Equitable Electrification: Using Smarter Data for Affordable, Resilient Heat Pump Programs

John Walczyk, Harris Enotiades, Cadmus
Suleyman Betin, PSE&G

ABSTRACT

As utilities expand residential electrification programs, accurate customer-facing bill projections are critical for program design and customer decision-making. Conventional billing-analysis methods and standard Technical Reference Manual assumptions were not developed to support detailed electrification cost modeling and can bias estimates of heating energy use, avoided gas consumption, and customer bill impacts.

This paper presents an analytical framework developed with PSE&G to improve electrification bill-impact estimates by combining hourly AMI analysis, end-use metering validation, and engineering-based adjustments for heat pump performance and seasonal domestic hot water loads. We also use HVAC replacement modeling to contextualize the market opportunity, showing that current program installations represent only a small share of natural replacement events.

Results show that monthly PRISM overestimated electric heating consumption by 31% relative to hourly AMI-based estimates. Validation against end-use metering showed that hourly PRISM closely matched metered heating use for all-electric heat pump homes on average, but substantially underestimated electric heating use in dual-fuel homes. Incorporating engineering adjustments improved load attribution and produced more realistic bill-impact estimates. Under current PSE&G rates, full electrification increased annual heating costs relative to gas heating, while dual-fuel heat pump operation with a 40°F switchover temperature increased annual heating costs by only about $100. Time-of-use and storage scenarios reduced, but did not eliminate, the heating-cost gap under modeled assumptions. These findings suggest that improved load estimation is essential for electrification planning and that dual-fuel systems may provide a practical near-term strategy for reducing fossil fuel use while limiting customer cost impacts.

Introduction

Residential electrification is expanding rapidly across the Northeast as utilities pursue decarbonization goals. Heat pump programs are a central component of these efforts. As adoption accelerates, there is growing need for accurate, customer-facing estimates of utility bill impacts, which are critical for both program design and customer decision-making. In particular, emerging electrification pathways such as dual-fuel heat pump systems are increasingly recognized as practical intermediate solutions that can balance emissions reductions with affordability, but require more refined analytical approaches to accurately estimate their performance and cost impacts.

Designing effective electrification strategies therefore requires accurate estimation of equipment replacement dynamics, end-use energy consumption, and resulting customer bill impacts. However, traditional evaluation tools, including TRM lifetime assumptions and

PRISM-based billing regression, were not originally designed to support detailed electrification cost analysis or to capture the operational complexity of systems such as dual-fuel heat pumps. These limitations can introduce bias in heating energy estimation and lead to inaccurate projections of customer costs.

This paper presents an integrated analytical framework applied within PSE&G's residential HVAC programs to address these challenges. The analysis combines three complementary components:

- Replacement dynamics modeling. TRM effective useful life assumptions are translated into an implied annual HVAC replacement rate using a Weibull survival model, enabling program participation to be evaluated relative to natural equipment turnover. Because most electrification occurs at the point of HVAC replacement, this analysis defines the scale and timing of the underlying market opportunity, providing essential context for interpreting adoption patterns and the role of customer cost impacts examined in subsequent sections.
- Billing analysis validation. PRISM-based load disaggregation is evaluated using both monthly billing data and hourly AMI data across approximately 2,400 homes, with device-level metering used to validate heating-load estimates and quantify model bias.
- Engineering-based adjustments. The analysis incorporates seasonal domestic hot water load variation and temperature-dependent heat pump performance to refine heating-load estimates and improve electrification bill-impact projections.

Together, these components address complementary aspects of electrification planning: when replacement decisions occur, how much energy electrified systems consume, and how those changes translate into customer costs.

These analyses help distinguish between participation dynamics, technology adoption patterns, and customer cost outcomes, supporting more realistic electrification planning and customer-facing bill projections. The remainder of this paper proceeds as follows. Section 2 examines HVAC replacement dynamics and program participation. Section 3 evaluates bias in PRISM-based load disaggregation. Section 4 validates heating estimates using device-level metering and introduces segmented change-point modeling for dual-fuel systems. Section 5 incorporates engineering adjustments and estimates customer bill impacts under alternative electrification scenarios.

Residential HVAC Replacement Dynamics and Program Participation

Understanding program participation relative to natural equipment turnover provides important context for electrification planning because most HVAC decisions occur at replacement. However, TRM effective useful life (EUL) assumptions are typically expressed as average service lives, not annual replacement rates. To translate EUL assumptions into an annual market opportunity, this study modeled HVAC replacement using a Weibull survival framework. The model treated the residential heating system EUL of 20 years as the median lifetime, consistent with the interpretation that 50% of installed systems remain operational at that age (SEE Action Network 2012; NJ BPU 2025). A Weibull shape parameter of $k=3.2$ was used to represent increasing failure probability as equipment ages, consistent with reliability applications for mechanical systems (Abernethy 2006; Tobias and Trindade 2012). Under a steady-state stock assumption, the resulting implied annual replacement rate is approximately 5% of residential HVAC systems per year.

Program participation in PSE&G's residential HVAC programs, including Home Performance with Energy Services and midstream HVAC, was evaluated relative to this estimated market turnover. During Program Year 2024, 10,850 PSE&G residential customers installed new HVAC systems through program participation, including approximately 980 heat pump installations. With approximately 2.1 million residential service accounts in PSE&G's territory, program activity captured roughly 10% of expected annual HVAC replacement events. For regional context, Mass Save reported heat pump installations in approximately 40,000 homes in 2024, illustrating the range of heat pump deployment scale across Northeastern program environments (Mass Save 2025). This indicates that most replacement decisions still occur outside program participation and that effective electrification strategies must increase engagement at the point of equipment replacement, where customer bill impacts and contractor recommendations strongly influence technology choice.

For additional equity context, participating households were assigned to 2020 Census block groups using the U.S. Census Bureau Geocoder (Census Bureau 2023). Block group housing counts were derived from ACS 5-year estimates using IPUMS NHGIS (2024), and overburdened community (OBC) status was assigned using NJDEP Environmental Justice mapping data (NJDEP 2026). Table 1 summarizes installation shares by technology type and OBC status.

Table 1. Distribution of Residential HVAC Installations by Equipment Type and Overburdened Community (OBC) Status within PSE&G Service Territory (Program Year 2024).

Community Type	CAC	Gas Furnace	Gas Boiler	CAC + Gas Furnace	Dual-Fuel Heat Pump	Air Source Heat Pump	Total: PSE&G HVAC Program	PSE&G Service Territory
OBC	24%	17%	5%	38%	2%	14%	39%	53%
Non-OBC	23%	18%	6%	37%	3%	13%	61%	47%

Technology columns represent the distribution of program installations within each community type. The final two columns show each community type's share of total PSE&G HVAC program installations and service-territory housing units. *Source:* PSE&G Program tracking data, ACS data, and NHGIS data.

OBC areas account for 53% of housing units and 39% of program installations, yielding a Participation Equity Ratio of 0.74, defined as the share of program installations divided by the share of housing units. Technology shares were similar across OBC and non-OBC participants, including air source heat pump adoption of 14% versus 13% and dual-fuel heat pump adoption of 2% versus 3%. This suggests that the primary equity gap is not technology choice among participating households, but lower program participation during replacement events. From a program-design perspective, equity improvements are therefore more likely to result from expanding program access during replacement events through outreach, contractor engagement, and barrier reduction than from changing technology-specific incentives alone.

Evaluating Heating Load Estimates for Electrification Analysis

A central objective of this research is to develop realistic, customer-facing estimates of utility bill impacts associated with residential electrification, including both full electrification (heat pumps serving as the primary heating system) and partial electrification through dual-fuel operation. Program administrators increasingly require defensible methods to translate modeled energy impacts into expected annual bill changes that customers can understand and rely upon when making equipment replacement decisions.

Accurate bill impact estimation depends primarily on correctly estimating electric heating energy use, which becomes the dominant driver of winter electricity consumption following electrification. Industry-standard practice frequently relies on PRISM-style disaggregation of utility billing data to estimate heating and cooling loads (Fels 1986). However, uncertainty in these estimates propagates into projected customer bill impacts. This analysis evaluates how well PRISM predicts electric heating consumption and quantifies how resulting uncertainty affects electrification cost estimates.

Data Sources and Analytical Framework. The analysis includes approximately 2,400 residential participants in PSE&G's Whole Home Energy Solutions program with both electric and gas consumption data available. These homes also have detailed equipment inventories and building characteristics collected during program participation using Snugg Pro, including HVAC system type, fuel, and efficiency, and modeled annual end-use energy estimates derived from engineering-based load calculations. The analysis evaluated two PRISM-style approaches for modeling home energy use:

- PRISM applied to monthly electric and gas billing data, representing conventional evaluation practice. This analysis uses pre-retrofit annual billing data from program participants, with data spanning the period from 2022 to 2025.
- PRISM applied to hourly electric AMI data. This analysis uses post-retrofit electricity consumption data following heat pump installation.

The availability of both datasets enables direct evaluation of how temporal resolution affects heating and cooling use disaggregation. In addition, a subset of 36 homes with heat pumps as the primary heating system were instrumented with Sense end-use meters, providing device-level measurements of electric heating consumption. These data serve as an independent validation reference for electrified homes. The analytical objective is not solely to assess statistical model fit, but to quantify bias and uncertainty in electric heating kilowatt-hours (kWh), since these quantities determine projected electrification bill impacts.

Bias in Monthly vs. Hourly PRISM Disaggregation. To examine how temporal aggregation affects end-use decomposition, Figure 1 compares average monthly heating and cooling energy estimated using PRISM applied to traditional monthly billing data versus PRISM applied to hourly AMI data for the same homes.

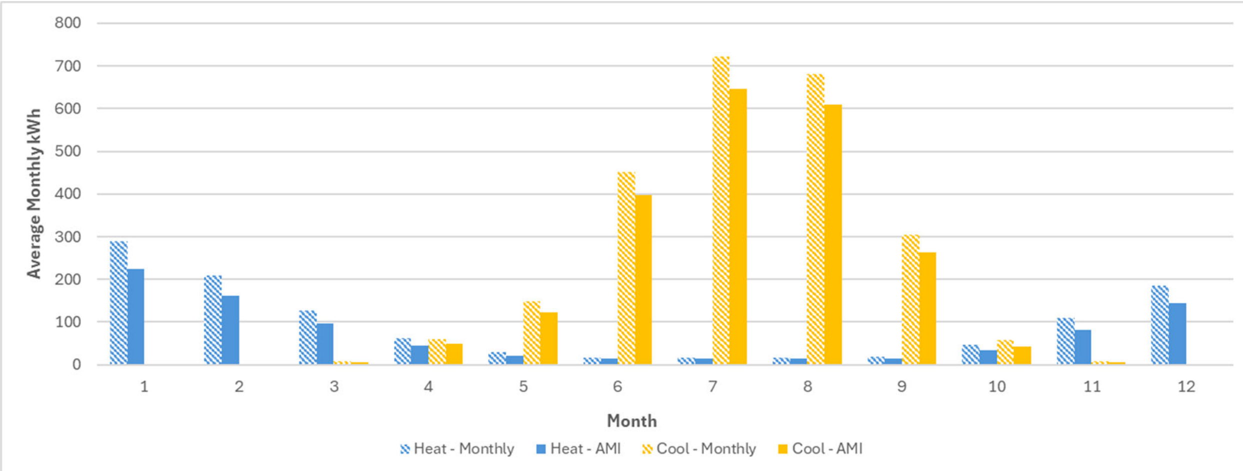

Figure 1. Average Monthly Heating and Cooling Energy: Monthly PRISM vs. Hourly AMI PRISM

Figure 1 presents mean monthly electric heating and cooling consumption across the sample of approximately 2,400 homes. Winter heating loads (January–March and November–December) and summer cooling loads (June–September) are consistently higher when estimated using monthly PRISM relative to AMI-based PRISM. Across the full year:

- Electric baseload was underestimated by approximately 9% in the monthly model relative to AMI-based estimates.
- Electric heating consumption was overestimated by approximately 31% in the monthly model relative to AMI-based estimates.
- Electric cooling consumption was overestimated by approximately 14% in the monthly model relative to AMI-based estimates.

The divergence is most visible during peak heating and cooling months, when total weather-sensitive consumption is largest.

Shoulder-Month Behavior. Prior to analysis, larger discrepancies were expected during shoulder months (April through May and October through November), when mixed heating and cooling signals and lower loads can complicate regression-based disaggregation. However, Figure 1 shows relatively modest differences during these transitional periods. Instead, divergence increases during peak winter and summer months. This pattern indicates that error is not primarily driven by seasonal misclassification or instability during mixed-load conditions. Rather, the discrepancy appears systematic and scales with overall heating and cooling intensity.

Structural Sources of Bias. The observed pattern is consistent with known limitations of monthly PRISM arising from temporal aggregation. PRISM decomposes energy consumption into temperature-sensitive and non-weather components according to:

$$Usage = \alpha + \beta_{heat} \times HDD + \beta_{cool} \times CDD$$

where α represents non-weather baseload consumption and the β coefficients represent temperature sensitivity for heating and cooling. When applied to monthly billing data, several mechanisms can bias these coefficients:

- Baseload reallocation. Seasonal variation in non-weather loads (e.g., lighting, ventilation, and plug loads) can correlate with temperature at monthly resolution, causing part of baseload consumption to be attributed to heating or cooling. The observed 9% baseload underestimation suggests that some non-weather energy is absorbed into weather-sensitive terms.
- Loss of intramonth temperature variability. Monthly aggregation smooths short-term temperature fluctuations and nonlinear heating responses that are captured by hourly AMI data. This smoothing can inflate estimated temperature-response slopes.
- Error scaling with load magnitude. Because heating and cooling consumption scale with degree days, even modest slope bias produces large absolute differences during peak seasons, explaining why divergence is most visible during winter and summer months.

Quantifying Temperature-Sensitivity Differences. To evaluate whether these effects reflect changes in model coefficients, implied temperature-sensitivity slopes were calculated using observed annual degree-days (4,901 heating degree days and 1,889 cooling degree days). Heating slopes were estimated as total annual heating kWh divided by cumulative heating degree days:

$$\beta_{heat,monthly} = 0.230\ kWh/HDD; \quad \beta_{heat,AMI} = 0.176\ kWh/HDD$$

This implies approximately 31% inflation in the heating slope coefficient when PRISM is applied to monthly billing data. Cooling slopes were similarly calculated as total annual cooling kWh divided by cumulative cooling degree days:

$$\beta_{cool,monthly} = 1.29\ kWh/CDD; \quad \beta_{cool,AMI} = 1.13\ kWh/CDD$$

These showed approximately 14% inflation in cooling temperature sensitivity with PRISM applied to monthly billing data. These observed annual biases (31% heating and 14% cooling) confirm that divergence between monthly and hourly PRISM estimates is primarily driven by systematic inflation of temperature-response coefficients rather than instability during transitional months. The findings indicate that monthly PRISM reallocates part of seasonal baseload into weather-sensitive components, increasing estimated heating and cooling slopes. Because absolute differences scale with degree-day magnitude, the resulting bias becomes most visible during peak winter and summer periods.

For electrification analysis, this distinction is consequential. Projected electric heating consumption (and associated heating bill impacts) depends directly on the heating slope coefficient. Inflation of temperature sensitivity under monthly aggregation can therefore lead to systematically higher projected electrification costs. Hourly AMI-based PRISM reduces this effect but still retains measurable uncertainty, motivating the validation analysis presented in the following section.

Validation Against End-Use Metering

To evaluate the accuracy of hourly PRISM-derived electric heating estimates in electrified homes, 36 participants with heat pumps were instrumented with Sense end-use meters, including 29 all-electric heat pump homes and seven dual-fuel heat pump homes. Sense meters measure high-frequency voltage and current waveforms at the service panel and apply machinelearning algorithms to disaggregate individual loads. To eliminate uncertainty associated with automated device detection, a dedicated circuit monitor was installed on each heat pump condenser, enabling direct measurement of compressor operation independent of load-classification algorithms. Sense data were therefore used to isolate heat pump compressor operation and, where separately detected or monitored, auxiliary heating loads, providing a direct measurement of electric heating consumption.

Figure 2 compares PRISM-estimated electric heating use with Sense-metered heating use for the monitored heat pump homes. The left panel compares annual heating energy by site, with all-electric homes shown as circles and dual-fuel homes shown as triangles. The dashed line represents a 1:1 relationship between PRISM-estimated and metered heating use. The right panel compares pooled average PRISM-estimated and Sense-metered heat pump demand across outdoor temperature bins. Because the right panel pools all monitored homes, it should be interpreted as an aggregate diagnostic of temperature-dependent bias rather than as a separate validation result for all-electric and dual-fuel systems. Although the all-electric average difference is small, the site-level scatter in Figure 2 indicates that individual-home estimates can still vary materially from metered use. The following section, “Improving Heating Load Estimation for Electrification Modeling,” presents illustrative dual-fuel examples in Figure 3 that show individual heat pump kW load profiles versus outdoor temperature alongside PRISM estimates.

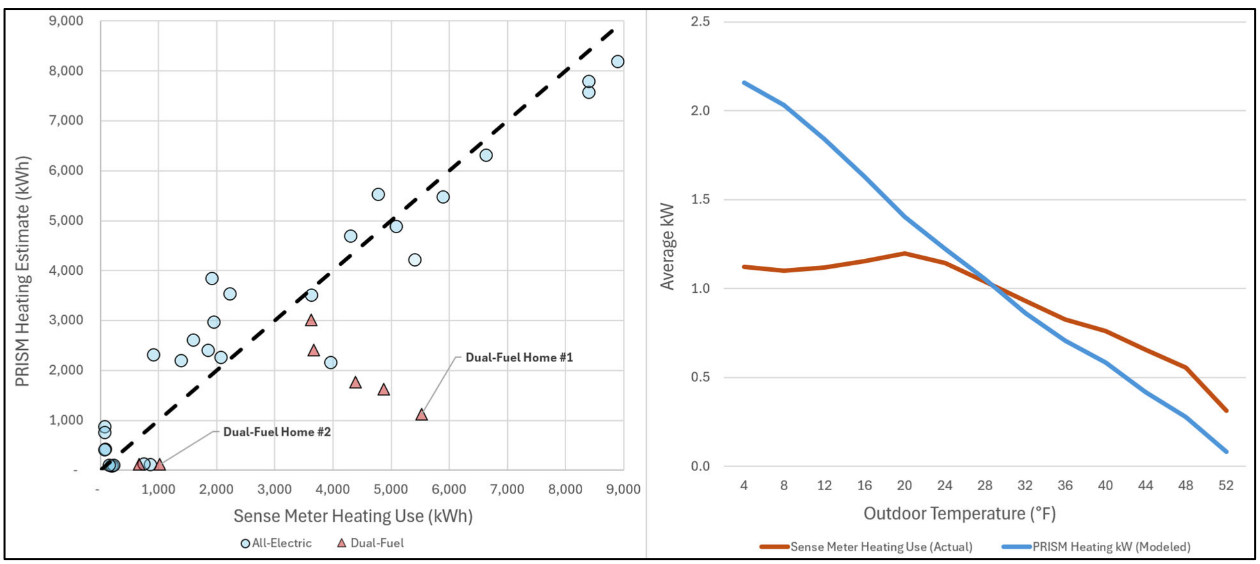

Figure 2. PRISM-estimated versus Sense-metered electric heating use. Left panel compares annual heating energy by monitored site, with the dashed line indicating a 1:1 relationship between PRISM estimates and metered heating use. Circles represent all-electric heat pump homes and triangles represent dual-fuel heat pump homes. Right panel compares pooled average PRISM-estimated and Sense-metered heat pump demand by outdoor temperature bin.

Table 2 summarizes the validation results by heat pump type. Across the 29 all-electric homes, PRISM closely matched metered heating use on average: metered heating consumption averaged 2,834 kWh, compared with a PRISM estimate of 2,942 kWh. This corresponds to a 3.8% overestimate, with a 90% confidence margin of ±264 kWh, or ±9.3% of average metered heating use. Because the 90% confidence interval includes zero difference, the all-electric results do not indicate meaningful average bias in AMI-based PRISM estimates.

Table 2. Comparison of Sense-metered and PRISM-estimated heating use by heat pump type

Heat Pump Type	Number of Homes	Actual Metered Heating Use (kWh)	PRISM Estimated Heating Use (kWh)	% Difference	Uncertainty
All-electric	29	2,834	2,942	+3.8%	±9.3%
Dual Fuel	7	3,399	1,449	-57.4%	±32.3%
All monitored homes	36	2,944	2,652	-9.9%	±12.2%

Note: % Difference is calculated as (PRISM - Sense) / Sense. Positive values indicate that PRISM estimates are higher than metered heating use; negative values indicate that PRISM estimates are lower. Uncertainty is calculated as the 90% confidence margin around the mean paired difference, normalized to average metered heating use.

Results differed substantially for dual-fuel systems. Across the seven dual-fuel homes, metered heating consumption averaged 3,399 kWh, compared with a PRISM estimate of 1,449 kWh, indicating that PRISM underestimated metered electric heating use by 57.4% on average. The 90% confidence margin around the mean paired difference was ±1,096 kWh, corresponding to ±32.3% of average metered heating use. Although the dual-fuel sample is smaller and more variable than the all-electric sample, the magnitude and direction of the difference indicate that conventional single-regime PRISM does not adequately capture dual-fuel heat pump operation.

The pooled temperature-bin comparison in the right panel of Figure 2 helps explain the direction of this bias. PRISM imposes a monotonic temperature-response relationship, causing modeled heating demand to increase steadily as outdoor temperatures fall. Metered heat pump operation follows a flatter and more complex pattern. In the pooled results, actual heat pump demand is lower than PRISM estimates at the coldest temperatures but exceeds PRISM estimates across much of the moderate heating range. Because moderate temperatures account for a large share of heating-season hours, underestimation across the primary operating range can dominate the annual estimate even when PRISM overestimates demand during colder periods.

When all 36 monitored homes are pooled, PRISM estimates averaged 2,652 kWh compared with metered heating use of 2,944 kWh, a 9.9% underestimate. However, the pooled result masks an important segmentation effect. PRISM performed well on average for all-electric heat pump homes, while the overall underestimate was driven primarily by dual-fuel systems. This finding supports the use of AMI-based PRISM for all-electric heat pump homes, while also motivating the segmented change-point approach for dual-fuel systems described below.

Improving Heating Load Estimation for Electrification Modeling

Standard PRISM methodology assumes a monotonic relationship between outdoor temperature and electric heating demand, with consumption increasing as temperatures fall below a reference point. This assumption holds for all-electric heat pump systems but does not reflect the operating behavior of dual-fuel heat pumps, which switch from electric heating to a secondary fuel source at low outdoor temperatures. In dual-fuel systems, electric heat pump use increases as temperatures decline toward the system’s switchover threshold but decreases once colder conditions trigger gas backup heating. The resulting temperature-load relationship is therefore non-monotonic. Because PRISM fits a single heating slope across all temperatures, it attempts to reconcile fundamentally different operating regimes with one coefficient, leading to biased slope estimates and inaccurate heating-load attribution. A more appropriate modeling framework is a segmented change-point regression that allows separate temperature regimes above and below the switchover threshold. The segmented model is not proposed as a wholesale replacement for AMI-based PRISM in all homes; rather, it addresses the specific operating-regime problem observed in dual-fuel systems. A compact representation of this model is:

$$E_{HP}(T) = \alpha + \beta_{heat}\max(T_{cp} - T, 0) - \gamma\max(T_{sw} - T, 0)$$

Where:

$E_{HP}(T)$ = electric heat pump energy use at outdoor temperature
α = non-heating electric baseload
β_{heat} = heat pump temperature sensitivity above the switchover point
T_{cp} = heating change-point temperature
T_{sw} = dual-fuel switchover temperature
γ = reduction in electric heating sensitivity below the switchover temperature

The first term represents a conventional PRISM-style heating response, while the second term subtracts electric load once temperatures fall below the switchover threshold and gas heating displaces compressor operation. This segmented structure preserves the simplicity of regression-based load disaggregation while more accurately representing the physical control logic of dual-fuel systems. By accounting for fuel-switching behavior, change-point models reduce slope distortion inherent in single-regime PRISM approaches and improve estimation of electric heating consumption and associated bill impacts. Figure 3 illustrates the improvement achieved by applying the segmented change-point approach to two representative dual-fuel homes.

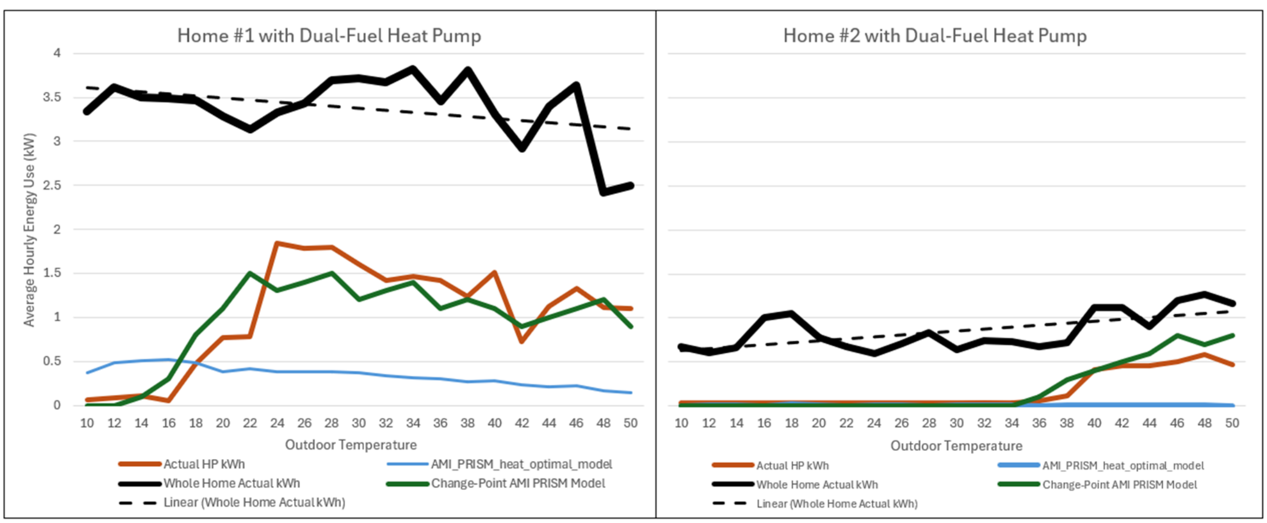

Figure 3. Improvement in heating-load estimation using segmented change-point modeling for representative dual-fuel homes

In both panels, the conventional PRISM model (blue line) underestimates electric heating across the primary operating range of the heat pump and fails to capture the transition in heating behavior near the switchover temperature. Because the standard PRISM formulation assumes a single monotonic heating slope, it smooths across fundamentally different operating regimes and produces heating estimates that do not track observed electric heat pump use. The change-point model (green line) more closely follows the observed heating profile by allowing electric heating response to vary across temperature ranges. Above the switchover temperature, the model reproduces the expected increase in electric heating as outdoor temperatures decline. Below the switchover point, the segmented structure reduces the temperature sensitivity to reflect displacement of electric heating by gas backup systems. This produces a heating profile that better aligns with measured heat pump energy use and avoids the slope distortion visible in the conventional PRISM estimates.

The improvement is most apparent in the mid-temperature range where heat pumps operate most frequently. By capturing the transition between operating regimes, the change-point approach reduces systematic bias in electric heating estimation while preserving the simplicity of regression-based methods. This refinement improves confidence in household-level heating estimates and supports more accurate electrification cost modeling for dual-fuel homes.

Correcting PRISM Heating Estimates for Seasonal DHW Variation

A second source of bias in PRISM-based gas heating estimates arises from seasonal variation in domestic hot water (DHW) use. Standard PRISM disaggregation treats non-heating gas use as a constant baseload term, implicitly assuming that baseload is invariant across seasons. However, gas water heater energy use varies seasonally due to changes in incoming mains water temperature.

To evaluate the magnitude of this effect, we analyzed 2,092 homes with both gas and electric billing data and known equipment inventories. Gas billing data were disaggregated using PRISM into heating and baseload components, and 32 representative ResStock models were used to benchmark end-use splits (Wilson and Merket 2022). As shown in Table 3, ResStock estimates that gas DHW accounts for approximately 159 therms per year, or about 15% of total annual gas usage, while other non-heating gas end uses account for approximately 47 therms per year.

Table 3. Comparison of Annual Gas End-Use Consumption: ResStock Archetypes vs. PSE&G Participant Homes

	n	Heating Energy Use (therms)	Gas Hot Water Heater Use (therms)	All Other Gas End-Uses (therms)	Total Non-Heating Gas Use (therms)	Total Annual Gas Usage (therms)
ResStock Models	32	908	159	47	206	1,114
PSE&G Homes	2,092	871	N/A	N/A	233	1,104

ResStock estimates indicate that a representative gas water heater using 159 therms per year consumes approximately 10 to 11 therms per month in summer and 15 to 16 therms per month in winter. Because PRISM estimates baseload primarily from summer consumption, the additional 4 to 5 therms per month of winter DHW consumption can be misattributed to space heating. For a typical gas water heater, this seasonal distortion implies that PRISM heating estimates may be overstated by roughly 20 to 25 therms over the heating season.

To address this limitation, analysts can apply a ResStock-derived monthly DHW adjustment factor to redistribute a portion of winter heating therms back into non-heating DHW.

This adjustment improves avoided-gas estimates under electrification scenarios and reduces the risk of overstating gas savings or distorting dual-fuel cost comparisons.

Electrification Bill Impact Estimates

To estimate customer bill impacts associated with residential electrification, heating energy consumption was modeled using observed heating loads and current PSE&G residential rate schedules. Gas heating consumption was assumed to equal 871 therms annually, consistent with the billing-analysis estimate derived from 2,092 PSE&G homes reported in Table 3. Adjusting for an average annual fuel utilization efficiency (AFUE) of 80%, this corresponds to an annual delivered heating load of approximately 69.7 MMBtu. These estimates reflect operating cost impacts only and do not include equipment capital costs, incentives, or installation cost differences between system configurations.

Hourly heating demand was allocated using TMYx weather data, which allowed the total annual heating load to be distributed across outdoor temperature conditions. Heat pump electricity consumption was then estimated by applying temperature-dependent coefficient-of-performance (COP) curves derived from manufacturer engineering submittals for three inverter-driven heat pumps commonly installed through PSE&G HVAC programs (Bosch Home Comfort n.d.; Daikin Comfort Technologies n.d.; Mitsubishi Electric 2024). These performance curves were used to estimate electricity consumption by temperature for a representative 8.5 HSPF2 (Heating Seasonal Performance Factor) inverter-driven heat pump, resulting in an annual electric heating consumption estimate of 8,222 kWh for a fully electrified home. Table 4 summarizes estimated annual heating costs under several system configurations and PSE&G residential rate structures (PSE&G 2026a; PSE&G 2026b). These scenarios are intended to illustrate how heating system configuration and rate structure influence operating costs under current PSE&G tariffs.

Table 4. Estimated Annual Heating Costs by System Configuration and Rate Schedule

System Configuration	PSE&G Rate	Total Annual Heating Consumption	Energy Price	Annual Heating Cost
80 AFUE Gas Furnace	RSG	871 therms	$1.066/therm	$929
All-Electric 8.5 HSPF2	RS	8,222 kWh	$0.1986/kWh	$1,632
All-Electric 8.5 HSPF2	RHS	8,222 kWh	$0.1458/kWh	$1,199
Dual-Fuel (30°F SOT)	RSG + RS	273 therms; 5,140 kWh	$1.066/therm; $0.1986/kWh	$1,312
Dual-Fuel (35°F SOT)		449 therms; 3,333 kWh		$1,140
Dual-Fuel (40°F SOT)		606 therms; 1,947 kWh		$1,033
Dual-Fuel (45°F SOT)		735 therms; 948 kWh		$972
Dual-Fuel (50°F SOT)		811 therms; 405 kWh		$945
All-Electric 8.5 HSPF2	RLM (TOU Rate)	2,940 kWh On-Peak; 5,279 kWh Off-Peak	On-Peak: $0.3730/kWh; Off-Peak: $0.0816/kWh	$1,528
All-Electric 8.5 HSPF2 w/ 5 kWh Storage		2,370 kWh On-Peak; 5,849 kWh Off-Peak		$1,362
All-Electric 8.5 HSPF2 w/ 10 kWh Storage		1,930 kWh On-Peak; 6,289 kWh Off-Peak		$1,233
All-Electric 8.5 HSPF2 w/ 15 kWh Storage		1,755 kWh On-Peak; 6,464 kWh Off-Peak		$1,182

Rate schedule definitions: RS: Residential Service; RHS: Residential Heating Service; RLM: Residential Load Management Service (time-of-use [TOU] rate. On-peak 7am-9pm weekdays); and RSG: Residential Service Gas.

Table 4 shows that under current PSE&G residential rates, natural gas heating remains the lowest-cost option across all modeled scenarios. A typical 80 AFUE gas furnace serving the assumed heating load results in an annual heating cost of approximately $929. Without storage, a fully electrified home using an 8.5 HSPF2 heat pump would incur annual heating costs between $1,199 and $1,632 under the modeled residential electric rates, with the RLM TOU case estimated at $1,528 before storage shifting. Even under TOU pricing, electrification remains more expensive than gas heating due to the relatively low cost of natural gas. At the estimated heating load, annual electricity consumption of approximately 8,222 kWh produces heating costs well above the avoided gas expense.

Dual-fuel heat pump systems reduce this cost differential by shifting heating demand to gas during colder conditions. With a 40°F switchover temperature (SOT), annual heating cost is estimated at approximately $1,033, or roughly $100 higher than gas-only heating. Higher switchover temperatures further reduce electricity consumption but remain slightly more expensive than gas due to the underlying rate differential. Because TOU rates provide substantially lower off-peak electricity prices, electrification outcomes were also evaluated under scenarios that incorporate battery storage to shift heating load from on-peak to off-peak periods. The analysis assumes that available storage capacity is fully utilized each day to offset on-peak heating demand. The storage scenarios do not account for battery capital costs, round-trip losses, degradation, or non-heating use cases. Although battery storage may provide resilience benefits, this analysis evaluates only heating-related operating-cost impacts under the applicable TOU rate structure. Even under this optimistic assumption, storage capacities of 5 kWh to 15 kWh reduce but do not eliminate the cost gap relative to gas heating.

For reference, a hypothetical scenario in which all heat pump consumption could be shifted to off-peak electricity pricing would result in an annual heating cost of approximately

$671, which is substantially below the gas heating cost. However, this outcome is not realistic under the modeled heating load scenario. The analysis assumes an average heating consumption of 871 therms annually (based on billing analysis), equivalent to approximately 8,222 kWh of heat pump electricity for an 8.5 HSPF2 system. Under this load profile, estimated daily heating electricity consumption exceeds 50 kWh on 68 winter days and reaches approximately 127 kWh on the coldest modeled day, far exceeding typical residential battery storage capacity.

It is also important to note that the storage scenarios presented in Table 4 evaluate shifting of only heating-related electricity consumption. Additional bill reductions could occur if storage were used to shift non-heating loads during the remainder of the year. For example, a 15 kWh battery fully utilized during approximately 180 non-heating days could shift roughly 2,700 kWh from on-peak to off-peak periods, producing an additional annual bill reduction of approximately $787 under the PSE&G RLM tariff. If full electrification also eliminates gas service, customers would avoid the $10 per month fixed gas service charge (approximately $120 annually). The analysis also focuses primarily on heating-related operating costs and does not include potential cooling savings associated with heat pump systems. Because heat pumps installed for electrification are typically sized to meet heating loads, they are often larger than air conditioning systems sized solely for cooling. In addition, modern inverter-driven heat pumps can operate at higher part-load efficiency during cooling than conventional single-speed air conditioners. These factors may produce additional cooling-season electricity savings that are not reflected in the heating-focused analysis presented here.

Overall, these results indicate that current energy prices prevent electrification from achieving direct heating cost savings for most PSE&G customers. However, dual-fuel heat pump configurations provide a practical intermediate pathway. A dual-fuel system with 40°F switchover temperature increases annual heating cost by roughly $100 while substantially reducing fossil fuel consumption during moderate winter conditions. This result is consistent with other studies that identify dual-fuel heat pumps as a practical pathway for reducing fossil fuel use while limiting customer bill and grid impacts. Emenike et al. (2023) modeled hybrid ASHP economics across 13 Midwestern states and found that, at standard residential electric rates, customer bills generally increase for ASHP adopters, particularly for all-electric systems. However, the study also found that lower dual-fuel electric rates can allow hybrid ASHPs to approach cost parity in moderate and cold climates and produce savings under more favorable electric and gas rate conditions. Similarly, Landman et al. (2024) found that hybrid heat pumps can reduce customer bill impacts, lower installation complexity, and mitigate winter peak-load impacts relative to all-electric heat pump configurations. Across E3 analyses in Seattle, New York City, and Minneapolis, hybrid systems achieved 40% to 90% of the emissions savings of all-electric options in 2035, while relying on fuel-based backup during the coldest hours to reduce electric peak impacts. These findings support the role of dual-fuel systems as a transitional electrification strategy in regions where current gas and electric rate structures make full electrification more costly for many customers.

Compared with relying solely on higher-efficiency equipment or substantial customer-sited storage to close the bill gap, dual-fuel systems represent a relatively low-cost option for utilities seeking to reduce heating-related emissions while limiting customer bill impacts.

Conclusion

This study demonstrates that combining survival modeling, high-resolution billing analysis, engineering performance modeling, and end-use validation improves electrification planning and customer cost projections. Within the PSE&G service territory, HVAC replacement modeling indicates that approximately 5% of systems turn over annually, while current program participation captures roughly 10% of these replacement events. Technology adoption among participating households was similar across overburdened and non-overburdened communities, suggesting that equity differences arise primarily from participation dynamics during replacement events rather than from technology preferences once households engage with the program.

The load estimation results show that model structure and data resolution matter for electrification analysis. Monthly PRISM inflated heating slope estimates relative to AMI-based approaches, which can overstate projected electric heating consumption and customer bill impacts. End-use metering validation further showed that AMI-based PRISM performed reasonably well for all-electric heat pump homes on average, but conventional single-regime PRISM was not adequate for dual-fuel systems. Across the monitored homes, PRISM overestimated all-electric heat pump heating use by 3.8% on average, but underestimated dual-fuel heat pump heating use by 57.4%. This distinction is important because pooled results can mask fundamentally different operating behavior across system types. For all-electric heat pump homes, AMI-based PRISM can provide a reasonable average estimate of heating use; for dual-fuel systems, segmented change-point methods are needed to reflect switchover behavior and fuel-based backup operation.

Engineering-informed adjustments further improved the realism of electrification bill-impact estimates. Seasonal domestic hot water corrections help avoid overstating gas heating baselines by reallocating winter DHW load from space heating back to non-heating gas use. Temperature-dependent heat pump performance modeling then allows avoided gas consumption and added electric consumption to be translated into more realistic customer cost projections under alternative system configurations and rate schedules.

Under current PSE&G residential rates, full electrification increases heating costs relative to gas heating. Time-of-use rates and customer-sited storage reduce this cost gap under the modeled assumptions, but do not eliminate it for the representative heating load evaluated in this study. Dual-fuel heat pump configurations provide a more practical intermediate pathway. A dual-fuel system with a 40°F switchover temperature increases annual heating cost by roughly $100 while substantially reducing fossil fuel consumption during moderate winter conditions. This finding is consistent with other research showing that hybrid heat pump configurations can reduce bill impacts, installation barriers, and winter peak-load impacts relative to full electrification.

For program administrators and analysts, these findings highlight the importance of using high-resolution data, end-use validation, and engineering-informed adjustments when estimating electrification impacts. Accurate customer-facing bill projections are not simply a technical modeling concern; they are central to program design, customer adoption, and equitable participation during HVAC replacement events. Programs seeking to expand residential electrification should therefore pair improved load-estimation methods with strategies that engage customers and contractors at the point of replacement, while recognizing that dual-fuel systems may offer a practical near-term pathway for reducing emissions while limiting customer cost impacts.

References

Abernethy, R. B. 2006. The New Weibull Handbook. North Palm Beach, FL. dl.icdst.org/pdfs/files3/c64437fb3adfa5efafd1cb89063cb323.pdf.

Bosch Home Comfort. n.d. "Inverter Ducted Split (IDS) Heat Pump." Accessed June 18, 2026. www.bosch-homecomfort.com/us/en/residential/technical-documentation/engineering-submittal-sheets/heating-and-cooling-heat-pump-systems/inverter-ducted-split-%28ids%29-heat-pump/.

Census Bureau. 2023. "Census Geocoding Services." www.census.gov/data/developers/data-sets/Geocoding-services.html.

Daikin Comfort Technologies. n.d. "DZ20VC: Split System Heat Pump." Accessed May 22, 2026. backend.daikincomfort.com/docs/default-source/product-documents/residential/specifications/ss-dz20vc.pdf.

Emenike, C., R. Tudawe, C. Nelson, and M. Garcia. 2023. Developing Electric Rates for Hybrid Air Source Heat Pumps in the Midwest. Minneapolis: Center for Energy and Environment. www.mncee.org/developing-electric-rates-hybrid-air-source-heat-pumps-midwest.

Fels, M. F. 1986. "PRISM: An Introduction." Energy and Buildings 9 (1-2): 5-18.

IPUMS NHGIS (National Historical Geographic Information System). 2024. Minneapolis, MN: IPUMS. www.nhgis.org.

Landman, J., S. Smillie, D. Alberga, M. Bertolacini, M. Sontag, M. Levine, D. Aas, and S. Price. 2024. "Debunking the Myths of Hybrid Heat Pumps." In Proceedings of the 2024 ACEEE Summer Study on Energy Efficiency in Buildings. Washington, DC: ACEEE. www.aceee.org/sites/default/files/proceedings/ssb24/assets/attachments/20240722163133624_dbffa54e-2033-4535-bbcc-ffa2bbbaa7cb.pdf.

Mass Save. 2025. 2024 Annual Impact Report. www.masssave.com/about-us/2024-annual-impact-report.

Mitsubishi Electric. 2024. Submittal Data: PVA-A36AA7 & PUZ-HA36NKA. www.mitsubishitechinfo.ca/sites/default/files/SB_PVA-A36AA7_PUZ-HA36NKA_202401.pdf.

NJ BPU (New Jersey Board of Public Utilities). 2025. "8G Order: NJ Program Year 5 Technical Reference Manual." Trenton, NJ: NJ BPU. www.nj.gov/bpu/pdf/boardorders/2025/20250521/8G%20ORDER%20NJ%20Program%20Year%205%20Technical%20Reference%20Manual.pdf.

NJDEP (New Jersey Department of Environmental Protection). 2026. "What Are Overburdened Communities (OBC)?" dep.nj.gov/ej/communities/.

PSE&G (Public Service Electric and Gas Company). 2026a. Current Electric Tariff (B.P.U.N.J. No. 17). Newark, NJ: PSE&G. nj.pseg.com/aboutpseg/regulatorypage/electrictariffs.

———. 2026b. Current Gas Tariff (B.P.U.N.J. No. 17). Newark, NJ: PSE&G. nj.pseg.com/aboutpseg/regulatorypage/gastariffs.

SEE Action Network. 2012. Energy Efficiency Program Impact Evaluation Guide. Washington, DC. www.energy.gov/sites/default/files/2014/05/f15/emv_ee_program_impact_guide.pdf.

Tobias, P. A., and D. C. Trindade. 2012. Applied Reliability. Boca Raton, FL: CRC Press. www.taylorfrancis.com/books/mono/10.1201/b11787/applied-reliability-paul-tobias-david-trindade.

Wilson, E., and N. Merket. 2022. An Interactive Visualization Tool for Large-Scale Building Stock Modeling: Preprint. Golden, CO: National Renewable Energy Laboratory. NREL/CP-5500-83078. www.nrel.gov/docs/fy22osti/83078.pdf.