DEVELOPING ELECTRIC RATES FOR HYBRID AIR SOURCE HEAT PUMPS IN THE MIDWEST

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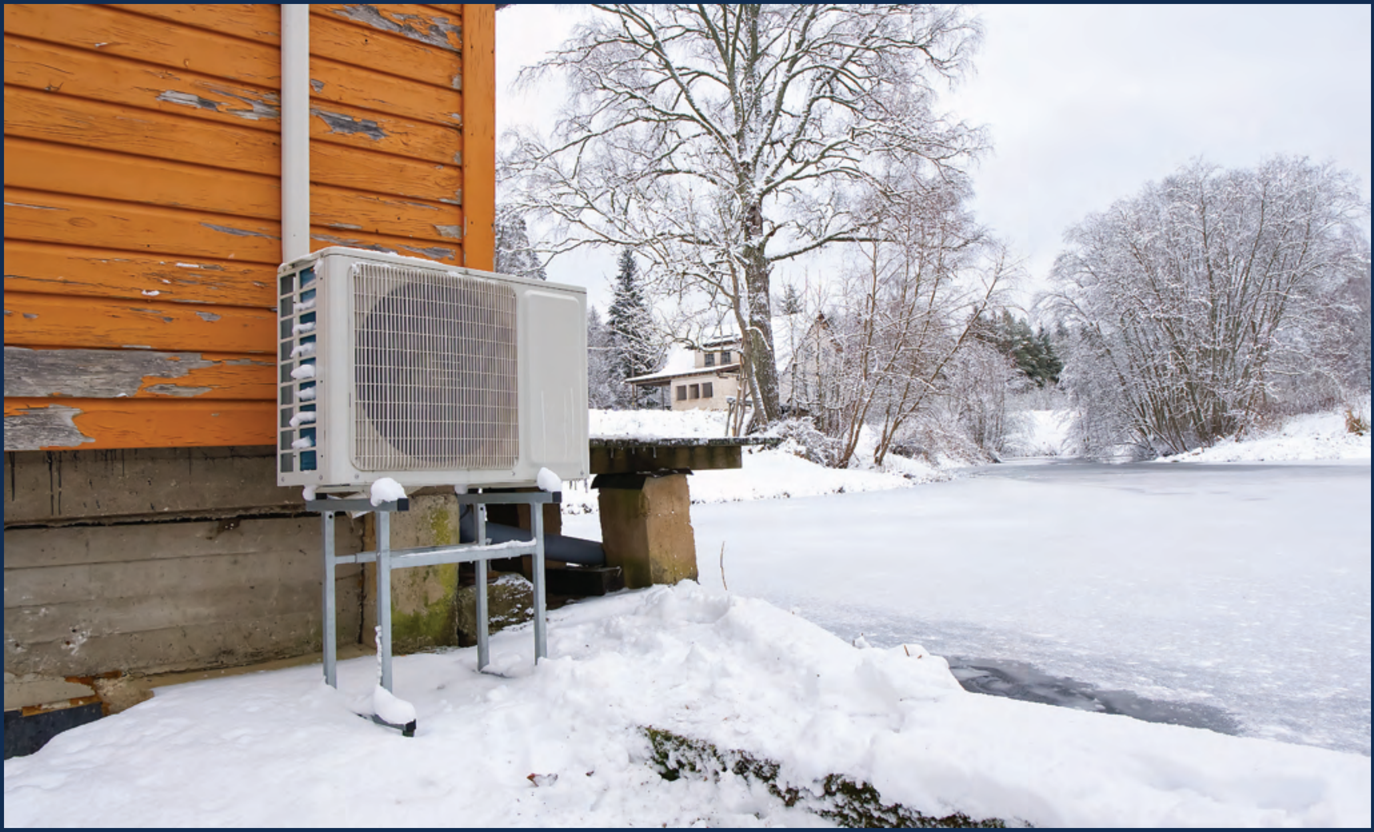

Center for Energy and Environment

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Contents

Executive Summary

Air-source heat pumps (ASHPs) are highly efficient space heating and cooling technology that offer an opportunity to electrify space heating, the largest source of energy use in the residential sector. ASHPs have various possible use cases; this report focuses on dual fuel (hybrid heat) ASHP applications because they are more practical and have a lower bill impact for customers in the Midwest.

ASHPs are not a substitute for weatherization. In fact, homes that have not been weatherized tend to experience worse cost outcomes following ASHP installation. Customers looking to reduce their energy bills should prioritize weatherization — the resulting decrease in energy use can improve customer bill impacts compared to the existing heating and cooling system.

Overall ASHP cost-effectiveness depends on both upfront costs and ongoing operating costs, and ASHP bill impacts are highly dependent on electric rates. A better understanding of how electric rates are determined will help ASHP proponents better advocate for lower electric rates while aligning with ratemaking principles. Our modeling of utility rates shows that in most Midwestern states, at standard residential electric rates, customer bills will increase for customers who install an ASHP, particularly for all-electric systems, presenting a major barrier to electrification. Addressing this barrier through electrification rates or other means is a critical component of achieving widespread electrification, as well as ensuring electrification does not result in an increased energy burden for those that do electrify. This is particularly important to achieve equitable electrification.

Providing a lower rate for dual fuel ASHP systems aligns with rate design principles. Broadly speaking, rate design is in response to utility revenue requirements — costs are allocated among customer classes (and customers in each class) in a way that is equitable and appropriate for the current market. Dual fuel ASHP systems can allow the utility to increase annual electricity sales without incurring larger infrastructure costs associated with peak consumption. Avoiding a winter peak and potentially improving the summer peak while bolstering year-round electricity sales can justify a lower ASHP-specific $/kWh rate. The reduced rate is offset by increased electric use from ASHP customers, allowing utilities to satisfy their revenue requirement. ASHP use can also increase utility load factors and create an opportunity for peak shaving via demand response, both of which lead to more efficient use of generating resources and reduced costs for utilities.

The project team modeled the impact of a dual fuel rate (calculated as 70% of the average $/kWh in each MEEA state, from 2021 EIA averages) across various rate scenarios and climate types. Systems in warmer states (those with fewer than 6,100 heating degree days [HDDs] per year) present the easiest pathway to savings, yielding cost parity or improved bill impacts without the need for special electric rates. In contrast, systems in cold climates (more than 7,300 HDDs) present a greater challenge for the economics of heating electrification, relying on special electric rates and higher gas prices to be cost competitive. Regions with large heating loads also demonstrate a greater sensitivity to rates, with smaller changes in electric rates and gas prices causing a more significant effect on bill impacts compared to warmer climates.

The outcomes described in this report are based on various assumptions — actual results will vary by utility and household depending on the local climate, efficiency of the in-home equipment, local gas/electric rates, home heating/cooling load, etc., as compared to those outlined in the modeling assumptions.

Our broad research conclusions are as follows.

- Electrification at current electric rates is not economic in the majority of the Midwest, presenting a major barrier to widespread electrification.
- Lower electric rates for dual fuel ASHPs in particular are justified and should be pursued.
- Economic impacts of dual fuel systems on customer bills will vary based on state weather patterns.
- Modestly lower electric rates can allow dual fuel ASHP to approach cost parity.
- Utilities and regulators should investigate appropriate rate structures for ASHPs.
- Utilities and regulators should consider dual fuel rate implications for customers with unique needs.

In general, ASHPs offer increased load factors and peak shaving opportunities that help justify more favorable electricity prices. These lower ASHP-specific prices can give partially electrified heating systems the advantage needed to compete with the low natural gas prices in the Midwest. The effect of special electric rates in colder climates can unlock considerable energy and emissions savings in states that present a more challenging economic landscape for electrification with ASHPs. Overall, states looking to pursue ASHP adoption will need to balance the environmental and grid benefits of the technology with the associated customer bill impacts. This is particularly critical for electrification opportunities in lower-income communities that are more sensitive to changing energy burdens.

Areas for future research include the expected utility transition from summer to winter peaks and its expected impact on customer bills, the interplay between dual fuel and TOU rates, and ways to increase the environmental benefits of dual fuel systems.

Introduction

Air source heat pumps (ASHPs) are a compelling efficiency and decarbonization measure across the country, even for cold climate Midwestern homes.[1] Specifically, ASHPs address the electrification of space heating, which has the largest potential for energy savings in the residential sector.[2]

ASHPs are a space heating and cooling technology that operate similarly to air conditioning systems, except they have a reversing valve and additional controls that enable them to operate in reverse, transferring energy from cold outside conditions to warm inside conditions to meet space heating needs.[3] Because ASHPs move heat instead of creating it, they can produce more heat energy for the home than is needed to create the energy, resulting in system COPs (i.e., coefficients of performance or

[1] "Investigation of Air Source Heat Pumps as a Replacement of Central Air Conditioning", Center for Energy and Environment (2022).
[2] "Minnesota Energy Efficiency Potential Study: 2020–2029", Center for Energy and Environment (2018).
[3] "Investigation of Air Source Heat Pumps as a Replacement of Central Air Conditioning", Center for Energy and Environment (2022).

energy output per unit of input energy) exceeding 100%. Under optimal conditions, new ASHPs can have rated efficiencies as high as 400%.[4]

ASHP systems can be configured to meet a variety of customer needs, but this report focuses on dual fuel (hybrid heat) systems, in which the ASHP replaces the central air conditioning system and heats the home down to a specific operating switchover temperature, at which point the furnace is used to meet the heating load.[5] For this application, the ASHP is typically sized to displace a portion of the home heating load, while retaining the existing furnace as a supplemental heat source for the coldest days of the year.[6]

While other regions in the U.S. are targeting full electrification, all-electric ASHP applications are not as practical in cold climates like the Midwest. In climates with very low outdoor air temperatures (OATs), larger ASHPs are required to meet the full home heating load (compared to a dual fuel system using a smaller ASHP to meet a portion of the home heating load). While a larger system can meet the load during the coldest times of the year, it would be oversized at all other times, which leads to reduced system performance due to short cycling (when the system comes on and starts heating the home, shuts off before reaching optimal performance levels, then restarts and repeats the process).

In addition, ASHPs have lower COPs (i.e., lower efficiencies) in cold climates because the lower OATs mean there is less heat that can be moved into the home.[7] As a result, ASHPs designed to meet the full heating load at cold temperatures have less competitive product efficiencies (and economics) compared to heat pumps that only displace a portion of the load.[8]

Larger ASHPs may also have higher upfront costs for the customer compared to a smaller system, which can still meet a substantial portion of the home load. Heat pumps sized for cooling instead of heating can meet anywhere from 50%–90% of home load, depending on system configuration.[9]

Retaining a backup furnace addresses these issues: a customer can install a smaller ASHP system at a lower upfront cost and experience the efficiency benefits of a right-sized system while still meeting most of the home load and maximizing ASHP use during the shoulder season in which it has the highest efficiency. For these reasons, this report focuses on dual fuel applications.

Regarding ASHP adoption in the Midwest, another important factor is fuel costs, specifically, the cost of natural gas compared to electricity. The cost of natural gas matters because it is the predominant fuel

[4] "Minnesota Energy Efficiency Potential Study: 2020–2029", Center for Energy and Environment, Optimal Energy and Seventhwave (2018).
[5] "Investigation of Air Source Heat Pumps as a Replacement of Central Air Conditioning", Center for Energy and Environment (2022).
[6] "Air Source Heat Pumps in Wisconsin Multifamily and Single-Family Applications", Center for Energy and Environment and Elevate Energy (2021).
[7] "Accelerating Air Source Heat Pump Adoption in ComEd Territory", Center for Energy and Environment (2021).
[8] Ibid.
[9] "Investigation of Air Source Heat Pumps as a Replacement of Central Air Conditioning", Center for Energy and Environment (2022).

type (used to heat more than 50% of residential single-family homes) in most MEEA (Midwest Energy Efficiency Alliance) states,[10] as shown in Figure 1.

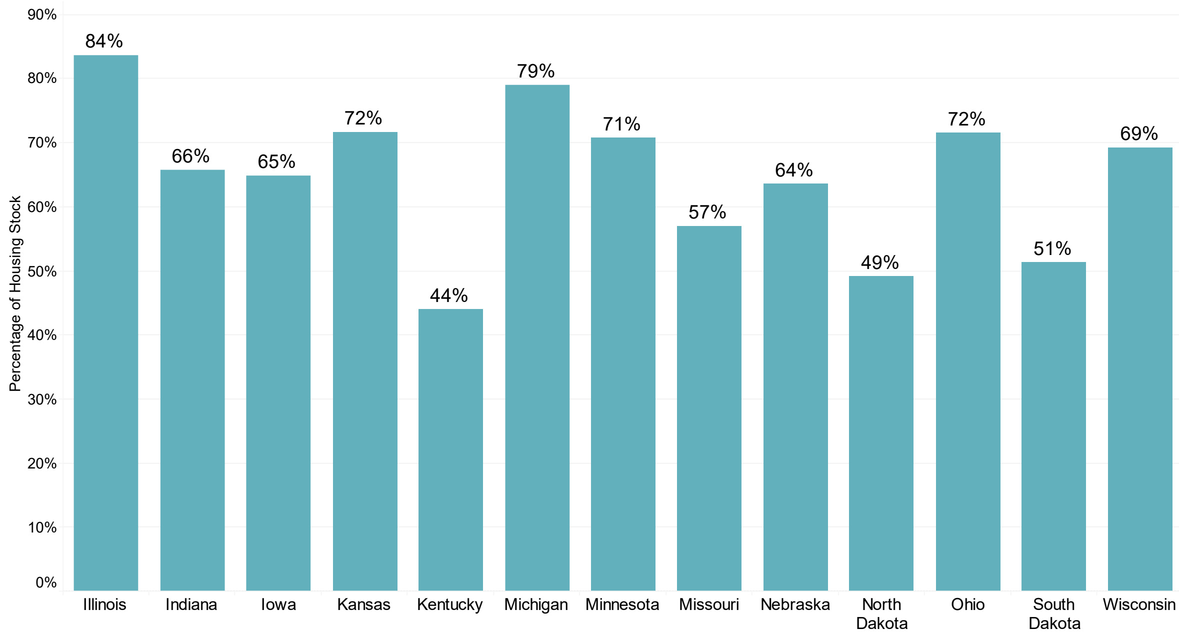

Figure 1: Percentage of single-family homes that use natural gas as the primary heating fuel, for each state in MEEA territory

Given the prevalence of natural gas as a heating fuel in the Midwest, consideration should be given to how switching from natural gas to electricity would impact operating costs for customers.

The ratio between natural gas and electric rates significantly impacts ASHP economics. As shown in Figure 2, dual fuel ASHP systems are economical to operate for space heating when the equipment efficiency ratio (ASHP/baseline) exceeds the fuel-neutral utility energy cost ratio ($/MMBTU electric/gas),[11] because the added cost of electricity used by the ASHP is offset by the decrease in energy consumption given the system's increased efficiency (though ASHP efficiency is also impacted by OATs, as mentioned previously).

[10] Steven Ruggles, Sarah Flood, Ronald Goeken, Megan Schouweiler and Matthew Sobek. IPUMS USA: Version 12.0 [dataset]. Minneapolis, MN: IPUMS, 2022. https://doi.org/10.18128/D010.V12.0
[11] "Investigation of Air Source Heat Pumps as a Replacement of Central Air Conditioning", Center for Energy and Environment (2022).

	Baseline Furnace Efficiency	Seasonal ASHP Efficiency	Equipment Efficiency Ratio	Gas Cost ($/MMBtu)	Elec Cost ($/kWh)	Elec Cost ($/MMbtu)	Utility Ratio	Cost effective?
				Varying electric rates				
1	0.9	3.5	3.9	7	0.07	20.5	2.9	**1.33**
2	0.9	3.5	3.9	7	0.08	23.4	3.3	**1.16**
3	0.9	3.5	3.9	7	0.09	26.4	3.8	**1.03**
4	0.9	3.5	3.9	7	0.10	29.3	4.2	**0.93**

Figure 2: ASHP cost-effectiveness fluctuates based on the system efficiency (ASHP vs. furnace) and fuel costs ($/kWh vs. $/MMBTU)

Though ASHPs have higher efficiencies than natural gas furnaces, MEEA states have relatively low natural gas costs compared to the rest of the nation. According to the historic EIA price data,[12] the average annual price of natural gas delivered to residential customers has been lower for MEEA states than the national average since 1989. As shown in Figure 3, a large cost differential occurs during the colder winter months, which is the peak period for natural gas consumption.

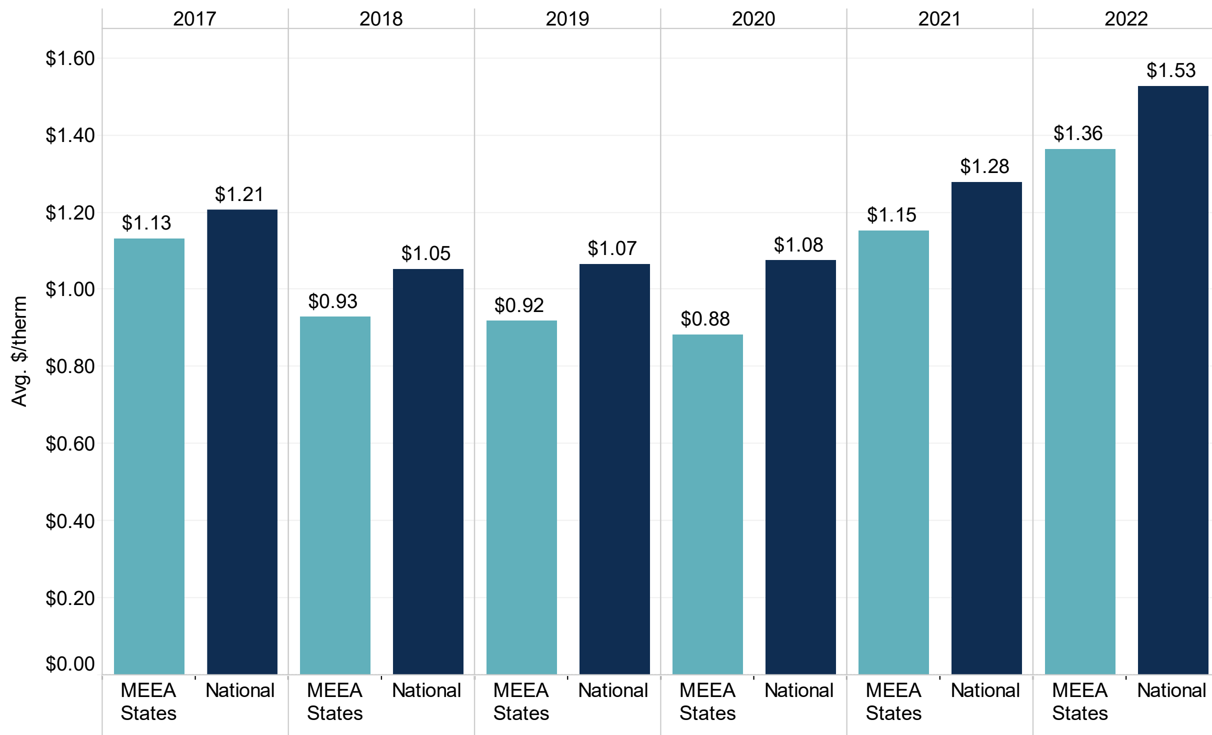

Figure 3: EIA five-year average residential natural gas costs (September–April only), MEEA states vs. the national average

Lower natural gas costs and colder climates mean the improved efficiency from using electricity with an ASHP does not currently compensate for the cost differential between natural gas and electricity. In other words, cheap natural gas makes full electrification economically infeasible in the Midwest.

ASHP operating costs are impacted by both unit efficiency and fuel costs. Heat pumps already have significantly higher efficiencies compared to gas furnaces, so the other way to improve ASHP economics

[12] EIA Natural Gas Prices, retrieved from https://www.eia.gov/dnav/ng/ng_pri_sum_a_EPG0_PRS_DMcf_m.htm

is to reduce their fuel costs (i.e., the cost of electricity). This requires an understanding of how electric rates are currently designed, as well as justification for offering ASHP-specific rates. Such justification could come from more in-depth research regarding how an increase in hybrid heat ASHP systems will cause utility load profiles to change (especially for electricity use), along with factors such as the potential for ASHPs to reduce peak load via load shifting, etc.) and quantifiable estimates of the financial impacts related to these factors. The benefits of ASHPs as both an electrification and demand response measure should also be considered.

Utilities typically experience peak demand during the summer months when customers increase their AC usage, but as electrification efforts continue, Midwest utilities will start experiencing more load during the winter months as customers use more electricity for space heating. Given the Midwest's typically harsh winters, shifting from summer peak to winter peak is expected to significantly increase peak demand and utility grids are not prepared to handle the increase in load. Because dual fuel heat pump systems are interruptible for load control events, they can help reduce both summer and winter peak loads, generating financial savings for utilities (by avoiding expensive peak load plant energy) that can be passed on to customers.

Summer peaking utilities whose customer bases primarily comprise gas-heated homes also display design inefficiencies stemming from disproportionately high summer peak consumption compared to electricity demand during the heating season. Interruptible dual fuel heat pump systems can decrease this summer peak with their high cooling efficiencies and approach a similar peak in the wintertime through load control events and system design considerations including size and switchover temperature. This would be very beneficial to utilities because it would fully utilize their investment in the grid without increasing peak demand.

If utility decisionmakers have a more comprehensive understanding of how ASHPs can reduce their peak load, they may be more willing to consider implementing ASHP-specific rates, but ASHP advocates generally do not have enough insight into a utility's ratemaking process to develop a framework for an ASHP-specific electric rate policy.

ASHPs offer significant benefits to customers and utilities, but the technology is not presently well recognized or understood by policy makers, and ASHP benefits are generally overlooked during the ratemaking process. At the same time, while rates policy is critical to ASHP economics (because lower electric rates increase ASHP cost-effectiveness), ASHP proponents are unfamiliar with ratemaking guidelines. This report attempts to span the knowledge gap between these two groups by serving as a primer for ASHP-specific electric rate considerations.

The purpose of this report is to explore the opportunity for electrification rates that would be applied to hybrid (dual fuel) ASHP systems in the Midwest. Findings from this report can inform discussions on electrification rate structures. While this report focuses on the single-family home application, the principles may be relevant to other applications as well.

The Economics of ASHPs

ASHP economics depend on one-time upfront costs and ongoing operating costs.

Upfront Capital Costs

Upfront ASHP costs depend on, among other things, the system's features and capabilities. Sizing the ASHP system to meet a portion of the home load (i.e., choosing a smaller system tonnage) has a lower upfront cost compared to using a larger system to meet the entire home heating load, especially in colder climates. Regarding system capabilities, ASHP products can generally be grouped into three categories (single-speed, two-speed, and variable speed) based on the degree of modulation they can achieve. Variable speed products, which perform the most fine-tuned modulation, are associated with both increased efficiencies and higher upfront costs. Upfront costs can be further elevated for variable speed ASHPs that are specifically designed for cold-climate operation. While variable speed operation is a desirable feature that can be worth the price, cheaper single- or two-speed units can also be suitable selections for systems that would not benefit greatly from modulating capacity or cold-climate capabilities. Such systems can include those that are not intended to operate in colder winter conditions and those sized for cooling loads in heating-dominated climates.

While wholesale prices are strongly tied to product performance and sizing, current fluctuations in contractor bids for similar equipment can lessen or outright eliminate this relationship. Evaluations of recent quotes in Minnesota find that the upfront cost is much more strongly dependent on the quoting contractor than the performance or capacity of the installed equipment.[13] While cost uncertainty is certainly an issue that homeowners currently face, this analysis assumes that upfront costs for these units are still tied to performance and sizing as evidenced by wholesale prices. This assumption should be reasonable when comparing quotes from the same contractor for varying equipment types, and for customers who are able to shop around and receive several bids for similar equipment.

Operating Costs

ASHP operating costs are impacted by various factors. ASHPs have lower efficiencies at colder OATs, so they cost more to operate as it gets colder. This is a key factor in choosing a switchover temperature (the temperature at which the ASHP is locked out and the gas furnace begins heating the home). In scenarios with lower fossil fuel prices, increasing the operating switchover temperature can lower operating costs by way of increased average electric heating efficiency and a decrease in the portion of home load addressed with electric heating. While this is the more economical system design, high switchover temperatures decrease the extent to which the system is electrified, potentially diminishing the environmental benefits of fuel switching. Conversely, more favorable rate combinations (lower electric prices and/or higher backup fuel prices) can demonstrate the exact opposite effect. In such cases, it can be more economical to use the ASHP more often during winter because the average efficiency required to overcome the difference in fuel prices is smaller.

Operating costs also depend on system efficiency as compared to relative costs. Depending on the product features and capabilities (efficiency, etc.), two products may have the same upfront costs but different operating costs. In addition, operating costs may have an inverse relationship with upfront product costs.

Overall cost-effectiveness depends on both one-time upfront costs and ongoing operating costs, but rebates and other incentive programs often target upfront costs and give less attention to the operating

[13] "Investigation of Air Source Heat Pumps as a Replacement of Central Air Conditioning", Center for Energy and Environment (2022).

costs of electrification. Even a free ASHP can be a net negative if customer bills are increasing. While the purchase of a more expensive, higher efficiency system can improve economics, bill impacts are extremely sensitive to the customer's energy prices. Eligibility for lower, special rates can clear pathways to electrification for income-eligible customers and communities that commonly reside in older buildings with higher heating and cooling loads.

Impact of Weatherization

Another option for homeowners looking to reduce system operating costs is weatherization, which generally entails installing various low-cost energy-saving measures (adding weatherstripping to doors and windows, installing additional insulation, etc.) that are identified and recommended based on the results of an energy audit. The energy-saving measures reduce air leakage (outside air entering and conditioned air leaving through cracks and openings) in the home, leading to reduced energy use and thus lower costs for customers. Weatherization is widely acknowledged as a cost-effective way to reduce heating and cooling costs, improve durability, increase in-home comfort, and create a healthier indoor environment[14] while also reducing carbon emissions. Weatherization should be the first course of action when preparing homes for future energy efficiency upgrades.

While weatherization predictably leads to reduced costs, the impact of ASHPs on customer bills is independent of the impact of weatherization, and so various cost outcomes are possible for homeowners who complete both measures. As mentioned previously, switching to an ASHP could yield a cost increase for weatherized homes (especially for gas-to-electric customers, due to the relatively higher cost of electricity), though the energy savings from weatherization could be significant enough for the combined measures to generate bill savings or potentially approach cost-neutrality (compared to the pre-weatherized home) for a significant portion of homeowners.

Notably, customers who install ASHPs without weatherizing will experience the worst cost outcomes compared to other use cases, because they're potentially incurring a higher cost of energy without the benefit of reduced energy use. Non-weatherized homes generally experience relatively large amounts of air leakage, so likely already have higher bills compared to similar weatherized homes (due to the large amounts of air that are heated only to be lost to the outdoors). Without weatherization, any cost disparities will likely increase once an ASHP is installed. While ASHPs can heat the home more efficiently, they don't address the high levels of heat loss in "leaky" homes. In other words, using an ASHP doesn't reduce the home's heating load (how much energy is needed to heat the home). For non-weatherized homes, the use of ASHPs could potentially increase the cost of energy that is not offset by reduced energy consumption as it would be in weatherized homes.

[14] https://www.energy.gov/energysaver/air-sealing-your-home#:~:text=Tips%20for%20Sealing%20Air%20Leaks%201%20Hire%20an,outlet%20and%20switch%20plates%20on%20walls.%20More%20items

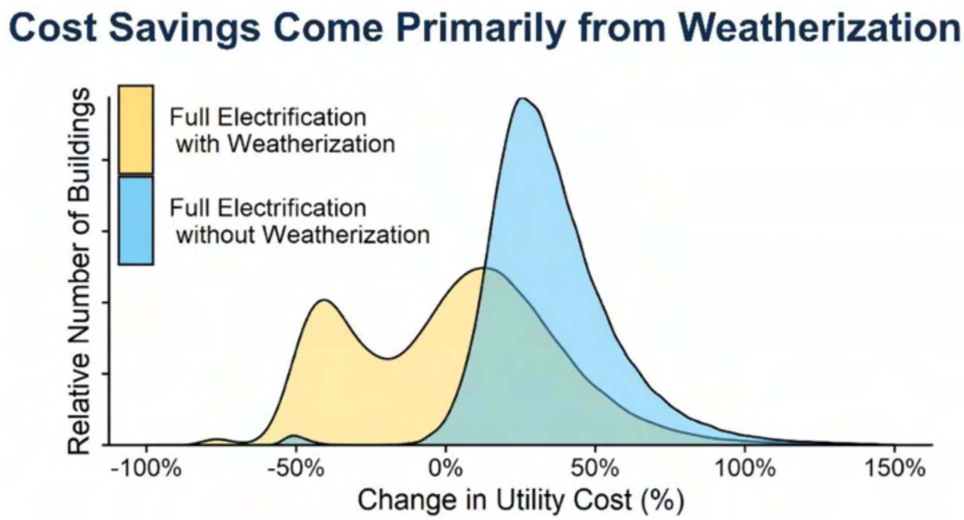

Figure 4: Homes that are not weatherized generally experience cost increases post-electrification, whereas weatherized homes have a broader range of possible cost outcomes[15]

Figure 4 shows the impact of full electrification on customer utility costs for Minneapolis, MN, homes that are weatherized compared to homes that are not. Figure 4 results are for full electrification, which would likely increase customer bills more than the dual fuel approach highlighted in this report. However, the general trend of varying cost outcomes (i.e., the potential for an increase or decrease in customer bills) for weatherized homes is consistent regardless of the degree of electrification.

In general, customers looking to reduce energy costs should begin with weatherization. The measures identified through the energy audit are generally low-cost and can often be installed on the same day, which means there is a much lower upfront financial commitment and barrier to entry for the homeowner (compared to the ASHP selection and installation process). Weatherization also directly reduces the home heating load by reducing the amount of conditioned air lost to the outdoors, which leads to immediate cost savings from the reduction in energy use. Given that ASHPs are generally sized in relation to the home load, weatherized homes generally can be served with a smaller ASHP than their non-weatherized counterparts, which could lead to reduced upfront costs for customers who decide to install an ASHP in the future.

Impact of Rates on ASHP Economics

ASHP operating costs (and overall cost-effectiveness) also heavily depend on the cost of electricity, as shown in one study examining ASHP customer economics of various rate structures. In one modeled scenario, with all else being equal, "Economics improve even more for natural gas and propane customers when modeling costs using the reallocated electric space heating rate of 6.4¢/kWh — the internal rate of return (IRR) for this scenario was 28% for natural gas customers, compared to an 18% IRR using the original (baseline) space heating rate of 8.7¢/kWh."[16] As shown in this example, operating costs are sensitive to rates; shifting electric costs by just a few cents has a significant impact (2.3¢/kWh decrease led to a 10% increase in IRR). While exact rates vary significantly by state, utilities in all states

[15] "Minneapolis 1-4 Unit Residential Weatherization and Electrification Roadmap", Center for Energy and Environment, 2023.

[16] "Impact of Alternative Rates on ASHP Adoption Study", Center for Energy and Environment, 2021.

can experience similar rate sensitivities, meaning that ASHP economics could be significantly impacted by electric prices throughout the Midwest.

While ASHP economics benefit from lower electric rates, electric rate proposals generally do not address how lower rates could be achieved through the ratemaking process. In fact, rate design principles are generally not considered in rate advocacy work, presumably due to a lack of knowledge regarding foundational ratemaking principles.

Rates (derived via a methodology) that ignore or violate key ratemaking principles are unlikely to be adopted, so a better understanding of the current ratemaking process is key to future rate advocacy work. A working knowledge of ratemaking guidelines provides baseline information about how rates are designed, as well as insight into whether lower rates are prudent or even possible under the relevant ratemaking framework.

The next section provides an overview of the ratemaking process and the factors considered during each stage of the process.

The Case for Special Electrification Rates

Overview of Ratemaking Principles

As outlined by the Regulatory Assistance Project (RAP), an independent NGO with the mission of advancing policy innovation in the energy community, there are three distinct phases of ratemaking and each phase feeds into the next.[17]

The first phase determines the required level of annual revenue, or the revenue requirement. The revenue requirement must be approved by regulators before taking effect — this is usually done via a utility rate case.

The second phase allots the revenue among the utility's various rate classes. Utilities divide customers into various classes (residential, commercial & industrial, street lighting, etc.) and analyze various data points specific to each customer class, such as number of customers and usage patterns during certain time periods. These data are then used in a cost-of-service study, a methodology used by utilities to equitably divide the revenue requirement among the rate classes.

Finally, during the rate design process, rates are determined for each customer in the specified rate class, with the goal of an equitable distribution of costs among individual customers within a rate class. At this stage, rates are designed with the purpose of collecting the assigned level of revenue from each class. In other words, rates are based on the utility's cost to serve its customers.

Rate costs are allocated between customer charges (charged per billing period without varying by usage), volumetric energy charges, and demand charges (both of which are based on electricity consumption over a given period). These three basic options allow for a wide range of variations based on season, time of day, and type of demand measurement.[18]

[17] "Electric Cost Allocation for a New Era", Regulatory Assistance Project (RAP), 2020.
[18] Ibid.

Rate Variation Example (TOU)

The closest existing proxy to the ASHP-specific rate variation considered in this report are time-of-use (TOU) rate structures, for which the cost of energy depends on when the energy is consumed.

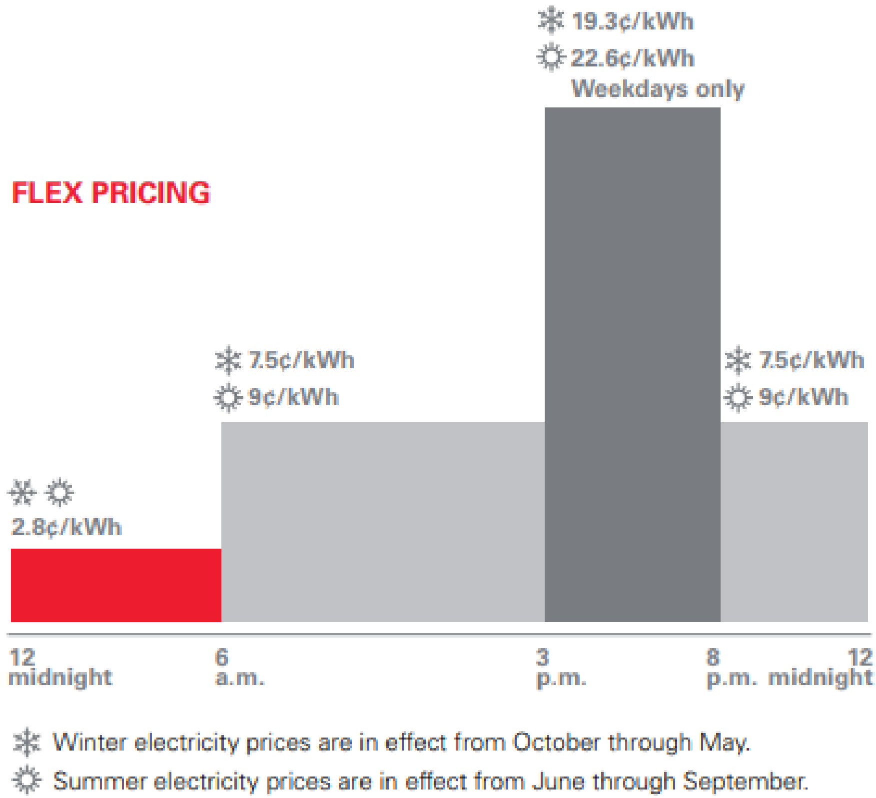

Figure 5: Example TOU rate structure, from Xcel Energy's Residential Time of Use Rate Design Pilot[19]

As shown in Figure 5, for customers enrolled in TOU programs, electric prices fluctuate throughout the day: costs are generally higher during on-peak periods with increased demand (often in the morning, as customers wake up and begin their days, and/or late afternoon, as customers return home after work) and lower during off-peak times (e.g., nighttime hours). Many TOU rate structures vary costs depending on the time of day, but some may also include seasonal fluctuations (e.g., higher rates during summer months, when demand for electric cooling increases).

Promoting TOU rates is a subpar approach for ASHP customers because the typical daily TOU rate structure disadvantages heating/cooling equipment by making them the most expensive to operate during the same time periods that they see the heaviest use. In addition, TOU rates motivate customers to respond to daily energy use trends rather than seasonal benefits, and so they overlook the system benefit of ASHPs during various times of year. TOU structures also operate as “blunt instruments” in that they are designed and implemented for all customers in response to predicted activity but cannot

[19] From https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={D0CA327F-0000-C130-B92D-0CF55C38B2F4}&documentTitle=20222-183193-02.

be adjusted in response to actual conditions for individual customers (e.g., customers whose peak usage times do not align with prescribed grid peak time periods).

Technological advancements that enable device interconnectedness allow systems to identify unique savings opportunities for customers in response to real-time grid activity and optimize energy use both for the individual system and the overall utility grid. Opportunities to increase the use of technology in DER planning are discussed later in this report.

Rate Design Principles for Today's Environment

Core ratemaking principles include affordability, efficiency, and equity/fairness (both to each rate class and to customers in the same rate class). Ideally, rates would achieve some semblance of each principle, rather than sacrificing one at the cost of another. In fact, rate makers may be required to aspire toward achieving a balance between all three principles. For example, in Minnesota, per statute, rates "shall be sufficient, equitable, and consistent in application to a class of consumers,"[20] while encouraging energy conservation.

The appropriateness of rate design principles for today's market should also be considered since rates can directly impact consumer energy use patterns. In fact, this guideline is explicitly called out in Minnesota 2022 statute, which states, "Rate design should always focus on forward-looking efficiency, including concepts like long-run marginal costs for the energy system and societal impacts more generally, because rate design will influence consumer behavior, which in turn will influence future costs."[21] Essentially, rates and customer energy use have a reciprocal relationship — rate design can encourage certain energy consumption trends, and the impacts of the resulting customer behaviors are considered as inputs whenever rates are redesigned.

The interactive nature of this relationship means that designing appropriate rates for the current market requires an accurate outlook of current energy use trends. However, some rate processes have remained unchanged since they were first established. For example, NARUC (the National Association of Regulatory Utility Commissioners), another authority in the rate design process, created an Electric Utility Cost Allocation Manual[22] outlining key rate design principles. This document is a cornerstone of ratemaking processes for many utilities, but it was written in 1992 and has not received significant updates since. In other words, the ratemaking process often begins with frameworks that were established to serve a vastly different energy market, i.e., are based on assumptions/circumstances that were more common 30 years ago when the documents were first published (e.g., less access to natural gas as a heating fuel for Midwest customers). Existing ratemaking principles can and should be adapted to incorporate current market trends, as that will allow the rates to better meet the needs of today's market.

A list of resources describing ratemaking methodology in further detail is available in Appendix A: Rate Design Methodology.

[20] https://www.revisor.mn.gov/statutes/cite/216B.03
[21] Ibid.
[22] Available at https://pubs.naruc.org/pub/53A3986F-2354-D714-51BD-23412BCFEDFD

Rationale for ASHP Electrification Rates

Energy costs generally comprise four components, which may be fixed or vary as energy use increases or decreases.

- Energy costs (variable)
- Generation capacity costs (fixed – demand charge)
- Transmission costs (fixed – demand charge)
- Distribution costs (fixed – demand charge)

As outlined by RAP, each cost component should be designed so that costs are equitable among individual members of a rate class. For residential customers, rates are generally bundled, that is, energy and demand costs are lumped together into a single per kWh charge.

$$\frac{(energy\ +\ demand)\ costs}{total\ energy\ usage} = \frac{\$}{kWh}$$

Equation 1: kWh bundled rate calculation

In general, homes with dual fuel systems tend to use more electricity and serve a larger portion of the home heating load with ASHPs (compared to homes only served with fossil fuels). Because fixed costs are the same for hybrid systems (that is, no additional fixed costs are incurred because no extra "wires" are required, because a hybrid system won't increase peak demand), the costs can be spread over the larger load incurred in homes with ASHPs. In Equation 1 above, the demand costs would remain static for ASHPs, while energy use increases. In other words, the same amount of fixed cost is incurred for a larger kWh load, which reduces the kWh bundled rate in Equation 1.

A dual fuel rate offers increased benefits compared to other technology-specific rates because it creates the opportunity to electrify space heating, which is the largest opportunity for energy savings in the residential sector. Utilities with municipal and co-operative ownership models recognize the benefits of lower electric heat rates and are already offering them to customers, such as the 6.31¢ rate offered by Dakota Electric[23] to customers receiving controlled interruptible service (a form of demand response).

A lower ASHP-specific dual fuel rate may also be rationalized by ASHPs' ability to improve utility load factors and participate in demand response, as outlined in the next section of this report.

Impact of Hybrid Heat Systems on Utility Load Factors

The U.S. Energy Information Administration (EIA) defines load factor as "the ratio of the average load to peak load during a specified time interval."[24] Load factor is calculated as

$$\frac{kWh\ generated}{Max\ capacity\ (KW) * hours\ of\ operation}$$

Equation 2: Load factor calculation

[23] From https://www.dakotaelectric.com/wp-content/uploads/2022/09/Residential-Tariff-Book-September-2022.pdf

[24] https://www.eia.gov/tools/glossary/index.php

The load factor value can be considered a measure of how efficiently utilities use their existing assets. A load factor of 1 signifies consistent energy demand (i.e., average load = peak load) during the specified timeframe. High load factors are preferred by utilities because they indicate predictable demand, which is easier to account for when planning for power generation. Additionally, a high load factor means a utility regularly uses most of its assets and can serve most or all the load using existing infrastructure.

In contrast, a low load factor indicates periods where significant load is being generated for relatively short periods of time (often during summer months). These additional loads increase a utility's overall peak, or the maximum load the utility needs to be able to meet at a given time. If utility infrastructure is already sized to meet peak load, a low load factor indicates a large portion of existing resources are being underutilized because they are only required to meet peak demand, and so are not used outside of peak periods. If peak load increases, a utility may need to install additional plants to meet the added demand, rather than increasing utilization of existing assets they've already invested in. The costs of additional asset acquisition would then be recouped from ratepayers.

When utilities increase their load factor, they increase their use of existing assets that have already been purchased and avoid the costs of additional peak-only infrastructure that will only be used some of the time (and avoid passing these costs to customers). ASHP customers can help increase a utility's load factor by participating in demand response, as outlined in the next section of this report.

Demand Response Capabilities of Hybrid Heat Systems

For customers using dual fuel rates, investor-owned utilities may require a separate meter to measure just space heat energy use. The upfront expense for a second meter (unit + installation) can be anywhere from $1,500–$2,000,[25] which can be cost-prohibitive for customers. In contrast, when using an ASHP, energy use could be measured via smart thermostat or AMI (advanced metering infrastructure), a smart meter technology that enables two-way system communication and automatically reports customer energy usage to the utility in smaller, more frequent intervals (e.g., every 15 minutes), rather than just once per month. Using AMI capabilities allows utilities to confirm that the energy being used is for space heat without installing a second meter, which would remove a significant upfront cost barrier for customers.

Many ASHP models are also interconnected devices (i.e., utilities can remotely interface with them). Requiring devices to meet certain interface standards creates both system monitoring and load control opportunities. One example of an interface mandate is Washington State House Bill 1444, which requires electric water heaters sold in the state to have a modular demand response communications port compliant with CTA-2045-A. CTA-2045-A is a communication interface standard requiring devices to have "a physical port and communication protocol, to facilitate communications with residential devices for applications such as energy management. This interface is comparable in concept to a USB socket specifically designed for appliances. The interface provides a standard port and communication protocol for energy management devices to be attached to, and communicate with, the specific end use appliance."[26] Implementing a similar standard for ASHPs is another way to encourage demand response participation for dual fuel systems.

[25] https://mn.my.xcelenergy.com/s/residential/heating-cooling/back-up-relief-program
[26] "Emerging Codes and Standards for Grid-Interactive Buildings", Northeast Energy Efficiency Partnership (2021).

Technological standards and advancements like the ones described above allow utilities to perform load control spontaneously, which offers new opportunities for load management. Currently, most utilities use load control to manage summer peak by installing equipment on customer ACs that allows the system to participate in demand response during the summer. This allows utilities to reduce their summer peak load, which saves money because the utility can minimize or altogether avoid the use of expensive peak load plants to meet the demand. Cost savings are passed on to customers, generally via a bill credit received during the summer months. Load control via smart thermostat, AMI, or an interfacing device would allow utilities to mitigate peak load during any time of the year, not just the summer months. This flexibility will become more important as electrification becomes more widespread, and utilities switch from summer-peaking to winter-peaking, at which time there will be increased value in using demand response management to avoid winter peak. Spontaneous load control would also enable utilities to increase ASHP use during shoulder seasons (i.e., when it's most efficient and economical) and allow dual fuel systems to respond to real-time market conditions, which provides benefits for customers and utilities by identifying opportunities for energy savings and adjusting system performance in response to those opportunities.

More research is needed regarding what technological or methodological standards utilities use to determine customer usage, and whether the use of a retail consumer smart thermostat or AMI disaggregation technology would be considered acceptable for revenue-grade metering. Consideration should also be given to customers in rural areas who may have difficulty implementing these technologies due to limited internet access. Similar discussions are taking place regarding electric vehicles, which essentially constitute one large load with significant opportunity for optimizing costs. Various possible options are available for reporting EV-specific energy use, including embedding a meter in the charger itself and sharing energy consumption with utilities via a secure connection (a version of the interfacing capability outlined in CTA-2045-A).

Exploring Potential Electrification Rates

To gain a better understanding of existing electric rates in the Midwest, the project team reviewed 2021 EIA blended electric rates[27] (calculated as $ revenue/kWh sales) for the 13 Upper Midwest states included in the Midwest Energy Efficiency Alliance (MEEA) territory. The data in Figure 6 show blended rate averages per state, filtered to include only utilities (investor-owned, municipal, and co-operatives) with high sales and large customer bases.

[27] From https://www.eia.gov/electricity/sales_revenue_price/ (table T6)

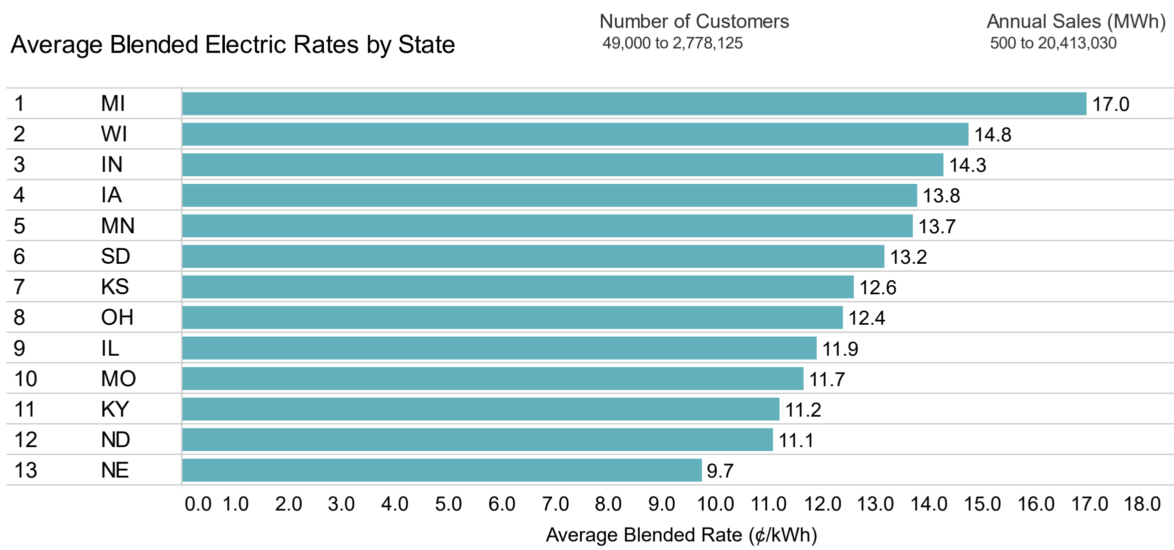

Figure 6: Average blended utility rate values ($ revenue / kWh sales) per MEEA state

The average ¢/kWh blended rate value for each state was used in the more detailed modeling described in the next section.

Modeling Methodology

An hourly household energy model was used to investigate the effects of rate scenarios on ASHPs in midwestern climates. Each model compares a dual fuel ASHP scenario to a counterfactual baseline system, representing the furnace and central AC combination that would have been used had the ASHP not been installed. The model results comprise 104 runs, each with a unique combination of weather, electric rate, and gas rate. Electricity rates are varied between current estimates and 70% electricity prices to estimate the effects of potential space heating rate eligibility. To this end, ASHP measures are designed to electrify at least 50% of the space heating load. Current gas rates are adjusted in additional scenarios to model potential price fluctuations. Table 1 lists variables and assumptions for these models, selected to represent a median midwestern home from RECS 2015 microdata.[28]

Table 1: Variables and assumptions for the hourly home HVAC energy model

	Parameter	Description
Assumptions	Home Type	2,100 square foot single-family detached home constructed in the 1970s. Home heating and cooling loads are held constant between the measure and baseline.
	Baseline System	SEER 14 air conditioner and 95% two-stage ECM gas furnace, sized for peak heating loads.
	Measure System	Cold-climate variable speed ASHP sized for the larger of 1) heating load at 5°F or 2) peak cooling load. Backup heat is provided by a 95% two-stage ECM gas furnace identical to the baseline.
	Heat Pump Utilization	Switchover temperature selected in 5°F increments to address at least 50% of the annual home heating load in each climate.

[28] From eia.gov/consumption/residential/data/2015/

	Non-HVAC Electricity	4,100 kWh per year attributed to non-HVAC electric end uses.
Variables	Electric Rates	Electric rates determined on a per-state basis from EIA historic volumetric energy prices.[29] A dual fuel rate is estimated to be 70% of the standard rate in each state.
	Gas Rates	Gas rates determined on a per-state basis from EIA historic volumetric energy prices.[30] Additional gas price scenarios were developed at 80%, 100%, 120%, and 140% of the historic price to account for price volatility.
	Location & Weather	The climate of each of the 13 states in this study is represented by a typical meteorological year in its most populous city.

The chosen ASHP is a cold-climate variable speed unit, designed to retain capacity at lower temperatures such that we can investigate the impacts of operating the ASHP into peak winter conditions. Figure 7 shows its performance across a range of outdoor air temperatures, including heating COP and capacity. Here, the variable speed capability of the ASHP is displayed as a ribbon, where its capacity can be modulated between a minimum and maximum value at each temperature. The system for each location was sized for heating load at 0°F or for peak cooling load, whichever is larger, and is operated to the nearest switchover temperature in 5°F increments that addresses at least 50% of the annual heating load with the ASHP. Depending on the location, this value is between 20°F and 30°F, below which the system relies on the backup gas furnace for the whole home load.

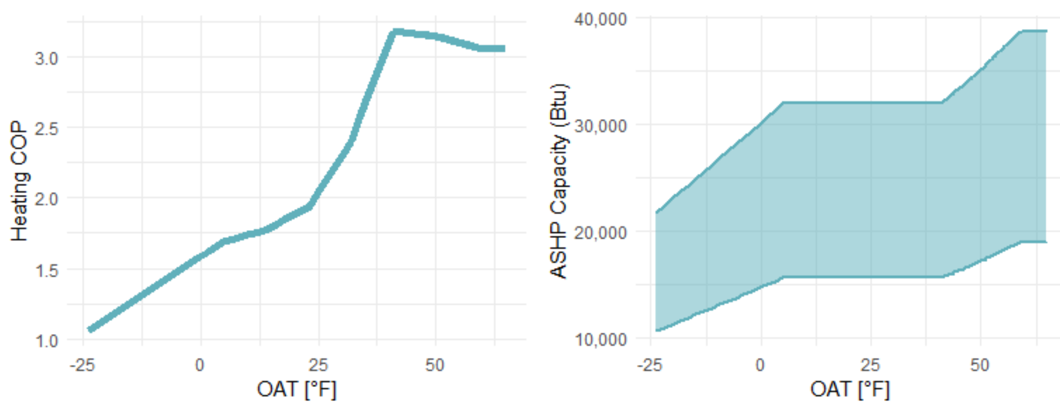

Figure 7: Cold-climate variable speed ASHP performance across heating OATs

Effects of Weather

These selected states span a broad gamut of climate types. Annual HVAC energy was modeled for the same home type in each of these climates, with each state represented by the climate of its most populous city. Weather influences system sizing, heating and cooling energy consumption, ASHP efficiency, ASHP capacity, and the switchover temperature selected to address at least 50% of annual heating load with the ASHP.

In addition to fluctuating between locations, weather also fluctuates year to year. Weather files for the typical meteorological year (TMY files) are used to represent each location. TMY files attempt to

[29] From https://www.eia.gov/electricity/sales_revenue_price/ (table T6)
[30] From https://www.eia.gov/dnav/ng/ng_pri_sum_dcu_SIL_a.htm

represent typical weather conditions over several years at each location. While this is useful for modeling efforts, fluctuations from typical weather can affect performance and economics. A warmer-than-average year would decrease the heating load, increase the cooling load, and increase load-weighted heat pump COP. In this example, systems with higher operating costs per MMBtu delivered (compared to the baseline) would see costs decrease with smaller annual heating loads, and systems with lower operating costs would see savings decrease. Conversely, a colder year would exaggerate costs and savings in the heating season. ASHP operating costs per MMBtu delivered would decrease in years with warmer weather and increase in years with colder weather. The extent of this effect is determined by the ASHP's COP vs. OAT profile. Figure 8 displays the difference between historic weather from 2012–2022 and the associated TMY weather data for Minnesota, Iowa, and Kansas. In every case, the TMY data estimates colder temperatures year-round, with consistently higher heating degree days (HDDs) and fewer cooling degree days (CDDs) compared to recent weather. This discrepancy will result in more conservative estimates for ASHP COP, increasing heating energy consumption and exaggerating customer bill impacts.

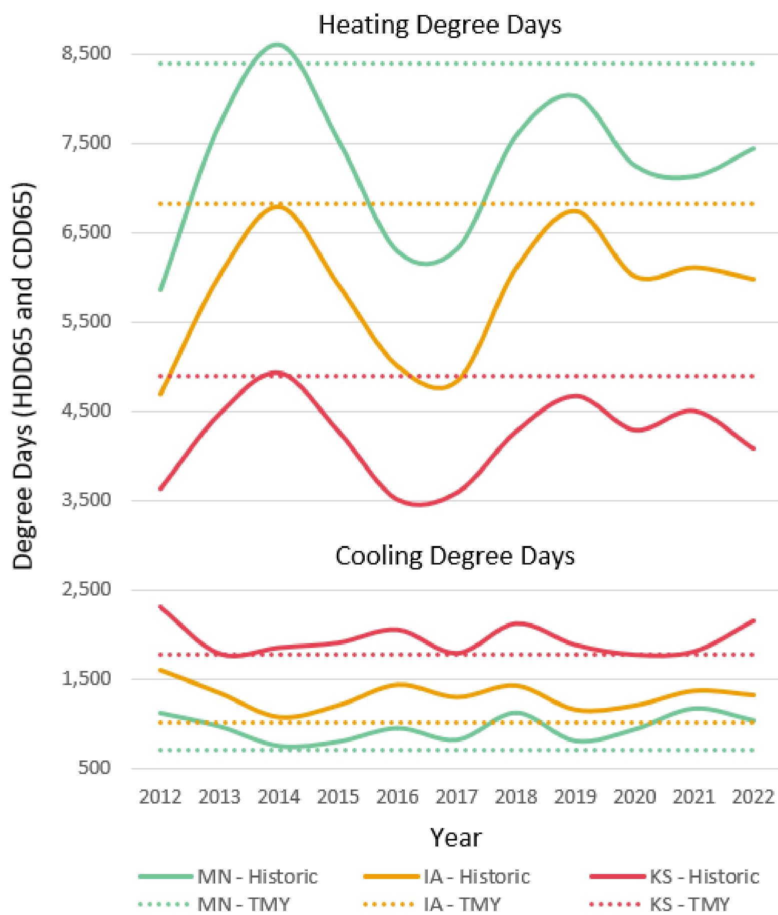

Figure 8: Comparison of historic degree days vs. TMY data for three example climates

Results/Observations

Customer Bill Impacts

The hourly energy model was iterated through these locations, each with their own weather, sizing, and rate combinations. Each ASHP addresses at least half the heating load in a typical weather year. The annual energy cost for each measure is then compared to its respective baseline gas system. Dual fuel electric rates are estimated to be 70% of the existing standard rate and can be applied to HVAC-only or to the entire home, inclusive of 4,100 annual kWh of non-HVAC electricity consumption for other end uses and plug loads. Natural gas (NG) prices are adjusted to 140% of the EIA value to represent recent fluctuations.[31] Figure 9 tabulates the energy bill outcomes in each of these scenarios.

		100% Electric Price		70% Electric Price HVAC only		70% Electric Price Whole Home	
State	**Climate**	**100% NG Price**	**140% NG Price**	**100% NG Price**	**140% NG Price**	**100% NG Price**	**140% NG Price**
MN	Colder	🔴	🔴	🔴	🟡	🟡	🟢
MI	Colder	🔴	🔴	🔴	🟡	🟡	🟢
WI	Colder	🔴	🔴	🟡	🟢	🟢	🟢
ND	Colder	🔴	🟡	🟡	🟢	🟢	🟢
SD	Colder	🔴	🟡	🟡	🟢	🟢	🟢
IL	Moderate	🔴	🟡	🟡	🟢	🟢	🟢
IA	Moderate	🔴	🟡	🟡	🟢	🟢	🟢
IN	Moderate	🔴	🟡	🟡	🟢	🟢	🟢
OH	Warmer	🟡	🟡	🟡	🟢	🟢	🟢
KY	Warmer	🟡	🟢	🟢	🟢	🟢	🟢
NE	Moderate	🟡	🟢	🟢	🟢	🟢	🟢
KS	Warmer	🟡	🟢	🟢	🟢	🟢	🟢
MO	Warmer	🟡	🟢	🟢	🟢	🟢	🟢

🔴 Significant Bill Increase
🟡 Cost Parity
🟢 Significant Bill Savings

Figure 9: Comparison of annual HVAC energy costs for dual fuel ASHPs vs. the baseline system.

Here, cost parity is defined as a net annual cost increase or savings of under $100 compared to the baseline, with costs and savings outside of this range deemed as significant. Climates are grouped into three categories based on the annual number of typical HDDs for each state's TMY data, as shown in Table 2 below.

Climate Type	**Typical HDDs**
Colder	> 7,300
Moderate	6,100–7,300

[31] Ibid.

Warmer	< 6,100

Table 2: Climate types by typical HDDs

Most of the modeled states would see annual bill increases greater than $100 with EIA's estimates for fuel prices, with only 5 out of 13 states achieving near cost parity, and no cases with significant bill savings. Adjusting for current gas prices (140% NG scenarios) with current electric rate estimates improves this landscape, with four warmer-climate states now seeing significant bill savings, and six states achieving near cost parity. Colder climates with less favorable electric rates still yield significant bill increases, and only one improves to approach cost parity when comparing potential HVAC-only dual fuel rates with current unadjusted gas price estimates. Combining dual fuel HVAC rates with 140% gas rates eliminates all cases of significant bill increases, with all states now seeing either significant savings or cost parity. Whole-home eligibility for dual fuel rates can be responsible for between $120 and $210 each year. This is enough to yield similarly positive results for dual fuel electric rate scenarios even without the gas price adjustment, and significant savings across the Midwest with 140% gas prices.

Rates Sensitivity Analysis

In addition to the rate iterations displayed in Figure 9, each state's weather scenario was iterated through a broader range of electricity and natural gas prices. This more in-depth analysis investigates the impacts of a broader variety of outcomes including rate combinations not grounded in current energy prices. This section highlights three such analyses, each exemplifying one of the three climate types listed in Figure 9. The results for all 13 states are available in Appendix B. Each state climate case was iterated through electric rates from 0.05 $/kWh–0.20 $/kWh and natural gas rates from 0.6 $/therm–1.8 $/therm. The resulting annual HVAC energy savings outcomes are displayed as a contour plot divided into bins of $100 and colored similarly to Figure 9. Outcomes in yellow are considered at cost parity with the annual energy costs for the baseline system, where the ASHP energy cost is estimated to be within $100 a year of the gas baseline. Savings above $100 are considered significant and are colored in green, and significantly increased costs (negative savings) are in red. Each plot also has a black rectangle highlighting the rates scenarios presented in Figure 9. The top left corner of this rectangle indicates the existing gas and electric rate combination. The bottom right corner represents the case in which gas prices are at 140% of current EIA estimates and a special dual fuel electric rate is available and set at 70% of current estimates. Note that the dual fuel rate is only applied to the HVAC system, thereby excluding an additional $120–$210 in savings from switching every electric end-use in the home from current rates to the proposed lower rate.

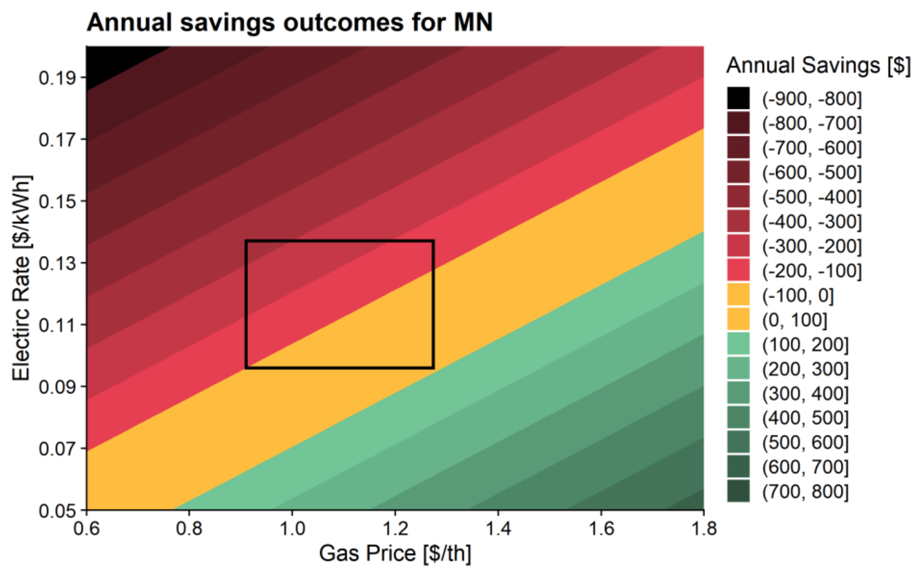

Figure 10: Contour plot of potential savings outcomes for a range of electric and gas rate combinations in Minnesota.

Colder climate scenarios present a greater challenge for positive customer economics while also representing the greatest potential for environmental benefit from the electrification of a comparatively large heating load. Figure 10 above shows the array of savings outcomes in Minnesota. Colder climates display a greater sensitivity to fuel prices, with narrower bands of annual savings and a broader range of bill impact outcomes. This example represents a colder climate in which cheaper natural gas currently presents a less favorable rate environment. Colder temperatures drive up heating requirements while decreasing ASHP seasonal efficiency, producing increased costs of about $350 per year with the current rate scenario. Scaling up gas price estimates by 140% approaches cost parity, lowering costs (compared to the baseline) to about $150 per year with current electric rates, or nearly $100 in estimated annual savings when paired with a special dual fuel rate. Although this scenario is excluded from this figure, annual savings can be further increased by roughly $170 (for a total of up to $270) when applying the 70% electric rate to the whole home rather than the HVAC system alone.

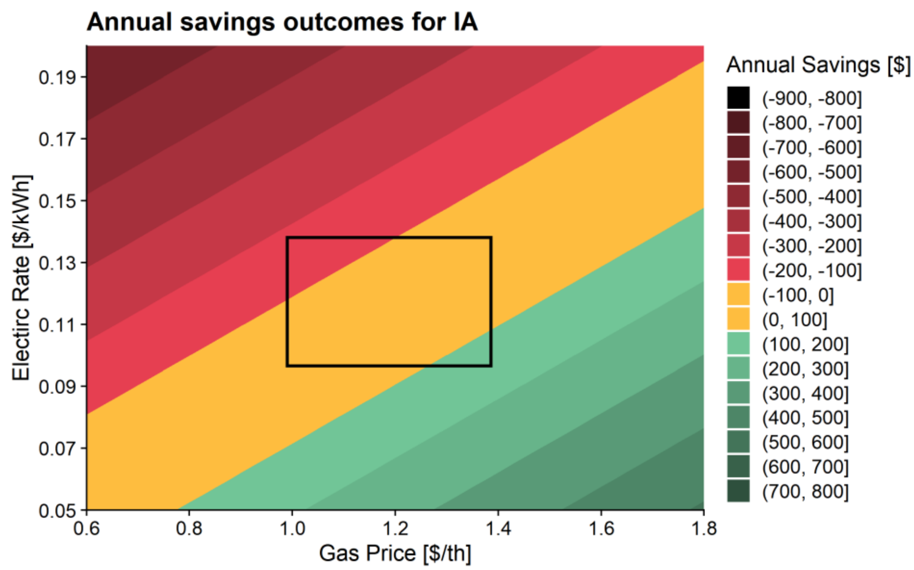

Figure 11: Contour plot of potential savings outcomes for a range of electric and gas rate combinations in Iowa.

States determined to be moderate climates in this analysis can still provide a considerable opportunity for energy and emissions savings, with typical annual heating degree days over 80% of that for colder climate states on average. These states also have over 40% more cooling degree days than colder climate states on average, allowing for a greater benefit from cooling efficiency improvements in the summer months. Figure 11 displays bill impacts for Iowa. Moderate climate states show less sensitivity to electric rates compared to colder climates, signified by fewer, wider bands in this figure. In addition to a more moderate climate, Minnesota's southern neighbor presents a more favorable rate combination thanks to higher comparative natural gas rates and similar electric rates. Although it is not considered a cold climate in this analysis, Iowa is still heating-dominated, with a peak heating load about 37% higher than its peak annual cooling load. This example is therefore more conducive to positive customer bill impacts despite an existing rate scenario yielding a nearly $200 cost increase in annual energy costs compared to the baseline. Adjusting gas rates by 140% to mimic current gas prices allows for cost parity between the baseline and measure without relying on lower electric rates. Special electric rates produce significant annual savings of about $150, or up to $320 if those rates are applied to the whole home (not pictured).

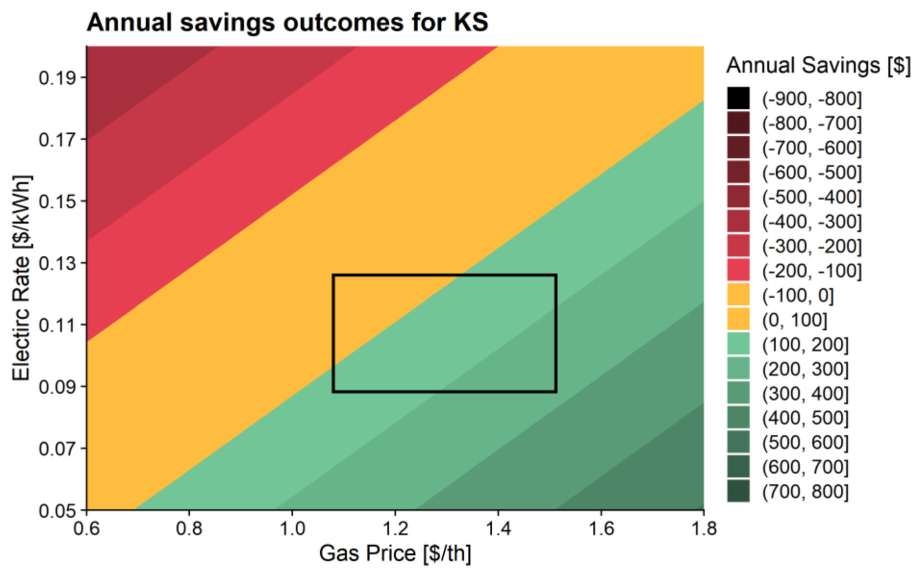

Figure 12: Contour plot of potential savings outcomes for a range of electric and gas rate combinations in Kansas

Continuing this exercise to the southernmost MEEA states brings us to warmer climates, exemplified by Kansas in Figure 12. Warmer states display the lowest sensitivity to changes in rates, with fewer, wider regions in this figure signifying that a broader range of rate combinations can produce similar bill impacts outcomes. With 17% fewer HDDs and 27% more CDDs compared to moderate climates on average, warmer states are more conducive to efficient ASHP performance. Their comparatively small heating loads can diminish potential energy and emissions savings from electrification, however, simply by virtue of using the heating system less. This applies to Kansas most of all, with the fewest typical annual heating degree days (4,900 HDDs) and the most cooling degree days (1,800 CDDs) of the MEEA states. Kansas represents a cooling-dominated climate, with a peak cooling load over 50% larger than its peak annual heating load. The comparatively large bill savings impact of cooling efficiency improvements combined with relatively high natural gas prices allows for cost parity with the baseline using existing rate conditions. Adjusting gas rates to 140% of the EIA estimated current value drives savings of over $150 per year, or over $250 per year with special dual fuel electric rates set at 70% of the current estimate. Applying these special electric rates to all the home's electric end uses unlocks further savings, bringing the annual estimate to roughly $400.

Grid Impacts

Having investigated the impacts on customer economics, we can also model the grid implications of a dual fuel system designed to electrify half the heating load, in comparison to a typical furnace and AC combination. Figure 13 below displays potential effects of partial heating electrification on annual HVAC load factor. Load factor is calculated based on peak summer loads in each case.

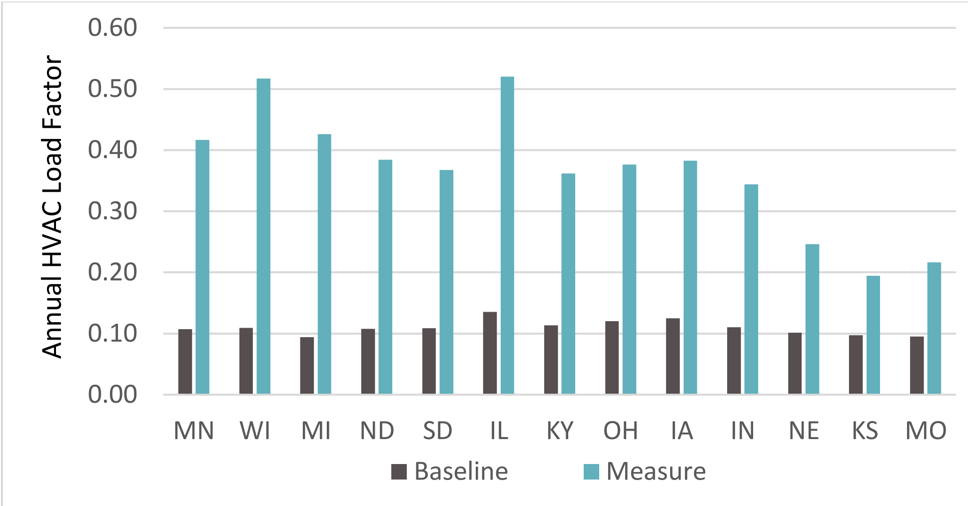

Figure 13: Annual HVAC load factor for the dual fuel ASHP measure compared to the baseline in each location

We see load factor improvements in every scenario, ranging from 200% to 470% of the baseline value. Smaller load factors imply peak cooling energy use is larger than the annual average hourly consumption, seen in warmer climates with sizeable cooling loads. While these load factors may be improved by further electrifying into the heating season and increasing heating electricity consumption, this may be at the expense of customer economics. We see larger load factors in colder climates, where the average hourly electricity consumed in partially electrifying the heating season is more like the peak cooling demand.

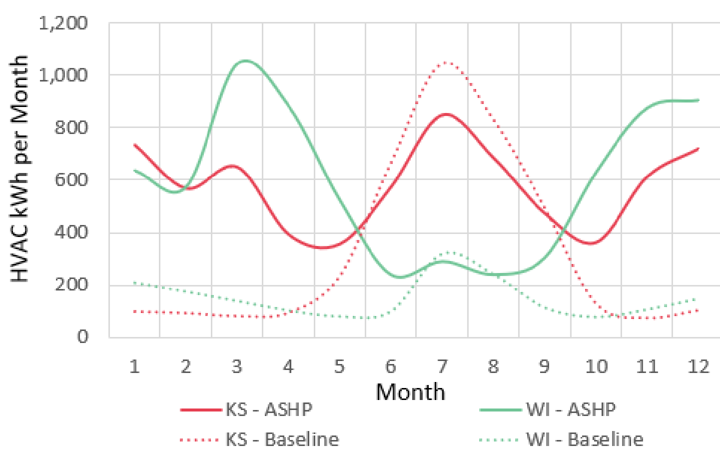

Figure 14: Monthly HVAC electricity consumption for ASHPs in KS and WI vs. their baselines

Figure 14 shows the trend of monthly electricity consumption through a typical year in Kansas, representing a warmer climate, and in Wisconsin, representing a cold climate, for each baseline and measure. The ASHP provides cooling efficiency savings in both cases, although the difference in cooling loads between the two locations yields much more significant savings in Kansas. In the heating season, we see the effect of the dual fuel switchover where consumption is high in milder months and trails off in peak winter when the ASHP is used less often. Given the milder winter weather in Kansas, electric heating demand is distributed more evenly through the heating season compared to the strong peak found in Wisconsin.

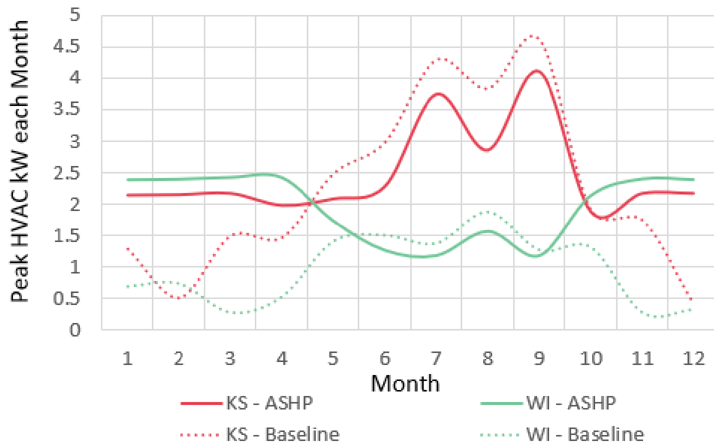

Figure 15: Peak HVAC electricity consumption for ASHPs in KS and WI vs. their baselines

Figure 15 displays the peak kW demand in each month for the same model runs. Both locations highlight the dual benefit of partial electrification with ASHPs. The baseline's summer peak is now shallower thanks to cooling efficiency improvements, and consumption continues into the heating season without creating disproportionate winter peaks, allowing for better use of grid resources throughout the year. Warmer climates remain summer peaking, albeit to a lesser extent than the baseline system. The discrepancy between peak demand in heating and cooling contributes to a lower load factor, potentially encouraging further electrification in similar climates. As shown in Figure 9, warmer climates are also more likely to have positive economics, allowing for a more aggressive electrification strategy. The opposite is true in cold climates like Wisconsin, where the summer peak is small compared to demand in the heating season, yielding a better load factor in this analysis. Colder climates with larger loads and reduced ASHP efficiency can find positive customer economics to be a difficult goal in current rate environments. Raising the switchover temperature can alleviate negative bill impacts at the expense of environmental and grid benefits.

Other Considerations

A cold-climate ASHP was selected for this study to capture additional flexibility in ASHP use at peak winter temperatures. The performance profile of the modeled system sacrifices mild-weather efficiency for a lower minimum operating temperature and improved cold-weather heating capacity retention. This is a capability that typically comes at an initial cost premium, and that may not be necessary if the desired switchover temperature is within the bounds of operation for non-cold-climate offerings. For higher switchover temperatures, a single-speed or (non-cold-climate) variable speed unit may deliver similar or improved average efficiency at a more attractive price point. Such products would likely be more than sufficient for the warmer climates investigated, where temperatures are unlikely to fall enough to justify the installation of a cold-climate unit.

The selected baseline is a counterfactual scenario of a higher-than-average performance furnace and air conditioner combination. While this is a useful perspective when considering ASHPs as an alternative to new replacement gas systems, customers with older, lower efficiency furnaces and air conditioners will likely see more positive outcomes when comparing against their historic energy costs. This is not only due to both a greater improvement in average heating efficiency and a potentially significant improvement over the existing air conditioner. Cooling savings can be large enough to flip borderline cases in Figure 9, particularly in climates with larger cooling loads.

The model also assumes the baseline and measure address the same home heating and cooling load. While this is suitable for a counterfactual argument, customers undergoing system upgrades can also opt to weatherize their homes. This effectively makes the ASHP responsible for a smaller home load compared to the baseline, thereby decreasing energy consumption and increasing savings. While weatherization is often treated as a way to buy down electrification by unlocking operational savings with an initial investment, it is important to note that in many cases, weatherization is required to avoid sizeable bill increases from electrification.

This study considers a median home, keeping the parameters of this home type constant between model runs and locations. The building stock across the Midwest ranges from homes with much higher energy use and poorer performing envelopes to much tighter homes with smaller heating and cooling loads. The existing systems in these homes would also vary from lower efficiency heating with no cooling to newer, higher efficiency heating and cooling combinations as we have assumed in these baseline models. The addition of cooling can result in poorer customer economics, representing a pure cost increase in warmer months. While these results present example outcomes across climates and rate combinations, the economic impact of electrification can also vary across the building stock. This is true from a bill impact standpoint, where poorer performing homes can see much more exaggerated outcomes, but it is also true from an equity perspective, where residents of such homes can be much more sensitive to changing energy burdens. Such instances would be prime candidates for weatherization, which is not only helpful but necessary for equitable electrification strategies.

More utilities are expected to transition toward winter peaking through the proliferation of space heating electrification. As more homes electrify their space heating loads, peak winter conditions can cause capacity constraints as electricity demand spikes. Although dual fuel systems sacrifice the environmental benefits of full electrification, the interruptible nature of dual fuel systems allows for wintertime peak shaving via load control events, during which the home can rely entirely on the backup furnace. ASHPs, dual fuel or otherwise, can also curtail existing winter peaks for utilities whose territories include significant populations of customers with traditional electric heating systems. Electric resistance heating is limited to a COP of 1 (100% efficient), while cold-climate ASHPs can outperform this benchmark even in peak winter conditions, as is shown in Figure 7, using less electricity to deliver the same heating load. A caveat to this benefit is that the ASHP would likely be unable to meet the whole home load well above the OAT at which it would approach the efficiency of traditional resistance heating.

Conclusions and Next Steps

Here we provide the major takeaways, conclusions, and recommendations from our research.

Conclusions

Electrification at current electric rates is not economic in the majority of the Midwest, presenting a major barrier to widespread electrification.

High-performing ASHPs experience reduced system performance at cold outdoor temperatures, which are common in the region during winter months. At current electric rates, customers generally pay a higher per unit cost for electric compared to natural gas, which has been historically cheaper than the national average (with an even more pronounced cost difference during the heating season). The combination of very cold weather and low natural gas prices increases costs for customers switching from natural gas to electric, especially during winter months. Given the harsh winters and low regional natural gas rates typical of the Midwest, lower dual fuel rates are needed to make ASHPs cost-competitive for Midwest customers.

Lower electric rates for dual fuel ASHPs in particular are justified and should be pursued.

Lower electric rates for dual fuel ASHPs offer several benefits. They encourage dual fuel ASHP adoption by improving customer economics and allow utilities to sell more energy (at a lower rate), while still satisfying their revenue requirements by avoiding a corresponding increase in fixed costs. As shown by this research, dual fuel ASHPs improve utility load factors and provide opportunities for peak shaving. An ASHP-specific electric rate also encourages energy consumption from a low-carbon source (that will become even less carbon-intensive as more renewable energy technologies are added to the grid) and could serve as a bridge between the common utility options of a standard rate and an all-electric rate, particularly for customers in colder climates for whom all-electric systems may be prohibitively expensive.

Economic impacts of dual fuel systems on customer bills will vary based on state weather patterns.

States with milder climates will have a larger portion of housing stock that can achieve cost parity using current rates (and would experience cost savings using a dual fuel rate). In comparison, states with colder climates will need to balance electrification efforts with customer and utility system economics. While utilities benefit from the increased load factor and peak shaving opportunities provided by dual fuel systems, current rate trends indicate that ASHP adoption will increase utility bills for customers in colder climates, though overall cost impact can be mitigated with a dual fuel rate option for customers.

Modestly lower electric rates can allow dual fuel ASHP to approach cost parity.

Modeled results indicate that in moderate climates and cold climates (those with more than 6,100 HDDs annually), dual fuel systems begin to approach cost parity with reduced electric rates (though customers in very cold climates only begin to approach cost parity when natural gas rates are higher than the estimates used). Lower rates would have an even larger impact in cold climates, which have a high sensitivity to fuel prices and the largest potential for environmental benefit from electrification.

Utilities and regulators should investigate appropriate rate structures for ASHPs.

Ratemaking is a complex endeavor and depends on utility-specific conditions and cost structures. It involves a combination of data analysis and consideration of rate equity between rate classes and can be a time-consuming undertaking. It is imperative that key regulators and utility stakeholders are engaged promptly in considering appropriate electrification rate structure.

Utilities and regulators should consider dual fuel rate implications for customers with unique needs.

The impact of a dual fuel rate on customer economics depends in part on local weather conditions and fuel costs as outlined previously, but certain customer populations have additional characteristics to consider before implementing a dual fuel rate.

In areas where monthly customer charges are a large portion of homeowner bills (e.g., Chicago), a lower dual fuel rate has minimal impact on total customer costs because the monthly customer fee is the same no matter how much energy is used. These customers may be better served by all-electric HVAC systems installed as a component to whole-home electrification, as this setup eliminates gas service (and the associated customer charge) entirely.

ASHP-specific rates should also be accessible to low-to-moderate (LMI) customers. A dual fuel rate would benefit residential customers who can afford the upfront costs of a dual fuel system but would exclude lower-income customers that can't afford the financial investment of more energy efficient technologies for themselves. While these customers may be able to access the technology by having their upfront installation costs 100% covered through a federal or regional utility program, any resulting increase in customer bills still creates a negative outcome, especially for LMI customers, who tend to have a higher-than-average energy burden compared to the average customer. Lower dual fuel rates could provide significant economic benefit for the LMI population.

Future Activities and Areas for Further Research

To make an impact, it is critical to impress the recommendations of this white paper to create ASHP-specific rates on those with the power to do so. Thus, in addition to the further research items listed, Center for Energy and Environment (CEE) intends to connect with regulators to disseminate report findings and educate them on why an ASHP-specific rate is justified for residential customers.

This engagement will include webinars and one-on-one meetings with interested and applicable parties at both the national and regional level. Events, such as biannual National Association of Regulatory Utility Commissioners (NARUC) policy meetings, are critical opportunities to reach a wide audience of regulators across the nation. MARC, the Mid-America Regulatory Conference, functions as the regional consortium of regulators associated with NARUC and is back to hosting in-person meetings after a multi-year hiatus due to the global coronavirus pandemic. CEE will also leverage existing relationships with regional representatives associated with the National Association of State Energy Officials (NASEO) to disseminate findings from both this paper and CEE's overarching market transformation strategy for the region as it relates to ASHPs.

Efforts to engage with these stakeholders will enable this information to reach a wide audience of decisionmakers and move the needle from analysis to actual implementation of these rates. Implementation may require a combination of additional work from regulators to make these rates possible and efforts by utility rate staff to build and recommend the rates within their associated rate case schedules.

While the work to disseminate these findings is ongoing, it is also critical that organizations like CEE continue conducting research that addresses emerging questions regarding the impacts of this energy transition.

Areas for further research include the broader utility transition from summer peaks to winter peaks. As utilities and states work toward their various electrification goals, electric use will increase during the winter months, especially for states with cold climates. Here are several areas of research that can be expanded on to evaluate the impact, timing, and cost of this shift.

- Complete analysis of different ASHP adoption rates and evaluate the timing and impact of a shift from a summer peak to a winter peak.
    - Evaluate the impacts on peak consumption for varying levels of ASHP market penetration (25%, 50%, etc.).
    - Determine potential timeline for ASHP adoption.
    - Evaluate the impact weatherization can have on peak demand when paired with ASHP adoption.
- Evaluate the impact rates can have on ASHP adoption and how rates can be used to avoid a shift to a large winter peak.

Many utilities are also adopting or considering TOU rates. Further analysis is needed to determine the impact TOU rates have on dual fuel systems. Here are a few key research questions.

- Would TOU rates increase customer bills when shifting to a dual fuel ASHP?
- Do TOU rates properly reflect the utility grid benefits dual fuel ASHPs offer?

The environmental benefits of fuel-switching largely depend on the emissions intensity of the electricity grid. Areas deriving more of their electricity from fossil fuel combustion are likely to see smaller emissions savings with dual fuel ASHP installations compared to those operating with electricity supplied from lower greenhouse gas-emitting sources. Some electric grid emissions intensities are high enough that positive net emissions impacts depend on ASHP efficiency. In such cases, a high enough COP is required to overcome the difference between emissions from the electrified system and those associated with onsite natural gas combustion. Future research can investigate several questions related to optimizing dual fuel systems for environmental benefits, including:

- How do environmental benefits vary with the emissions intensity of the electricity grid?
- What are the implications of optimal system design and operation?
- Which midwestern states have the greatest opportunity for improved environmental impacts while providing positive customer economics?
- How effective are electric rates as a lever to improve environmental impacts?
    - Interruptible dual fuel systems under demand-response programs can prevent electricity use in peak periods supplied by carbon-intense generating sources.
    - Systems optimized around time-of-use rates (via intelligent controls, customer action, or otherwise) can shift consumption away from more emissions-intense periods of high demand and increased electricity prices.
- How do the answers to these questions change with varying grid forecasts over the life of the equipment?
- What are the pathways to maximize emissions savings?
    - Future research can identify promising avenues to improve emissions savings through methods such as demand response, intelligent controls, onsite distributed generation, and energy storage.

Appendix

Appendix A: Rate Design Methodology

“Electric Cost Allocation for a New Era,” Regulatory Assistance Project (2020). Available at https://www.raponline.org/wp-content/uploads/2020/01/rap-lazar-chernick-marcus-lebel-electric-cost-allocation-new-era-2020-january.pdf.

“Electric Utility Cost Allocation Manual,” National Association of Regulatory Utility Commissioners (1992). Available at https://pubs.naruc.org/pub/53A3986F-2354-D714-51BD-23412BCFEDFD.

Appendix B: Modeling Inputs and Results

Table 3: Representative cities for each state, with weather and system inputs used for each modeled location

State	City	TMY HDD65	TMY CDD65	Furnace Capacity (Btu/h)	CAC Capacity (Btu/h)	ASHP Heat/Cool Capacity (Btu/h)	Dual Fuel Switchover Temperature (°F)
MN	Minneapolis	8,400	700	50,000	30,000	30,000	20
MI	Detroit	6,900	600	40,000	24,000	30,000	30
WI	Milwaukee	7,300	500	50,000	24,000	30,000	30
ND	Fargo	8,900	700	60,000	30,000	30,000	20
SD	Sioux Falls	7,700	900	50,000	30,000	30,000	25
IL	Chicago	6,400	800	60,000	24,000	30,000	30
IA	Des Moines	6,800	1,000	50,000	24,000	30,000	30
IN	Indianapolis	6,100	1,000	50,000	24,000	30,000	30
OH	Columbus	5,900	1,000	50,000	24,000	30,000	30
KY	Lexington	5,300	1,100	40,000	24,000	30,000	30
NE	Omaha	6,500	1,300	50,000	36,000	36,000	30
KS	Wichita	4,900	1,800	40,000	48,000	48,000	30

The complete rate sensitivity results for all 13 states are available below. Each state climate case was iterated through electric rates from 0.05 $/kWh–0.20 $/kWh and natural gas rates from 0.6 $/therm–1.8 $/therm. The resulting annual HVAC energy savings outcomes are displayed as a contour plot divided into bins of $100 and colored similarly to Figure 9. Outcomes in yellow are considered at cost parity with the annual energy costs for the baseline system, where the ASHP energy cost is estimated to be within $100 a year of the gas baseline. Savings above $100 are considered significant and are colored in green, and significantly increased costs (negative savings) are in red. Each plot also has a black rectangle highlighting the rates scenarios that are presented in Figure 9. The top left corner of this rectangle indicates the existing gas and electric rate combination. The bottom right corner represents the case where gas prices are at 140% of current EIA estimates and a special dual fuel electric rate is available and set at 70% of current estimates. Note that the dual fuel rate is only applied to the HVAC system, thereby excluding an additional $120–$210 in savings from switching every electric end-use in the home from current rates to the proposed lower rate.

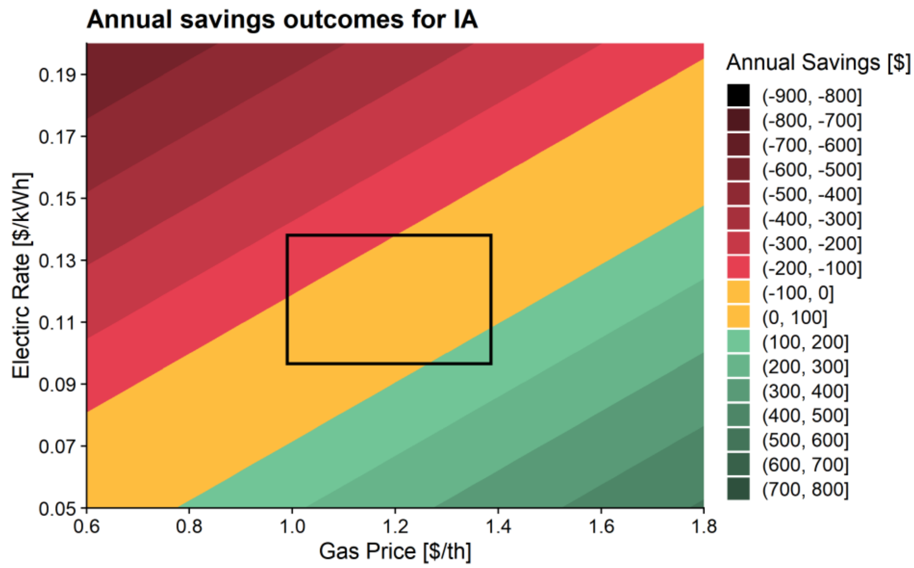

Figure 16: Contour plot of potential savings outcomes for a range of electric and gas rate combinations in Iowa

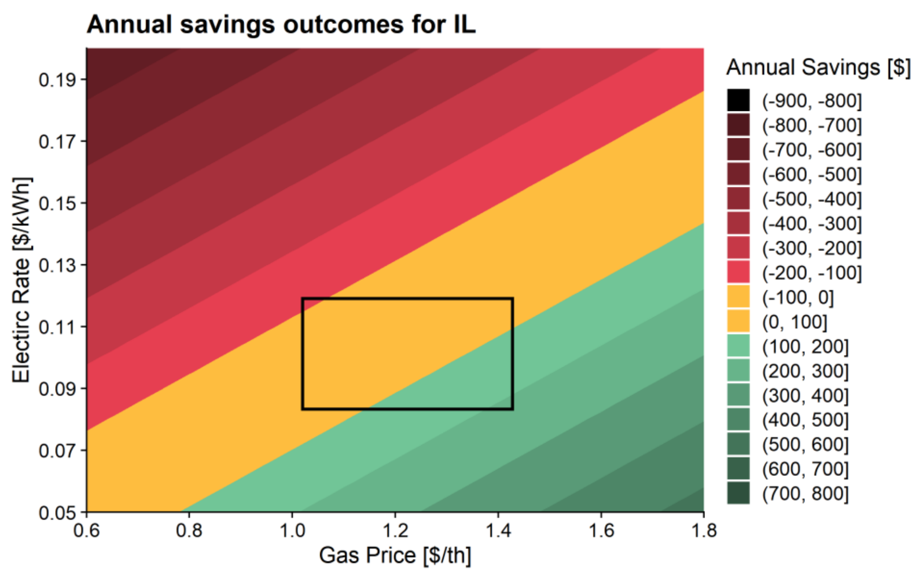

Figure 17: Contour plot of potential savings outcomes for a range of electric and gas rate combinations in Illinois

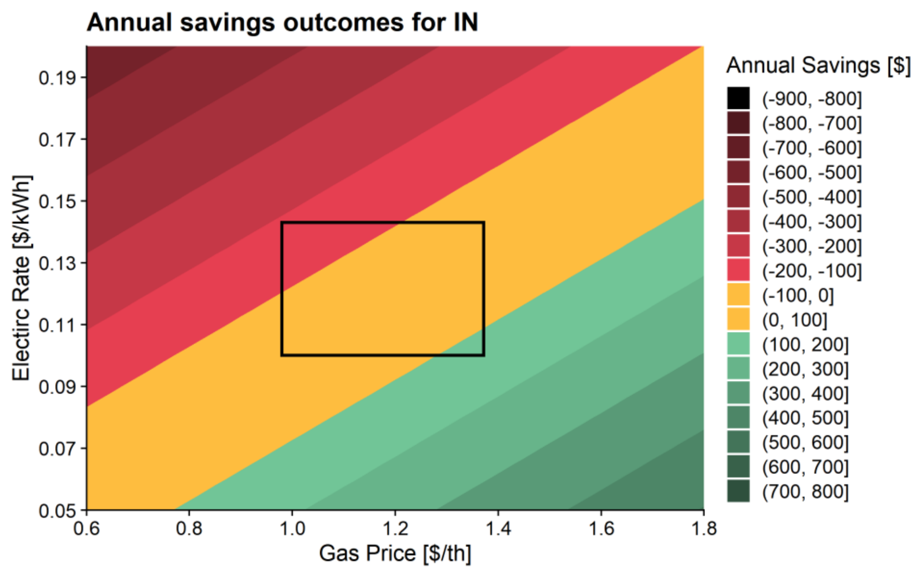

Figure 18: Contour plot of potential savings outcomes for a range of electric and gas rate combinations in Indiana

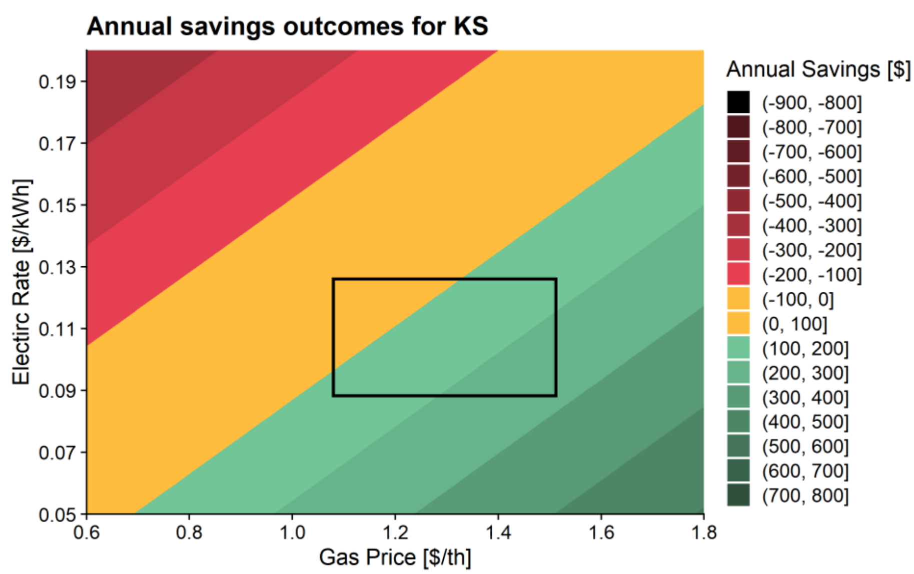

Figure 19: Contour plot of potential savings outcomes for a range of electric and gas rate combinations in Kansas

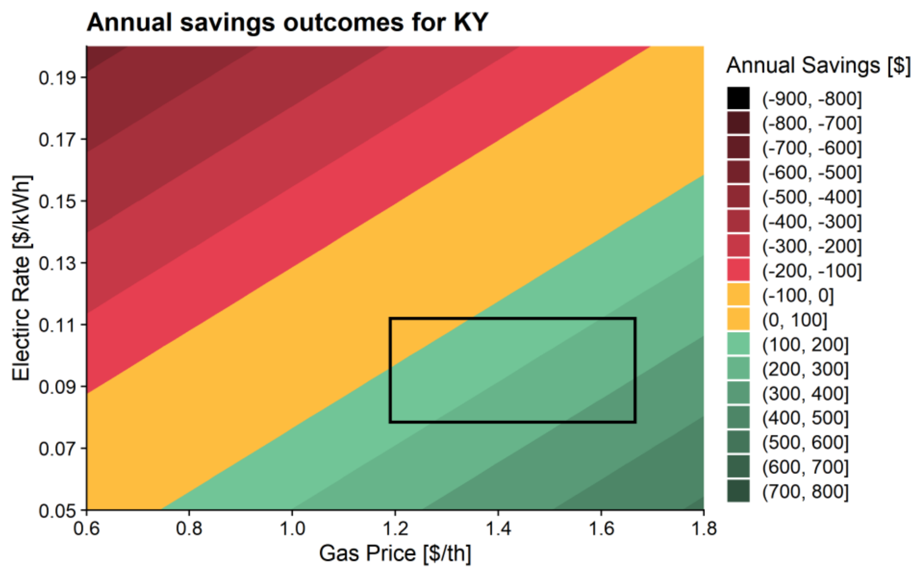

Figure 20: Contour plot of potential savings outcomes for a range of electric and gas rate combinations in Kentucky

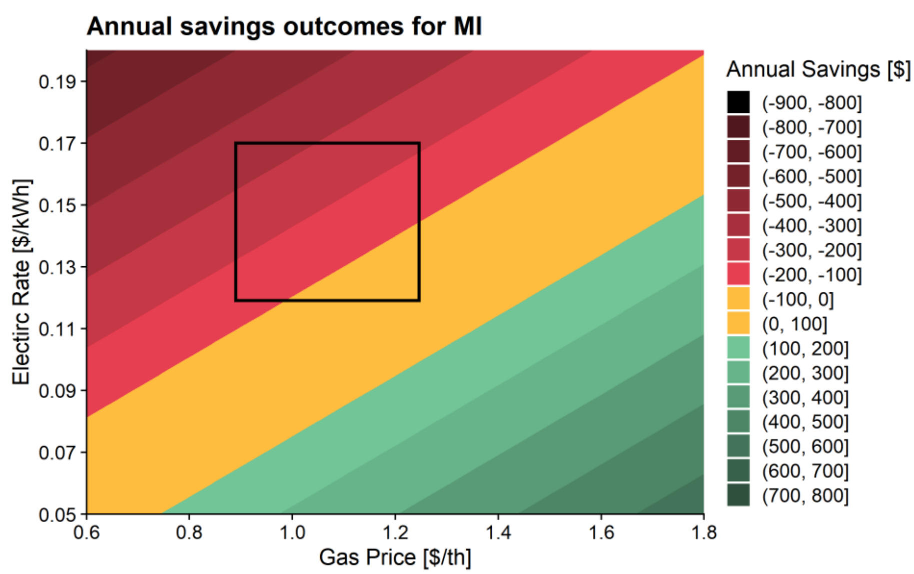

Figure 21:Contour plot of potential savings outcomes for a range of electric and gas rate combinations in Michigan

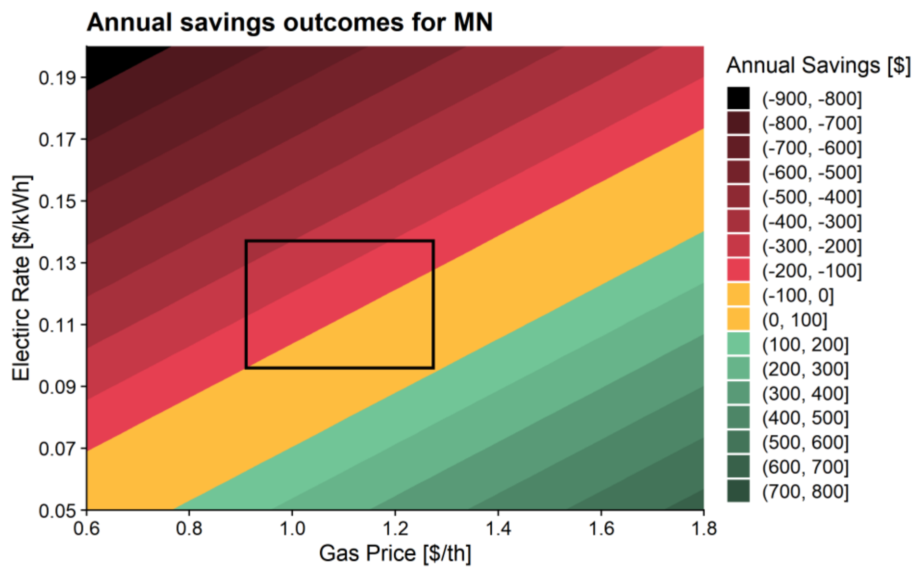

Figure 22: Contour plot of potential savings outcomes for a range of electric and gas rate combinations in Minnesota

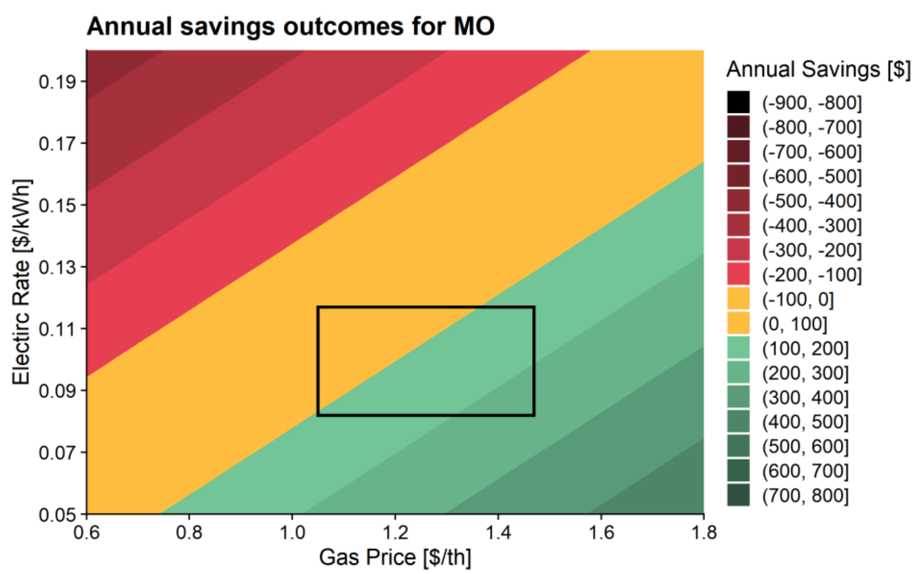

Figure 23: Contour plot of potential savings outcomes for a range of electric and gas rate combinations in Missouri

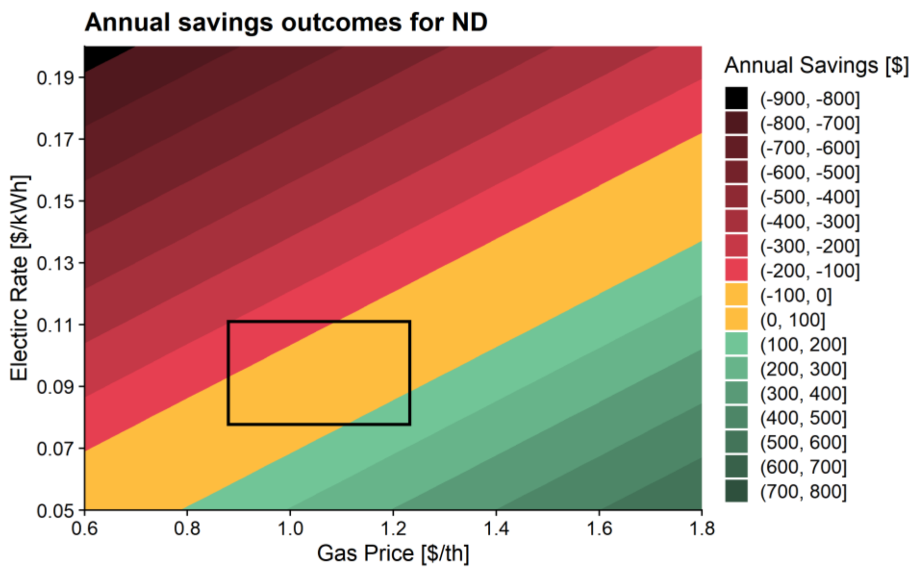

Figure 24: Contour plot of potential savings outcomes for a range of electric and gas rate combinations in North Dakota

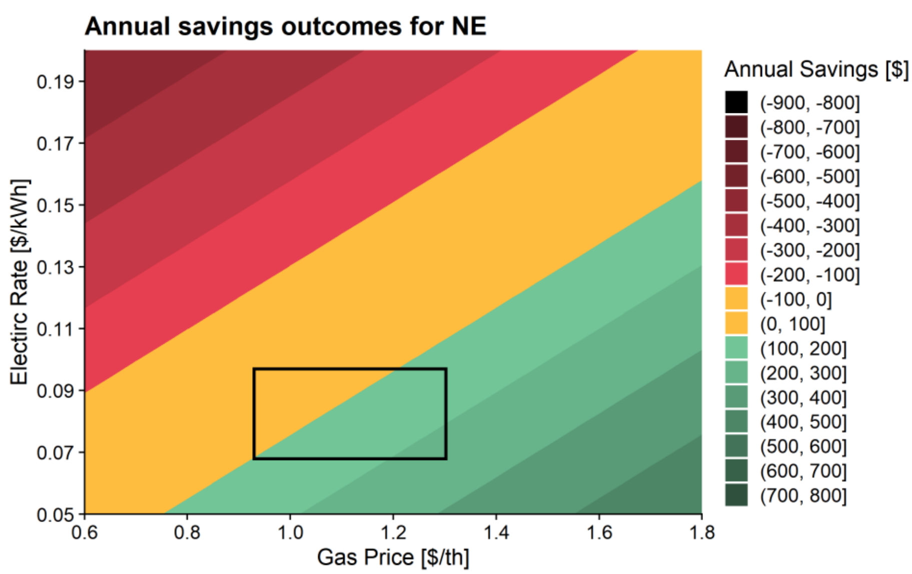

Figure 25: Contour plot of potential savings outcomes for a range of electric and gas rate combinations in Nebraska

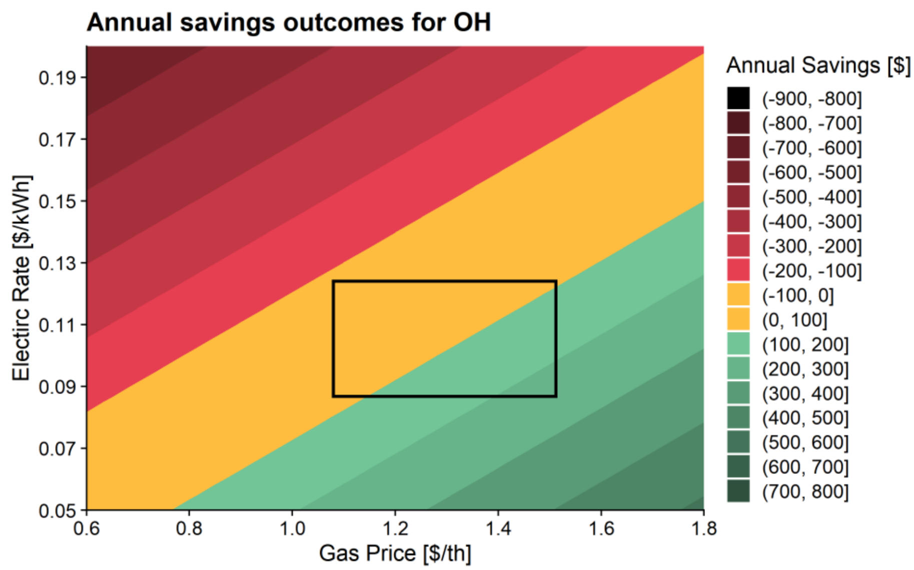

Figure 26: Contour plot of potential savings outcomes for a range of electric and gas rate combinations in Ohio

Figure 27: Contour plot of potential savings outcomes for a range of electric and gas rate combinations in South Dakota

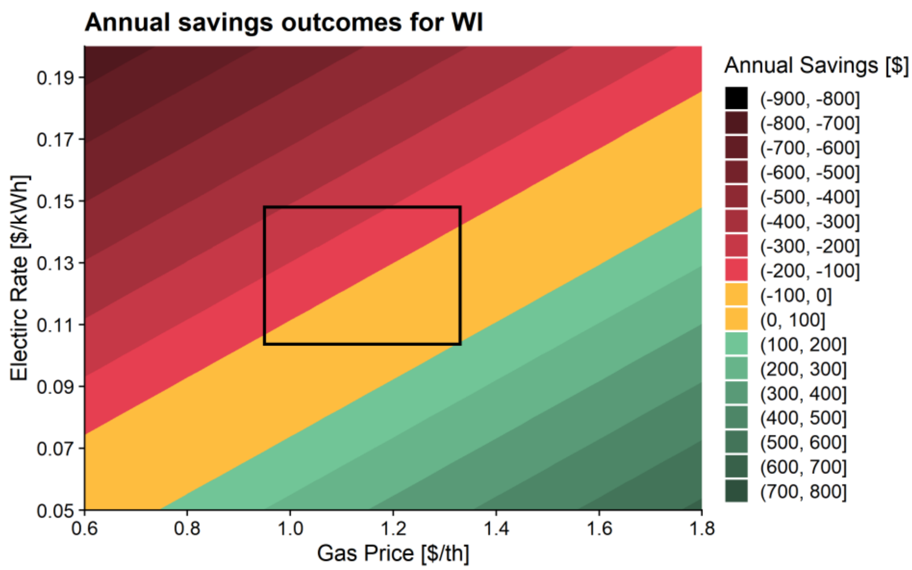

Figure 28: Contour plot of potential savings outcomes for a range of electric and gas rate combinations in Wisconsin