 2021 are likely driven by smaller counts of customers in the earliest months, as the data were trimmed to include only one year of the baseline period. Using a 95% confidence interval, we determined that the differences between the treatment and matched comparison group were not significantly different in the majority of the common baseline period months.

Figure 46. Gas Participant and Comparison Group Overall Equivalency



To further assess the equivalency of the comparison group, we conducted an event study to check for differences in mean consumption before treatment. We modeled the differences in consumption between the two groups by the months relative to the start of treatment. This model included premise and month-year fixed effects as well as heating degree-days interacted with climate zone indicator variables. We found small and statistically insignificant differences in consumption between the treatment and comparison groups during the baseline period. This suggests there were no pre-treatment consumption trends for either the treatment or comparison group that would violate the parallel trends assumption required for difference-in-differences estimation to produce an unbiased estimate of gas impacts (Figure 47).

Figure 47. Overall Gas Premise Event Study



Segment Specific Equivalency

As we did for the electric analysis, we also assessed the equivalency of matches by each segment we defined for our models.

Measure Types

Our equivalency assessment for each of the measures that were installed through participation in the TECH incentive yielded insignificant differences between the treatment and matched comparison groups for all of the months of the year (Figure 48, Figure 50, and Figure 50).

Figure 48. Gas Participant and Comparison Group Central Heat Pump Equivalency

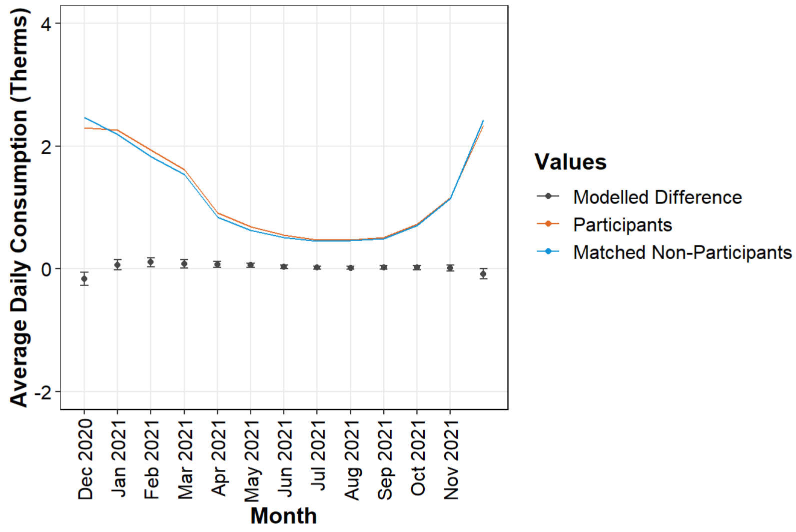


Figure 49. Gas Participant and Comparison Group Ductless Heat Pump Equivalency

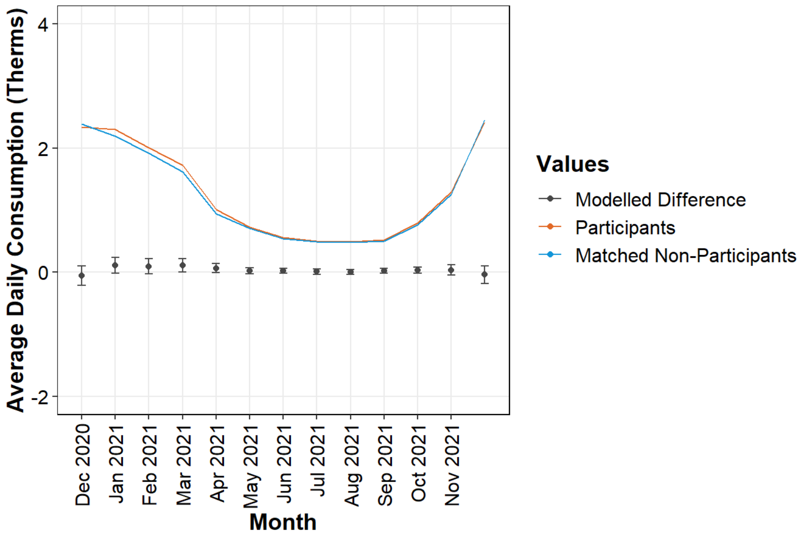
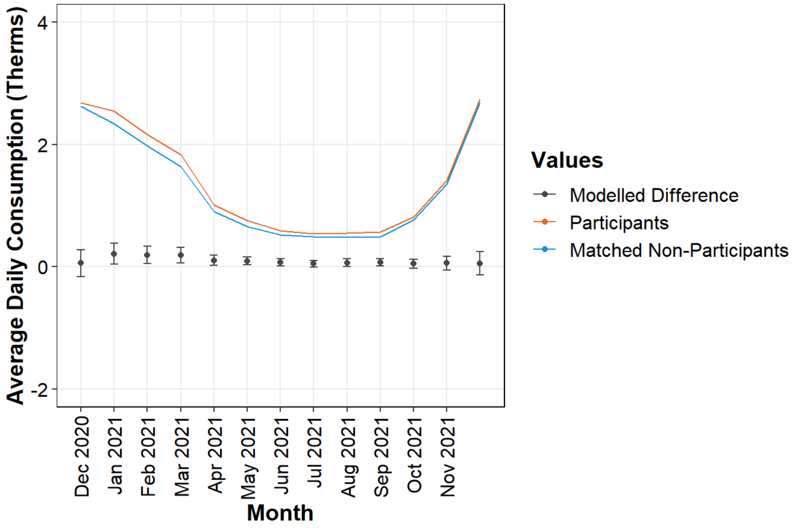


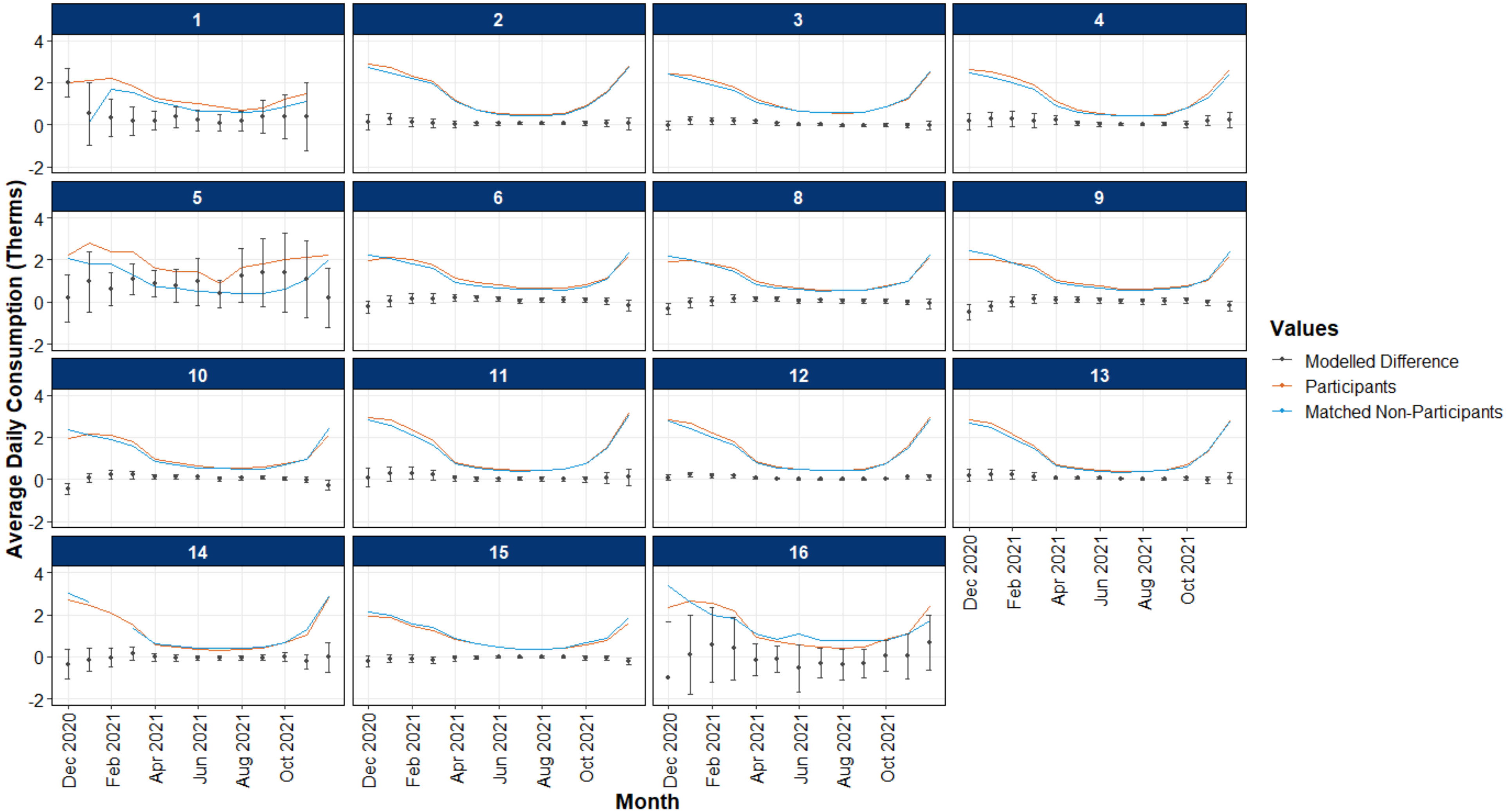
Figure 50. Gas Participant and Comparison Group HPWH Equivalency



Climate Zone

Some climate zones with a small number of participants and matched nonparticipants exhibit statistically significant differences in baseline consumption (Figure 51).

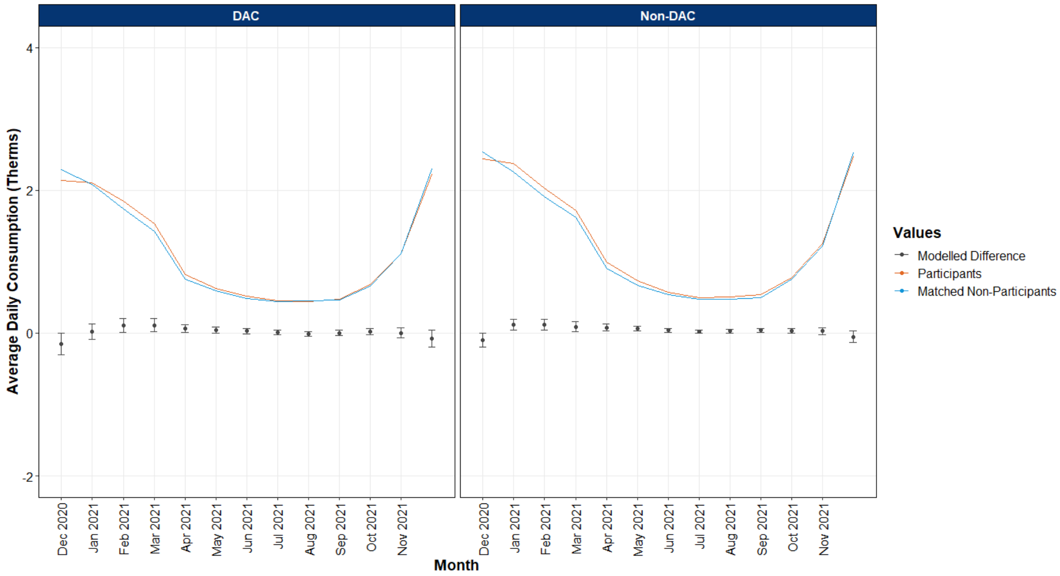
Figure 51. Gas Participant and Comparison Group Summer Weekday Equivalency by Climate Zone



Disadvantaged Communities

In Figure 52, we illustrate that both DAC and non-DAC premises have good equivalency between the treatment and matched comparison group.

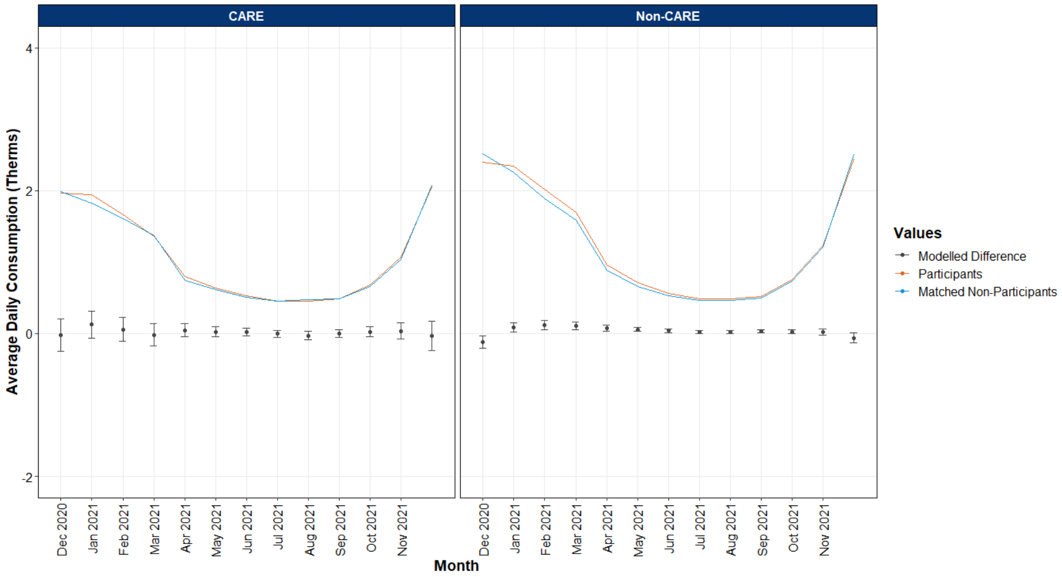
Figure 52. Gas Participant and Comparison Group Summer Weekday Equivalency by DAC Status



CARE Discount

In Figure 53, we show that both the CARE and non-CARE groups are equivalent; however, the CARE group has larger error bounds due to the lower counts of participants and nonparticipants with the CARE discount.

Figure 53. Gas Participant and Comparison Group Summer Weekday Equivalency by CARE Discount Status



APPENDIX A.3. MODELED PARTICIPANTS AND POPULATION COMPARISON

The study population was Cap-and-Trade-funded projects between July 2021 and July 2023 at customer premises receiving electric service from PG&E, SCE, or SMUD and gas service from PG&E or SoCalGas. However, many TECH participants could not be included in the analysis sample due to the unavailability of energy consumption data or other reasons. The report's main body describes the sample selection criteria. In this appendix, we compare the attributes of the analysis sample and the study population.

MODELED AND EXTRAPOLATED POPULATION

MEASURE

The measure mix between the participant population and modeled participants was more similar for electric modeled participants than for gas modeled participants. There were slightly more central heat pumps, slightly fewer ductless heat pumps, and fewer HPWHs in the electric modeled sample. There were modest differences between the participant population and gas modeled sample, particularly for central heat pumps and HPWHs (Table 51).

Table 51. Comparison of Extrapolated Population and Modeled Participants by Measure Types

Measure Type	Participant Population		Electric Modeled Participants		Gas Modeled Participant	
	#	%	#	%	#	%
Central Heat Pump	4,781	58%	2,528	61%	2,483	67%
Ductless Heat Pump	2,126	26%	936	23%	765	21%
HPWH	1,743	21%	644	16%	424	12%
Total	**8,250**		**4,108**		**3,672**	

Notes: Participant population measure counts exceed total sites and percentages exceed 100%, as some premises received more than one measure. Modeled counts exclude multi-measure premises.

ELECTRIC AND GAS UTILITY

The utility composition of the participant population and the modeled sample for electric premises was similar. This was particularly the case for PG&E, with modest differences for SCE and SMUD. However, the differences between the participants and the modeled sample for gas were more substantial. The difference was close to 10 percentage points for both PG&E and SoCalGas.

Table 52. Comparison of Extrapolated Population and Modeled Participants by Utility

Utility	Participant Population		Electric Modeled Participants		Gas Modeled Participant	
	#	%	#	%	#	%
Electric						
PG&E	3,942	48%	1942	47%		
SCE	3,383	41%	1899	46%		
SMUD	925	11%	288	7%		
Total	**8,250**	**100%**	**4129**	**100%**		
Gas						
PG&E	5,248	61%			1,898	52%
SoCalGas	3,297	39%			1,786	48%
Total	**8,545**	**100%**			**3,684**	**100%**

CLIMATE ZONE

The distributions of participants across climate zones were similar for the participant population and modeled participants for both electric and gas, except for climate zone 15, where the modeled sample for gas was different from the participant population by eight percentage points.

Table 53. Comparison of Extrapolated Population and Modeled Participants by Climate Zone

Climate Zone	Participant Population		Electric Modeled Participants		Gas Modeled Participants	
	#	%	#	%	#	%
1	33	0%	22	1%	5	0%
2	541	7%	235	6%	205	6%
3	1,164	14%	493	12%	377	10%
4	316	4%	154	4%	120	3%
5	2	0%	2	0%	9	0%
6	384	5%	234	6%	249	7%
7	1	0%				
8	669	8%	423	10%	298	8%
9	461	6%	251	6%	279	8%
10	621	8%	340	8%	250	7%
11	161	2%	89	2%	88	2%
12	2,350	28%	1,069	26%	891	24%
13	525	6%	298	7%	213	6%
14	180	2%	60	1%	35	1%
15	794	10%	437	11%	657	18%
16	47	1%	22	1%	8	0%
Unknown	1	0%				
Total	**8,250**	**100%**	**4,129**	**100%**	**3,684**	**100%**

Note: The following climate zones overlap with the service territory of utilities excluded from the analysis sample due to missing or unreliable data. SDG&E: CZ6, CZ7, CZ8, CZ10, CZ14, and CZ15. LADWP: CZ6, CZ8, and CZ9.

OTHER PARTICIPANT ATTRIBUTES

Across the participant attributes such as NEM status, housing type, TOU rate enrollment, CARE status, and DAC status, the modeled samples for electric and gas are very similar to the participant population.

Table 54. Comparison of Extrapolated Population and Modeled Participants by Attributes

Attribute	Participant Population		Electric Modeled Participants		Gas Modeled Participants	
	#	%	#	%	#	%
NEM Status						
NEM	1,886	27%	1,193	29%		
Not NEM	5,128	73%	2,936	71%		
Unknown	34	0%				
Housing Type						
Single Family	8,029	97%	4,044	98%	3,609	98%
Multi Family	218	3%	85	2%	75	2%
Mobile Home	3	0.04%				
Time-of-Use Rate						
On TOU	4,132	59%	2,391	58%		
Not on TOU	2,793	40%	1,738	42%		
Unknown	123	2%				
Low Income Discount						
On CARE/FERA	758	11%	472	11%	349	9%
Not on CARE/FERA	6,256	89%	3,657	89%	3,335	91%
Unknown	34	0%	40	0%		
DAC Resident						
In a DAC	2,118	26%	1,109	27%	1,011	27%
Not in a DAC	6,132	74%	3,020	73%	2,673	73%

EXISTING AC BY MEASURE TYPE

In terms of the distribution across baseline air conditioning equipment type, the participant population and the modeled sample stratified by measure type are similar (Table 55).

Table 55.Comparison of Extrapolated Population and Modeled Participants by Measure Type/Existing AC

Measure Type/Existing AC	Participant Population		Electric Modeled Participants		Gas Modeled Participants	
	#	%	#	%	#	%
Central Heat Pump						
Central or Ducted	2,894	61%	1,515	60%	1,560	63%
Room, Window, or Wall Unit	32	1%	12	0%	7	0%
None	1,817	38%	1,000	40%	915	37%
Unknown	40	1%	1	0%	1	0%
Total	**4,783**	**100%**	**2,528**	**100%**	**2,483**	**100%**
Ductless Heat Pump						
Central or Ducted	624	29%	244	26%	221	29%
Room, Window, or Wall Unit	73	3%	34	4%	18	2%
None	1,339	63%	650	69%	525	69%
Unknown	90	4%	8	1%	1	0%
Total	**2,126**	**100%**	**936**	**100%**	**765**	**100%**

APPENDIX A.4 BILL IMPACT ANALYSIS

We converted the estimated energy impacts of central heat pumps, ductless heat pumps, and HPWHs to bill impacts by applying estimates of the average cost of electric and gas energy based on the participant rate code at the time of their TECH participation. Our analysis leveraged participants' hourly electric consumption and daily gas consumption across different IOUs and rate groups at the time of intervention to calculate the weighted average rate while taking into consideration the identified baseline allowances, tiering structure, specific TOU rate structure, and CARE and FERA discounts. These calculations were completed separately by fuel, for each customer segment, and for the baseline and reporting periods. Table 56 summarizes the rate codes used to estimate the bill impacts and the percentage of TECH participants on each rate. TOU rates are grouped based on the peak period structure.

Table 56 . Rate Codes Used to Calculate Bill Used to Calculate Bill Impacts

Utility	Rate Group	Example Rate Code(s)	# Participants	% Participants
Electric				
PG&E	Tiered Rate	HE1, E1, HE1N, ETL	753	19%
	Time of Use Structure #1	HETOUC, H2ETOUCN, ETOUC, HETOUCN	712	18%
	Time of Use Structure #2	HETOUD, H2ETOUDN, ETOUD HETOUDN	114	3%
	Time of Use Structure #3	H2E6N, HE6, HE6N	121	3%
	Time of Use EV	HEV2A, EV2A, H2EV2AN, HEV2AN, H2EVAN, EVA, HEVA, HEVAN	160	4%
SCE	Tiered Rate	DOMESTIC, D-SDP, D-CARE, D-CARE-SDP, D-SDP-O	968	24%
	Time of Use Structure #1	TOU-D-4, TOU-D-4-C, TOU-D-4-SDP	494	12%
	Time of Use Structure #2	TOU-D-5, TOU-D-5-C	285	7%
	Time of Use Structure #3	TOU-D-PRIME	84	2%
SMUD	Fixed Rate	R	256	6%
	Time of Use Structure #2	EAPR	24	1%
Total			**3,971**	**100%**
Gas				
PG&E	Residential	G-1, GM, GS, GT, GL-1, GML, GSL, and GTL	1,898	52%
SoCalGas	Residential	GR, GR-C and GT-R	1,786	48%
Total			**3,684**	**100%**

Note: For consistency, only rate codes from participants included in the energy impact modeling were included in the weighted rates analysis. Rate codes applying to fewer than 100 participating utility customer-premises were not included in the weighted rates (n=158 customer-premises). These customer-premises were assigned the average weighted rate in the bill impact calculations.

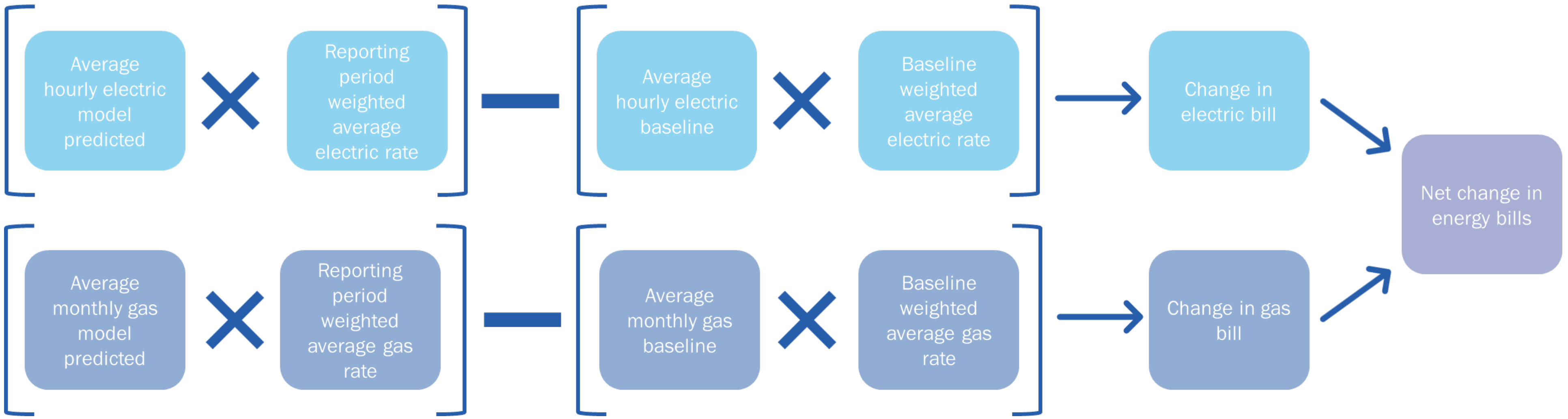
The key steps we followed for the electric and gas average rate code developed are described in more detail.

- For each utility and rate grouping, we researched and identified historic rates as of January 2022 or, when not available, rates closest to this timeframe. We excluded legacy and other rare rates.
- For each of the rates, we considered three specific components: (i) per-therm or per-kWh cost; (ii) adjustments for tiering/baseline credits based on actual participant usage; (iii) for gas, variation in baseline allowance by season and for electric, variation in rate by period, day and season.
- We assumed the following: (i) the same rates applied before and after the retrofit; (ii) heating/baseline allowances are the averages of all regions within each IOU territory; (iii) per unit energy costs include generation/procurement and delivery charges; (iv) current baseline allowances and peak period definitions if historical documentation was unavailable; (v) all customers get electricity from the IOU—not a CCA; (vi) for electricity rates, in the baseline period, we used dual-fuel electric baseline value, and in the reporting period, we assumed all-electric baseline allowance while for gas rates, the heating charge was only applied in the baseline period; (vii), we calculated bill impacts for NEM customers using their net consumption values.
- Our analysis resulted in an average weighted rate per hour for each customer segment, based on the unique usage of customers in that segment and the distribution of utility rates under which they were served. In rare cases, these calculations led to unreasonable per-kWh rates, which were driven by fluctuations in interval-level consumption values. These outlier rates were replaced with the value from the preceding hour.

- The analysis did not account for fixed charges that would remain the same during the baseline period and reporting period because all participants in the analysis sample retained their gas and electric accounts following TECH participation. The all-electric bill impact analysis accounts for gas fixed charges in the baseline period to illustrate how gas account closure following TECH participation would further impact customer bills.
- The analysis did not account for changes in taxes, fees, or riders.

We applied these weighted rates on the estimated energy impacts to calculate the change in electric and gas bills. Furthermore, we calculated the net change in energy bills as a difference between the fuel-specific change in bills as described below in Figure 54. This calculation was completed separately for the baseline and reporting periods to account for differences in energy consumption and heating baseline allowances.

Figure 54. Approach for Calculating Net Change in Energy Bills



APPENDIX B. DETAILED OUTPUTS

B.1 ANALYSIS SAMPLE SUMMARY STATISTICS

Table 57 and Table 58 summarize the measure mix and baseline cooling equipment for each segment.

Table 57. Measure Counts by Segment

Segment	Central Heat Pump		Ductless Heat Pump		HPWH		Total Count
	#	%	#	%	#	%	
Overall	2,644	61%	1,054	24%	655	15%	4,353
Measure Type							
Ducted HP	2,623	100%	0	0%	0	0%	2,623
Ductless HP	0	0%	1,033	100%	0	0%	1,033
HPWH	0	0%	0	0%	655	100%	655
Climate Zone							
CZ1	4	17%	17	74%	2	9%	23
CZ2	63	25%	155	63%	30	12%	248
CZ3	78	15%	279	53%	167	32%	524
CZ4	47	30%	64	41%	46	29%	157
CZ5	1	50%	0	0%	1	50%	2
CZ6	170	70%	66	27%	6	2%	242
CZ7							
CZ8	357	82%	67	15%	14	3%	438
CZ9	188	72%	56	21%	17	7%	261
CZ10	319	88%	33	9%	10	3%	362
CZ11	49	51%	31	32%	17	18%	97
CZ12	559	51%	199	18%	340	31%	1098
CZ13	305	96%	11	3%	3	1%	319
CZ14	24	27%	63	72%	1	1%	88
CZ15	462	99%	6	1%	1	0%	469
CZ16	18	72%	7	28%	0	0%	25
NEM Status							
NEM	788	61%	259	20%	242	19%	1,289
Not NEM	1,856	61%	795	26%	413	13%	3,064
TOU Status							
TOU	1397	55%	641	8%	482	19%	2,520
Not TOU	1247	68%	413	23%	173	9%	1,833
Low Income Status							
CARE/FERA	300	62%	112	23%	72	15%	484
Not CARE/FERA	2,344	61%	942	24%	583	15%	3,869
DAC Status							
DAC	774	68%	264	23%	99	9%	1,137
Not DAC	1,870	58%	790	25%	556	17%	3,216

Note: Measure type models exclude premises with multiple measures.

Table 58. Baseline Air Conditioning Equipment by Segment

Segment	Central or Ducted		Room, Window, or Wall Unit		None		Unknown		Total Count
	#	%	#	%	#	%	#	%	
Overall	1,759	51%	46	1%	1,659	48%	9	0%	3,473
Measure Type									
Central HP	1,504	60%	12	0%	999	40%	1	0%	2,516
Ductless HP	244	26%	34	4%	650	69%	8	1%	936
Climate Zone									
CZ1	4	20%	0	0%	16	80%	0	0%	20
CZ2	58	28%	2	1%	146	71%	0	0%	206
CZ3	55	17%	1	0%	262	80%	8	2%	326
CZ4	33	31%	1	1%	73	68%	1	1%	108
CZ5	1	100%	0	0%		0%	0	0%	1
CZ6	75	33%	1	0%	151	67%	0	0%	227
CZ7									
CZ8	164	40%	2	0%	243	59%	0	0%	409
CZ9	117	50%	9	4%	108	46%	0	0%	234
CZ10	158	48%	4	1%	168	51%	0	0%	330
CZ11	51	71%	3	4%	18	25%	0	0%	72
CZ12	424	58%	18	2%	287	39%	0	0%	729
CZ13	254	86%	1	0%	40	14%	0	0%	295
CZ14	17	29%	1	2%	41	69%	0	0%	59
CZ15	340	78%	2	0%	93	21%	0	0%	435
CZ16	8	36%	1	5%	13	59%	0	0%	22
NEM Status									
NEM	522	55%	5	1%	425	45%	2	0%	954
Not NEM	1,237	49%	41	2%	1,234	49%	7	0%	2,519
TOU Status									
TOU	922	48%	23	1%	955	50%	6	0%	1,906
Not TOU	837	53%	23	1%	704	45%	3	0%	1,567
CARE/FERA Status									
CARE/FERA	205	51%	13	3%	183	46%	0	0%	401
Not CARE/FERA	1,554	51%	33	1%	1,476	48%	9	0%	3,072
DAC Status									
DAC	528	53%	18	2%	454	45%	0	0%	1,000
Not DAC	1,231	50%	28	1%	1,205	49%	9	0%	2,473

Note: Previous air conditioning was not recorded for HPWH-only projects.

B.2 DETAILED ELECTRIC IMPACTS

Each workbook linked below contains hourly model outputs for summer weekday, summer weekend, shoulder weekday, shoulder weekend, winter weekday, and winter weekend models (Table 59). In addition to the numeric values, we provide hourly load shapes for each model and segment here.

Table 59. Detailed Electric Model Outputs by Segment

Category	Segment and Link to Outputs
Overall	Average All Segments
Measure	Central Heat Pump
	Ductless Heat Pump
	HPWH
Climate Zone	CZ1
	CZ2
	CZ3
	CZ4
	CZ5
	CZ6
	CZ8
	CZ9
	CZ10
	CZ11
	CZ12
	CZ13
	CZ14
	CZ15
	CZ16
Net Metered	NEM
	Non-NEM
Time-of-Use Rate	TOU Rate
	Non-TOU Rate
Low-Income Discount	CARE or FERA Discount
	Non-CARE or FERA Discount
Disadvantaged Community	Resides in a DAC
	Does Not Reside in a DAC

B.3 DETAILED GAS IMPACTS

Table 60 shows the monthly gas impact estimates by month of the year for the TECH population and by segment. All values represent mean daily impacts per participant and calculated for normal weather using the CZ2022 weather year.

Table 60. Modeled Monthly Gas Impacts by Segment

Month	Average Daily Impact (therms)	Standard Error	Average Daily Baseline (therms)	% Impact	Model Predicted
Overall					
1	-1.05	0.0191	2.38	-44.0%	1.33
2	-0.89	0.0156	2.11	-42.2%	1.22
3	-0.42	0.0099	1.35	-31.1%	0.93
4	-0.43	0.0099	1.04	-41.4%	0.61
5	-0.27	0.0110	0.75	-36.1%	0.48
6	-0.14	0.0129	0.56	-25.4%	0.41
7	-0.14	0.0130	0.52	-25.9%	0.39
8	-0.12	0.0134	0.50	-23.2%	0.39
9	-0.15	0.0127	0.55	-27.7%	0.40
10	-0.32	0.0105	0.75	-42.3%	0.43
11	-0.54	0.0101	1.44	-37.2%	0.90
12	-1.00	0.0179	2.30	-43.3%	1.31
Central Heat Pump					
1	-1.11	0.0223	2.34	-47.5%	1.23
2	-0.94	0.0185	2.08	-45.0%	1.14
3	-0.37	0.0126	1.32	-28.3%	0.95
4	-0.37	0.0126	1.01	-36.8%	0.64
5	-0.21	0.0141	0.74	-28.2%	0.53
6	-0.07	0.0162	0.54	-13.5%	0.46
7	-0.06	0.0164	0.49	-12.9%	0.43
8	-0.05	0.0166	0.47	-10.9%	0.42
9	-0.08	0.0160	0.52	-16.2%	0.44
10	-0.28	0.0133	0.75	-37.5%	0.47
11	-0.50	0.0125	1.39	-35.8%	0.89
12	-1.05	0.0210	2.27	-46.4%	1.22
Ductless Heat Pump					
1	-1.25	0.0415	2.40	-52.2%	1.15
2	-1.06	0.0343	2.12	-49.7%	1.07
3	-0.50	0.0200	1.37	-36.6%	0.87
4	-0.53	0.0203	1.10	-48.4%	0.57
5	-0.24	0.0205	0.74	-33.0%	0.50
6	-0.07	0.0240	0.53	-12.9%	0.47
7	-0.07	0.0240	0.51	-13.5%	0.44

Month	Average Daily Impact (therms)	Standard Error	Average Daily Baseline (therms)	% Impact	Model Predicted
8	-0.03	0.0250	0.49	-6.2%	0.46
9	-0.08	0.0237	0.54	-15.3%	0.46
10	-0.28	0.0201	0.74	-38.0%	0.46
11	-0.64	0.0222	1.46	-44.1%	0.82
12	-1.18	0.0388	2.30	-51.3%	1.12
HPWH					
1	-0.54	0.0545	2.71	-20.0%	2.17
2	-0.51	0.0419	2.27	-22.6%	1.75
3	-0.45	0.0248	1.36	-33.0%	0.91
4	-0.45	0.0250	1.05	-43.0%	0.60
5	-0.42	0.0278	0.70	-59.0%	0.29
6	-0.40	0.0337	0.59	-67.4%	0.19
7	-0.39	0.0341	0.61	-64.9%	0.21
8	-0.39	0.0350	0.60	-64.8%	0.21
9	-0.40	0.0331	0.63	-62.6%	0.24
10	-0.42	0.0270	0.71	-58.9%	0.29
11	-0.47	0.0289	1.58	-29.9%	1.11
12	-0.54	0.0513	2.53	-21.1%	2.00
CZ1					
1	-0.37	0.2845	1.89	-19.3%	1.53
2	-0.43	0.3405	2.11	-20.6%	1.67
3	-0.30	0.2337	1.43	-20.9%	1.13
4	-0.35	0.2713	1.41	-24.6%	1.07
5	-0.28	0.2176	1.24	-22.1%	0.97
6	-0.19	0.1676	0.96	-19.5%	0.77
7	-0.13	0.1512	0.98	-13.4%	0.84
8	-0.10	0.1493	1.01	-10.1%	0.91
9	-0.16	0.1576	1.18	-13.5%	1.02
10	-0.19	0.1696	1.00	-19.1%	0.81
11	-0.34	0.2626	1.61	-21.0%	1.27
12	-0.38	0.3002	2.05	-18.8%	1.66
CZ2					
1	-1.36	0.0958	2.89	-46.9%	1.54
2	-1.17	0.0806	2.51	-46.7%	1.34
3	-0.69	0.0468	1.72	-40.3%	1.02
4	-0.55	0.0407	1.26	-44.1%	0.70
5	-0.35	0.0379	0.87	-40.6%	0.51
6	-0.14	0.0440	0.63	-22.0%	0.49
7	-0.09	0.0466	0.57	-15.3%	0.48
8	-0.05	0.0486	0.52	-9.7%	0.47
9	-0.13	0.0442	0.59	-22.6%	0.46
10	-0.36	0.0378	0.84	-43.3%	0.47

Month	Average Daily Impact (therms)	Standard Error	Average Daily Baseline (therms)	% Impact	Model Predicted
11	-0.75	0.0501	1.61	-46.5%	0.86
12	-1.28	0.0897	2.69	-47.7%	1.41
CZ3					
1	-0.99	0.0553	2.36	-42.0%	1.37
2	-0.86	0.0464	2.03	-42.4%	1.17
3	-0.47	0.0266	1.23	-37.8%	0.76
4	-0.56	0.0294	1.09	-51.0%	0.54
5	-0.28	0.0266	0.65	-43.0%	0.37
6	-0.15	0.0310	0.56	-26.5%	0.41
7	-0.17	0.0302	0.60	-27.9%	0.43
8	-0.12	0.0325	0.62	-18.8%	0.50
9	-0.14	0.0312	0.64	-22.6%	0.49
10	-0.24	0.0276	0.65	-36.8%	0.41
11	-0.55	0.0293	1.34	-41.4%	0.78
12	-0.92	0.0506	2.13	-43.3%	1.21
CZ4					
1	-1.26	0.1070	2.55	-49.4%	1.29
2	-1.07	0.0872	2.13	-50.2%	1.06
3	-0.59	0.0519	1.25	-46.8%	0.67
4	-0.65	0.0543	1.20	-54.3%	0.55
5	-0.32	0.0542	0.84	-37.7%	0.52
6	-0.13	0.0663	0.55	-22.9%	0.42
7	-0.11	0.0674	0.50	-22.3%	0.39
8	-0.09	0.0692	0.51	-17.6%	0.42
9	-0.14	0.0651	0.62	-22.8%	0.48
10	-0.40	0.0512	0.94	-42.9%	0.53
11	-0.72	0.0581	1.53	-47.3%	0.80
12	-1.17	0.0972	2.29	-50.9%	1.12
CZ5					
1	-1.23	0.0422	3.16	-39.1%	1.92
2	-1.03	0.0330	2.95	-34.9%	1.92
3	-0.64	0.0198	2.18	-29.5%	1.53
4	-0.76	0.0228	2.00	-38.1%	1.24
5	-0.57	0.0187	2.16	-26.2%	1.59
6	-0.35	0.0201	1.94	-17.9%	1.59
7	-0.30	0.0212	1.89	-15.9%	1.59
8	-0.18	0.0248	0.92	-19.7%	0.74
9	N/A	N/A	N/A	N/A	N/A
10	N/A	N/A	N/A	N/A	N/A
11	-0.71	0.0212	2.25	-31.4%	1.54
12	-1.12	0.0372	2.67	-42.1%	1.55
CZ6					

Month	Average Daily Impact (therms)	Standard Error	Average Daily Baseline (therms)	% Impact	Model Predicted
1	-0.80	0.0241	2.17	-36.9%	1.37
2	-0.81	0.0244	2.04	-39.7%	1.23
3	-0.40	0.0192	1.42	-27.9%	1.02
4	-0.42	0.0189	1.18	-35.2%	0.77
5	-0.31	0.0209	1.06	-29.7%	0.74
6	-0.16	0.0255	1.11	-14.5%	0.95
7	-0.12	0.0272	0.94	-12.3%	0.82
8	-0.11	0.0273	1.04	-10.9%	0.92
9	-0.12	0.0270	1.23	-9.9%	1.10
10	-0.14	0.0264	0.98	-13.9%	0.85
11	-0.35	0.0201	1.31	-26.4%	0.96
12	-0.69	0.0208	1.99	-34.4%	1.31
CZ8					
1	-0.74	0.0222	2.00	-36.9%	1.26
2	-0.67	0.0204	1.81	-37.2%	1.13
3	-0.35	0.0200	1.28	-27.5%	0.93
4	-0.35	0.0200	1.00	-35.4%	0.65
5	-0.24	0.0230	0.84	-28.2%	0.61
6	-0.12	0.0269	0.85	-14.5%	0.73
7	-0.11	0.0275	0.81	-13.5%	0.70
8	-0.11	0.0275	0.36	-30.4%	0.25
9	-0.11	0.0275	0.26	-41.5%	0.15
10	-0.11	0.0273	-0.06	194.6%	-0.17
11	-0.40	0.0192	1.26	-31.7%	0.86
12	-0.71	0.0214	1.94	-36.7%	1.23
CZ9					
1	-0.87	0.0266	2.18	-40.0%	1.31
2	-0.85	0.0257	2.04	-41.5%	1.19
3	-0.44	0.0187	1.44	-30.3%	1.01
4	-0.45	0.0186	1.16	-38.6%	0.71
5	-0.32	0.0207	0.94	-34.0%	0.62
6	-0.12	0.0271	0.49	-23.8%	0.38
7	-0.11	0.0275	0.83	-13.1%	0.72
8	-0.11	0.0275	0.75	-14.4%	0.65
9	-0.12	0.0270	0.78	-15.5%	0.66
10	-0.19	0.0244	0.51	-37.5%	0.32
11	-0.43	0.0188	1.33	-32.0%	0.90
12	-0.80	0.0240	2.06	-38.8%	1.26
CZ10					
1	-1.04	0.0336	2.27	-46.0%	1.23
2	-1.16	0.0389	2.25	-51.8%	1.08
3	-0.54	0.0185	1.47	-36.9%	0.93

Month	Average Daily Impact (therms)	Standard Error	Average Daily Baseline (therms)	% Impact	Model Predicted
4	-0.55	0.0186	1.17	-46.5%	0.63
5	-0.32	0.0208	0.74	-42.7%	0.43
6	-0.12	0.0270	0.43	-27.8%	0.31
7	-0.11	0.0275	0.42	-26.0%	0.31
8	-0.11	0.0275	0.47	-23.4%	0.36
9	-0.12	0.0272	0.59	-19.8%	0.47
10	-0.29	0.0214	0.79	-36.8%	0.50
11	-0.43	0.0189	1.29	-32.9%	0.87
12	-0.92	0.0285	2.12	-43.4%	1.20
CZ11					
1	-1.43	0.1234	3.01	-47.6%	1.58
2	-1.12	0.0893	2.40	-46.5%	1.29
3	-0.74	0.0557	1.69	-43.9%	0.95
4	-0.54	0.0472	1.05	-52.0%	0.50
5	-0.19	0.0589	0.66	-29.0%	0.47
6	-0.08	0.0681	0.51	-15.2%	0.43
7	-0.07	0.0685	0.47	-15.5%	0.40
8	-0.07	0.0685	0.46	-15.7%	0.39
9	-0.09	0.0673	0.50	-17.1%	0.42
10	-0.29	0.0523	0.69	-42.7%	0.39
11	-0.94	0.0715	1.80	-52.0%	0.86
12	-1.49	0.1294	2.97	-50.1%	1.48
CZ12					
1	-1.37	0.0445	2.82	-48.3%	1.46
2	-1.07	0.0326	2.30	-46.5%	1.23
3	-0.53	0.0165	1.31	-40.4%	0.78
4	-0.54	0.0166	1.08	-49.8%	0.54
5	-0.23	0.0179	0.67	-34.2%	0.44
6	-0.09	0.0215	0.49	-19.1%	0.40
7	-0.08	0.0218	0.45	-18.0%	0.37
8	-0.07	0.0221	0.44	-16.9%	0.36
9	-0.11	0.0210	0.50	-22.3%	0.38
10	-0.29	0.0168	0.73	-40.4%	0.43
11	-0.78	0.0223	1.65	-47.4%	0.87
12	-1.32	0.0427	2.75	-48.0%	1.43
CZ13					
1	-1.61	0.0972	2.75	-58.4%	1.15
2	-1.15	0.0662	2.27	-50.7%	1.12
3	-0.39	0.0340	1.22	-31.9%	0.83
4	-0.39	0.0340	0.93	-42.1%	0.54
5	-0.12	0.0394	0.64	-19.3%	0.52
6	-0.02	0.0438	0.48	-4.6%	0.46

Month	Average Daily Impact (therms)	Standard Error	Average Daily Baseline (therms)	% Impact	Model Predicted
7	-0.02	0.0439	0.44	-4.8%	0.42
8	-0.02	0.0439	0.43	-4.6%	0.41
9	-0.03	0.0437	0.46	-5.5%	0.43
10	-0.16	0.0380	0.64	-25.6%	0.48
11	-0.78	0.0449	1.58	-49.5%	0.80
12	-1.56	0.0936	2.73	-57.0%	1.17
CZ14					
1	-1.57	0.2677	3.01	-52.1%	1.44
2	-1.14	0.1936	2.40	-47.6%	1.26
3	-0.37	0.0976	1.29	-28.8%	0.92
4	-0.18	0.0973	0.80	-23.0%	0.61
5	0.12	0.1217	0.40	28.8%	0.52
6	0.18	0.1303	0.31	59.3%	0.50
7	0.19	0.1305	0.16	114.0%	0.35
8	0.19	0.1305	0.15	124.8%	0.34
9	0.18	0.1304	0.21	86.8%	0.40
10	0.04	0.1133	0.45	9.1%	0.49
11	-0.80	0.1390	1.64	-48.5%	0.84
12	-1.51	0.2576	2.72	-55.6%	1.21
CZ15					
1	-0.77	0.0231	1.91	-40.3%	1.14
2	-0.59	0.0190	1.63	-36.4%	1.04
3	-0.16	0.0255	1.01	-16.0%	0.85
4	-0.15	0.0259	0.71	-21.2%	0.56
5	-0.12	0.0270	0.72	-16.8%	0.60
6	-0.11	0.0275	0.66	-16.5%	0.55
7	-0.11	0.0275	0.49	-22.0%	0.39
8	-0.11	0.0275	0.56	-19.4%	0.45
9	-0.11	0.0275	0.65	-16.9%	0.54
10	-0.11	0.0275	0.32	-33.9%	0.21
11	-0.24	0.0228	1.01	-24.2%	0.76
12	-0.76	0.0228	1.86	-41.0%	1.10
CZ16					
1	-1.71	0.0653	2.72	-62.9%	1.01
2	-1.66	0.0627	2.60	-63.8%	0.94
3	-0.92	0.0286	1.64	-56.4%	0.71
4	-1.20	0.0405	1.64	-73.3%	0.44
5	-0.89	0.0272	1.45	-61.5%	0.56
6	N/A	N/A	N/A	N/A	N/A
7	N/A	N/A	N/A	N/A	N/A
8	N/A	N/A	N/A	N/A	N/A
9	N/A	N/A	N/A	N/A	N/A

Month	Average Daily Impact (therms)	Standard Error	Average Daily Baseline (therms)	% Impact	Model Predicted
10	N/A	N/A	N/A	N/A	N/A
11	-1.01	0.0320	1.66	-60.5%	0.66
12	-1.57	0.0581	2.54	-61.6%	0.98
CARE					
1	-0.78	0.0569	1.99	-39.1%	1.21
2	-0.65	0.0457	1.77	-36.6%	1.12
3	-0.30	0.0301	1.13	-26.9%	0.82
4	-0.31	0.0301	0.90	-34.4%	0.59
5	-0.18	0.0342	0.63	-28.3%	0.45
6	-0.10	0.0390	0.50	-20.0%	0.40
7	-0.10	0.0393	0.47	-20.2%	0.38
8	-0.09	0.0397	0.46	-19.5%	0.37
9	-0.11	0.0383	0.51	-21.5%	0.40
10	-0.22	0.0323	0.66	-33.2%	0.44
11	-0.40	0.0309	1.22	-32.7%	0.82
12	-0.74	0.0539	1.95	-38.2%	1.21
Non-CARE					
1	-1.07	0.0201	2.42	-44.4%	1.34
2	-0.91	0.0165	2.14	-42.6%	1.23
3	-0.43	0.0104	1.37	-31.6%	0.94
4	-0.44	0.0104	1.05	-42.0%	0.61
5	-0.28	0.0115	0.76	-36.8%	0.48
6	-0.15	0.0136	0.56	-26.0%	0.42
7	-0.14	0.0137	0.53	-26.5%	0.39
8	-0.12	0.0141	0.51	-23.6%	0.39
9	-0.16	0.0134	0.56	-28.3%	0.40
10	-0.33	0.0110	0.76	-43.1%	0.43
11	-0.55	0.0107	1.46	-37.6%	0.91
12	-1.02	0.0189	2.34	-43.6%	1.32
DAC					
1	-1.06	0.0351	2.19	-48.5%	1.13
2	-0.89	0.0283	1.93	-45.9%	1.04
3	-0.37	0.0176	1.19	-30.9%	0.82
4	-0.38	0.0176	0.92	-41.3%	0.54
5	-0.18	0.0202	0.64	-27.9%	0.46
6	-0.05	0.0235	0.45	-11.8%	0.40
7	-0.05	0.0236	0.44	-11.3%	0.39
8	-0.04	0.0238	0.41	-10.5%	0.37
9	-0.06	0.0232	0.44	-14.2%	0.38
10	-0.22	0.0194	0.65	-33.4%	0.43
11	-0.50	0.0182	1.29	-38.9%	0.79
12	-1.00	0.0326	2.14	-46.6%	1.14

Month	Average Daily Impact (therms)	Standard Error	Average Daily Baseline (therms)	% Impact	Model Predicted
Non-DAC					
1	-1.04	0.0226	2.45	-42.5%	1.41
2	-0.89	0.0185	2.18	-41.0%	1.28
3	-0.44	0.0118	1.40	-31.6%	0.96
4	-0.45	0.0118	1.08	-41.6%	0.63
5	-0.31	0.0129	0.80	-38.9%	0.49
6	-0.18	0.0153	0.60	-29.8%	0.42
7	-0.17	0.0154	0.56	-30.7%	0.39
8	-0.15	0.0159	0.54	-27.3%	0.39
9	-0.19	0.0150	0.59	-31.9%	0.40
10	-0.36	0.0123	0.79	-45.3%	0.43
11	-0.55	0.0121	1.49	-37.0%	0.94
12	-1.00	0.0213	2.36	-42.2%	1.37

Note: Due to missing data, we could not produce impact estimates for some of the summer months in climate zones 5 and 16.

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