

Electric Utility Rates Are Critical to Broad Space-Heating Electrification: Data from the Midwest

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ABSTRACT

In the Upper Midwest, space heating from natural gas represents approximately half of all residential energy use. The recent passages of the Energy Conservation and Optimization Act in Minnesota, and the Climate and Equitable Jobs Act in Illinois, open up major opportunities for electrification of space heating from natural gas. The authors have conducted detailed air source heat pump (ASHP) modeling that finds that the customer economics compared to natural gas are extremely challenging. This has implications not only for market adoption, but also for the energy burden of those switching to ASHPs. The importance of rates in this equation is magnified in extremely cold environments such as Minneapolis, where the coefficient of performance of even the best heat pumps drops significantly, and heating loads are high.

Most residential customers are currently on volumetric rates, usually based on typical household energy usage. Because such a large share of electricity delivery cost is fixed (think wires and poles) rather than variable, and because the electric usage of homes on ASHPs can be double that of typical natural gas heated homes, the utility can justify a more favorable rate for homes adding ASHPs.

The authors conducted an analysis of customer economics of five different rate structures — one baseline and four different permutations of a dual-fuel ASHP-specific rate — to determine the impact on customer economics and customer adoption of ASHPs.

Our analysis shows that rates have a big impact on customer economics — ranging from hardly any electrification being economically beneficial to customers, to nearly 100% being beneficial — and illustrates the point that rate design can either be a barrier to the progress of space heating electrification efforts, or a contributing factor to its success.

Introduction

Space heating electrification is critical to meeting climate goals for emissions reduction. Increasingly, states are taking action to help spur beneficial electrification. The Minnesota Energy Conservation and Optimization (ECO) Act (Minnesota State Senate 2021) expands the ability for utilities to encourage the transition away from natural gas space heating, opening the door for the exploration of greenhouse gas-reducing methods in the sector. Similarly, the Illinois Climate and Equitable Jobs Act (CEJA) (Illinois General Assembly 2021) redefined utilities' claimable electrification savings, driving new incentives focused on equitable energy efficiency.

Promoting electrification through programs, particularly those with customer rebates to reduce the capital cost of installing equipment, has received much attention. This includes a proposed expansion of electrification-focused rebate programs within the Build Back Better framework announced by the Biden administration. Less attention has been paid to the operating

costs that customers who fuel-switch will face once the equipment is installed, and until the equipment is replaced 15 or more years later.

This study investigates the implications of several fixed electric utility rates in the design and economics of fully electrified and dual-fuel ASHP installations in single-family (SF) households within Commonwealth Edison Company's (ComEd) service territory in Chicago, Illinois. The comparison of ASHP scenarios against common baseline system types is prefaced with an introduction to the key drivers influencing the energy and cost savings potential of partial and full electrification of existing residential natural gas, electric, or propane heating systems.

The authors have been involved in technical and economic analysis of ASHPs for over 5 years; during that time, they have developed advanced energy and economic modeling tools designed for the evaluation of potential heat pump scenarios. Past projects include detailed residential and commercial heat pump system performance models developed for electrification and energy efficiency efforts in partnership with stakeholders in private and public sectors nationwide.

Economics of Heat Pumps Displacing Natural Gas in the Midwest

The Midwest footprint represents 35% of the total U.S. residential space heating consumption (Energy Information Administration [EIA] 2015). Space heating loads represent approximately half of all residential energy use in the Upper Midwest. As of 2015, the Midwest Census Division (CD) contributes 43% of the nation's space-heating-related natural gas consumption (EIA 2015), while only contributing 37% of natural gas expenditure for this end use (EIA 2015). Comparatively, the Northeast CD contributes 23% to national consumption and 27% to national expenditure. This regional difference is driven by the Midwest historically having the lowest natural gas rate of all divisions (EIA 2022). The region is also notorious for long, harsh winters, with the majority of IECC climate zone 7 within the lower 48 states being confined to the Upper Midwest (U.S. Department of Energy 2012), where annual heating degree days exceed 8,500 in a typical year (National Renewable Energy Laboratory, 2020).

While high fuel consumption in space heating coupled with cheap natural gas rates paint a grim picture for the displacement of fossil fuels, the efficiency improvements yielded by electrification measures can lower energy consumption enough to overcome comparatively high volumetric energy costs. Heat pumps commonly exceed 300% efficiency in warm outdoor conditions. Higher-performance cold-climate heat pump models can maintain similarly high efficiencies even nearing peak winter conditions. While this sounds like a slam dunk solution on paper, operational costs and true performance tell a different story.

Operating and cost drivers for ASHPs displacing gas

When considering that a heat pump takes heat from the outdoor air and “pumps” it into the envelope, it is intuitive to conclude that they work well when ambient outdoor heat is abundant. While this is true, space heating is not often required in those higher-temperature environments, and the opposite effect occurs when the unit must work harder to provide the same heating load with cold air as a heat source. Cold ambient outdoor temperatures cause heat pumps to yield lower efficiency and capacity when heating loads are at their highest (Shoenbauer, Kessler, and Kushler 2017).

The high efficiencies provided by heat pumps generally come at an increased capital cost compared to natural gas heating systems. Despite site energy savings, most heat pumps, including those designed for cold climate operation, will increase space heating costs due to the increase in fuel costs associated with switching from gas to electricity. To avoid this and provide a return on incremental cost, the heat pump system requires some combination of several factors, namely maintaining efficiency and capacity down to very cold ambient temperatures, deferring to a backup natural gas system at lower temperatures, or electricity rates low enough to allow cheaper heat pumps to remain competitive despite reduced cold-climate efficiency performance.

Specialized cold-climate heat pumps are rated for much lower minimum temperatures and are therefore able to retain sufficient efficiency and capacity to handle a larger share of the heating season than non-cold-climate options. These benefits come at a premium though, and despite their high performance, cold-climate units may still struggle to meet the load in the peak heating season.

To avoid the possibility of not providing the heating load in cold outdoor conditions, currently, heat pumps are being installed with backup heating, where the system is designed with these low-temperature shortcomings in mind. These backup systems generally lock out the heat pump and provide 100% of the home load when the heat pump capacity is lower than heat load demanded. Some systems with electric backups can be configured to supplement or “boost” the heat pump, improving the system efficiency into colder temperatures by allowing the ASHP and backup to run in tandem. When considering backup heating systems for heat pumps, consumers can either fully electrify their heating with high-efficiency electric resistance systems, or partially electrify with natural gas, referred to as a “dual-fuel” system capable of using either electric heating or gas.

The temperature at which the backup takes over for the heat pump — referred to as the “switchover temperature” — is a crucial consideration in the design of a heat pump system. In dual-fuel uses (i.e., partial electrification), the customer can benefit from using cheaper natural gas when the heat pump is less efficient or uneconomic. The switchover temperature yielding the greatest economic return is dependent on the heat pump’s ability to retain performance improvements over the baseline gas furnace into low temperatures, and on the comparative costs of electricity and natural gas.

Full electrification maximizes site (and potentially source) emissions savings and likely brings higher combined system efficiencies. Electric resistance systems generally outperform gas units with efficiencies approaching 99%, compared to gas furnaces that are typically 80% efficient, up to 97% for newer, more advanced variants. Electric backups also bring the added capability to “boost” the heat pump system by supplying the difference between the heat pump’s capacity and the load required. This capability allows the heat pump to be operated for as long as it can provide useful heat, rather than switching to the backup system as soon as the ASHP is incapable of providing the whole load. Additionally, a completely electrified system may be eligible for utility electric space heating rates, reducing the operational costs of the entire system (i.e., heat pump and electric backup). This cost reduction can have a significant effect on whether installing a fully electric heat pump system is economically feasible, as the system relinquishes the cost savings attributed to utilizing a backup system fueled by cheaper natural gas. As an electrification measure, this is only possible when replacing an existing fossil fuel system with a new electric backup. Eligibility for reduced electric rates can also provide significant secondary benefits if applied to non-HVAC energy expenditure. Such secondary effects amplify customer

cost savings in scenarios where special rates are applied to non-HVAC end uses and the customer has considerable electricity consumption outside of space heating and cooling.

A popular and cost-effective approach is to use the home's existing natural gas heating system as a backup (assuming the heat pump is not an end-of-life upgrade) in a dual-fuel setup, as it is already sized for the whole house load and minimizes work required. A dual-fuel system requires only the replacement of the home's central air conditioner with a heat pump that is capable of both heating and cooling. Due to the prevalence of natural gas heating, partial electrification (i.e., heat pump with gas backup) can save on up-front costs by avoiding the installation of a brand-new backup electric heating system, allowing the consumer to make use of the reliable and cheaply operated gas system when the heat pump is unable to provide the required load. In many cases, partial electrification would not qualify for special electric rates, so the operational cost of the system would be higher for the times of year when the heat pump is able to provide load without backup. This could also increase operational costs if the backup system is aging or inefficient, as the benefits of low natural gas prices are offset by poor system performance. As with full electrification, this method could also use a new, efficient backup if the existing natural gas furnace is replaced in addition to the central air conditioner.

Load characteristics of air-source heat pumps

Heat pumps use the most electricity when it is cold and the heating requirement is highest, pushing most of the annual home electrical load into the winter months. This trend remains true for heat pumps that provide cooling in the summer, as they are most efficient during the warmer months and cooling loads are generally smaller. With high efficiencies in the summertime, cooling capable ASHPs generally offer cooling savings compared to baseline air conditioners. Gas furnace systems with central air conditioners for cooling depend on electricity only in the cooling season. Utilities often set seasonal rates to reflect this, charging an increased rate in the summer months surrounding the expected annual peak demand for electricity. With an annual load profile contrary to the incumbent systems, heat pumps require the most electricity when generation costs are lower.

The shift in annual energy consumption to the winter months due to space heating electrification causes a large peak in operational costs in the heating season, which are magnified by lowered heat pump efficiencies. While dual-fuel systems can lower operational costs in the wintertime, these lower costs come at the expense of emissions savings and, potentially, eligibility for electric space heating rates. However, dual-fuel installations also open the door to demand response programs through which the customer opts to switch to their backup fossil fuel system to ease peak loads on the grid. Designing around such load-shedding programs could make the installation more economically viable.

Electrified heating systems can also unlock the benefits associated with changing generation portfolios. As more utilities in the Midwest commit to the expansion of renewable generation in the region, electric heating systems will garner higher emissions savings compared to systems dependent on delivered fuels. The extent of this benefit is, however, dependent on the ability for these systems to coincide with the times of year for which renewable generation is maximized. For example, a grid whose renewable portfolio is heavily dependent on solar photovoltaics would not offer peak renewable generation in the heating season when days are shortest. Conversely, a wind-dominated portfolio might better align peak generation with peak demand from electric heating systems.

Operating and cost performance in Midwestern climates

Electric and gas rates can greatly affect the savings potential for heat pump installations. As it stands, heat pumps face an uphill battle in the effort to gain market share in the Midwest. A significant barrier to expansion is the unfavorable economics introduced by existing rate structures. The economic viability of heat pumps compared to natural gas systems is largely affected by the relationship between electric and gas rates in the heating season. Higher electric rates require ASHPs with natural gas backup to rely more heavily on the backup to prevent increasing operating costs.

The results in Table 1 explore the relationship between the cost of electricity and the share of annual load that can be served at an economically determined switchover temperature with a ducted ASHP unit. These values represent the results of an hourly HVAC energy model applied for a single-speed air source heat pump operated in a dual-fuel system installed in a single-family home in Chicago. A typical winter electricity rate would be around \$0.11 per kilowatt-hour (kWh) consumed, at which the ASHP would only economically deliver 8% of load by running at ambient temperatures above 53°F, or just into the shoulder season. With a system that is eligible for a reduced electric space heating rate of roughly \$0.09/kWh, the heat pump is capable of economically serving 32% of the estimated annual load. While such a rate is generally reserved for fully electrified households without natural gas backup, there is a justification for lower rates for dual-fuel installations in the pursuit of emissions savings. Some regional customer-owned utilities offer rates as low as \$0.06/kWh, allowing the heat pump to operate economically for 78% of the annual load by switching to backup heat sources only below 16°F.

Table 1. Relationship between electricity cost, economic switchover temperature, and load with a gas cost of \$0.744/therm

Cost of Electricity (\$/kWh)	Economic Switchover Temperature (°F)	Annual Load Met (%)
\$0.05	3	92%
\$0.06	16	78%
\$0.07	25	62%
\$0.08	33	45%
\$0.09	41	32%
\$0.10	47	17%
\$0.11	53	8%
\$0.12	58	2%
\$0.13	60	1%
\$0.14	63	0%
\$0.15	65	0%

Although Table 1 only varies the cost of electricity, the economic switchover temperature is dependent on the ratio between the costs of electricity and natural gas. This analysis uses a fixed natural gas rate of \$0.744 per therm, though varying natural gas rates can greatly affect the economic switchover as well. For a given electric rate, an increase in gas prices would decrease

the economic switchover temperature, allowing the heat pump to operate economically for more of the heating season as increased gas prices allow for savings even when heat pumps operate at reduced efficiencies. Conversely, cheap gas would make the heat pump comparatively more expensive to run in cold temperatures, increasing the switchover and decreasing the share of load served by the ASHP.

Based on this relationship, it is clear that eligibility for reduced electric rates represents the removal of a sizable barrier to electrification in the region. Special rate programs would not only provide increased customer cost savings with the use of ASHPs at lower temperatures but also offer the additional benefit of increased claimable site emissions savings for utility programs.

Lower Rates for Air Source Heat Pumps Are Justified

A recurring theme throughout the design of heat pump systems is that (per unit energy) electric rates are higher than those for gas and balancing these two rates can require costly compromises in energy and emissions savings. Favorable electric rates can greatly affect the economic feasibility of covering a larger fraction of annual heating load with an ASHP.

Electricity rates are generally designed around the costs involved in generation and distribution, including energy consumption (cost per kilowatt-hour) and demand (cost per kilowatt) components. For commercial rates, these are treated as separate energy and demand charges, while residential rates bundle these together into one rate per kilowatt-hour. In Commonwealth Edison Company's current fixed, non-electric space heating rates for single family residential customers, 38% of the per-kWh cost is attributed to distribution, while the remaining 62% is for energy consumed (ComEd 2022).

These residential rates are determined based on typical usage and demand. Heat pumps can double typical electric usage, while yielding lower peak demand for summer-peaking utilities due to their favorable annual load profile and efficient cooling performance. The demand component of residential electric rates is usually determined by peak summer values. Although heat pumps consume more energy in heating than cooling, electric heating systems are uncommon and therefore do not greatly contribute to overall winter loads. This peak demand is used to calculate the load factor — a ratio of true annual energy consumption to the capabilities of a generating capacity sized to meet peak demand. Peak demand in this equation represents the maximum capacity requirement (in kilowatts) occurring in the cooling season. The equation for load factor is as stated below:

$$\text{Load Factor} = \frac{\text{Annual Energy Use (kWh)}}{\text{Peak Demand (kW)} \times 24 \text{ hours} \times 365 \text{ days}}$$

A low load factor represents a large discrepancy between annual usage and peak load, implying a disproportionately high summer peak. Conversely, a high load factor implies the generating portfolio is used efficiently, without large fluctuations through the year. As the peak load is currently calculated using peak summer consumption, a higher load factor signifies an electric grid that is efficiently used through the heating season. Despite increasing power consumption, heat pumps increase load factor through efficient summertime cooling and higher-load heating.

As space heating becomes increasingly electrified, utilities in heating-dominated regions will begin to see peaks shift from the cooling season to the heating season. While this trend currently offers an economic benefit by consuming the most power under cheaper winter rates, a future wintertime peak could see electric rates in the heating season exceed those in the summer. Higher electric rates in the wintertime will dramatically shift economics to favor dual-fuel and demand-response-eligible applications that provide an alternative to high, peak electricity rates, particularly when operating heat pumps that do not retain high efficiencies in cold weather.

While special rate programs are currently offered, they are generally focused on all-electric installations and may require that the customer forgo natural gas service of any sort, including cooking. The expansion of special rate programs to dual-fuel customers would encourage electrification while allowing for peak control events to damp the effects of increased electric load in the heating season.

The Economics of Dual-Fuel Rates in Illinois

ASHPs exhibit promising potential for beneficial electrification and energy efficiency in the Midwest. In collaboration with ComEd, a study was conducted to explore the customer economics in the adoption of varying ASHP system designs when applying several proposed fixed and hourly rate structures for a typical residential single-family home in ComEd's service territory in northern Illinois. The modeled ASHP scenarios include both dual-fuel and purely electric systems with varying ASHPs, backups, and switchover temperatures.

Combining Technical Expertise of ASHPs with Rate Structure Analysis

This study approached ASHP system design from a customer cost perspective. Optimizing the customer costs for a given system requires an understanding of both the technical specifications and performance of a heat pump system across the range of ambient temperatures and knowledge of utility rate programs and eligibility. Each scenario consists of a newly installed heat pump system ("ASHP Measure") replacing an existing baseline system comprising a combination of propane, natural gas, or electric heat, with an electric central air conditioner (AC). This analysis included electric space heating and regular rates on fixed and hourly structures, applied to four single-family (SF) residential ASHP cases specified in Table 2 below.

Table 2. Definitions for simulated single-family (SF) ASHP scenarios

Scenario	ASHP Measure	Baseline
SF-1: Electric Furnace	Variable-speed ASHP (HSPF 10, SEER 18), 5°F switchover to electric resistance backup heating	Central AC (SEER 13) and electric furnace (99% efficiency)
SF-2: Gas Furnace (Economic)	Single-speed ASHP (HSPF 8.5, SEER 15), 50°F switchover to natural gas backup heating	Central AC (SEER 13) and natural gas furnace (80% efficiency)
SF-3: Gas Furnace (Maximum)	Variable-speed ASHP (HSPF 10, SEER 18), 5°F switchover to natural gas backup heating	Central AC (SEER 13) and natural gas furnace (80% efficiency)
SF-4: Propane Furnace	Variable-speed ASHP (HSPF 10, SEER 18), 5°F switchover to propane backup heating	Central AC (SEER 13) and propane furnace (80% efficiency)

This study used a detailed building simulation model to estimate hourly single-family HVAC system performance and load for these scenarios over 8,760 hours (i.e., one year). Aside from varying the inputs specified in Table 2, all building and system characteristics are held constant between scenarios at values selected to approximate a representative Chicago single-family residence. The model uses historic 2020 hourly temperatures for the Chicago area to best correlate with ComEd’s 2020 hourly rates.

Three rate scenarios were applied to each of these heat pump systems, each with an electric space heat (ESH) and a non-electric space heat (regular) rate case (ComEd 2022). This includes one scenario in which ComEd’s rates have been adjusted (reallocated) to reflect a potential future scenario. Rate scenarios are summarized in Table 3 below:

Table 3. ComEd regular and electric space heating (ESH) rates used with every single-family (SF) ASHP scenario

Rate Type	Regular \$/kWh	ESH \$/kWh
Fixed — Non-reallocated	\$0.11	\$0.09
Fixed — Reallocated	\$0.09	\$0.06
Hourly*	\$0.09	\$0.07
Hourly [SF-2] *	\$0.18	\$0.15

*Hourly rates vary through the year and are load-weighted averages as reported. They have been applied to system electricity demand on an hourly basis. This can vary by heat pump based on switchover temperature and peak summer HVAC demand.

Hourly rates factor in a capacity charge determined by the system’s peak summer electricity demand. Here, SF-1, SF-3, and SF-4 share a load-weighted hourly rate as they use the same variable-speed ASHP with identical switchover temperatures. The row labeled “Hourly [SF-2]” reflects rates applied to the single-speed ASHP’s electricity demand above its switchover of 50°F, primarily in the cooling season when rates are highest.

Customer Economics Under Alternative Rate Structures

Table 4. Comparison of SF-1 ASHP and baseline annual energy cost scenarios across electric space heating (ESH) rates

Scenario	Annual Energy Cost
ASHP — Hourly ESH	\$590
Baseline — Non-reallocated ESH	\$1,800
% Difference to baseline	-67%

Scenario	Annual Energy Cost
ASHP — Hourly ESH	\$590
Baseline — Reallocated ESH	\$1,300
% Difference to baseline	-55%

Scenario	Annual Energy Cost
ASHP — Non-reallocated ESH	\$740
Baseline — Non-reallocated ESH	\$1,800
% Difference to baseline	-59%

Scenario	Annual Energy Cost
ASHP — Reallocated ESH	\$540
Baseline — Reallocated ESH	\$1,300
% Difference to baseline	-58%

In Table 4, only ASHP scenarios are eligible for hourly rates, and both the baseline and measure qualify for special electric space heating (ESH) programs.

Table 4 displays annual energy costs for the purely electric scenario SF-1. SF-1 (variable-speed ASHP with a 5°F switchover to an electric resistance backup) represents a pure efficiency application (in contrast to electrification), where an electric resistance baseline is displaced by a variable-speed ASHP, maintaining an electric backup. The customer economics of this efficiency-based comparison are influenced by ASHP equipment selection and operational strategies (like switchover temperature). This contrasts the dual-fuel scenarios, in which the customer economics are additionally influenced by non-electric fuel costs (i.e., propane and natural gas). As can be predicted from the sizable efficiency increase, the ASHP provides cost savings in every scenario. The largest savings occurs when the incumbent system is on a non-reallocated ESH rate and the ASHP is on an hourly ESH rate as this is when the annual electric rates differ the most in Table 3.

Table 5. Comparison of SF-2, SF-3, and SF-4 ASHP and baseline annual energy costs across electric space heating (ESH) and regular rate types

Scenario	Annual Energy Cost		
	SF-2	SF-3	SF-4
ASHP — Hourly ESH	\$870	\$590	\$600
Baseline — Non-reallocated	\$770	\$770	\$1,400
% Difference to baseline	13%	-23%	-57%

Scenario	Annual Energy Cost		
	SF-2	SF-3	SF-4
ASHP — Hourly ESH	\$870	\$590	\$600
Baseline — Reallocated	\$740	\$740	\$1,400
% Difference to baseline	18%	-20%	-57%

Scenario	Annual Energy Cost		
	SF-2	SF-3	SF-4
ASHP — Non-reallocated ESH	\$730	\$730	\$750
Baseline — Non-reallocated	\$770	\$770	\$1,400
% Difference to baseline	-5%	-5%	-46%

Scenario	Annual Energy Cost		
	SF-2	SF-3	SF-4
ASHP — Reallocated ESH	\$680	\$530	\$550
Baseline — Reallocated	\$740	\$740	\$1,400
% Difference to baseline	-8%	-28%	-61%

Here, only ASHP scenarios are eligible for hourly and special electric space heating rates.

Table 5 displays annual energy costs for dual-fuel scenarios SF-2, SF-3, and SF-4. SF-2 (single-speed ASHP with a 50°F switchover to a natural gas backup) provides increased costs when comparing an ASHP on hourly ESH rates to baseline systems on a fixed-rate (reallocated or non-reallocated). Modest savings are possible when the ASHP costs are calculated using low, fixed ESH rates, compared to baseline systems on a fixed rate. Altering the switchover temperature for SF-2 can provide additional savings, as will be discussed in the sensitivity analysis below.

For SF-3 (variable-speed ASHP with a 5°F switchover to a natural gas backup), reallocated rates greatly improve customer economics in comparison to non-reallocated rates. Moving from a baseline system on fixed rates to an ASHP on hourly rates may also lower energy costs.

SF-4 (variable-speed ASHP with a 5°F switchover to a propane backup) uses a fixed propane rate of \$1.47/gallon for its baseline and backup heat. This application provides large savings as with SF-1 due to comparatively high propane costs, primarily when switching either from a baseline system on a fixed-rate to an ASHP on an hourly rate, or when the ASHP and baseline are both charged reallocated rates.

Switchover Temperature Sensitivity Analysis — SF-2

Single-family scenario 2 (SF-2) represents the case where an existing natural gas furnace is partially displaced with a relatively low-cost, single-speed ASHP. As the results in Table 5 show, rate structures have a large impact on the economics of using a single-speed heat pump to meet shoulder season load. To further explore this relationship, the SF-2 model was iterated across switchover temperatures between 15°F and 65°F for each possible rate scenario, identifying a new cost-neutral optimum switchover temperature for each case. This analysis uses a fixed natural gas rate of \$0.774 per therm. These results are plotted in Figure 1 below. It must be noted that SF-2 is a dual-fuel system and would not be traditionally eligible for ESH rates. The use of ESH rates in this analysis is intended to investigate the savings potential when the heat pump system is eligible for reduced electricity costs.

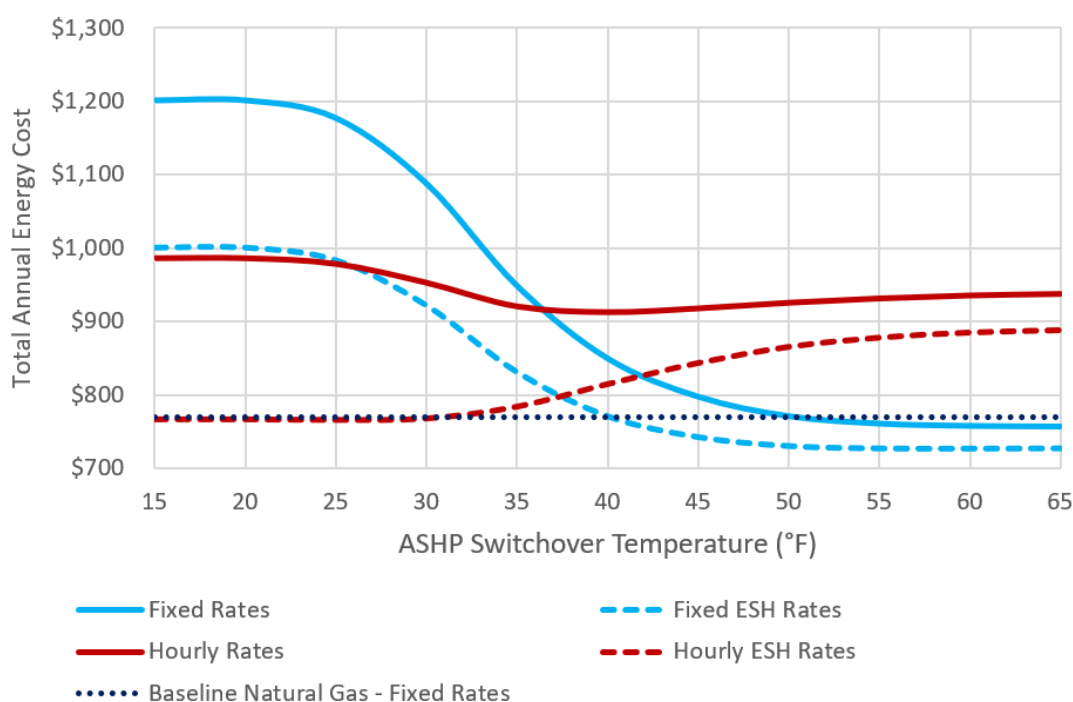


Figure 1: Total annual energy costs (electricity and natural gas) for SF-2 as a function of switchover temperature with Electric Space Heating (ESH) and Regular ASHP rates.

These results reveal a large flexibility in economic switchover temperatures depending on the electricity rate. Comparing the results for fixed rates (blue lines) versus hourly rates (red lines) reveals that economic optimization is heavily dependent on the rate class, potentially to a similar extent to equipment selection. A system with a switchover of 20°F or lower could incur an annual energy cost increase between 0% and 56% compared to the baseline, depending on the electricity rate applied.

Figure 1 also identifies the switchover temperature at which the ASHP is said to be “capacity limited.” Because dual-fuel systems typically do not boost or run in parallel with a heat pump, the curves all flatten below a switchover of 20°F. The heat pump capacity below this temperature is too low to provide the full load and the natural gas backup must be used. As the

usage of the heat pump does not change with switchover temperature below this point, the energy costs at 15°F and 20°F are identical.

The results also indicate the importance of considering the customer's rate scenario in the selection of switchover temperatures. The minimum economic switchover for the SF-2 scenario can vary from 55°F to 20°F below which there is no change in the amount of annual load met by the ASHP. Hourly rates provide attractive energy costs when operating the heat pump to low switchover temperatures, while fixed rates provide lower costs at higher switchovers. As energy usage is much lower in the cooling season than it is in the heating season, higher switchover temperatures cause ESH rates to converge toward their respective regular rates. These then diverge at lower switchovers as the heat pump provides more of the annual load. It is also notable that regular hourly rates have a local minimum cost at around 40°F, although this can shift based on system specifications and variations in weather year to year. Hourly ESH rates, however, are low enough to overcome the balance between efficiency and energy costs that causes this minimum point.

Overall, the flexibility in switching rate classes provides an opportunity significant enough that it must be given equal consideration to the decisions surrounding system design and product selection — although it is possible to minimize cost as a function of switchover in each case. While costs are the primary subject of this analysis, it must also be noted that lower switchover temperatures will provide site emissions savings as an added benefit, although source emissions depend on the carbon intensity of the electrical grid, which varies throughout the Midwest. Emissions savings are a key consideration when comparing two switchovers with similar costs, as could be the case in the regular hourly rate scenario that exhibits minimal fluctuation based on switchover.

Other Considerations

This investigation was performed to understand the relationships between energy rates and heat pump system design specifications in designing a system optimized for cost savings within ComEd's service territory. To this end, all inputs that do not vary between scenarios have been selected to best match single-family residences located within ComEd's territory in the year 2020. Heat pump efficiencies are heavily dependent on ambient temperature, and the results presented in this section may not hold true for other regions or even other years within the same region, given year-to-year climate fluctuations and those across ComEd's expansive service area.

Table 6. Distribution of heating degree days in the Chicago O'Hare area in 2020

HDD Proportion	HDDs (% of total)
Total Annual	5,642 (100%)
Above 5°F	5,585 (99%)
Above 50°F	452 (8%)

Heating degree days are calculated with a reference temperature of 65°F.

Table 6 lists the total heating degree days (HDDs) for the area of analysis in 2020 (NOAA 2021), as well as the proportion of the total occurring above 5°F (the switchover temperature for SF-1, SF-3, and SF-4) and above 50°F (the switchover temperature for SF-2). A

colder year with more HDDs and a larger share falling below 50°F would shift the load away from the cooling season, shrinking the energy expended in cooling and yielding smaller cooling savings. Conversely, a warmer year would shift annual load closer to the cooling season. The heat pump competes with an AC system in summer and a lower efficiency furnace for heating. Colder temperatures would result in a larger difference in annual energy consumption between the ASHP and baseline systems due to the larger difference in efficiency between the heat pump and furnace. This effect is amplified in dual-fuel scenarios in which the baseline heating system is less efficient, particularly in those that employ a high-efficiency variable-speed heat pump for a large portion of the heating season (i.e., with a low switchover temperature as in SF-3 and SF-4). SF-2 has a switchover temperature of 50°F, while SF-3 and SF-4 both use 5°F. Dual-fuel options may also exist for switchover temperatures between these two values, where lower rates provide an opportunity to provide a higher fraction of the heating load than that of SF-2 while still relying on more secondary fuel compared to applications SF-3 and SF-4.

Modern smart thermostats can adjust the switchover temperature to optimize for cost or emissions savings in real time. While this optimization could cause savings fluctuations, it would provide additional assurance that the system can provide more reliable savings. Real time optimization would eliminate some of the guesswork surrounding cost and emissions savings, as variations between homes can significantly change the optimal system specifications.

The results for dual-fuel systems (as in SF-2, SF-3, and SF-4) depend, in part, on the existing system configurations, introducing additional variability between sites. For the purposes of this model, the baseline unit efficiencies have been selected to be representative of the average system. Older, poorly maintained, or improperly designed systems may operate at lower efficiencies than this assumption. While this is unlikely for baselines with 80% efficient furnaces or 99% efficient electric backups, the performance of baseline central air conditioners can vary due to these effects. Conversely, newer units may outperform the modeled baseline system, yielding smaller savings in applications where the baseline is largely replaced (as in SF-3 and SF-4) and lower annual costs for all baselines. This could be the case in sites with higher efficiency baselines, like 95% efficient furnaces.

Hourly rates generally can have a bigger fluctuation in total costs compared to fixed rates depending on the weather and other factors. The capacity obligation rate component is dependent on the peak cooling capacity and contributes a significant amount to the annual energy cost. Warmer or cooler summers would therefore have a large effect on the set capacity obligation. Additionally, varying characteristics such as the quality of building envelopes, occupant behavior, internal gains, shading/solar gains can all significantly alter the capacity obligation for a given site. These are not fluctuations that are considered in fixed rate calculations. Fuel-switching applications will also introduce a new electric load in the heating season, which may shift peak electricity use to the wintertime, although this is dependent on the ASHP and switchover temperature. Cold climate heat pumps that maintain high efficiencies in winter and heat pumps that aren't operated in colder temperatures may not exhibit a heating peak larger than in the cooling season. This effect should be relatively independent of specific climate as peak cooling loads tend not to vary by a large amount between regions.

Electrification of Residential Space Heating Poses Equity Issues

It is essential to approach electrification with equitable strategies in mind. Inherently, the process of electrification in space heating proposes the replacement of a cheaply operated natural gas heating system with new, costly electric heating. In the Midwest, there is a strong case

against space heating electrification in that, historically, regional natural gas prices have been some of the cheapest in the nation (EIA 2022). It is crucial that space heating electrification for low-income populations is handled in such a way that maintains or improves upon the low operational costs of existing fossil fuel systems. Results of this study have shown that customer economics are very sensitive to rate program eligibility and switchover temperatures, but there is no one-size-fits-all approach to optimizing a system for cost. A system designed for a typical single-family residence that is eligible for reduced rates and capable of withstanding a long payback period may be unsuitable for a home in a low-income community.

Capital cost incentives can be popular as a measure to increase heat pump adoption by reducing or eliminating one of their larger barriers to entry. While such programs may seem favorable for low-income communities, high electric rates or improperly designed systems can easily lead to higher operational costs. Even a free heat pump can be a net negative economic decision if it is not able to provide operational savings compared to the existing heating system.

Bill Credit is an Alternative to Special Rates

An alternative approach to reducing the costs of heat pump systems is to incentivize adoption with bill credits. Such programs would address the increase in customer costs with credits applied to utility bills rather than with an alternate rate. A 12-month Residential HVAC Optimization pilot program proposed by Xcel Energy in February 2021 provides residential customers with bill credits when offsetting or replacing a gas furnace with an electric heat pump (Minnesota Public Utilities Commission 2021). Participating customers would receive a recurring bill credit in recognition that heat pumps can incur costs both in installation and operation of the system. These incentive levels range from \$8 to \$62 per month, with some situations warranting an additional up-front incentive of \$100. Annual bill credit totals range from \$96 to \$744 at these incentive levels. In addition to this, customers with compatible heat pump water heaters will also be eligible for their load curtailment program, yielding an additional \$75 enrollment incentive and increased monthly bill credit.

While this program can make a meaningful contribution toward covering some or all the increased cost in installing and operating a dual-fuel heat pump system, there are several drawbacks compared to special rates. While customers are locked into special rates, bill credits are only applied for the duration of the incentive program. Should the program end during the life of the system, the customer may be left shouldering the added operational costs for the heat pump. Unexpected costs can pose equity issues when considering effects on low-income communities, considering the heat pump will likely be dependent on the program to maintain neutral or positive customer economics.

Conclusions

Systems that fully displace natural gas heating produce marginal or negative customer cost savings. This is particularly true in regions like the Upper Midwest, where climates are colder, and costs are higher. While full displacement of fossil fuel heating produces large site emissions savings, the comparative costs of delivered fuels versus electric rates introduce significant hurdles to overcome on the path to reduced operational costs. Partial displacement in dual-fuel applications is generally more economical, allowing systems to be designed such that the heat pump is operated to lower customer costs. The operational costs of dual-fuel systems can be improved by introducing special rate structures. Lower rates reduce the efficiency

improvement the ASHP must provide over the incumbent system to be economically advantageous to operate, thereby allowing for a lower switchover temperature. Lower switchover temperatures are desired to maximize the economic use of electric heat pumps, yielding greater site emissions and energy savings. Future heat pump developments may, however, yield greater efficiency benefits to offset increased energy costs when switching from fossil fuels to electric heating. Future increases in the cost of delivered fuels relative to electricity rates would also provide a similar effect to reduced electricity costs in producing positive customer economics in heating electrification.

Given the goal of both reducing customer operational costs and providing equitable emissions savings in residential heating, it is unlikely that these targets will be met without rate reform to allow for further displacement of fossil fuel heating. Further analysis in partnership with utility rates experts will be required to support new rate structures to best target heating electrification through ASHPs.

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