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Witness: Ben Schwartz

REBUTTAL TESTIMONY OF BEN SCHWARTZ
ON BEHALF OF THE CLEAN COALITION

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I. INTRODUCTION

Pursuant to the Rules of Practice and Procedure of the California Public Utilities Commission ("the Commission"), the Clean Coalition submits this rebuttal testimony in response to Administrative Law Judge's ("ALJ") *Procedural email granting request for extension of deadlines for Track A testimony*, served to parties on February 22, 2023.

This rebuttal testimony will highlight how the extreme nature of other proposals led the Clean Coalition to develop a reasonable rebuttal proposal and then will lay out a litany of reasons why our proposal should be adopted by the Commission. Our analysis balances the four weighing mechanisms that the Commission should use to determine the viability of a proposal: the benefit to low-income customers, the effect on other ratepayers, the level of difficulty associated with implementation, and whether the change will increase the pace of electrification. With these four considerations in mind, the Solar Energy Industries Association's ("SEIA") proposal far outpaces the other proposals made in opening testimony due to the practical structure and implementation process. Moreover, SEIA's proposed income-graduated fixed charge ("IGFC") is modest in comparison to the surprisingly high proposals from the Joint Investor-Owned Utilities ("the Joint IOUs"), PacifiCorp, the National Resources Defense Council ("NRDC") & The Utility Reform Network ("TURN"), the California Environmental Justice Alliance ("CEJA"), the Sierra Club, and Cal Advocates. However, despite SEIA's proposal being the most reasonable amongst more extreme options, the Clean Coalition feels that there is room for improvement prior to the Commission making a final decision.

We built on the foundational principles from SEIA's proposal (e.g., a modest fixed charge, three tiers, CARE/FERA tiers, applies to all residential rates, not technology-specific, etc.…)[1] to create an ideal IGFC that meets the goals of the legislature better than any other proposal, while also being the easiest (and least costly) to implement. Key faces include:

- Redistributes the cost of existing minimum bills without increasing the total amount of money being collected from ratepayers.
- Imposes a reasonable fixed charge on all residential customers, with low-income customers saving money on top of savings from existing subsidized rates.
- Includes three distinct groups, each paying a slightly different fixed charge: **CARE** customers will pay **$0 per month**, **FERA** customers will pay **$5 per month**, and all **other ratepayers** will pay between **$12.77 and $18.51 per month** (depending on the utility).
- Easy to implement because CARE and FERA customers are already registered for an existing subsidized rate.
- Ensures that the volumetric components of rates continue to represent the true cost of

[1] Prepared Direct Testimony of R. Thomas Beach on behalf of the Solar Energy Industries Association, at p. ii-iii

maintaining the grid in accordance with statute, promoting conservation and the use of price signals to incentivize energy usage during times when the grid is saturated with renewable energy, rather than at peak periods.

- Avoids the conflict of high fixed charges resulting in the ratepayers with the least efficient consumption patterns realizing the greatest amount of savings, an outcome that would be antithetical to state goals.
- Ensures that electrification remains finically viable (and beneficial) for all ratepayers.

In addition to questions on the pricing, allocation, and implementation of an IGFC, the ever-present consideration must be whether the pace of electrification will speed up or be deterred because of an IGFC. We will present research showing that the highest IGFCs among party proposals would lead to bill increases for many average Californians and would make electrification almost completely financially infeasible.

II. GENERAL COMMENTS IN RESPONSE TO PARTY PROPOSALS

Nine parties submitted IGFC proposals,[2] with eight of nine including a fixed charge at or above $25/month for non-CARE customers. A charge that high represents more than just the cost to meter and bill a residential customer. Existing minimum bills for residential customers are around $10/month, meaning a $25/month IGFC would be a 150% increase. Certain proposals would even result in increased charges for CARE customers as well as non-CARE customers. For example, the Joint IOUs are proposing a $15/month IGFC for CARE customers (and $24/month for SDG&E), which is a 50% increase on the minimum bill.[3] A CARE customer with zero electricity consumption over a month, perhaps due an out-of-town vacation, would still pay more than under the status quo. Alarmingly, the Joint IOUs are also requesting that the IGFC be implemented on top of existing fixed charges for PG&E's Schedule E-ELEC, SDG&E's Schedules EV-TOU-5 and TOU-ELEC, and SCE's Schedule TOU-D-PRIME.[4] Ratepayers need the certainty that the IGFC is static and will not be subject to annual increases and that it is **the** fixed charge, not one of many. Since the IGFC includes only non-variable costs, the only reason an increase would occur is if a request is made to include additional components, to guarantee that the revenue is collected rather than relying on recovery from volumetric rates. Clean Coalition urges the Commission to specify that the IGFC is only a respite for low-income customers from the burden of high rates and not the answer to the underlying debate surrounding rate reform. AB 205 clearly states that the point of a fixed charge is, "so that low-income ratepayers in

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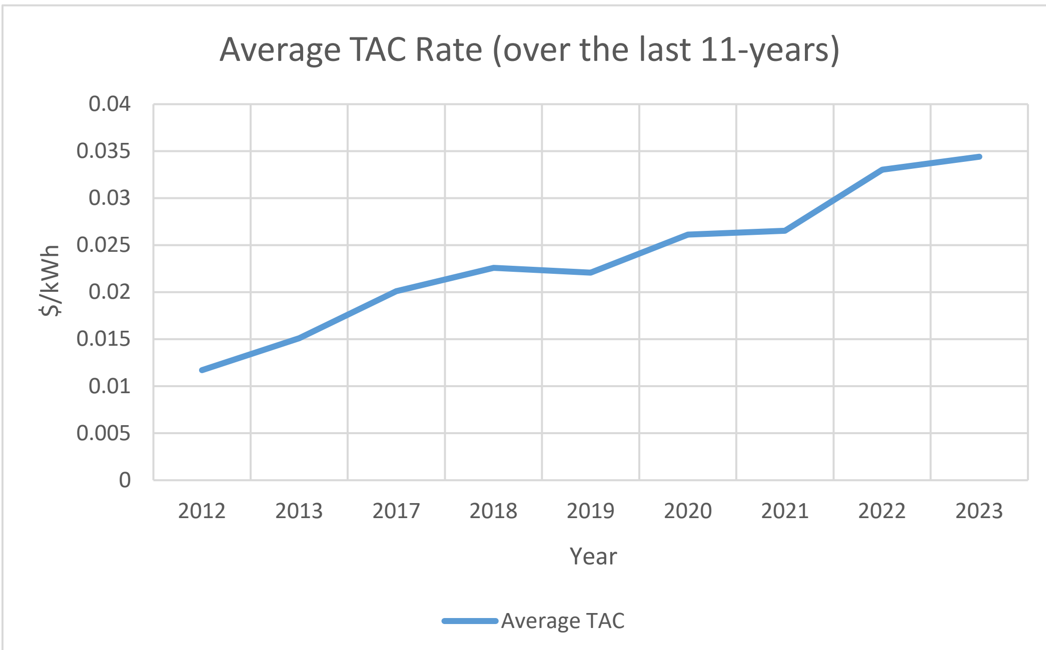
[2] Parties that submitted proposals include:
[3] The Joint IOUs Opening Testimony at p. 22-23.
[4] Ibid, at p. 23.

each baseline territory would realize a lower average monthly bill without making any changes in usage,"[5] making the IGFC primarily an equity issue, rather than an opportunity for universal rate reform. A residential fixed charge cannot be considered a silver bullet solution to achieve affordable electric rates, particularly a high fixed charge. The main driver of rising electric rates continues to be transmission costs (see the graph of average Transmission Access Charges, TAC, over the last 11 years) and wildfire related expenditures.



As a result, a fixed charge might reduce volumetric rates for some customer classes, but it will not reduce the pace at which rates are increasing (greater than inflation). Moreover, an IGFC does not affect peak system demand, which is the main variable used to determine how much additional infrastructure is necessary to meet the system load reliably, even during extreme weather conditions.[6] The Clean Coalition still believes that the majority of costs associated with the cost of service are based on usage (volumetric) and we disagree with the Joint IOU's assertion, "This statutory change [AB 205] endorses the end of the longstanding presumption that costs should be predominantly recovered through volumetric rates for most residential customers."[7] The use of the word "should" incorrectly suggests that AB 205 opines on the effectiveness of recovering rates on a volumetric basis. In fact,

[5] AB 205 at Section 4
[6] See the Clean Coalition's article on the value of Local Solar in reducing Peak Transmission Usage: https://clean-coalition.org/news/local-solar-is-the-best-solution-for-reducing-peak-transmission-usage-and-electricity-costs-for-ratepayers/
[7] The Joint IOU's Opening Testimony at p. 7 lines 1-3.

the law eliminates the standard that rates **must be** recovered through volumetric rates, without prescribing whether costs **should be** recovered on a volumetric basis. Allowing a fixed charge to improve affordability for low-income customers has little to do with increasing affordability for all residential customers by reducing the costs collected volumetrically. It is important that the two issues are not conflated to ensure that the Commission can properly weigh the different proposals.

There is no consensus among parties about the optimal number of tiers for an IGFC or the income differentiation for each tier. Five parties propose an IGFC with three tiers,[8] which is the minimum number of tiers required by AB 205. The other four proposals argue for more than three tiers, with recommendations ranging from four through ten tiers.[9] The Clean Coalition agrees with the parties recommending three tiers for practical reasons; the more tiers, the more costly and time consuming the proposal is to implement, especially if there is income verification involved. Specifically, we find SEIA's choice to use CARE, FERA, and all other ratepayers as the delineations for each of the three tiers to be the most effective option.[10] CARE and FERA offer discounted rates to low-income ratepayers within a certain percentage of the Federal Poverty Level (up to 200% for CARE and up to 250% for FERA). Because these are existing categories used for billing purposes, no additional mechanism would be required to implement an IGFC. Proposals that include greater stratification among CARE and FERA customers or have multiple tiers for non-low-income ratepayers will require income declarations, verification (potentially by a third party), new pathways in the billing system, and additional administration. Therefore, it is necessary to weigh the added benefit of having a greater number of tiers against the increased cost and time to implement the IGFC. The Clean Coalition does not find this to be a worthwhile tradeoff and recommends three tiers based on existing billing distinctions (e.g., CARE, FERA, and all other ratepayers).

III. CLEAN COALITION'S REBUTTAL PROPOSAL

The Clean Coalition's proposal balances the need to ensure that low-income ratepayers save money under an IGFC with the fact that a reasonable fixed charge should not significantly increase costs for all other ratepayers. Unlike other parties that include many different rate components in their fixed charge proposals, we are focused on capturing savings from redistributing the money collected through minimum bills, which represent the costs of the

[8] Parties that propose three tiers: SEIA, NRDC & TURN, PacifiCorp, Bear Valley, and Liberty Utilities.

[9] The Joint IOUs propose 4 tiers, Sierra Club proposes 5 tiers, Cal Advocates proposes 6 tiers, and CEJA proposes 10 tiers.

[10] Opening Testimony of SEIA at p. 13-14

line drop, transformer, meter, and customer billing, which are truly fixed costs. Importantly, under the Clean Coalition's proposal, the total amount of money being collected will not change with the switch from a minimum bill to an IGFC, the only thing that is changing is who the money is being collected from.

For example, consider how the California Independents System Operator ("CAISO") allocates TAC, which are assessed to ratepayers on a volumetric basis. However, as seen in the image below, the base components used to calculate TAC are the total TAC requirement, gross system load, and the Transmission Revenue Requirement ("TRR") for all Participating Transmission Owners ("PTOs"). The TRR is set in advance, meaning that the only thing that changes when determining the appropriate TAC rate to be recovered volumetrically from ratepayers is the PTO's gross load. Similarly, the IGFC amount to be collected is a known quantity based on the number of questions, not volumetric usage. The only variable that changes is who among the ratepayers will be responsible for shouldering the costs.

	Filed Annual TRR ($) [1]	Filed Annual Gross Load (MWh) [2]	HV Utility Specific Rate ($/MWH) [3] = [1] / [2]	TAC Rate ($/MWH) [4] = total [1]/total [2]	TAC Amount ($) [5] = ([2]) * [4]
PG&E	$ 1,099,761,306	87,128,022	$ **12.6224**	$ **16.3885**	$ 1,427,895,154
SCE	$ 1,231,857,668	84,432,528	$ **14.5898**	$ **16.3885**	$ 1,383,720,125
SDG&E	$ 543,548,426	18,450,857	$ **29.4593**	$ **16.3885**	$ 302,381,352
Anaheim	$ 31,883,670	2,218,120	$ **14.3742**	$ **16.3885**	$ 36,351,598
Azusa	$ 1,220,257	257,416	$ **4.7404**	$ **16.3885**	$ 4,218,655
Banning	$ 783,146	144,652	$ **5.4140**	$ **16.3885**	$ 2,370,625
Pasadena	$ 15,957,447	1,065,579	$ **14.9754**	$ **16.3885**	$ 17,463,212
Riverside	$ 29,066,428	2,180,985	$ **13.3272**	$ **16.3885**	$ 35,743,012
Vernon	$ 3,213,545	1,119,215	$ **2.8712**	$ **16.3885**	$ 18,342,224
DATC Path 15	$ 20,549,264	-	$ **-**	$ **16.3885**	$ 0
Startrans IO	$ 2,841,338	-	$ **-**	$ **16.3885**	$ 0
Trans Bay Cable	$ 131,766,205	-	$ **-**	$ **16.3885**	$ 0
Citizens Sunrise	$ 15,431,285	-	$ **-**	$ **16.3885**	$ 0
Colton	$ 1,231,482	372,179	$ **3.3088**	$ **16.3885**	$ 6,099,445
VEA	$ -	544,970	$ **-**	$ **16.3885**	$ 8,931,226
GLW	$ 34,645,909	-	$ **-**	$ **16.3885**	$ 0
MCCT	$ 1,402,936	-	$ **-**	$ **16.3885**	$ 0
CSPT	$ 3,941,031	-	$ **-**	$ **16.3885**	$ 0
HZWT	$ 12,523,877	-	$ **-**	$ **16.3885**	$ 0
DSLK	$ 23,837,373	-	$ **-**	$ **16.3885**	$ 0
Morongo Trans	$ 38,054,033	-	$ **-**	$ **16.3885**	$ 0
ISO Total	**$ 3,243,516,626**	**197,914,523**			**$ 3,243,516,626**

CAISO TAC Totals as of January 2023

The central tenet of the Clean Coalition's proposal is that the total amount of money being collected from the rate base should not change, it should be related to existing money collected from minimum bills (e.g., costs related to the transformer, the service drop, the meter, and billing). Moreover, there is no reason to include as many aspects of rates as possible in a fixed charge; it will only result in a needlessly high IGFC that reduces the effectiveness of volumetric rates. AB 205 mandates that a fixed charge with stratification based on income is created in a way that eases the burden on low-medium income ("LMI") customers. However, the IGFC should not be considered a universal solution to improve affordability and must not prevent other rate reforms from occurring.

Utility	CARE (<200% FPL)	FERA (200% to 250% FPL)	All Others (> 250% FPL)
PG&E	$0	$5	$12.77
SCE	$0	$5	$13.94
SDG&E	$0	$5	$18.51

Table Summarizing the Clean Coalition's IGFC Proposal

The Clean Coalition's proposal reduces the cost burden for CARE customers to $0/month and allocates a very affordable $5/month charge for FERA customers. All LMI customers, up to 250% of the Federal Poverty Limit, will save money without adding significant costs to the bills of the rest of the rate base under our proposal. SEIA's proposal, which is the closest comparison to the Clean Coalition's proposal, would have all ratepayers paying a modest fixed charge.[11] Based on this proposal we were able to determine that the ideal way to translate the language of AB 205 into a fixed charge is to ensure that the lowest-income ratepayers are not paying any fixed charge at all and everyone else is only responsible for a modest charge. Most other party proposals do not meet this standard. While some of the proposals would levy a charge of $0/month for the lowest income bracket, all but SEIA impose charges of between $25 and $50 for the next group, with each additional tier paying even more.[12] Proposals with a fixed charge that is higher than $25 have the potential to create what the Rocky Mountain Institute describes as whiplash, which occurs when, "it will become attractive enough for customers to entirely defect from the grid."[13] This same issue is part of the reason that the Commission declined to adopt a fixed charge in the recent Net Energy Metering ("NEM") proceeding. The 75% reduction in compensation for solar customers from NEM 2.0 to the Net Billing Tariff was enough to send the rooftop solar industry into a state of flux, even without an additional fixed charge. Now that the April 14 NEM 2.0 cutoff date has passed, it remains

[11] Opening Testimony of SEIA at p. ii.
[12] The Joint IOUs at p. 5, Cal Advocates at p. 3, CEJA at p. 17, PacifiCorp at p. 10, Bear Valley at p. 8, NRDC/TURN at p. 1, Liberty Utilities at p. 5, and Sierra Club at p. 26.
[13] https://rmi.org/blog_2015_05_28_fixed_charges_dont_fix_the_problem/

to be seen whether the market will recover and continue to grow. However, it is crystal clear that adopting a high fixed charge will not help create the stable market conditions that are required to ensure that customer-sited renewables continue to grow sustainably. Moreover, adding an IGFC on top of—rather than in the place of—existing fixed charges on electrification rates will be punitive toward ratepayers adopting electrification measures.

The other important aspect of the Clean Coalition's proposal is that the three-tiered IGFC is simple to implement because it requires no changes to existing ratepayer delineations and does not require any sort of income declaration/verification. Therefore, once a final decision is released, implementation should not take a significant amount of time and there will not be an exorbitant cost. Rollout of the Clean Coalition's proposal could likely occur before the end of 2023. The same cannot be said for CEJA's IGFC proposal,[14] which has ten income brackets or Cal Advocates' proposal[15] with six income brackets and income verification from an outside company.

IV. SAVINGS FROM A FIXED CHARGE AND IMPACT ON ELECTRIFICATION

To validate the Clean Coalition's proposal, we analyzed the other party proposals based on the bill savings from implementing an IGFC and how the financial incentive to electrify will be impacted. A proposal that results in savings for CARE customers but eliminates the benefits of electrification for non-CARE customers must not be adopted by the Commission. Ideally, a proposal should both result in savings for CARE customers and retain the financial incentives to electrify, a standard which we believe the Clean Coalition's reasonable IGFC meets, but other higher IGFC proposals do not.

The following text and figures below are excerpted from a Flagstaff Research Report.[16]

A. Bill Savings from Three IGFC Proposals

Flagstaff Research assessed proposals from Cal Advocates,[17] NRDC/TURN, and the

[14] Opening Testimony of CEJA, at p. 3.
[15] Opening Testimony of Cal Advocates at p. 3.
[16] The report was authored by Josh Plaisted at Flagstaff Research. Workpapers can be made available as needed.
[17] Referred to as PAO in the report for the sake of simplicity.

Joint IOUs to determine annual bill impacts by utility, income class, energy use, and other metrics for customers that do not engage in fuel switching. The full report is included below as Attachment A. Though each of the proposals contains a different number of tiers, modeling the effect of the proposed IGFCs on representative Californians demonstrates the lack of viability of each of the three proposals. Specifically, the IGFC proposals were analyzed according to three income levels: a California median income of $84,000 per household,[18] customers with $150,000 in household income, and CARE customers with half the California median income.

Flagstaff Research's report also analyzed the impacts on customers switching home appliances from natural gas to electricity under the fixed charge proposals and the alternative of encouraging electrification via more highly differentiated time of use ("TOU") rates. Three separate households were modeled for each climate to assess the impact of usage and load shape:

- A 1,250 square-foot home with light efficiency upgrades (e.g., lighting + EnergyStar appliances).

- A 2,500 square-foot home built to 2016 Title 24 standards. This aligns with typical home consumption.

- A 3,750 square-foot larger and older home with lower insulation, increased leakage, and heavier appliance use resulting from higher occupancy.

	Low Use	Normal Use	High Use
Construction			
Home size (sq ft.)	**1250**	**2500**	**3750**
Bedroom/Bath	2/1.5	3/2	4/3
Wall Insulation	R-13	R-13	R-7
Ceiling Insulation	R-30	R-30	R-13
Window U-Value	0.49	0.49	0.76
Leakage	6 ACH50	6 ACH50	10 ACH50
Ventillation	ASHRAE 2013 Exhaust	ASHRAE 2013 Exhaust	None
Ducts	R-8, 10% Leakage	R-8, 10% Leakage	R-4, 15% Leakage
Appliances/Fixtures			
Air Conditioner	SEER 13	SEER 13	SEER 13
Furnace	80% AFUE	80% AFUE	80% AFUE
Water Heater	0.59 EF Gas	0.59 EF Gas	0.59 EF Gas
Lighting	100% LED	80% LED	80% LED
Refrigerator	18 sq. ft. 21.9 EF	18 sq. ft. 17.6 EF	25 sq. ft. 19.6 EF
Washer	EnergyStar (80% usage)	EnergyStar	EnergyStar (120% usage)
Misc loads (kWh/year)	1365	2351	4314

Specifications of Modeled Home Types

Key questions are whether a proposal simply rewards high consumption and whether it incentivizes the deployment of more efficient appliances. In addition to bill savings for

[18] U.S. Census Bureau, "Quick Facts: California," available at https://www.census.gov/quickfacts/CA.

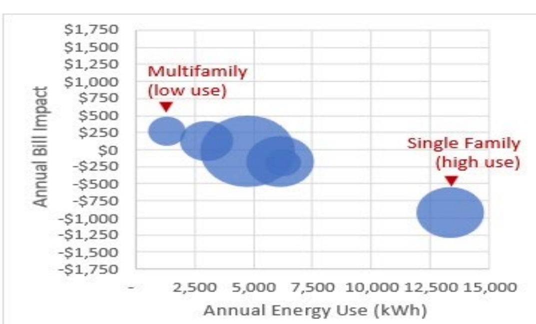
low-income ratepayers, one of the intentions of the proposed IGFC is to buy down the variable rate ($/kWh) to make electrification more economic and cost competitive against fossil fuel sources (gasoline, natural gas). Lower variable rates require higher fixed charges to maintain a revenue neutral position on the rate base. However, higher fixed charges promote higher consumption patterns to ensure financial savings.

In all proposals, there will be a balance point in home consumption against the current rates where the discounted variable rate offsets the fixed component, and the proposal is revenue neutral for the customer. At consumption levels above this level, the proposal will result in annual savings. Below this level the fixed rate becomes more dominant, and the customer sees increased utility costs.[19] This varies primarily by the wide range in fixed charges according to income level between the proposals. Consider the results for PAO and the Joint IOUs:

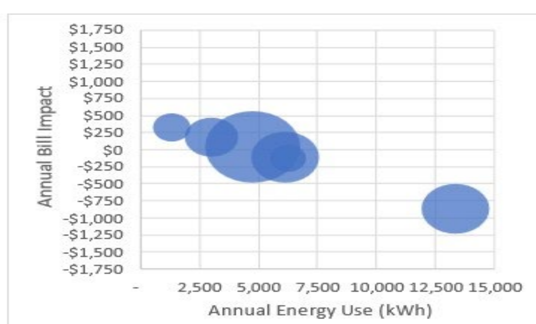
- **PAO:** Under the median household income on a simple TOU-D-4-9 rate with the consumption profile of the mid-line 2500 square-foot home, there is a $383 fixed charge with a $0.059/kWh ($0.336 -$0.277) variable rate discount. This results in a balance point consumption of 6,220 kWh/year where the fixed charge proposal matches the existing rate on the annual bill. Homes using less than that amount will see their bills increase under the proposal, and homes using more will see their bill decrease.

- **IOU:** Under the Joint IOU proposal for a household earning $150,000, the fixed charge increases nearly three-fold to $1,022/year, but with an increase in the variable rate discount to $0.104/kWh. The balance point usage for this household income is 9,836 kWh for the proposed rate to break even with the current rate. The net impact is an 18% bill increase for a 2,500 square-foot home with normal consumption.

$84,000 Annual Household Income



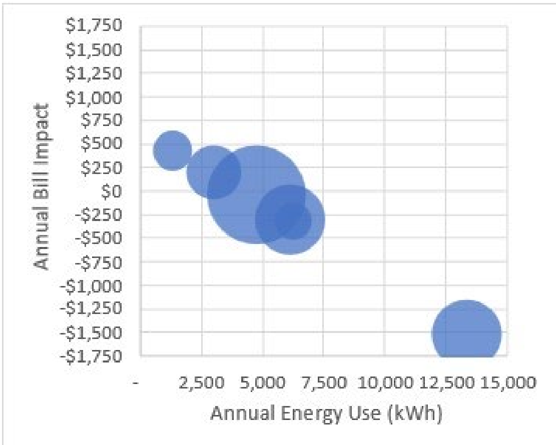
$150,000 Annual Household Income

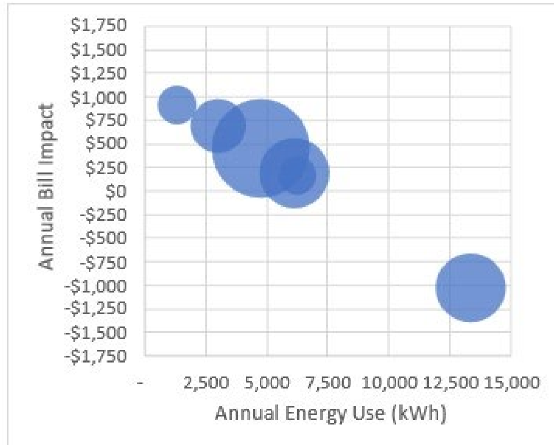


[19] This balance point in usage can be calculated by dividing the increase in the fixed bill component by the decrease in the blended variable rate used by the home.

Impacts by Dwelling Type and Income Under Cal Advocates Proposal (above)

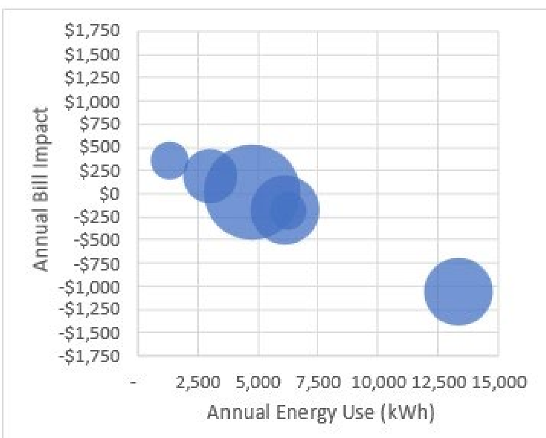
$84,000 Annual Household Income $150,000 Annual Household Income

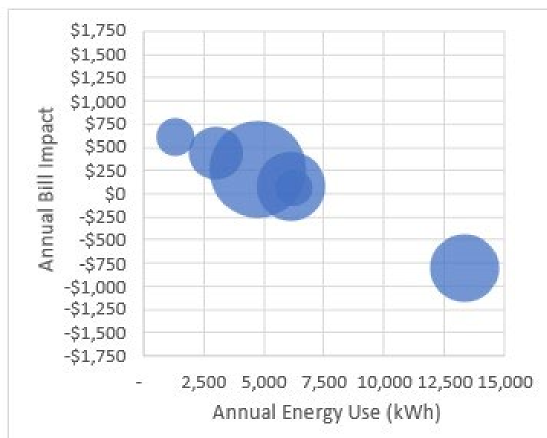




Impacts by Dwelling Type and Income Under the Joint IOU's Proposal (above)

$84,000 Annual Household Income $150,000 Annual Household Income





Impacts by Dwelling Type and Income Under NRDC/TURN Proposal (above)

The Flagstaff Research report notes the following trends (details can be found in Tables 6-14):

Marginal Impact: The proposals are reasonably neutral for the median income home with average home energy use (e.g., 2500 square-foot home with typical use). This is the impact presented in most proposals. Across all three proposals, we find representative savings to be 10% for PG&E, no impact for SCE, and 2% for SDG&E.

Significant Negative Impact: The most severe bill increases occur in small efficient homes with household income of $150k or more. Looking at the TOU-D-4-9 rate structure in SCE territory, there is a 62% rate increase under the Joint IOU's proposal. Focusing specifically on the fixed charge components, the $1,023 annual fixed charge under the Joint IOU's proposal nearly matches the full annual bill of $1,105 under the current rate structure without accounting for the additional energy charges of $765. A similar trend is evident across all utility territories, with bill increases exceeding 50% across territories under the Joint IOU's proposals. The PAO proposal has lower fixed charges partially mitigating this impact, but bill increases of ~10% – 20% are still found under this proposal. In addition to the small single family detached home that was modeled, this energy usage profile is common for apartments, duplexes, townhomes, and condominiums. Specifically, we see many apartment renters as falling into this impacted customer class.

Significant Positive Impact: Homes with high energy use well above the balance point see significant bill savings. If we look at the large 3750 square-foot home with median household income, bill reductions are in the 15-30% range under the IOU proposals, with annual household savings on the order of $1,000. This level of savings is achieved without any investment in efficiency or electrification for this customer group. Simply having high existing energy use associated with the typical needs of a larger home leads to material savings under the proposals.

As can be seen from tables 6-8 in the report, the only non-CARE customers in PG&E's service territory that realize double digit bill savings annually under all three proposals are 3,750 square-foot homes. The results are not quite as drastic for the other two utilities (tables 9-14), but the trend is still clear. Under the highest fixed charge proposals, the real winners are inefficient properties with high consumption patterns. Low energy users are subsidizing higher energy users under each of the three proposals modeled. This pattern runs counter to the state's goals of increasing efficiency as part of electrification efforts and shifting consumption patterns to periods when the grid is saturated with renewable energy.

Flagstaff Research's report demonstrates that when compared to the high IGFC proposals that were modeled, Clean Coalition's modest proposed fixed avoids creating a massive subsidy from small homes to large homes while implementing the statutory obligation to recover some fixed costs through a fixed charge and include a component based on income.

B. Impacts for Customers Adopting Electrification

The specific impact of an IGFC on each customer is absorbed upon rate implementation before significant levels of electrification occur. Any customer that sees bill savings under the proposals is under no obligation to invest those savings in electrification. The benefits and drawbacks of new fixed charges are fully absorbed in this initial phase. However, with the new rates in place that have a lower variable component (subsidized through the fixed charge), the report assesses whether the reduced rates are sufficient to incentivize customers to invest in electrification measures. The key metric in such an analysis is the annual bill savings in moving appliances from natural gas onto these new reduced electric rates. At a bare minimum, electrification cannot result in increased utility bills or the customer willingness to pay will be zero. More practically, there must be sufficient bill savings to justify the equipment upgrades with a reasonable payback period.

	PG&E	SCE/SCG	SDG&E	PG&E	SCE/SCG	SDG&E
Gas Usage & Cost	Low Efficiency Gas Appliances			High Efficiency Gas Appliances		
Space Heating (therms/yr)	334	96	76	256	73	57
Water Heating (therms/yr)	159	146	149	94	85	87
Appliances (therms/yr)	57	57	57	57	57	57
Annual Gas Usage (Therms)	550	299	281	407	214	201
Annual Gas Variable Charges	$ 941	$ 388	$ 549	$ 663	$ 279	$ 392
Annual Gas Fixed Meter Charges		$ 60			$ 60	
Annual Gas Total Charges	$ 941	$ 448	$ 549	$ 663	$ 339	$ 392
Electrification Use (kWh)	4,080	2,299	2,224	4,080	2,299	2,224
Breakeven Rate ($/kWh)	$ 0.231	$ 0.195	$ 0.247	$ 0.162	$ 0.147	$ 0.176
Rate Proposal						
Cal Advocates	$ 0.237	$ 0.249	$ 0.362	$ 0.237	$ 0.249	$ 0.362
TURN	$ 0.198	$ 0.211	$ 0.317	$ 0.198	$ 0.211	$ 0.317
IOU	$ 0.177	$ 0.201	$ 0.236	$ 0.177	$ 0.201	$ 0.236

Target Rates for Electrification[20]

Non-CARE Customers: When converting from modern high efficiency gas appliances, there is no case under any of the evaluated rate proposals where electrification results in annual bill savings for customers. The target electricity rate necessary to break even against modern high efficiency gas appliances is $0.147/kWh - $0.176/kWh. This rate is not achieved under any of the evaluated proposals. With legacy low-efficiency gas appliances there are annual savings in PG&E territory under the Joint IOU and NRDC/TURN proposals, but they are marginal. Assuming a maximum 10-year simple payback for residential consumers to be willing to adopt, the turnkey cost (equipment plus installation) for whole home electrification would need to be less than $2,170, post all incentives, to break even. Actual costs for the modeled electric appliances are likely in excess of $20,000 installed.

CARE Customers: Customers on CARE rates see some expanded markets where electrification results in annual bill savings in homes with legacy low-efficiency appliances, but those savings are equal to or less than those for non-CARE customers because of lower baseline bills due to the CARE discount. There is simply less gas savings to be recovered. On the other hand, for those CARE households with high-efficiency gas appliances, the result is the same as for non-CARE customers. There is no proposal that results in annual savings from electrification.

Overall, Flagstaff Research finds that a highly differentiated TOU rate structure would do a better job of encouraging electrification than the modeled fixed charge proposals, while avoiding the inequity that is inherent in the fixed charge proposals of having small homes subsidize larger homes. This conclusion effectively rebuts statements from parties such as Cal Advocates who attest that, "Collecting costs entirely in volumetric rates hinders vital electrification."[21] In the discussion of this point in opening testimony, Cal Advocates proves the opposite to be true by suggesting that the problem is with exorbitantly high rates and not inherently related to volumetric rates.[22] On the other hand, Flagstaff

[20] Table 21 in the Flagstaff Research Report

[21] Opening Testimony of Cal Advocates at table of contents, section II.B.

[22] On p. 1-6, Cal Advocates states, "at a minimum, volumetric electricity rates need to remain low to reduce the costs of electrification." (Ibid)

Research's case study demonstrates that high IGFCs, including the proposal by Cal Advocates would significantly reduce the incentive to deploy electrification measures. Therefore, the Commission should not find a fixed charge to be the sole solution required to shape affordable rates and enable electrification, especially high fixed charges.

V. Conclusion

The Clean Coalition appreciates the opportunity to submit this rebuttal testimony and we urge the Commission to adopt our proposal, which represents a reasonable middle ground solution that meets the statutory goals of AB 205, in that it creates a more equitable and affordable solution for low-incomes ratepayers, while also being the most practical solution due to the simple implementation process.

Attachment A

Assessment of Fixed Charge Proposals

June 1, 2023

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I. Introduction

This paper assesses proposals on residential fixed charges from CPUC Public Advocates Office (PAO), TURN/NRDC, and the Joint IOUs. We analyzed the impacts on customers with three home sizes. The fixed charge proposals were used according to three income levels: California median income of $84,000 per household,[1] customers with $150,000 in household income, and CARE customers with half the California median income. The analysis is done with tools from the U.S. Department of Energy (USDoE) and the National Renewable Energy Laboratory (NREL) that model hourly energy usage profiles from specific appliances in specific climate zones.

The results of this analysis for the mid-size home and the middle-income household are similar to those in the E3 Fixed Charge Design Model that was used by parties in opening testimony. Our assessment diverges significantly from that model for different home sizes and income levels.

We also analyzed the impacts on customers switching home appliances from natural gas to electricity under the fixed charge proposals and an alternative concept to encourage electrification with more highly differentiated time of use (TOU) rates.

II. Modeling Inputs and Assumptions

Costs under current and proposed rates for each utility were analyzed with home load profiles corresponding to following climate zones (CZ): PG&E CZ12 (Sacramento), SCE CZ9 (Los Angeles), and SDG&E CZ7 (San Diego). Three separate households were modeled for each climate to assess the impact of usage and load shape:

- A 1,250 square-foot home with light efficiency upgrades (e.g. lighting + EnergyStar appliances).
- A 2,500 square-foot home built to 2016 Title 24 standards. This aligns with typical home consumption.
- A 3,750 square-foot larger and older home with lower insulation, increased leakage, and heavier appliance use resulting from higher occupancy.

A. Home Energy Usage

EnergyPlus simulation software (from USDoE) was used to model each home in the respective climates using the BEopt front end from the National Renewable Energy Laboratory (NREL). This includes specific appliance specifications for air conditioner, furnace, water heater, cooking, and dryer.

- Baseline homes were modeled with gas appliances typical in California construction.
- EnergyPlus weather files for representative climate zones were used to determine the hourly energy profile of each household.
- Variance against a California Energy Commission (CEC) 2019 residential saturation survey was checked to ensure close alignment.

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[1] U.S. Census Bureau, "Quick Facts: California," available at https://www.census.gov/quickfacts/CA.

Table 1. Specifications of Modeled Home Types

	Low Use	Normal Use	High Use
Construction			
Home size (sq ft.)	**1250**	**2500**	**3750**
Bedroom/Bath	2/1.5	3/2	4/3
Wall Insulation	R-13	R-13	R-7
Ceiling Insulation	R-30	R-30	R-13
Window U-Value	0.49	0.49	0.76
Leakage	6 ACH50	6 ACH50	10 ACH50
Ventilation	ASHRAE 2013 Exhaust	ASHRAE 2013 Exhaust	None
Ducts	R-8, 10% Leakage	R-8, 10% Leakage	R-4, 15% Leakage
Appliances/Fixtures			
Air Conditioner	SEER 13	SEER 13	SEER 13
Furnace	80% AFUE	80% AFUE	80% AFUE
Water Heater	0.59 EF Gas	0.59 EF Gas	0.59 EF Gas
Lighting	100% LED	80% LED	
Refrigerator	18 sq. ft. 21.9 EF	18 sq. ft. 17.6 EF	25 sq. ft. 19.6 EF
Washer	EnergyStar (80% usage)	EnergyStar	EnergyStar (120% usage)
Misc loads (kWh/year)	1365	2351	4314

Figure 1. Pre-Electrification Profile of Electricity Usage for 2,500 Square Foot Home in PG&E Territory

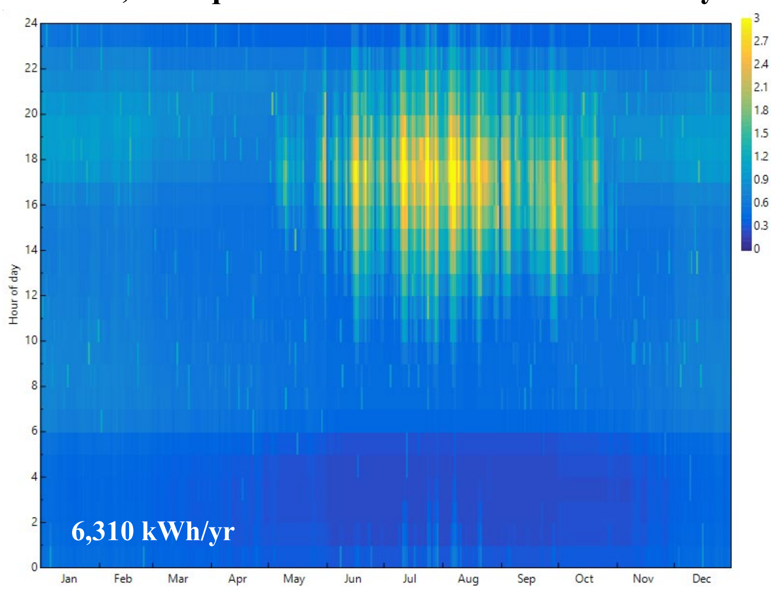


Figure 2. Pre-Electrification Profile of Electricity Usage for 2,500 Square Foot Home in SCE Territory

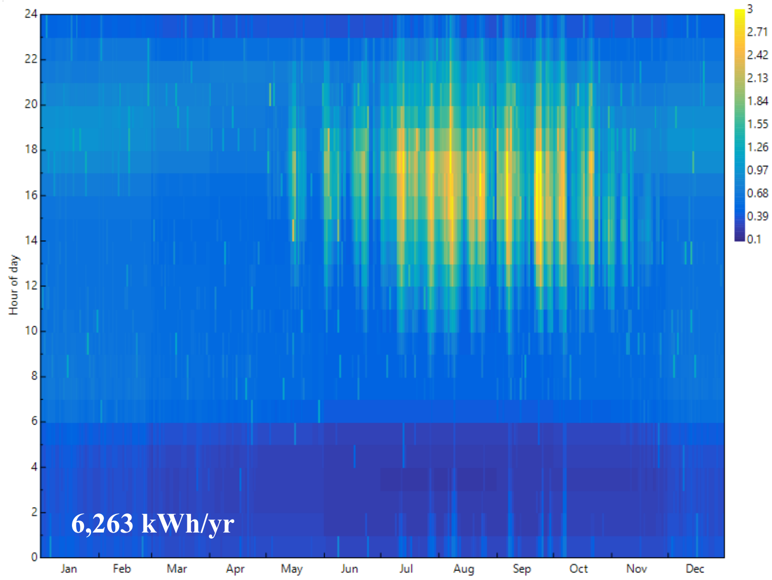
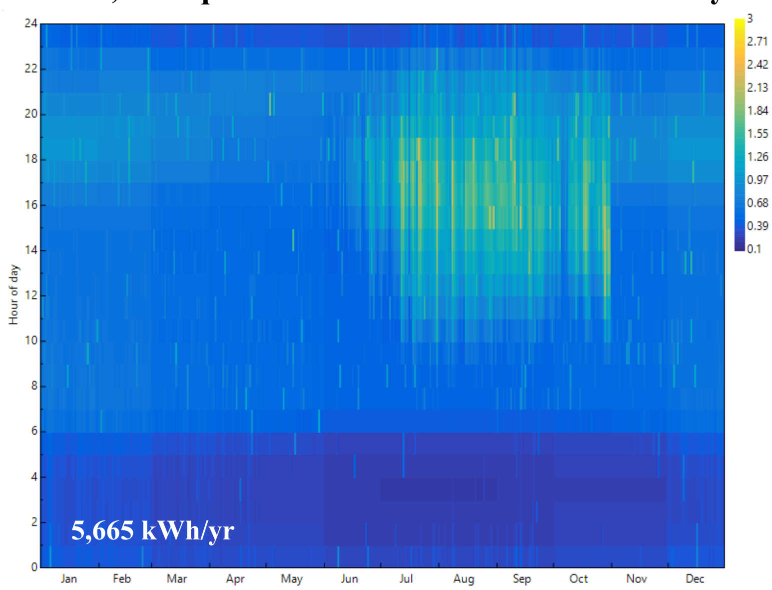


Figure 3. Pre-Electrification Profile of Electricity Usage for 2,500 Square Foot Home in SDG&E Territory



B. Distribution of Energy Use by Building Type

The 2019 CEC survey breaks out three classes of customer usage for single-family and multifamily homes representing low, medium, and high usage. For each classification, the survey presents a representative annual consumption as well as the number of units in each class. This is shown in the rows labeled "Population Count" and "Population kWh/Yr" in Table 14 from the CEC survey, which is reproduced as Table 2 below.[2]

Table 2. Energy Consumption in 2019 CEC Survey

Utility	Study Characteristic	Single family Dwelling Low	Single family Dwelling Medium	Single family Dwelling High	All	Net Metered	Multi-family Dwelling Low	Multi-family Dwelling Medium	Multi-family Dwelling High	All	Net Metered	Utility Total
LADWP	Population Count	130,613		42,971	288,699	29,944	482,086		155,624	230,958	1,850	1,362,745
LADWP	Population kWh/Yr	4,726		18,157	9,232	6,696	2,454		7,933	4,677	4,731	5,702
LADWP	Sample Count	276		74	934	111	791		208	400	2	2,796
LADWP	Respondent kWh/Yr	5,345		16,420	8,476	4,625	2,593		6,557	4,356	3,038	5,332
LADWP	StdErr of Respondent kWh/Yr	303		1,160	766	465	114		427	273	1,077	236
PG&E	Population Count	1,418,740	727,135	702,012	134,827	332,802	224,884	431,210	213,042	469,544	13,171	4,667,367
PG&E	Population kWh/Yr	4,747	6,112	13,337	8,300	4,216	1,334	3,009	6,254	4,528	2,638	6,032
PG&E	Sample Count	4,716	2,753	2,143	434	1,671	594	1,074	871	1,647	64	15,967
PG&E	Respondent kWh/Yr	4,878	6,107	12,606	10,157	3,973	1,352	2,904	5,928	4,335	1,990	5,949
PG&E	StdErr of Respondent kWh/Yr	135	129	380	1,437	460	52	64	208	157	343	131
SCE	Population Count	1,199,237	1,003,043	723,300	130,936	248,342	323,941	275,658	196,564	282,133	2,033	4,385,187
SCE	Population kWh/Yr	4,676	6,142	13,391	7,869	8,683	2,397	3,353	6,853	4,746	6,249	6,622
SCE	Sample Count	3,778	2,895	1,718	757	1,370	1,091	564	505	693	10	13,381
SCE	Respondent kWh/Yr	4,633	6,139	12,261	7,849	8,805	2,348	3,328	7,250	4,936	6,251	6,446
SCE	StdErr of Respondent kWh/Yr	127	79	268	497	455	98	83	456	448	1,400	112
SDGE	Population Count	251,239	267,135	174,511		115,752	92,340	174,854	86,284	70,323	6,732	1,239,170
SDGE	Population kWh/Yr	3,160	5,398	11,205		3,039	1,623	3,296	6,291	3,296	2,473	4,891
SDGE	Sample Count	1,250	1,343	743		475	323	548	284	196	10	5,172
SDGE	Respondent kWh/Yr	3,037	5,395	10,166		2,762	1,502	3,372	5,860	3,104	2,958	4,650
SDGE	StdErr of Respondent kWh/Yr	110	82	304		830	74	80	206	368	831	140
SMUD	Population Count	282,190		92,790		16,754				133,073	157	524,964
SMUD	Population kWh/Yr	7,383		18,042		7,389				5,731	7,057	8,848
SMUD	Sample Count	1,518		370		125				352	1	2,366
SMUD	Respondent kWh/Yr	7,177		16,035		7,907				5,610	21,356	8,371
SMUD	StdErr of Respondent kWh/Yr	216		705		1,252				540		306

Source: 2019 California Residential Appliance Saturation Survey;

Plotting the energy use of each dwelling type by its percentage representation within each IOU gives us the plot in Figure 4. Within this plot, the vertical dotted line indicates the average annual energy consumption for all California homes. This has close alignment with the medium usage single family detached homes clustering around this line. However, we see other clusters far from the average.

A. **Low Use:** This cluster is made of low and medium use multifamily dwellings using roughly half of the statewide average. Approximately 1 in 5 IOU households falls in this category.
B. **High Use:** This cluster is made of high usage single family detached homes using approximately double the statewide average. Just under 1 in 5 IOU households falls in this category
C. **Efficient Single Family:** The highest representation is in low usage single family homes making up nearly 1 in 3 households and using 24% less energy than the average home.

[2] CEC, "2019 California Residential Appliance Saturation Study," available at https://www.energy.ca.gov/publications/2021/2019-california-residential-appliance-saturation-study-rass. The reproduced table is Table 14 in the original.

Figure 4. Energy Consumption in 2019 CEC Survey

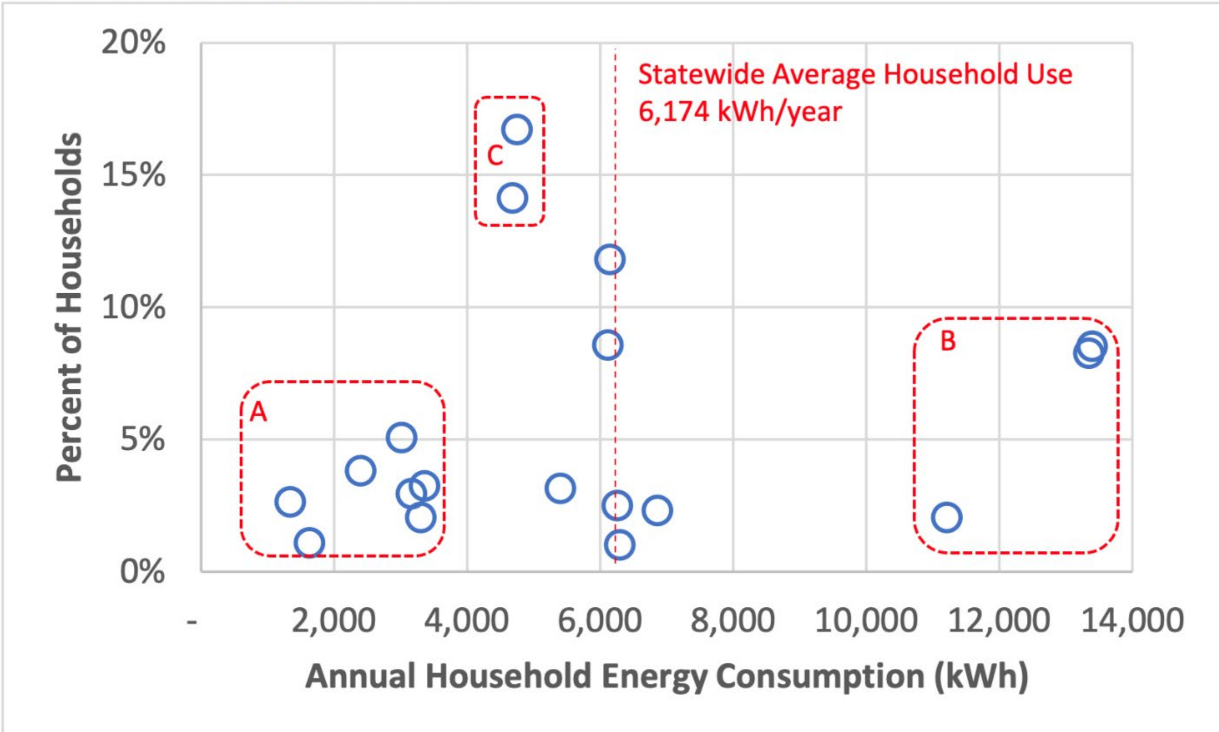


Table 3. Comparison of Modeled Energy Use with CEC Survey

	CEC 2019 Survey (kWh)	BeOpt/EnergyPlus (kWh)	Variance (%)	Gas Usage (Therms)
PG&E (CZ12)	6,266	6,310	+1%	550
SCE (CZ9)	6,424	6,263	-3%	299
SDG&E (CZ7)	5,230	5,665	+8%	281

Customer bills were calculated using hourly (8760) home electricity load profiles using NREL's System Advisor Model (SAM). This bill modeling used current and proposed tariffs from each proposal under three separate rate types: flat, TOU, and electrification/EV. Standard residential gas tariffs were used with the proper allocation of baseline and excess rates based on modeled home gas consumption. In the analysis of CARE customers, the rates were discounted according to the CARE discounts as shown. Impacts on homeowner annual electric bills as compared to existing rate structures were assessed for each proposal across regions and housing types.

Table 4. Modeled Rate Schedules

	Electricity				Natural Gas	
	Flat	TOU	Electrification	CARE Discount	Gas	CARE Discount
PG&E	E1	E-TOU-C	E-ELEC	35.0%	G-1	20.0%
SCE/SCG	D	TOU-D-4-9	TOU-D-PRIME	32.5%	GR	20.0%
SDG&E	DR	TOU-DR1	TOU-E-ELEC	35.0%	GR	20.0%

C. Electrification

The cost effectiveness of fuel switching from natural gas to high efficiency electric appliances (e.g. heat pumps) was assessed under the new proposed rates, all of which aim to reduce variable energy charges to promote electrification.

In all cases, we presume the customer is moving to the most modern heat pump and induction cooking technologies as represented by the highest efficiency levels in NREL's BEopt appliance database. However, potential savings are dependent on the efficiency of the gas appliances the customer is converting from. Homes with more efficient gas appliances will have a larger challenge switching to electric appliances because their current gas costs are low. We cover this sensitivity by modeling two boundaries of existing home types, one with legacy low-efficiency technologies (non-condensing) and one with modern high-efficiency (condensing) technology that has become more common in the last decade. Most homes will fall between these two modeled limits.

Gas costs were pulled from residential general service tariff and annual costs were calculated using consumption rates for below and above baseline. SCE was modeled using service from Southern California Gas. All major appliances were moved from gas to high efficiency electric. The resultant home had no natural gas consumption.

Table 5. Appliance Assumptions Before and After Electrification

	Gas – Low Efficiency	Gas – High Efficiency	Electric – High Efficiency
HVAC – Heating	80% AFUE Furnace	98% AFUE Furnace	10 HSPF Heat Pump
HVAC – Cooling	SEER 13 Air Conditioner	SEER 21 Air Conditioner	22 SEER Heat Pump
Water Heating	0.59 EF Gas Storage	0.96 Tankless	3.5 UEF Heat Pump
Cooking	Gas	Gas	Induction Cooktop
Dryer	Gas	Gas	Heat Pump

III. Discussion and Findings

A. Impacts with Current Consumption Profiles

One of the intentions of the proposed fixed charge is to buy down the variable rate ($/kWh) to make electrification more economic and cost competitive against fossil fuel sources (gasoline, natural gas). Lower variable rates require higher fixed charges to maintain a revenue neutral position on the rate base.

In all proposals, there will be a balance point in home consumption against the current rates where the discounted variable rate offsets the fixed component and the proposal is revenue neutral for the customer. At consumption levels above this level, the proposal will result in annual savings. Below this level the fixed rate becomes more dominant and the customer sees increased utility costs. This balance point in usage can be calculated by dividing the increase in the fixed bill component by the decrease in the blended variable rate used by the home. This varies primarily by the wide range in fixed charges according to income level between the proposals.

Here are two examples for SCE territory:

- **PAO:** Under the median household income on a simple TOU-D-4-9 rate with the consumption profile of the mid-line 2500 square-foot home, there is a $383 fixed charge with a $0.059/kWh ($0.336 -$0.277) variable rate discount. This results in a balance point consumption of 6,220 kWh/year where the fixed charge proposal matches the existing rate on the annual bill. Homes using less than that amount will see their bills increase under the proposal, and homes using more will see their bill decrease.

- **IOU:** Under the Joint IOU proposal for a household earning $150,000, the fixed charge increases nearly three-fold to $1,023/year, but with an increase in the variable rate discount to $0.104/kWh. The balance point usage for this household income is 9,836 kWh for the proposed rate to break even with the current rate. The net impact is an 18% bill increase for a 2,500 square-foot home with normal consumption.

There are significant impacts for all three proposals across household income levels, the specific proposal, and annual home energy use. Details can be found in Tables 6-14. We call out the following trends:

- **Marginal Impact:** The proposals are reasonably neutral for the median income home with average home energy use (e.g. 2500 square-foot home with typical use). This is the impact presented in most proposals. Across all three proposals, we find representative savings to be 10% for PG&E, no impact for SCE, and 2% for SDG&E.

- **Significant Negative Impact:** We find the most severe bill increases in small efficient homes with household income of $150k or more. Looking at the TOU-D-4-9 rate structure in SCE territory, we see a 62% rate increase under the IOU proposal. If we specifically look at the fixed charge components, the $1,023 annual fixed charge (IOU proposal) nearly matches the full annual bill of $1,105 under the current rate structure without accounting for the additional energy charges of $765. We see a similar trend across all utility territories with bill increases exceeding 50% across territories under the IOU proposals. The PAO proposal has lower fixed charges partially mitigating this impact, but bill increases of ~10% – 20% are still found under this proposal. In addition to the small single family detached home that was modeled, this energy usage profile is common for apartments, duplexes, townhomes, and condominiums. Specifically, we see many apartment renters as falling into this impacted customer class.

- **Significant Positive Impact:** Homes with high energy use well above the balance point see significant bill savings. If we look at the large 3750 square-foot home with median household income, bill reductions are in the 15-30% range under the IOU proposals, with annual household savings on the order of $1,000. This level of savings is achieved without any investment in efficiency or electrification for this customer group. Simply having high existing energy use associated with the typical needs of a larger home leads to material savings under the proposals.

Table 6. PG&E Bill Impacts for 1250 Square-Foot Home

		E1	E-TOU-C	E-ELEC
Current Rates	Blended Variable Charge $/kWh	$ 0.341	$ 0.340	$ 0.349
	Annual Variable Charge	$ 1,190	$ 1,189	$ 1,219
	Annual Fixed Charge	$ -		$ 180
	Annual Electric Bill	$ 1,190	$ 1,189	$ 1,399
Proposed Rates	Blended Variable Charge ($/kWh)			
	CPUC PAO	$ 0.256	$ 0.267	$ 0.287
	NRDC/TURN	$ 0.240		$ 0.247
	IOU	$ 0.203	$ 0.212	$ 0.228
	Annual Variable Charge			
	CPUC PAO	$ 895	$ 934	$ 1,003
	NRDC/TURN	$ 839		$ 863
	IOU	$ 709	$ 740	$ 796
Bill Impacts	**$84k Income Household**			
	Annual Fixed Charge			
	CPUC PAO	$ 383	$ 382	$ 381
	NRDC/TURN	$ 492		$ 600
	IOU	$ 612	$ 611	$ 610
	Annual Bill			
	CPUC PAO	$ 1,278	$ 1,316	$ 1,384
	NRDC/TURN	$ 1,331	$ -	$ 1,463
	IOU	$ 1,321	$ 1,351	$ 1,406
	Annual Bill Change			
	CPUC PAO	7%	11%	-1%
	NRDC/TURN	12%		5%
	IOU	11%	14%	1%
	$150k Income Household			
	Annual Fixed Charge			
	CPUC PAO	$ 440	$ 440	$ 438
	NRDC/TURN	$ 744		$ 900
	IOU	$ 1,101	$ 1,100	$ 1,098
	Annual Bill			
	CPUC PAO	$ 1,335	$ 1,374	$ 1,441
	NRDC/TURN	$ 1,583	$ -	$ 1,763
	IOU	$ 1,810	$ 1,840	$ 1,894
	Annual Bill Change			
	CPUC PAO	12%	16%	3%
	NRDC/TURN	33%		26%
	IOU	52%	55%	35%

Table 7. PG&E Bill Impacts for 2500 Square-Foot Home

		E1	E-TOU-C	E-ELEC
Current Rates	Blended Variable Charge $/kWh	$ 0.367	$ 0.367	$ 0.350
	Annual Variable Charge	$ 2,318	$ 2,318	$ 2,206
	Annual Fixed Charge	$ -		$ 180
	Annual Electric Bill	$ 2,318	$ 2,318	$ 2,386
Proposed Rates	Blended Variable Charge ($/kWh)			
	CPUC PAO	$ 0.276	$ 0.288	$ 0.288
	NRDC/TURN	$ 0.259		$ 0.248
	IOU	$ 0.219	$ 0.228	$ 0.228
	Annual Variable Charge			
	CPUC PAO	$ 1,742	$ 1,820	$ 1,815
	NRDC/TURN	$ 1,635		$ 1,562
	IOU	$ 1,379	$ 1,441	$ 1,441
Bill Impacts	**$84k Income Household**			
	Annual Fixed Charge			
	CPUC PAO	$ 383	$ 382	$ 381
	NRDC/TURN	$ 492		$ 600
	IOU	$ 612	$ 611	$ 610
	Annual Bill			
	CPUC PAO	$ 2,125	$ 2,202	$ 2,196
	NRDC/TURN	$ 2,127	$ -	$ 2,162
	IOU	$ 1,991	$ 2,052	$ 2,051
	Annual Bill Change			
	CPUC PAO	-8%	-5%	-8%
	NRDC/TURN	-8%		-9%
	IOU	-14%	-11%	-14%
	$150k Income Household			
	Annual Fixed Charge			
	CPUC PAO	$ 440	$ 440	$ 438
	NRDC/TURN	$ 744		$ 900
	IOU	$ 1,101	$ 1,100	$ 1,098
	Annual Bill			
	CPUC PAO	$ 2,182	$ 2,260	$ 2,253
	NRDC/TURN	$ 2,379	$ -	$ 2,462
	IOU	$ 2,480	$ 2,541	$ 2,539
	Annual Bill Change			
	CPUC PAO	-6%	-3%	-6%
	NRDC/TURN	3%		3%
	IOU	7%	10%	6%

Table 8. PG&E Bill Impacts for 3750 Square-Foot Home

		E1	E-TOU-C	E-ELEC
Current Rates	Blended Variable Charge $/kWh	$ 0.393	$ 0.396	$ 0.357
	Annual Variable Charge	$ 4,469	$ 4,505	$ 4,056
	Annual Fixed Charge	$ -		$ 180
	Annual Electric Bill	$ 4,469	$ 4,505	$ 4,236
Proposed Rates	Blended Variable Charge ($/kWh)			
	CPUC PAO	$ 0.295	$ 0.312	$ 0.295
	NRDC/TURN	$ 0.277		$ 0.255
	IOU	$ 0.233	$ 0.247	$ 0.236
	Annual Variable Charge			
	CPUC PAO	$ 3,356	$ 3,545	$ 3,353
	NRDC/TURN	$ 3,153		$ 2,895
	IOU	$ 2,654	$ 2,813	$ 2,679
Bill Impacts	**$84k Income Household**			
	Annual Fixed Charge			
	CPUC PAO	$ 383	$ 382	$ 381
	NRDC/TURN	$ 492		$ 600
	IOU	$ 612	$ 611	$ 610
	Annual Bill			
	CPUC PAO	$ 3,739	$ 3,927	$ 3,734
	NRDC/TURN	$ 3,645	$ -	$ 3,495
	IOU	$ 3,266	$ 3,424	$ 3,289
	Annual Bill Change			
	CPUC PAO	-16%	-13%	-12%
	NRDC/TURN	-18%		-17%
	IOU	-27%	-24%	-22%
	$150k Income Household			
	Annual Fixed Charge			
	CPUC PAO	$ 440	$ 440	$ 438
	NRDC/TURN	$ 744		$ 900
	IOU	$ 1,101	$ 1,100	$ 1,098
	Annual Bill			
	CPUC PAO	$ 3,796	$ 3,985	$ 3,791
	NRDC/TURN	$ 3,897	$ -	$ 3,795
	IOU	$ 3,755	$ 3,913	$ 3,777
	Annual Bill Change			
	CPUC PAO	-15%	-12%	-10%
	NRDC/TURN	-13%		-10%
	IOU	-16%	-13%	-11%

Table 9. SCE Bill Impacts for 1250 Square-Foot Home

		D	TOU-D-4-9	TOU-D-PRIME
Current Rates	Blended Variable Charge $/kWh	$ 0.311	$ 0.316	$ 0.339
	Annual Variable Charge	$ 1,087	$ 1,105	$ 1,184
	Annual Fixed Charge	$ -		$ 155
	Annual Electric Bill	$ 1,087	$ 1,105	$ 1,339
Proposed Rates	Blended Variable Charge ($/kWh)			
	CPUC PAO	$ 0.258	$ 0.260	$ 0.303
	NRDC/TURN	$ 0.240		$ 0.265
	IOU	$ 0.216	$ 0.218	$ 0.255
	Annual Variable Charge			
	CPUC PAO	$ 905	$ 912	$ 1,062
	NRDC/TURN	$ 842		$ 930
	IOU	$ 758	$ 765	$ 895
Bill Impacts	**$84k Income Household**			
	Annual Fixed Charge			
	CPUC PAO	$ 367	$ 367	$ 368
	NRDC/TURN	$ 492		$ 612
	IOU	$ 612	$ 612	$ 612
	Annual Bill			
	CPUC PAO	$ 1,272	$ 1,279	$ 1,430
	NRDC/TURN	$ 1,334	$ -	$ 1,542
	IOU	$ 1,370	$ 1,377	$ 1,507
	Annual Bill Change			
	CPUC PAO	17%	16%	7%
	NRDC/TURN	23%		15%
	IOU	26%	25%	13%
	$150k Income Household			
	Annual Fixed Charge			
	CPUC PAO	$ 422	$ 422	$ 423
	NRDC/TURN	$ 744		$ 912
	IOU	$ 1,022	$ 1,023	$ 1,023
	Annual Bill			
	CPUC PAO	$ 1,327	$ 1,334	$ 1,485
	NRDC/TURN	$ 1,586	$ -	$ 1,842
	IOU	$ 1,780	$ 1,788	$ 1,918
	Annual Bill Change			
	CPUC PAO	22%	21%	11%
	NRDC/TURN	46%		38%
	IOU	64%	62%	43%

Table 10. SCE Bill Impacts for 2500 Square-Foot Home

		D	TOU-D-4-9	TOU-D-PRIME
Current Rates	Blended Variable Charge $/kWh	$ 0.326	$ 0.333	$ 0.337
	Annual Variable Charge	$ 2,058	$ 2,104	$ 2,125
	Annual Fixed Charge	$ -		$ 155
	Annual Electric Bill	$ 2,058	$ 2,104	$ 2,280
Proposed Rates	Blended Variable Charge ($/kWh)			
	CPUC PAO	$ 0.274	$ 0.277	$ 0.305
	NRDC/TURN	$ 0.255		$ 0.267
	IOU	$ 0.228	$ 0.232	$ 0.257
	Annual Variable Charge			
	CPUC PAO	$ 1,713	$ 1,737	$ 1,907
	NRDC/TURN	$ 1,595		$ 1,670
	IOU	$ 1,431	$ 1,456	$ 1,609
Bill Impacts	**$84k Income Household**			
	Annual Fixed Charge			
	CPUC PAO	$ 367	$ 367	$ 368
	NRDC/TURN	$ 492	$ -	$ 612
	IOU	$ 612	$ 612	$ 612
	Annual Bill			
	CPUC PAO	$ 2,080	$ 2,104	$ 2,275
	NRDC/TURN	$ 2,087	$ -	$ 2,282
	IOU	$ 2,043	$ 2,068	$ 2,221
	Annual Bill Change			
	CPUC PAO	1%	0%	0%
	NRDC/TURN	1%		0%
	IOU	-1%	-2%	-3%
	$150k Income Household			
	Annual Fixed Charge			
	CPUC PAO	$ 422	$ 422	$ 423
	NRDC/TURN	$ 744	$ -	$ 912
	IOU	$ 1,022	$ 1,023	$ 1,023
	Annual Bill			
	CPUC PAO	$ 2,135	$ 2,159	$ 2,330
	NRDC/TURN	$ 2,339	$ -	$ 2,582
	IOU	$ 2,453	$ 2,479	$ 2,632
	Annual Bill Change			
	CPUC PAO	4%	3%	2%
	NRDC/TURN	14%		13%
	IOU	19%	18%	15%

Table 11. SCE Bill Impacts for 3750 Square-Foot Home

		D	TOU-D-4-9	TOU-D-PRIME
Current Rates	Blended Variable Charge $/kWh	$ 0.346	$ 0.358	$ 0.332
	Annual Variable Charge	$ 3,934	$ 4,076	$ 3,774
	Annual Fixed Charge			$ 155
	Annual Electric Bill	$ 3,934	$ 4,076	$ 3,929
Proposed Rates	Blended Variable Charge ($/kWh)			
	CPUC PAO	$ 0.298	$ 0.307	$ 0.309
	NRDC/TURN	$ 0.278		$ 0.271
	IOU	$ 0.249	$ 0.257	$ 0.262
	Annual Variable Charge			
	CPUC PAO	$ 3,275	$ 3,370	$ 3,392
	NRDC/TURN	$ 3,054		$ 2,977
	IOU	$ 2,730	$ 2,825	$ 2,870
Bill Impacts	**$84k Income Household**			
	Annual Fixed Charge			
	CPUC PAO	$ 367	$ 367	$ 368
	NRDC/TURN	$ 492	$ -	$ 612
	IOU	$ 612	$ 612	$ 612
	Annual Bill			
	CPUC PAO	$ 3,642	$ 3,737	$ 3,760
	NRDC/TURN	$ 3,546	$ -	$ 3,589
	IOU	$ 3,342	$ 3,437	$ 3,482
	Annual Bill Change			
	CPUC PAO	-7%	-8%	-4%
	NRDC/TURN	-10%		-9%
	IOU	-15%	-16%	-11%
	$150k Income Household			
	Annual Fixed Charge			
	CPUC PAO	$ 422	$ 422	$ 423
	NRDC/TURN	$ 744	$ -	$ 912
	IOU	$ 1,022	$ 1,023	$ 1,023
	Annual Bill			
	CPUC PAO	$ 3,697	$ 3,792	$ 3,815
	NRDC/TURN	$ 3,798	$ -	$ 3,889
	IOU	$ 3,752	$ 3,848	$ 3,893
	Annual Bill Change			
	CPUC PAO	-6%	-7%	-3%
	NRDC/TURN	-3%		-1%
	IOU	-5%	-6%	-1%

Table 12. SDG&E Bill Impacts for 1250 Square-Foot Home

		DR	TOU-DR1	TOU-E-ELEC
Current Rates	Blended Variable Charge $/kWh	$ 0.452	$ 0.462	$ 0.429
	Annual Variable Charge	$ 1,455	$ 1,486	$ 1,378
	Annual Fixed Charge			$ 192
	Annual Electric Bill	$ 1,455	$ 1,486	$ 1,570
Proposed Rates	Blended Variable Charge ($/kWh)			
	CPUC PAO	$ 0.382	$ 0.391	$ 0.408
	NRDC/TURN	$ 0.370		$ 0.365
	IOU	$ 0.271	$ 0.281	$ 0.283
	Annual Variable Charge			
	CPUC PAO	$ 1,228	$ 1,258	$ 1,312
	NRDC/TURN	$ 1,190		$ 1,175
	IOU	$ 871	$ 903	$ 911
Bill Impacts	**$84k Income Household**			
	Annual Fixed Charge			
	CPUC PAO	$ 445	$ 444	$ 443
	NRDC/TURN	$ 492		$ 612
	IOU	$ 860	$ 857	$ 855
	Annual Bill			
	CPUC PAO	$ 1,673	$ 1,702	$ 1,755
	NRDC/TURN	$ 1,682	$ -	$ 1,787
	IOU	$ 1,731	$ 1,760	$ 1,766
	Annual Bill Change			
	CPUC PAO	15%	15%	12%
	NRDC/TURN	16%		14%
	IOU	19%	18%	12%
	$150k Income Household			
	Annual Fixed Charge			
	CPUC PAO	$ 512	$ 511	$ 510
	NRDC/TURN	$ 744		$ 912
	IOU	$ 1,505	$ 1,500	$ 1,496
	Annual Bill			
	CPUC PAO	$ 1,740	$ 1,769	$ 1,822
	NRDC/TURN	$ 1,934	$ -	$ 2,087
	IOU	$ 2,376	$ 2,403	$ 2,407
	Annual Bill Change			
	CPUC PAO	20%	19%	16%
	NRDC/TURN	33%		33%
	IOU	63%	62%	53%

Table 13. SDG&E Bill Impacts for 2500 Square-Foot Home

		DR	TOU-DR1	TOU-E-ELEC
Current Rates	Blended Variable Charge $/kWh	$ 0.480	$ 0.492	$ 0.430
	Annual Variable Charge	$ 2,719	$ 2,789	$ 2,438
	Annual Fixed Charge			$ 192
	Annual Electric Bill	$ 2,719	$ 2,789	$ 2,630
Proposed Rates	Blended Variable Charge ($/kWh)			
	CPUC PAO	$ 0.405	$ 0.416	$ 0.410
	NRDC/TURN	$ 0.393		$ 0.367
	IOU	$ 0.287	$ 0.298	$ 0.285
	Annual Variable Charge			
	CPUC PAO	$ 2,296	$ 2,359	$ 2,322
	NRDC/TURN	$ 2,229		$ 2,080
	IOU	$ 1,626	$ 1,689	$ 1,614
Bill Impacts	**$84k Income Household**			
	Annual Fixed Charge			
	CPUC PAO	$ 445	$ 444	$ 443
	NRDC/TURN	$ 492	$ -	$ 612
	IOU	$ 860	$ 857	$ 855
	Annual Bill			
	CPUC PAO	$ 2,741	$ 2,803	$ 2,765
	NRDC/TURN	$ 2,721	$ -	$ 2,692
	IOU	$ 2,486	$ 2,546	$ 2,469
	Annual Bill Change			
	CPUC PAO	1%	1%	5%
	NRDC/TURN	0%		2%
	IOU	-9%	-9%	-6%
	$150k Income Household			
	Annual Fixed Charge			
	CPUC PAO	$ 512	$ 511	$ 510
	NRDC/TURN	$ 744	$ -	$ 912
	IOU	$ 1,505	$ 1,500	$ 1,496
	Annual Bill			
	CPUC PAO	$ 2,808	$ 2,870	$ 2,832
	NRDC/TURN	$ 2,973	$ -	$ 2,992
	IOU	$ 3,131	$ 3,189	$ 3,110
	Annual Bill Change			
	CPUC PAO	3%	3%	8%
	NRDC/TURN	9%		14%
	IOU	15%	14%	18%

Table 14. SDG&E Bill Impacts for 3750 Square-Foot Home

		DR	TOU-DR1	TOU-E-ELEC
Current Rates	Blended Variable Charge $/kWh	$ 0.517	$ 0.534	$ 0.437
	Annual Variable Charge	$ 4,947	$ 5,112	$ 4,180
	Annual Fixed Charge			$ 192
	Annual Electric Bill	$ 4,947	$ 5,112	$ 4,372
Proposed Rates	Blended Variable Charge ($/kWh)			
	CPUC PAO	$ 0.436	$ 0.452	$ 0.416
	NRDC/TURN	$ 0.425		$ 0.373
	IOU	$ 0.308	$ 0.323	$ 0.291
	Annual Variable Charge			
	CPUC PAO	$ 4,177	$ 4,325	$ 3,982
	NRDC/TURN	$ 4,067		$ 3,575
	IOU	$ 2,951	$ 3,091	$ 2,788
Bill Impacts	**$84k Income Household**			
	Annual Fixed Charge			
	CPUC PAO	$ 445	$ 444	$ 443
	NRDC/TURN	$ 492	$ -	$ 612
	IOU	$ 860	$ 857	$ 855
	Annual Bill			
	CPUC PAO	$ 4,622	$ 4,769	$ 4,425
	NRDC/TURN	$ 4,559	$ -	$ 4,187
	IOU	$ 3,811	$ 3,948	$ 3,643
	Annual Bill Change			
	CPUC PAO	-7%	-7%	1%
	NRDC/TURN	-8%		-4%
	IOU	-23%	-23%	-17%
	$150k Income Household			
	Annual Fixed Charge			
	CPUC PAO	$ 512	$ 511	$ 510
	NRDC/TURN	$ 744	$ -	$ 912
	IOU	$ 1,505	$ 1,500	$ 1,496
	Annual Bill			
	CPUC PAO	$ 4,689	$ 4,836	$ 4,492
	NRDC/TURN	$ 4,811	$ -	$ 4,487
	IOU	$ 4,456	$ 4,591	$ 4,284
	Annual Bill Change			
	CPUC PAO	-5%	-5%	3%
	NRDC/TURN	-3%		3%
	IOU	-10%	-10%	-2%

The bubble charts in Figures 5-7 demonstrate the winners and losers under the three modeled proposals. The size of the bubbles represents the number of customers in each of the customer groups from the 2019 CEC study on California residential electricity consumption.

Apartment residents with low electricity usage would face higher bills, as would customers in small single-family homes. Single-family homes with high existing electricity consumption would experience significant decreases in their bills. As a general rule, small efficient homes would subsidize larger, less-efficient homes. Looking back at Figure 4, groups A and C would have bill increases and group B would have a bill reduction.

Figure 5. Impacts by Dwelling Type and Income Under Cal Advocates Proposal

$84,000 Annual Household Income | $150,000 Annual Household Income

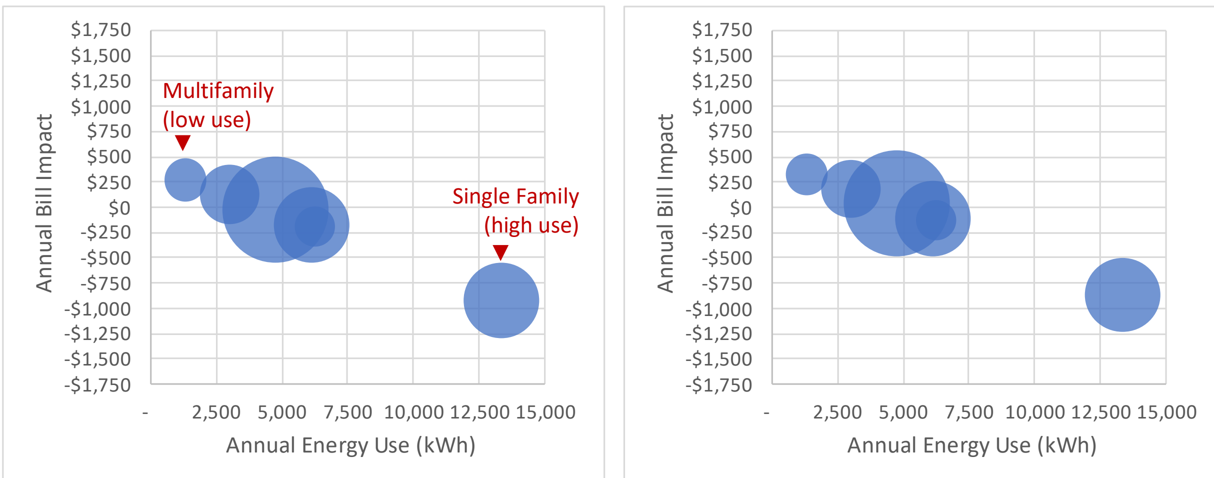


Figure 6. Impacts by Dwelling Type and Income Under NRDC/TURN Proposal

$84,000 Annual Household Income | $150,000 Annual Household Income

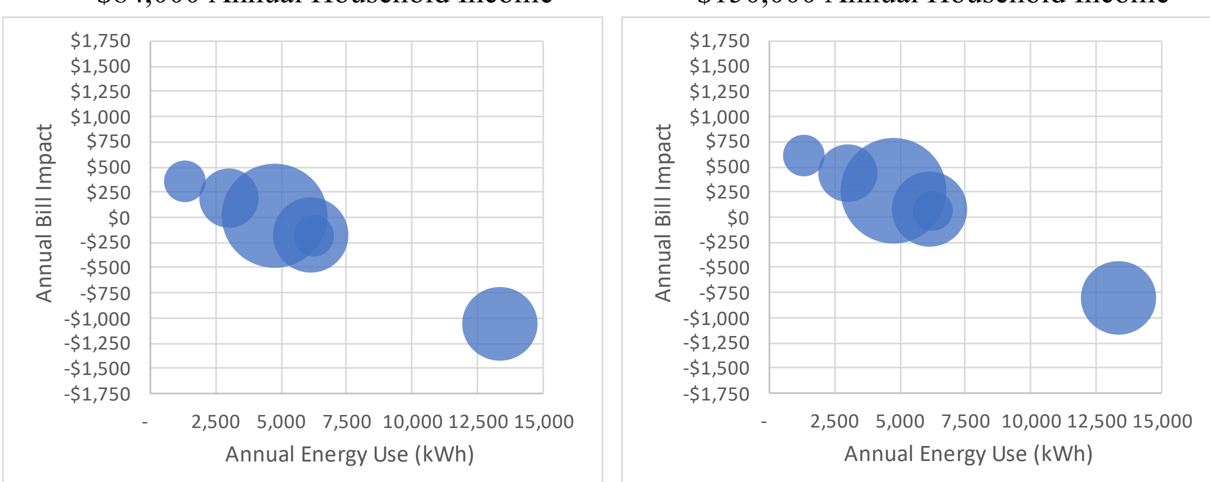
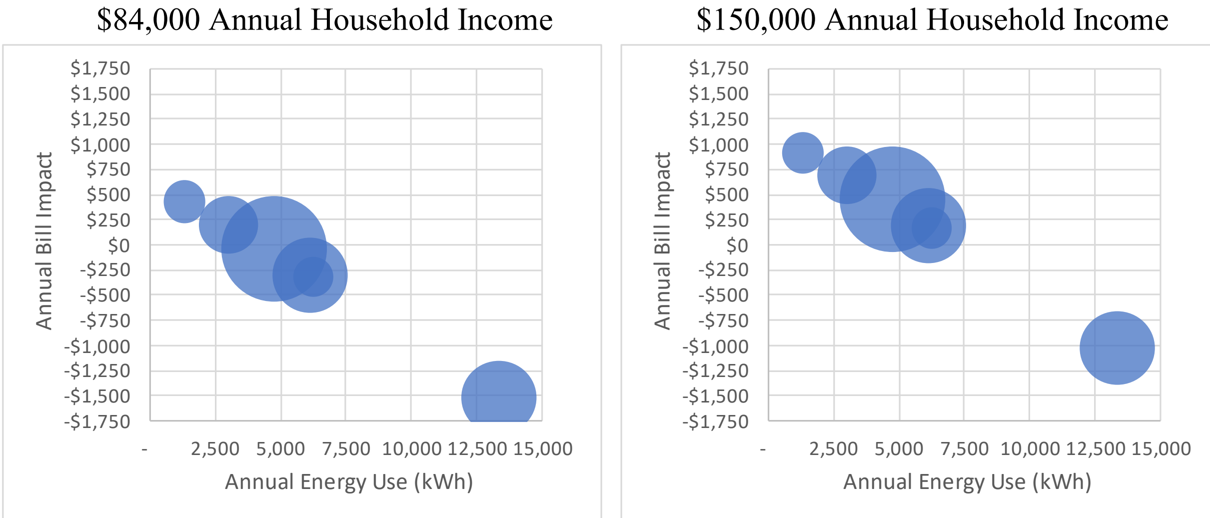


Figure 7. Impacts by Dwelling Type and Income Under Joint IOU Proposal



B. Impacts for CARE Customers

All proposals materially decrease the fixed rate component for CARE customers to a fraction of the non-CARE burden. We limited the CARE modeling to only the non-TOU rate structures after seeing that the savings for TOU and non-TOU rate schedules closely tracked for non-CARE customers. While we modeled all three house profiles, we believe the 1,250-2,500 square-foot homes to be most representative.

Within these home load profiles, we see the new rate proposals as being generally advantageous. The IOU proposal for the smallest home in PG&E territory results in a 4% bill increase, but most customer types see bill decreases.

Table 15. Bill Impacts for 1250 Square-Foot Home on CARE Rates

		PG&E E1	SCE D	SDG&E DR
Existing Rates	Blended Variable Charge $/kWh	$ 0.221	$ 0.210	$ 0.271
	Annual Variable Charge	$ 773	$ 734	$ 946
	Annual Fixed Charge			
	Annual Electric Bill	$ 773	$ 734	$ 946
Proposed Rates	Blended Variable Charge ($/kWh)			
	CPUC PAO	$ 0.166	$ 0.168	$ 0.233
	NRDC/TURN	$ 0.150	$ 0.160	$ 0.230
	IOU	$ 0.128	$ 0.144	$ 0.161
	Annual Variable Charge			
	CPUC PAO	$ 580	$ 588	$ 814
	NRDC/TURN	$ 524	$ 561	$ 804
	IOU	$ 447	$ 502	$ 563
Bill Impacts	**$44k Household**			
	Annual Fixed Charge			
	CPUC PAO	$ 122	$ 130	$ 164
	NRDC/TURN	$ 60	$ 60	$ 60
	IOU	$ 360	$ 240	$ 408
	Annual Bill			
	CPUC PAO	$ 702	$ 718	$ 978
	NRDC/TURN	$ 584	$ 621	$ 864
	IOU	$ 807	$ 742	$ 971
	Annual Bill Change			
	CPUC PAO	-9%	-2%	3%
	NRDC/TURN	-24%	-15%	-9%
	IOU	4%	1%	3%

Table 16. Bill Impacts for 2500 Square-Foot Home on CARE Rates

		PG&E E1	SCE D	SDG&E DR
Existing Rates	Blended Variable Charge $/kWh	$ 0.239	$ 0.220	$ 0.280
	Annual Variable Charge	$ 1,507	$ 1,389	$ 1,768
	Annual Fixed Charge			
	Annual Electric Bill	$ 1,507	$ 1,389	$ 1,768
Proposed Rates	Blended Variable Charge ($/kWh)			
	CPUC PAO	$ 0.179	$ 0.185	$ 0.241
	NRDC/TURN	$ 0.163	$ 0.171	$ 0.237
	IOU	$ 0.138	$ 0.150	$ 0.167
	Annual Variable Charge			
	CPUC PAO	$ 1,130	$ 1,168	$ 1,520
	NRDC/TURN	$ 1,027	$ 1,068	$ 1,496
	IOU	$ 872	$ 949	$ 1,051
Bill Impacts	**$44k Household**			
	Annual Fixed Charge			
	CPUC PAO	$ 122	$ 130	$ 164
	NRDC/TURN	$ 60	$ 60	$ 60
	IOU	$ 360	$ 240	$ 408
	Annual Bill			
	CPUC PAO	$ 1,252	$ 1,298	$ 1,684
	NRDC/TURN	$ 1,087	$ 1,128	$ 1,556
	IOU	$ 1,232	$ 1,189	$ 1,459
	Annual Bill Change			
	CPUC PAO	-17%	-7%	-5%
	NRDC/TURN	-28%	-19%	-12%
	IOU	-18%	-14%	-17%

Table 17. Bill Impacts for 3750 Square-Foot Home on CARE Rates

		PG&E E1	SCE D	SDG&E DR
Existing Rates	Blended Variable Charge $/kWh	$ 0.255	$ 0.234	$ 0.283
	Annual Variable Charge	$ 2,905	$ 2,656	$ 3,215
	Annual Fixed Charge			
	Annual Electric Bill	$ 2,905	$ 2,656	$ 3,215
Proposed Rates	Blended Variable Charge ($/kWh)			
	CPUC PAO	$ 0.191	$ 0.196	$ 0.243
	NRDC/TURN	$ 0.175	$ 0.187	$ 0.238
	IOU	$ 0.148	$ 0.160	$ 0.168
	Annual Variable Charge			
	CPUC PAO	$ 2,177	$ 2,231	$ 2,763
	NRDC/TURN	$ 1,988	$ 2,056	$ 2,708
	IOU	$ 1,681	$ 1,818	$ 1,911
Bill Impacts	**$44k Household**			
	Annual Fixed Charge			
	CPUC PAO	$ 122	$ 130	$ 164
	NRDC/TURN	$ 60	$ 60	$ 60
	IOU	$ 360	$ 240	$ 408
	Annual Bill			
	CPUC PAO	$ 2,299	$ 2,361	$ 2,927
	NRDC/TURN	$ 2,048	$ 2,116	$ 2,768
	IOU	$ 2,041	$ 2,058	$ 2,319
	Annual Bill Change			
	CPUC PAO	-21%	-11%	-9%
	NRDC/TURN	-30%	-20%	-14%
	IOU	-30%	-23%	-28%

C. Impacts for Customers Adopting Electrification

In the previous section, we assessed the annual bill impacts for each of the rate proposals to determine impact by utility, income class, energy use, and other metrics for customers that do not engage in fuel switching. As previously discussed, there are customer types that benefit from the proposals and those that are negatively impacted. The specific impact on each customer is absorbed upon rate implementation before significant levels of electrification occur. Any customer that sees bill savings under the proposals is under no obligation to invest those savings in electrification. The benefits and drawbacks of new fixed charges are fully absorbed in this initial phase.

With the new rates in place that have a lower variable component (subsidized through the fixed charge), we assess if these reduced rates are sufficient to incentivize customers to invest in electrification. The key metric in such an analysis is the annual bill savings in moving appliances from natural gas onto these new reduced electric rates. At a bare minimum, electrification cannot result in increased utility bills. More practically, there must be sufficient bill savings to justify the equipment upgrades with a reasonable payback period.

To assess changes in consumption, baseline pre-electrification home loads and additional electrification loads were binned by month and TOU period to see usage and cost within the existing rate structure. The most important insight is that winter off-peak is nearly 2/3 of increased usage for electrification. This is driven by winter off-peak being the hours of heaviest heat pump use for both space heating and water heating. Equally interesting, only 5% of the usage in electrification falls in the summer on-peak and mid-peak periods.

Table 18. Pre-Electrification Residential Load by TOU Period

	Summer			Winter			
	On-Peak	Mid-Peak	Off-Peak	On-Peak	Mid-Peak	Off-Peak	Total
Jan				149	91	297	537
Feb				129	81	256	465
Mar				112	89	241	441
Apr				97	82	222	401
May				149	93	211	453
Jun	223	118	212				553
Jul	310	156	257				723
Aug	307	152	243				702
Sep	246	130	219				594
Oct				186	108	219	513
Nov				123	70	223	415
Dec				145	85	283	514
Annual Total	1,086	555	931	1,090	699	1,951	6,311
Annual Pct	17%	9%	15%	17%	11%	31%	

Table 19. Additional Load from Electrification by TOU Period

	Summer			Winter			
	On-Peak	Mid-Peak	Off-Peak	On-Peak	Mid-Peak	Off-Peak	Total
Jan				130	127	605	861
Feb				79	73	410	562
Mar				59	65	344	468
Apr				57	47	242	346
May				40	26	115	181
Jun	43	22	63				127
Jul	25	25	71				121
Aug	21	13	52				87
Sep	19	21	107				147
Oct				57	47	242	346
Nov				54	51	245	349
Dec				91	107	455	653
Annual Total	108	81	294	567	543	2,657	4,249
Annual Pct	3%	2%	7%	13%	13%	63%	

Table 20. Post-Electrification Residential Load by TOU Period

	Summer			Winter			
	On-Peak	Mid-Peak	Off-Peak	On-Peak	Mid-Peak	Off-Peak	Total
Jan				279	218	902	1398
Feb				208	153	666	1028
Mar				171	154	584	909
Apr				154	130	463	747
May				188	119	326	633
Jun	266	140	274				680
Jul	336	180	328				844
Aug	328	165	296				789
Sep	265	151	326				741
Oct				244	156	460	860
Nov				177	120	467	764
Dec				236	193	738	1167
Annual Total	1,194	636	1,224	1,657	1,242	4,608	10,560
Annual Pct	11%	6%	12%	16%	12%	44%	

When converting from modern high efficiency gas appliances, there is no case under any of the evaluated rate proposals where electrification results in annual bill savings for customers. The target electricity rate necessary to break even against modern high efficiency gas appliances is $0.147/kWh - $0.176/kWh. This rate is not achieved under any of the evaluated proposals.

With legacy low-efficiency gas appliances there is annual savings in PG&E territory under the IOU and NRDC/TURN proposals, but they are marginal. Assuming a maximum 10-year simple payback for residential consumers to be willing to adopt, the turnkey cost (equipment plus installation) for whole home electrification would need to be less than $2,170, post all incentives, to break even. For existing homes, actual installed costs for the modeled electric appliances are likely to be in excess of $20,000.

Table 21. Target Rates for Electrification

	PG&E	SCE/SCG	SDG&E	PG&E	SCE/SCG	SDG&E
Gas Usage & Cost	Low Efficiency Gas Appliances			High Efficiency Gas Appliances		
Space Heating (therms/yr)	334	96	76	256	73	57
Water Heating (therms/yr)	159	146	149	94	85	87
Appliances (therms/yr)	57	57	57	57	57	57
Annual Gas Usage (Therms)	550	299	281	407	214	201
Annual Gas Variable Charges	$ 941	$ 388	$ 549	$ 663	$ 279	$ 392
Annual Gas Fixed Meter Charges		$ 60			$ 60	
Annual Gas Total Charges	$ 941	$ 448	$ 549	$ 663	$ 339	$ 392
Electrification Use (kWh)	4,080	2,299	2,224	4,080	2,299	2,224
Breakeven Rate ($/kWh)	$ 0.231	$ 0.195	$ 0.247	$ 0.162	$ 0.147	$ 0.176
Rate Proposal						
Cal Advocates	$ 0.237	$ 0.249	$ 0.362	$ 0.237	$ 0.249	$ 0.362
TURN	$ 0.198	$ 0.211	$ 0.317	$ 0.198	$ 0.211	$ 0.317
IOU	$ 0.177	$ 0.201	$ 0.236	$ 0.177	$ 0.201	$ 0.236

IV. Redesigning TOU for Electrification

Our analysis indicates that modifying TOU rate structures would be more beneficial to electrification than increased fixed charges. We modeled a TOU structure that is revenue neutral for a typical customer and demonstrate that it would result in energy bill savings, combining gas and electric bills, compared to the existing electrification rate. We recognize that this rate design is not designed to be revenue neutral for the residential class as a whole. This analysis should be replicated with a revenue neutral rate design that is similar in structure.

As stated above, 2/3 of increased usage for electrification is during winter off-peak and only 5% is in summer on-peak and mid-peak periods. For this reason, highly differentiating the rate structure would benefit electrification while avoiding the problems of inequity among households with the more blunt instrument of significant monthly fixed charges that go beyond the cost of customer access.

We created modified TOU pricing, using the PG&E E-ELEC tariff as an example. We reduce the winter off-peak to $0.08/kWh to enable electrification, with a resulting increase in the summer on-peak rate to $0.874/kWh. Other winter rates have a moderate discount and other summer rates see a moderate increase to balance revenue for the baseline home at the same $0.349/kWh blended rate for this typical customer.

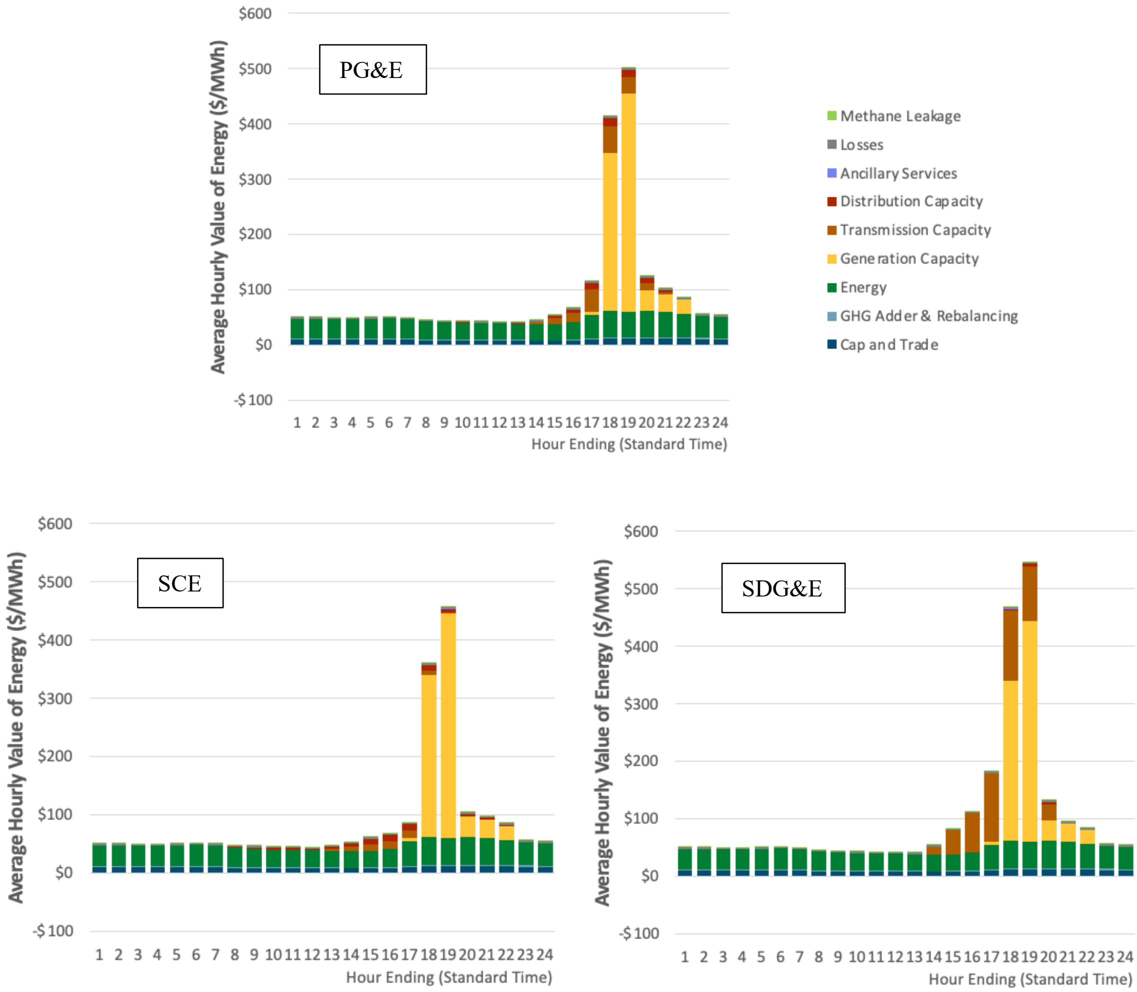
As shown in Table 22, the existing E-ELEC rate structure has a blended rate of $0.349/kWh for the existing home profile and $0.298/kWh for the off peak and winter weighted electrification. Because electrification is winter off-peak biased, the proposed rate decreases the blended rate from $0.298 to $0.163/kWh for additional electrification load, and from $0.329/kWh to $0.273/kWh for the total load after electrification. This would create greater savings than any of the assessed fixed charge proposals for electrification of gas loads. The $681 additional electricity cost after electrification would be less than the pre-electrification average gas cost of $802 that represents the mid-point between our low and high efficiency appliance scenarios.

Table 22. Bill Impacts of Electrification Under Modified TOU

		Existing		Modified		
Pre-Electrification Baseline						
		Total	Price	Total	Price	Pct of Usage
Summer	On-Peak	$ 593	$ 0.546	$ 949	$ 0.874	17%
	Mid-Peak	$ 214	$ 0.385	$ 342	$ 0.615	9%
	Off-Peak	$ 305	$ 0.328	$ 427	$ 0.459	15%
Winter	On-Peak	$ 343	$ 0.315	$ 257	$ 0.236	17%
	Mid-Peak	$ 205	$ 0.293	$ 72	$ 0.103	11%
	Off-Peak	$ 544	$ 0.279	$ 156	$ 0.080	31%
	Total	$ 2,204	$ 0.349	$ 2,203	$ 0.349	
Additional Load from Electrification						
		Total	Price	Total	Price	Pct of Usage
Summer	On-Peak	$ 59	$ 0.546	$ 95	$ 0.874	3%
	Mid-Peak	$ 31	$ 0.385	$ 50	$ 0.615	2%
	Off-Peak	$ 96	$ 0.328	$ 135	$ 0.459	7%
Winter	On-Peak	$ 178	$ 0.315	$ 134	$ 0.236	13%
	Mid-Peak	$ 159	$ 0.293	$ 56	$ 0.103	13%
	Off-Peak	$ 741	$ 0.279	$ 213	$ 0.080	63%
	Total	$ 1,265	$ 0.298	$ 681	$ 0.160	
Total Load with Electrification						
		Total	Price	Total	Price	Pct of Usage
Summer	On-Peak	$ 652	$ 0.546	$ 1,044	$ 0.874	11%
	Mid-Peak	$ 245	$ 0.385	$ 391	$ 0.615	6%
	Off-Peak	$ 401	$ 0.328	$ 562	$ 0.459	12%
Winter	On-Peak	$ 522	$ 0.315	$ 391	$ 0.236	16%
	Mid-Peak	$ 364	$ 0.293	$ 127	$ 0.103	12%
	Off-Peak	$ 1,286	$ 0.279	$ 369	$ 0.080	44%
	Total	$ 3,469	$ 0.329	$ 2,884	$ 0.273	

Because this is additional load, it results in increased electricity sales. The $0.08/kWh winter off-peak rate in our modified TOU example is higher than utility avoided costs of energy during off-peak hours. Total avoided costs in the Avoided Cost Calculator for off-peak hours, averaged across all summer and winter months, is approximately $0.06/kWh, as shown in Figure 8. This rate would not be scaled up to recover legacy costs, but it would recover current avoided costs and would be an effective tool to encourage electrification.

Figure 8. Hourly Avoided Costs in the Avoided Cost Calculator[3]



Our approach and findings using a highly differentiated TOU structure are in line with those from a January 2023 study by Brattle Group analysts.[4] This study evaluated the cost effectiveness of electrification of the heating load for 80 homes under an existing flat rate structure as well as a rate structure with a higher fixed charge and another with highly differentiated TOU rates. The study found that the highly differentiated TOU delivered over twice the annual customer savings ($521 vs $221), reducing the system payback by over half while remaining revenue neutral for the utility. The preferred TOU structure included a marginal 28% increase in the fixed rate component, as compared to a 250% increase in the less effective fixed charge proposal.

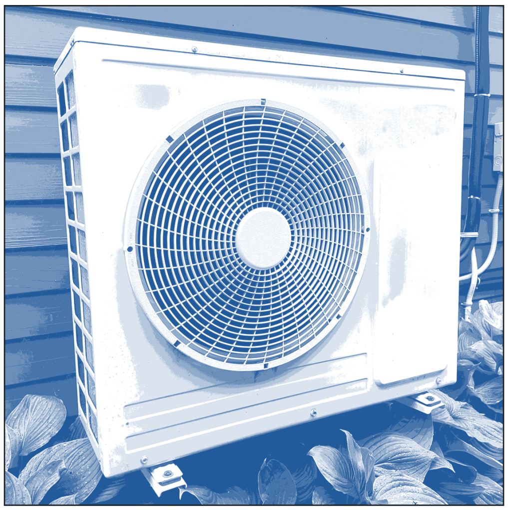
[3] Summary tables from the 2022 ACC Electric Model for 2024 start year and a 1 year levelization period. Representative climate zones are CZ 12 for PG&E, CZ 10 for SCE, and CZ 10 for SDG&E.
[4] Energy Systems Innovation Group, "Heat Pump-Friendly Cost-Based Rate Designs," January 2023, available at https://www.esig.energy/wp-content/uploads/2023/01/Heat-Pump%E2%80%93Friendly-Cost-Based-Rate-Designs.pdf.

Attachment B

WHITE PAPER

Heat Pump–Friendly Cost-Based Rate Designs

By Sanem Sergici, Akhilesh Ramakrishnan, Goksin Kavlak, Adam Bigelow, and Megan Diehl, The Brattle Group



The economics of heat pumps relative to natural gas heating will be an important driver of customer adoption of these technologies and will determine the extent to which ambitious building electrification goals can be met in a timely manner. If the operating costs for heat pumps turn out to be favorable compared to the operating costs for natural gas equipment, it is possible to see a significant uptake of the heat pumps even before the technology cost declines. In this white paper, we examine the role of alternative "cost-based" and "cost-reflective" electricity rate designs in improving the economics of heat pumps by reducing their operating costs. We use a proprietary dataset of gas and electricity usage for 80 single-family residential customers of a large investor-owned utility for modeling customers' electric and gas heating bills before and after electrification. We find that the operating cost gap is positive for all 80 customers under the default electricity rate (energy costs for operating the heating equipment are higher post-electrification). However, moving to one of the three alternative rates flips all 80 customers from a positive cost gap to a negative cost gap, in which energy costs for operating the heating equipment are lower post-electrification.

A White Paper from the Energy Systems Integration Group's Retail Pricing Task Force

January 2023

ESIG
ENERGY SYSTEMS INTEGRATION GROUP

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Sanem Sergici is a Principal, Akhilesh Ramakrishnan and Goksin Kavlak are Associates, and Adam Bigelow and Megan Diehl are Research Analysts with The Brattle Group. The views expressed here are their own.

About ESIG

The Energy Systems Integration Group is a nonprofit organization that marshals the expertise of the electricity industry's technical community to support grid transformation and energy systems integration and operation. More information is available at https://www.esig.energy.

ESIG Publications Available Online

This white paper is available at https://www.esig.energy/aligning-retail-pricing-with-grid-needs. All ESIG publications can be found at https://www.esig.energy/reports-briefs.

Get in Touch

To learn more about the topics discussed in this white paper or for more information about the Energy Systems Integration Group, please send an email to info@esig.energy.

Suggested Citation

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Introduction

Residential and commercial buildings consume large amounts of energy for cooling, heating, and lighting needs. In the U.S., the building sector has been contributing roughly 30 percent of total greenhouse gas emissions. According to a recent United Nations report, the building sector was responsible for 38 percent of CO_2 emissions globally in 2019 (UNEP/GABC, 2020). Given the magnitude of building sector emissions, the decarbonization of this sector, mainly through heating electrification using heat pumps, constitutes a key component of state and city climate action plans.

The economics of heat pumps relative to natural gas heating will be an important driver of customer adoption of these technologies, and thereby determine the extent to which ambitious building electrification goals can be met in a timely manner. While heat pumps are much more efficient in converting energy into heating output than efficient natural gas boilers and furnaces, they also have higher initial capital costs.[1] Heat pumps' operating costs can also be higher than natural gas equipment depending on climate, equipment type and efficiency, electricity rates, and rate structures. Even in regions where heat pump operating costs are lower than operating costs for natural gas equipment, the operating cost gap will need to be significant to offset the upfront cost premium and return a reasonable payback for customers who are in the market to purchase a new heating system.

According to a recent United Nations report, the building sector was responsible for 38 percent of CO_2 emissions globally in 2019. Given the magnitude of building sector emissions, the decarbonization of this sector, mainly through heating electrification using heat pumps, constitutes a key component of state and city climate action plans.

Technology costs are expected to come down over time, and heat pumps will likely reach cost-parity with natural gas equipment eventually. However, if the operating costs for heat pumps turn out to be favorable compared to the operating costs for natural gas equipment, it is possible to see a significant uptake of the heat pumps even before the technology cost declines. In this white paper, we examine the role of alternative "cost-based" and "cost-reflective" rate designs in improving the economics of heat pumps by reducing their operating costs. We define cost-based rates as rates that recover a utility's entire cost of providing service to a class of customers, and define cost-reflective rates as rates that send efficient price signals reflective of the extent to which a change in a customer's timing or magnitude of usage would change overall utility costs. Default utility rates for the residential class typically consist of a small fixed monthly charge and a volumetric charge on kWh consumption. This type of rate is typically cost-based because it recovers the utility's revenue requirement for the class, but not very cost-reflective because transmission and distribution costs are not driven by kWh consumption.

1 A heat pump can deliver around 300 percent more energy in the form of heat than it consumes over the course of the heating season. An efficient gas boiler or furnace can convert about 95 percent of input energy into heating output.

This analysis considers alternative rates that are cost-based in the sense that they would collect the same amount of revenue from the average customer (who has not yet electrified) as the default rate. Therefore, the rates need not be limited to electric heating customers but could be designed for the residential class and made available to all residential customers (not just the electric heating customers) on a voluntary basis. In addition, all three alternative rates put forth in this analysis incorporate more cost-reflective components than the default rate. This includes components such as higher fixed charges, time-varying volumetric charges, and time-varying demand charges, all of which are more reflective of utility cost causation than flat volumetric charges. In other words, we are not advancing differing, subsidized rates for different end uses here. Rather, we are assessing the broader appeal of these structures, finding that there are alternative cost-based rates that could be made available to all customers, with customers with different appliances and use cases opting into these rates if the structure of the rates is better aligned with their usage profiles.

This white paper is structured in four sections. The second section describes our analytical approach to modeling customers' gas and electric usage for heating. The third section describes our modeling results from calculating heat pump and natural gas boiler heating bills under various rate structures. The fourth section concludes with the key takeaways from the white paper.

This analysis considers alternative rates that are cost-based in the sense that they would collect the same amount of revenue from the average customer (who has not yet electrified) as the default rate. Therefore, the rates need not be limited to electric heating customers but could be designed for the residential class and made available to all residential customers (not just the electric heating customers) on a voluntary basis.

Analytical Approach

The following general operating characteristics of heat pumps show the potential use of alternative cost-based rate designs that can help improve the economics of heat pumps:

- Heat pumps lead to higher electricity consumption (compared to using other fuels for heating) for a given household; therefore, lower volumetric rates would favor heat pump usage, all else equal.
- Most of the heat pump load materializes in the non-summer months; therefore, seasonally differentiated rates in summer-peaking systems (with lower non-summer rates) might favor heat pump usage, all else equal.
- A significant portion of the heat pump load tends to fall into off-peak periods (periods of relatively low system-wide electricity usage), which implies that various cost-based time-of-use (TOU) rates might favor heat pump usage, all else equal.
- Heat pumps tend to have high load factors,[2] which implies that demand-based rates might favor heat pump usage, all else equal.

Given these characteristics of heat pumps, we modeled heating requirements of a sample of single-family residential customers and computed their heating bills under heat pump and natural gas heating scenarios using alternative rate designs. This approach allows us to answer two key questions:

1. **What is the operating cost gap between gas heat and electric heat when using default rate structures?**

We modeled heating requirements of a sample of single-family residential customers and computed their heating bills under heat pump and natural gas heating scenarios using alternative rate designs.

2. **Do heat pump operating costs decline enough when using alternative cost-based electricity rate structures to mitigate the cost gap?**

We studied these operating cost gap metrics using a proprietary dataset of natural gas and electricity usage for 80 single-family residential customers of a large investor-owned utility with relatively high electricity rates and cold winters. Our analysis consisted of four steps:

Step 1: Estimate heating requirements for each customer by applying a regression model to their monthly gas usage. The regression model uses heating degree days (HDDs) to estimate the fraction of each customer's total gas usage that is used for space heating.[3]

Step 2: Model a hypothetical stand-alone cold-climate heat pump installed to replace each customer's natural gas heating system. The heat pump's hourly electric load profile was modeled using the customer's monthly heating requirement, historical hourly temperature data, and assumed heat pump technical specifications. This heat

2 Load factor refers to the ratio of the average hourly usage to the peak hourly usage for an appliance or for a customer. Higher load factors mean a usage profile is less "peaky."

3 Heating degrees are defined as the difference between an assumed set point (e.g., 65°F) and the outdoor temperature. Heating energy use is directly proportional to heating degrees.

pump load was then added to their actual electric load from the usage data to construct a "post-electrification" load profile.

Step 3: Calculate each customer's gas and electricity bills using both their actual "pre-electrification" usage and modeled "post-electrification" usage. We assumed all customers remain connected to the natural gas system to serve other end uses post-electrification (water heating, cooking, etc.). While gas bills were calculated using the default gas rate, electricity bills were calculated for four different rate structures including a flat default rate with a low fixed charge, a flat rate with a higher fixed charge, a seasonal volumetric TOU day/night rate, and a seasonal demand-based TOU rate. These are explained in detail in the sections below.

Step 4: Analyze the findings using two metrics to illustrate the cost gap between air source heat pumps (ASHPs) and natural gas heaters, and evaluate how these metrics change based on electricity rate structure:

1. **Operating cost gap:** comparison of gas heating bill vs. electric heating bill
2. **Payback period:** number of years needed to recoup the upfront cost premium of the heat pump based on annual operating cost savings

While we were able to uncover various insights with our approach, it has a few limitations. First, the analysis is based on one historical year of weather and usage data (2021); expanding this to several years would likely capture more weather variability and extreme events. Second, we modeled only two heating equipment types, cold-climate ASHPs and natural gas equipment, and we did not explicitly consider ASHP usage for space cooling. While we did not model the impact of ASHPs on cooling loads, cooling load is likely included in the original usage data for most customers due to the high penetration of air conditioning in this region.[4] ASHPs are typically more efficient at cooling than air conditioners and would have the effect of reducing customers' cooling loads.[5] We did not attempt to include this effect due to the difficulty of accurately disaggregating cooling loads from other electricity uses and due to the relatively small efficiency difference between air conditioners and heat pumps. Lastly, we did not model customer price response to alternative rate designs. Customers who opt into a different rate structure are likely to alter their usage to take advantage of their new rates. This will likely improve the economics of heat pumps further under these rate designs.

The following sections describe the assumptions and each stage of the analytical approach in further detail.

Step 1: Estimation of Customer Heating Requirement

Energy use for heating in buildings varies due to customer behavior, physical building characteristics, and outdoor temperature. In order to capture the diversity of heating requirements that will need to be served by heat pumps, we used each customer's historical monthly gas usage to estimate customer-specific heating energy use.

ASHRAE Guideline 14 Annex D outlines regression techniques that can be used to estimate a building's heating energy use using its whole-building energy use and one or more variables such as outdoor temperature and building occupancy.[6] Based on this guideline, we applied a three-parameter change-point linear model to estimate the customer's gas usage for heating based on their total usage, the outdoor temperature, and an assumed change-point temperature. The regression model was defined as:

4 According to the most recent results from the 2020 U.S. Energy Information Administration's Residential Energy Consumption Survey, 88 percent of U.S. households use air conditioning. Two-thirds of U.S. households use central air conditioning or a central heat pump as their main air conditioning equipment. See https://www.eia.gov/consumption/residential.

5 For customers who do not already have air conditioners, ASHP adoption and use for cooling will cause an increase in electric load. This should not be considered a negative effect, as the customer benefits from the availability of cooling. Indeed, as temperatures increase due to the impacts of climate change, cooling will become an increasingly necessary resource in most regions of the U.S. Under these circumstances, the adoption of ASHPs can be very beneficial, as they serve both heating and cooling needs and provide upfront cost savings by avoiding investment in two appliances.

6 ASHRAE Guideline 14–2014, Measurement of Energy, Demand, and Water Savings Annex D, Regression Techniques.

$$E = C + B_1 (B_2 - T)^+$$

Where:

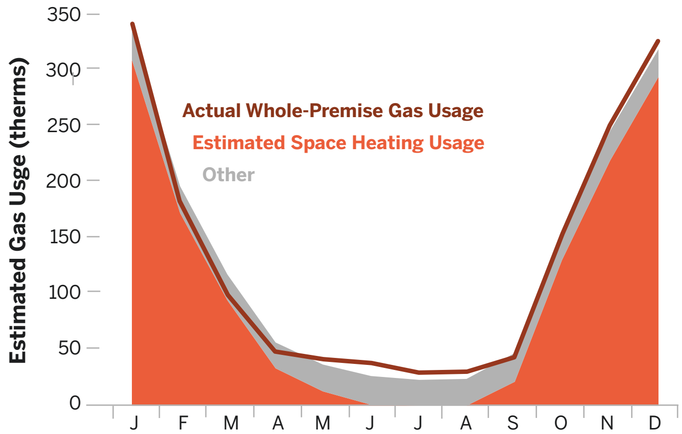
- E = Total gas usage
- C = Constant gas usage
- B_1 = Coefficient describing linear dependency of gas usage with outdoor temperature
- B_2 = Heating change-point temperature (assumed to be 65°F)
- T = Outdoor temperature
- + = Only positive values inside the parenthesis

This regression model yields a temperature coefficient of gas usage for each customer, which we used to calculate their monthly heating gas usage. Figure 1 illustrates a sample customer's actual monthly gas usage and the heating gas usage estimated by the regression model.

Figure 2 shows the distribution of estimated heating gas use across the 80 single-family residential customer sample. Most customers consume 1,000 to 2,000 therms of gas per year for space heating. Since only a portion of this gas usage is converted into useful heat by the natural gas heating equipment, we applied an efficiency factor of 80 percent to convert gas usage into heating energy requirements.[7] These heating energy requirements calculated for each individual customer formed the basis for heat pump electric load profiles modeled in this study.

FIGURE 1

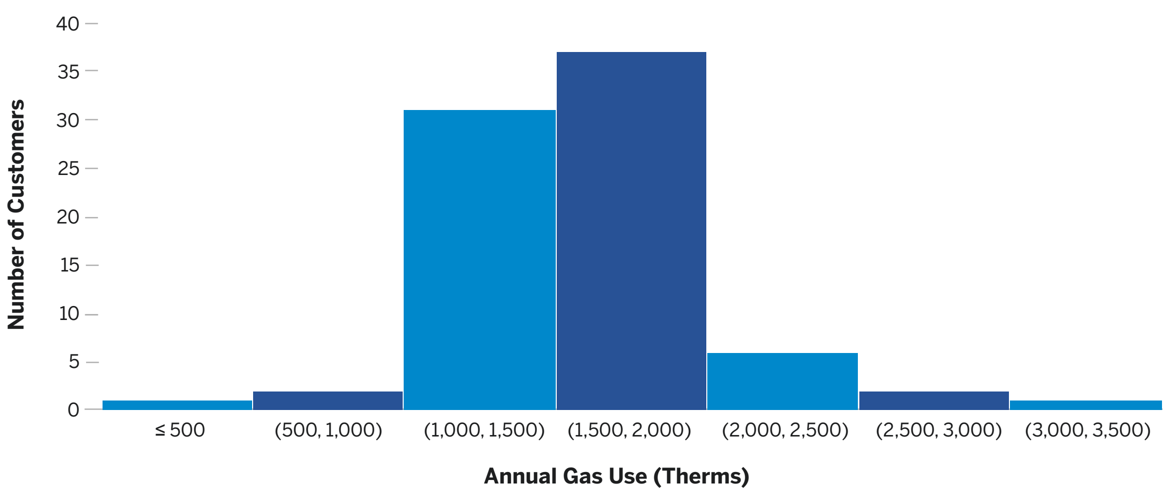
Actual Whole-Premise Gas Usage and Estimated Heating Gas Usage for a Sample Customer



Source: The Brattle Group.

FIGURE 2

Histogram of Estimated Heating Gas Use in the 80-customer Sample



Source: The Brattle Group.

7 "EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Reference Case" shows that the efficiency of the installed base of residential gas furnaces was 80 percent. See https://www.eia.gov/analysis/studies/buildings/equipcosts.

Step 2: Modeling of Heat Pump Electric Load

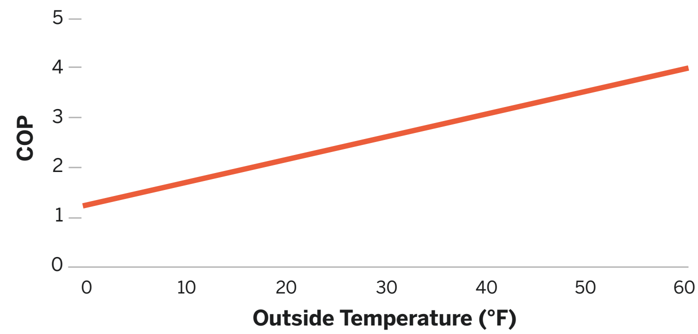
Heat pump loads are dependent on a range of factors including space heating needs, heat pump configuration, efficiency, and outdoor temperature. We utilized the customer-specific heating requirement estimates (as detailed above), historical hourly temperature data, and the assumed ASHP specifications to model hourly electricity demand.

First, we calculated hourly heating energy requirements by allocating the monthly heating energy requirement calculated in the previous section to each hour of the month based on the proportion of heating degrees that occurred in that hour. We then calculated the hourly electric load using the heat pump's coefficient of performance (COP)[8] in that hour given the outdoor temperature, as shown in Figure 3. This relationship is based on an assumed stand-alone cold-climate ASHP that meets the minimum requirements of the Northeast Energy Efficiency Partnership.[9]

We calculated hourly heating energy requirements by allocating the monthly heating energy requirement calculated in the previous section to each hour of the month based on the proportion of heating degrees that occurred in that hour.

FIGURE 3

Modeled Relationship Between Air Source Heat Pump COP and Temperature



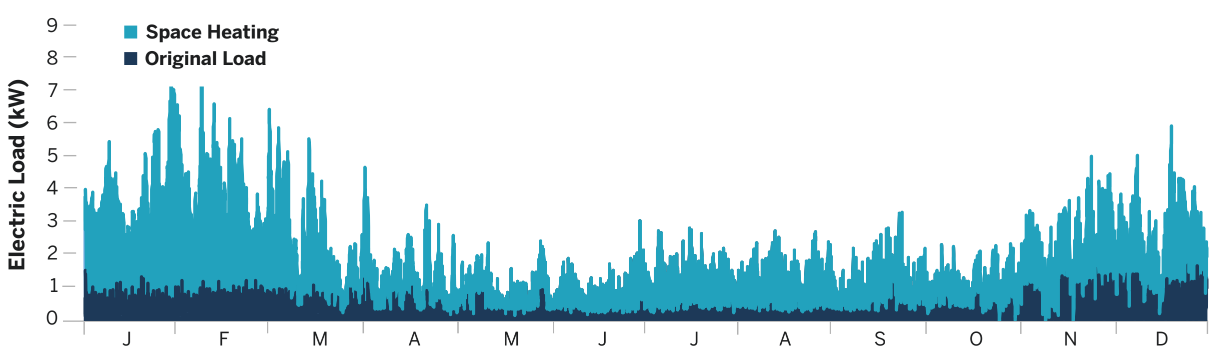
Air source heat pumps become less efficient as the outdoor temperatures fall.

Source: The Brattle Group.

Figure 4 illustrates that adding the modeled heat pump load to a customer's actual pre-electrification load significantly increases their total electric load. As shown in Table 1 (p. 7), both peak and annual usage more than

FIGURE 4

Modeled Hourly Post-Electrification Load for a Sample Customer



Source: The Brattle Group.

8 COP is a metric of heat pump efficiency, defined as the ratio of the thermal energy delivered to conditioned space to the electrical energy consumed by the heat pump.

9 The Northeast Energy Efficiency Partnership's Cold Climate Air Source Heat Pump Specifications Version 4.0 require that cold climate ASHPs have a COP of at least 1.75 at 5°F. We modeled a linear temperature relationship between a COP of 1.75 at 5°F and COP of 4 at 47°F with a 15 percent derating to account for the difference between rated and actual performance.

TABLE 1

Modeled Hourly Post-Electrification Load for a Sample Customer

	Non-Summer Peak Load	Summer Peak Load	Annual Total Load	Load Factor
Pre-electrification	2.37 kW	3.33 kW	6,100 kWh	21%
Post-electrification	8.13 kW	3.33 kW	15,943 kWh	22%
Percentage change	243%	0%	161%	7%

Note: Summer is defined as June-September, while non-summer is defined as October-May.

Source: The Brattle Group.

double for the sample customer. Heat pump impacts on load across the 80-customer sample are discussed below.

Step 3: Customer Energy Bill Modeling: Pre- vs. Post-Electrification and Alternative Rate Designs

Modeled ASHP adoption and associated changes in energy usage affect both natural gas and electricity bills. We calculated both types of bills using actual pre-electrification usage data, modeled post-electrification usage, and default and alternative rate structures.

Natural Gas Bill and Rate Assumptions

In this analysis we modeled a default gas rate option and assumed that all customers are on this rate pre- and post-electrification. We assumed that customers stay connected to the gas system post-electrification and continue to use gas for end uses other than space heating, such as cooking, water heating, or cooling. Table 2 shows the default natural gas rate, which has a declining block structure and seasonal differentiation, for this modeled utility. Gas bills were calculated based on this rate pre- and post-electrification. The billing determinant used for the gas rate was the total usage in a month across all hours. The declining block structure leads to different rates being applied for different blocks of usage as detailed in Table 2.

TABLE 2

Default Natural Gas Rate

	Season	Gas Rate (Default)
Customer charge ($/month)	All year	$24
Commodity charges ($/therms)	Summer	$0.60
	Non-summer	$0.55
Delivery charges ($/therms)	Summer	Block 1: $1.34 Block 2: $0.99 Block 3: $0.79
	Non-summer	Block 1: $1.32 Block 2: $0.97 Block 3: $0.77

Note: For the gas rate, summer is defined as April-October, while non-summer is defined as November-March.

Source: The Brattle Group.

In this analysis we modeled a default gas rate option and assumed that all customers are on this rate pre- and post-electrification. We assumed that customers stay connected to the gas system post-electrification and continue to use gas for end uses other than space heating, such as cooking, water heating, or cooling.

TABLE 3

Four Alternative Electricity Rate Designs

	Season	Rate I	Rate II	Rate III	Rate IV
Customer charge ($/month)	All year	$18	$45	$23	$28
Supply charges ($/kWh)	Summer	$0.09	$0.09	Peak: $0.265 Off-peak: $0.035	Peak: $0.215 Off-peak: $0.065
	Non-summer	$0.09	$0.09	Peak: $0.115 Off-peak: $0.035	Peak: $0.165 Off-peak: $0.065
Delivery charges, volumetric ($/kWh)	Summer	$0.155	$0.125	Peak: $0.215 Off-peak: $0.055	$0.015
	Non-summer	$0.145	$0.105	Peak: $0.075 Off-peak: $0.055	$0.015
Delivery charges, demand ($/kW)	Summer	—	—	—	Peak: $20.00 Off-peak: $5.50
	Non-summer	—	—	—	Peak: $15.00 Off-peak: $5.50
Peak definition	All year	—	—	8 AM-midnight on all days including holidays	Noon-8 PM on weekdays except holidays

Note: For electricity rates, summer is defined as June-September, while non-summer is defined as October-May.

Source: The Brattle Group.

Electricity Bill and Rate Assumptions

Electricity bills were calculated based on four rate options (Table 3):

- **Rate I:** Default rate with a fixed charge and flat volumetric charge
- **Rate II:** Rate with a higher fixed charge and lower flat volumetric charge
- **Rate III:** Seasonal volumetric TOU day/night rate
- **Rate IV:** Seasonal demand-based TOU rate

Each of the four modeled rate options uses one or more of the following monthly billing determinants:

- **Monthly usage (kWh):** Total usage in a month across all hours
- **Peak period usage (kWh):** Monthly usage within the day time window, defined as 8 AM to midnight all days including holidays for Rate III and noon to 8 PM on weekdays except holidays for Rate IV
- **Off-peak period usage(kWh):** Monthly usage in hours outside the peak window
- **Peak billable demand (kW):** Average of the four highest daily demand values in a month within peak window hours
- **Off-peak billable demand (kW):** Average of the four highest daily demand values in a month within off-peak window hours

Rate I is a default rate that is commonly offered to residential customers across many utilities. Rates II through IV were chosen to represent the various alternatives that are being considered in the industry as potential cost-based rate structures that can support heating electrification, without subsidizing these end-use technologies. Under Rate II, a higher fixed charge recovers a larger portion of the fixed costs of the delivery system independent of a customer's energy usage, thereby lowering the volumetric charge. Lower volumetric rates may encourage heat pump adoption since increasing electricity usage will not increase the bills as steeply

Demand charges have been rarely offered to residential customers in the U.S. due to their presumed complexity; however, they are being considered as an alternative voluntary rate design option that may help avoid large increases in bills due to increased usage.

as the default rate would. Rate III introduces a time-varying rate option in the form of a day vs. night TOU rate structure, where the lower costs of generating and delivering electricity during nighttime hours are reflected in the prices.[10] Rate IV also employs a time-varying structure but with demand charges instead of volumetric charges. Demand charges are generally used to recover costs associated with sizing infrastructure to serve peak demand. Demand charges have been rarely offered to residential customers in the U.S. due to their presumed complexity; however, they are being considered as an alternative voluntary rate design option that may help avoid large increases in bills due to increased usage. Moreover, heat pump usage tends to improve customer load factors, which is a favorable outcome under a demand charge–based rate design.

It is important to note that the alternative rates are designed to be revenue-neutral with the default rate pre-electrification. This implies that for the 80 customers in our sample, each of these rate designs would result in approximately the same total utility revenue based on their total pre-electrification load.[11]

Step 4: Heat Pump Cost Gap Metrics

Having developed the energy requirement associated with space heating, electricity requirement to meet this energy need, and alternative electricity rates that could be made available to heat pump customers, we then developed metrics to illustrate the operating cost gap between ASHPs and natural gas equipment under alternative rate designs.

Operating Cost Gap: Definition and Assumptions

We defined the operating cost gap as the difference between the heating portion of the electricity bill post-electrification and the heating portion of the natural gas bill pre-electrification. For an existing gas heating customer to consider replacing her heating system with a heat pump, she may at a minimum want to pay less for electric heating than gas heating—in other words, to achieve a negative operating cost gap. If this initial condition is not met, then to replace a natural gas heating system with a heat pump does not make economic sense. Once this condition is met, that is, if the operating cost gap is negative, then the prospective heat pump buyer could look for a reasonable payback period, which is typically in the range of five to 10 years for residential customers.

Figure 5 (p. 10) illustrates the operating cost gap in relation to natural gas and electricity bills pre- and post-electrification. The total energy bill is the sum of the gas bill (orange) and electricity bill (blue). The pre-electrification total energy bill includes the electricity bill for end uses other than heating, the gas bill for heating, and the gas bill for end uses other than heating. Post-electrification, the gas bill for heating reduces to zero due to electrification, and the electricity cost for heating is added to the electricity bill. Note that post-electrification, electricity and gas bills for end uses other than heating may also change if the customer switches to different rate schedules or changes their energy usage. *In this study, we focused on the change in the heating portion of the bills rather than the total bill in order to isolate the effect of electrification of heating.*

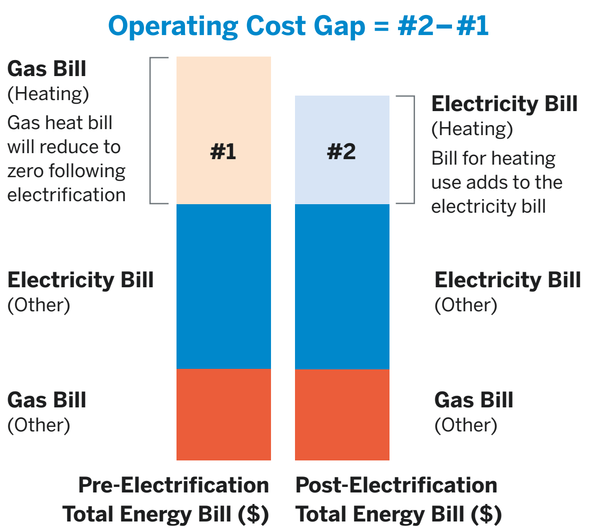
10 Although a TOU rate may encourage customers to shift usage to lower-priced hours in order to reduce bills, we do not capture this behavior in this analysis. We assume that customers continue with their consumption patterns.

11 Less than +/– 1 percent difference from the default rate.

Post-electrification, electricity and gas bills for end uses other than heating may also change if the customer switches to different rate schedules or changes their energy usage. In this study, we focused on the change in the heating portion of the bills rather than the total bill in order to isolate the effect of electrification of heating.

FIGURE 5

Illustration of a Negative Operating Cost Gap, $/month



The operating cost gap is the difference between #2 the heating portion of the electric bill (post-electrification) and #1 the heating portion of the gas bill (pre-electrification).

Source: The Brattle Group.

Payback Period: Definition and Assumptions

We defined the payback period as the number of years needed to recoup the upfront cost premium of the heat pump based on annual operating cost savings. We performed the payback analysis for the average customer using generic equipment cost assumptions; we do not attempt to estimate a customer-specific equipment cost. Instead, we show three cost cases (low, base, and high) to reflect the broad range of potential equipment costs across a diverse customer base. In addition, we conducted the payback analysis with and without the heat pump rebates of up to $8,000 provisioned by the Inflation Reduction Act (IRA).[12] We assumed that all components of both electric and natural gas rates grow at 2.4 percent per year. Cost assumptions used in the analysis are provided in Table 4.

TABLE 4

Assumptions for Payback Analysis for Air Source Heat Pumps

Assumption	Low	Base	High
Gas furnace installation cost		$3,908	
ASHP installation cost*	$9,225	$13,605	$17,984
Federal ASHP rebate	$4,612	$6,802	$8,000

* ASHP installation costs assume a cold climate heat pump. AHSP costs were obtained from Nadel and Fadali (2022).

Notes: The table refers to all-in upfront cost including equipment and installation costs. The incentive value is calculated assuming a rebate of 50 percent of the cost of the ASHP up to a cap of $8,000, based on the provisions of the Inflation Reduction Act. ASHP = air source heat pump.

Source: The Brattle Group.

12 Under the IRA, income-qualified customers can receive rebates of 100 percent of the equipment cost, and average-income customers can receive rebates of 50 percent of equipment cost, with a cap of $8,000 per customer. We modeled only the average-income customer's rebate incentive in our analysis.

Modeling Results

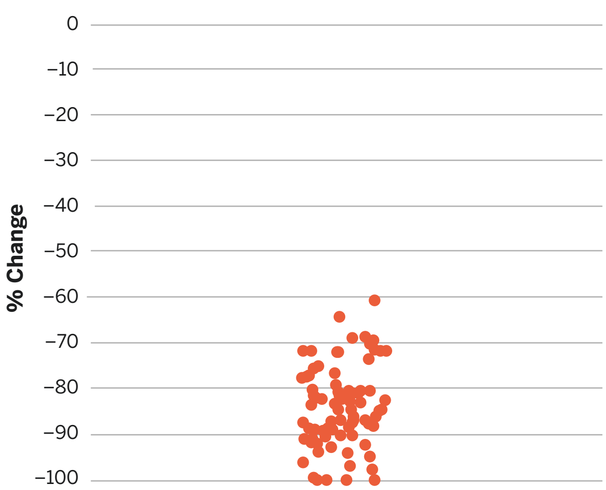
This section outlines the key results from our analysis of heating operating costs before and after electrification. First, we discuss modeled changes in customer usage and associated impacts on billing determinants. We then summarize the impact of these changes on the gas bill and compare the impact on the electricity bill under four different rate structures. Finally, we present the implications for heat pump economics using the operating cost gap and payback period metrics.

Energy Usage and Billing Determinants

Natural Gas

Given that space heating is the largest end use for natural gas customers, replacement of a gas furnace or boiler with an ASHP results in a major reduction in gas usage. As shown in Figure 6, for the 80-customer sample, our results show that switching to an ASHP would reduce annual gas usage by 60 to 100 percent, with an average reduction of 83 percent (Table 5). Any remaining gas usage is likely for cooking, water heating, or clothes drying, and customers are assumed to continue this usage after space heating electrification for the purposes of this study. The gas rate structure modeled in this study is relatively simple, with monthly usage being the only billing determinant.

FIGURE 6
Change in Natural Gas Usage Post-Electrification



Switching to an ASHP would reduce annual gas usage by 60 to 100 percent for the 80-customer sample.

Source: The Brattle Group.

TABLE 5
Average Gas Usage for the Sample, Pre- and Post-Electrification

	Average Annual Gas Usage in Sample
Pre-electrification	1,589 therms
Post-electrification	264 therms
Percentage change	−83%

Source: The Brattle Group.

Electricity

While the analysis of monthly total gas usage is sufficient to calculate natural gas bills, electricity bills require a more in-depth analysis of the temporality of usage in order to capture the impacts of alternative rates considered in this study. We added modeled ASHP load to each customer's pre-electrification actual usage and evaluated five different billing determinants to calculate bills under four different rate structures. The billing determinants are described in the section "Customer Energy Bill Modeling: Pre- vs. Post-Electrification and Alternative Rate Designs" above.

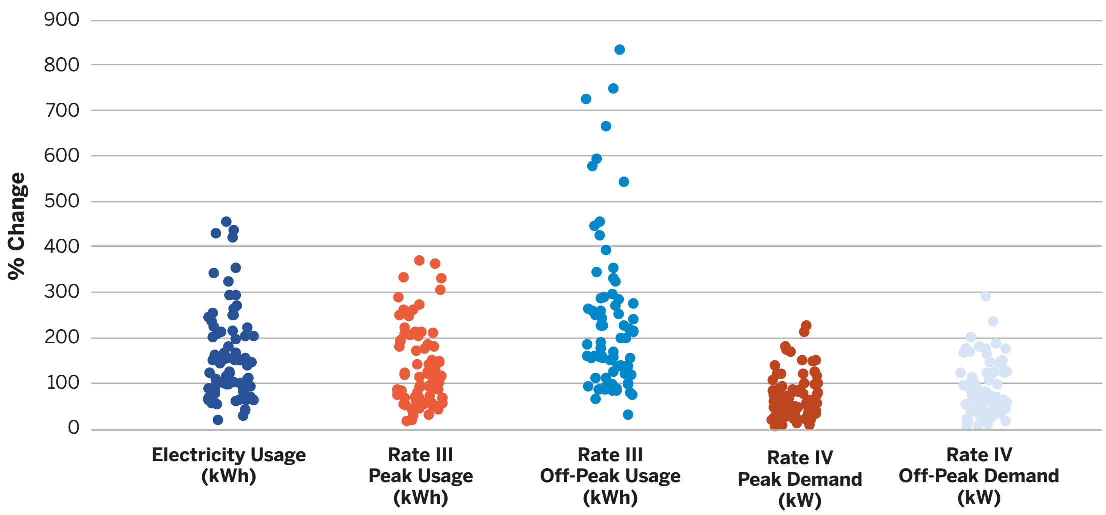
Figure 7 illustrates the impacts of electrification on each billing determinant for each customer. Table 6 summarizes the average annual billing determinants pre- and post-electrification across the 80-customer sample.

As seen in Table 6, the addition of ASHP load results in a significant increase in all five billing determinants. However, different billing determinants are affected to different extents due to patterns in the timing of ASHP load. Impacts on volumetric usage are greater than impacts on peak demand. In addition, ASHP load has greater impacts on off-peak billing determinants (both usage and demand) than on-peak billing determinants. This is because ASHP load is driven by outdoor temperature, and the coldest hours occur at night and early in the morning, outside the peak window.

In addition, all of the impacts are in the winter and shoulder season months, since we modeled heating electrification, as shown in Figure 8. This seasonality is significant as many summer-peaking utilities, including the one modeled in this study, currently have lower costs to serve in the non-summer months, with correspondingly lower cost-based rate levels in non-summer months.

FIGURE 7

Change in Annual Electricity Billing Determinants



Source: The Brattle Group.

TABLE 6

Average Monthly Billing Determinants Pre- and Post-Electrification

	Total Usage	Rate III Peak Usage	Rate III Off-Peak Usage	Rate IV Peak Period Demand	Rate IV Off-Peak Period Demand
Pre-electrification	740 kWh	544 kWh	196 kWh	3.2 kW	3.4 kW
Post-electrification	1,613 kWh	1,075 kWh	539 kWh	4.8 kW	5.5 kW
Percentage change	118%	98%	174%	53%	65%

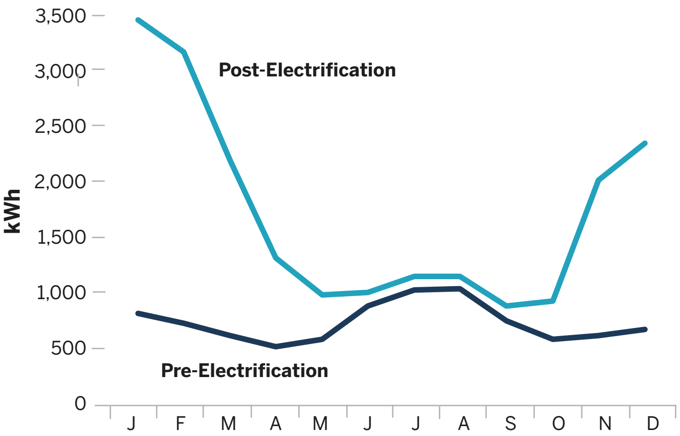
Electrification of heating with an ASHP would increase different electricity billing determinants to different extents. Peak window demand increases the least (53%), and off-peak window usage increases the most (174%).

Notes: Values shown in the table are monthly billing determinants averaged across all customers and months. Monthly billable demand for Rate IV is the average of the four highest daily demand values in a month within peak or off-peak window hours.

Source: The Brattle Group.

FIGURE 8

Average Monthly Electricity Usage in the 80-Customer Sample, Pre- and Post-Electrification



Source: The Brattle Group.

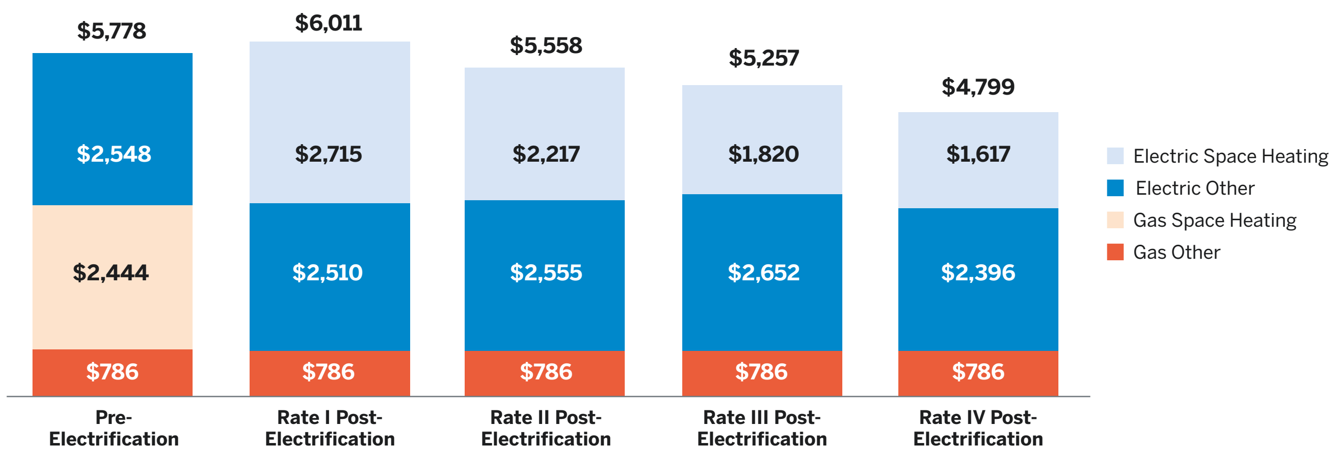
Both electrification and migration from the default rate to an alternative rate structure—even if it were to happen without electrification—affect customer bills. To provide a holistic view of the impact of these two changes, we analyzed annual total energy bills, defined as the sum of the natural gas and electricity bills. In addition, to isolate electrification-related costs we broke up the bills into a space heating component and a non-space heating, "other" component.

Figure 9 shows that the average annual total energy bill in the 80-customer sample was $5,778 before electrification. Replacing natural gas space heating with an ASHP while remaining on the default electricity rate would result in the average annual total energy bill increasing by about $233, leading to a total annual bill of $6,011. However, switching to any of the three alternative electricity rates changes this outcome. Under the three alternative rates, the post-electrification average annual total energy bill is $220 to $979 lower than the pre-electrification average annual total energy bill.

Recall that the three alternative rates are: Rate II with a higher fixed charge and lower volumetric charges, Rate III with time-varying volumetric charges, and Rate IV with time-varying demand charges. By switching from the default rate to one of these three alternative rates post-electrification of heating, the average customer with an ASHP could realize electricity bill savings of $453 to

FIGURE 9

Average Annual Energy Costs Before and After Electrification



Total energy bills are higher after electrification if a customer remains on electricity Rate I, the default rate. However, switching to one of the modeled alternative rates makes the post-electrification bill cheaper than the pre-electrification bill. The alternative rates are Rate II with a higher fixed charge and lower volumetric charges; Rate III with time-varying volumetric charges; and Rate IV with time-varying demand charges.

Source: The Brattle Group.

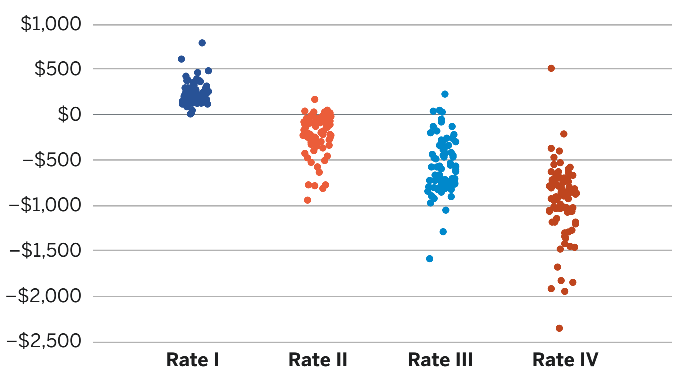
$1,212 annually. A significant portion of this reduction is from the cost of the ASHP's electricity usage, which is reduced from $2,677 on the default rate to $1,600 to $2,217 on the alternative rates. These ASHP operating costs should be compared to the average natural gas heating cost of $2,444 when a customer is deciding whether to electrify.

Rate migration also affects the non-heating portion of the electricity bill ("electric other"). This impact varies from customer to customer, with minimal average impact.

Post-electrification, switching from Rate I to one of the alternative rates largely results in customers saving. Out of 80 customers, 71 have lower bills on Rate II, 75 on Rate III, and 79 on Rate IV. However, there are some important differences between these three rates (as illustrated by Figure 10). The scale of bill reduction differs—Rate IV results in the lowest bills overall, followed by Rate III and then Rate II.[13] In addition, not all customers experience similar outcomes. The

FIGURE 10

Distribution of Total Energy Bill Changes Post-Electrification



Total energy bills are higher for most customers post-electrification if they remain on the default rate (Rate I). However, post-electrification bills are lower if they switch to one of the alternative rates (Rates II-IV).

Source: The Brattle Group.

scale of bill reduction is much more variable for Rate IV than for Rate II,[14] i.e., it is easier to predict the change in a customer's bill when switching to Rate II. This is likely because it is possible for some customers' non-heating usage profile ("Electric Other") to be ill-suited to one or more components of the alternative rate structures. For example, if a customer's non-heating electricity usage is especially "peaky" (i.e., they have a low load factor), they may see bill increases from switching to a demand-based rate. A customer's usage might be peaky due to infrequently used but energy-intensive appliances such as pool pumps or a sauna. This type of impact is independent of heating electrification—this customer would have experienced a bill increase from migration to Rate IV regardless of whether they electrified. We outline some policy implications of these differences in the section "Key Takeaways" below.

Finally, we evaluated two heat pump cost metrics that a customer could consider when deciding between the purchase of a heat pump or a natural gas furnace: the operating cost gap and the payback period. As detailed in the section "Heat Pump Cost Gap Metrics," the heating operating cost gap is the difference between the heating portion of the gas bill and the heating portion of the electricity bill. This metric is calculated using the electric heating bill on each electricity rate schedule, thereby isolating heating bills from any costs that may be the effect of rate migration.[15] The heating operating cost gap is then used in conjunction with upfront cost assumptions to calculate the second metric, the payback period. These metrics can be used to assess the efficacy of different cost-based electricity rate designs in bridging the cost gap between ASHPs and gas furnaces.

Operating Cost Gap

Figure 11 (p. 15) shows that under the default electricity rate (Rate I), the operating cost gap is positive for all 80 customers and ranges from $12 to $790 per year. A positive operating cost gap means the electric heating bill is higher than the gas heating bill. Increasing the fixed charge and lowering the volumetric charge (Rate

13 Median savings is $927 for Rate IV and $583 for Rate III.

14 As measured by the standard deviation of the annual bill differences between the alternative rate and the default rate for the 80 customers.

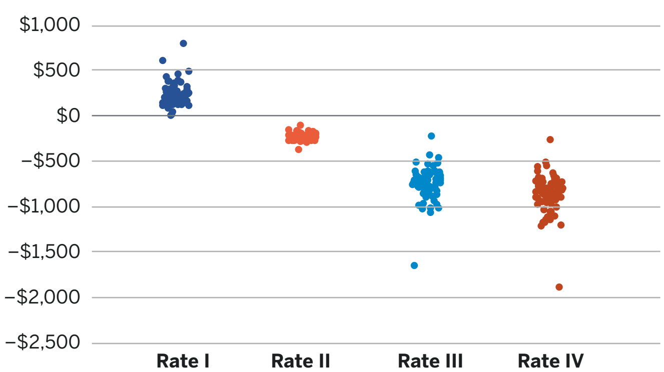
15 For example, a customer that has a very flat electricity usage profile pre-electrification is likely to see bill reductions from switching to a demand-based rate. Non-heating-related impacts such as this are excluded from our definition of the heating operating cost gap.

Rate design is a powerful tool in addressing the operating cost gap between heat pumps and natural gas equipment. A change in electricity rate structure was shown to flip all 80 customers from a positive cost gap to a negative cost gap.

II) reduces the electric heating bill to a sufficient extent that the operating cost gap turns negative for all customers —they are saving money relative to heating with natural gas. Further, switching to a TOU day/night structure (Rate III) or a demand-based structure (Rate IV) results in even larger negative operating cost gaps. Rate IV is the most effective rate for reducing electric heating bills for our sample of 80 single-family residential customers.

FIGURE 11

Heating Operating Cost Gap



Source: The Brattle Group.

In summary, Figure 11 shows that rate design is a powerful tool in addressing the operating cost gap between heat pumps and natural gas equipment. A change in electricity rate structure is shown to flip all 80 customers from a positive cost gap to a negative cost gap. The scale of the impact is significant—the average operating cost gap can be reduced from $233 on Rate I to -$844 on Rate IV.

Most importantly, these impacts are possible to achieve with alternative rates that are cost-based and revenue-neutral to the default rate.

Payback Period

We used the average operating cost gap on each rate to calculate the number of years needed to recoup the upfront cost premium of an ASHP relative to natural gas heating. Table 7 shows that there is a significant degree of variance in payback periods based on the ASHP cost, the addition of the IRA incentive, and selection of the electricity rate schedule. Under the default Rate I, there is no scope for payback because heat pump operating costs are greater than gas heating operating costs; both upfront and ongoing costs are higher for heat pumps. However, the alternative rates greatly reduce payback periods across cases. For example, under the base cost assumptions with the IRA incentive, a heat pump can be paid back within its lifespan (~15 years) under any of the three alternative rate schedules. Rates III and IV are particularly beneficial, as the upfront cost of ASHPs can be fully recouped even in the high ASHP installation cost scenario. The IRA incentive cuts payback periods further.

TABLE 7

ASHP Payback Periods, by Electricity Rate Schedule, Without IRA Incentive | With IRA Incentive

ASHP Cost Case	Rate I	Rate II	Rate III	Rate IV
Base	NA | NA	>15 | 11 years	15 | 5 years	9 | 2 years
Low	NA | NA	>15 | 3 years	9 | 1 year(s)	5 | 1 year(s)
High	NA | NA	>15 | >15 years	>15 | 10 years	12 | 5 years

Table shows simple payback based on equipment costs and projected annual differences in total energy bills relative to the case with a gas heater. "N/A" means there are no operating cost savings, so payback is not possible.

Source: The Brattle Group.

Key Takeaways

This analysis shows that there are alternative cost-based rate designs that can improve the economics of heat pumps by resulting in electric heating bills being lower than natural gas heating bills (i.e., a negative operating cost gap). Specifically, we show that while the operating cost gap is positive for all 80 customers under the default electricity rate (Rate I) (energy costs for operating the heating equipment are higher post-electrification), moving to one of the three alternative rates flips all 80 customers from a positive cost gap to a negative cost gap, in which energy costs for operating the heating equipment are lower post-electrification.

All of the alternative rates modeled in this study are cost-based and revenue-neutral in that they recover the same costs as the default rate. They also improve upon the cost-reflectivity of the default rate by better aligning one or more components of the rate design with the underlying cost structure.

Increasing the fixed charge and lowering the volumetric charge (Rate II) reduces the electric heating bill to a sufficient extent that the operating cost gap turns negative for all customers. Further, switching to a TOU day/night structure (Rate III) or a demand-based structure (Rate IV) results in even larger negative operating cost gaps. Rate IV is the most effective rate for reducing electric heating bills, for our sample of 80 single-family residential customers, with Rate III closely following it.

More Cost-Reflective Rate Designs Improve the Economics of Electrification

These results reflect the fact that all of the alternative rate designs are better aligned with the marginal cost of generating and delivering power, compared to the default residential rate design, which typically is not. In many jurisdictions across the country, retail electricity prices are largely disconnected from the marginal costs. As Borenstein and Bushnell (2022) argued, "residential electricity rates exceed average social marginal cost in most of the U.S." and "there is large variation both geographically and temporally." To the extent that retail prices are above the short-run marginal costs because a large portion of the fixed costs of delivering power are also collected through volumetric rates, this creates a distortion in price signals and leads to suboptimal levels of electricity consumption and adoption of new customer-sited technologies. One of the unintended consequences of this phenomenon is the slower adoption of heat pumps, because heat pump usage increases total electricity consumption and therefore electricity bills, turning out to be uneconomic under typically volumetric default residential electricity rate structures.

All of the alternative rates modeled in this study are cost-based and revenue-neutral in that they recover the same costs as the default rate. They also improve upon the cost-reflectivity of the default rate by better aligning one or more components of the rate design with the underlying cost structure. These alternative rates also favor the operating characteristics of heat pumps:

- **Rate II** has a higher fixed charge and lower volumetric charge, which is favorable for heat pumps since this equipment substantially increases a household's electricity usage.

- **Rate III** is a seasonal day/night TOU rate, with lower rates for off-peak (night) hours and also lower day and night rates for the non-summer season. A significant portion of the heat pump load tends to fall into the off-peak periods because those tend to be the coldest, which implies that various cost-based TOU rates might favor heat pump usage, all else equal. Moreover, most of the heat pump load materializes in the non-summer months; therefore, seasonally differentiated rates in summer-peaking systems (with lower non-summer rates) might favor heat pump usage, all else equal.
- **Rate IV** is a seasonal TOU-based demand rate. Heat pumps tend to have high load factors, which implies that demand-based rates might favor heat pump usage, all else equal. In our rate design, we defined the billing demand to be the average of the top four demand hours, with the averaging intended to avoid the unpleasant customer experience of getting a high bill due to one high hour.

It is important to note that as the system conditions evolve, and summer-peaking systems become winter peaking with increasing levels of building electrification, rate structures may need to be refreshed to maintain their cost-reflectivity. Some of the attractive features of the rates modeled in this study (i.e., lower non-summer rates due to seasonality) may need to be eliminated at that time since the system cost drivers would no longer support these design choices. These revisions and adjustments are all part of the rate design process, since it is not possible to "future-proof" rate designs.

These Alternative Rate Structures Have Implications for Customers' Other Electric Loads

While our analysis showed that these alternative rates were effective in creating a negative operating cost gap for heating (a lower cost of heating after electrification), it is important to understand the implications of these rates for customers' other electric loads. Rate migration can create costs or savings independent of heating electrification, depending on the nature of customers' non-heating loads. This is an important consideration when marketing alternative rates to customers. For some of the customers in the sample, even before any electrification, switching to the TOU rate (Rate III) would increase their electricity bill by ~$200/year. (This increase could be reduced or eliminated through load response to TOU rates, although we did not model this impact in our study.) On the other hand, there are some customers for whom switching to one of the demand-based rates would reduce the bill by ~$100/year even before any electrification. Utilities may choose to develop screening tools to determine which customers may benefit from these alternative rates and market these rates accordingly to the customer base.

For the purposes of this study, we assumed that customers maintain their gas service for non-heating-related use cases such as cooking. This implies that these customers continue to pay the fixed customer charges for the gas service, along with the cost of volumetric gas usage. Fully electrifying a household would create additional savings by allowing it to avoid all gas charges (an additional $350/year in fixed gas charges for a single-family home). It is very likely that gas rates will increase faster than electricity rates in the next decade; therefore, the cost advantage of heat pumps will only increase over time.

It is important to note that as the system conditions evolve, and summer-peaking systems become winter peaking with increasing levels of building electrification, rate structures may need to be refreshed to maintain their cost-reflectivity.

Information Barriers Need to Be Addressed

Lastly, the availability of alternative rates that favor the economics of heat pumps does not necessarily mean that customers will start taking advantage of these rates in droves. Information barriers need to be addressed through utility programs targeting customers and pairing them with the rate design most favorable to them. Utilities can develop data analytics tools to identify customers who may be getting close to replacing their heating systems and "catch" them before they make their investment decision. Contractor training programs could be developed in which contractors increase awareness for new rates for customers who are in the market for a new heating system. With the availability of alternative rates, contractors could take into account the rate characteristics to make system recommendations. For example, if the demand charges are very high in an alternative rate, it could mean that purchasing a highly efficient cold-climate heat pump is a better choice than a less efficient heat pump with resistance backup even if there is an upfront cost premium for the cold climate heat pump.

The Use of Cost-Reflective Rate Designs Is Increasing

More and more utilities are starting to move toward more cost-reflective rate designs. Some are increasing their fixed customer charges to move them closer to the values implied by their cost-of-service studies. Others are moving toward time-varying rates, mostly in the form of voluntary/opt-in rates, but in a few cases offered as default, opt-out rates. When utilities offer opt-in cost-reflective rates, customers are able to opt in to the rates that are most convenient for their "energy lifestyle." To the extent that all of these alternative voluntary rates are cost-reflective, it will be possible to achieve a win-win: customer satisfaction will increase and utility cost recovery will become more equitable.

When utilities offer opt-in cost-reflective rates, customers are able to opt in to the rates that are most convenient for their "energy lifestyle." To the extent that all of these alternative voluntary rates are cost-reflective, it will be possible to achieve a win-win: customer satisfaction will increase and utility cost recovery will become more equitable.

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Heat Pump–Friendly Cost-Based Rate Designs

By Sanem Sergici, Akhilesh Ramakrishnan, Goksin Kavlak, Adam Bigelow, and Megan Diehl

A White Paper from the Energy Systems Integration Group's Retail Pricing Task Force

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