Heat Pump Water Heaters in Every Home? Forecasting the Costs and Emissions Impacts for Residential Customers and Long-Term Resource Planning Impacts

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ABSTRACT

Across the country, there is a concerted push to decarbonize the residential building sector by transitioning from fossil fuel to electric end-uses powered by carbon-free generation. Heat pumps and heat pump water heaters are often cited as two opportunities for "beneficial" electrification. But what are the true costs, carbon emissions, and impacts to the electrical grid associated with wide-scale adoption of heat pumps?

Understanding the demand and supply-side impacts associated with electrification through the utility cost-to-serve, carbon emissions, customer costs and resource planning forecasts will help inform when and how residential fossil fuel-based end-uses should be transitioned to electricity. In this study, we used regional energy market data, PLEXOS-modeled[1] marginal energy prices and emissions factors as well as capacity, transmission, and distribution costs from the recently filed Resource Plans for Colorado and Minnesota to estimate the cost-to-serve and carbon emissions associated with heat pump, electric resistance, and natural gas water heaters. Using a resource optimization model, we also analyzed the long-term effects of large-scale electrification on utility rates, emissions, and generation resources.

This paper presents the study findings and discusses the current barriers and opportunities that impact the adoption of heat-pump water heaters from a utility perspective and looks at the potential for these increased electric loads to support higher levels of renewable generation.

Introduction

For this paper we focus on the Xcel Energy service territories in Colorado (CO) served by the Public Service Company (PSCo) and Minnesota (MN) served by Northern States Power-Minnesota (NSP). In the analysis of the water heater energy requirements we use climate data for these regions. In addition, the emissions and cost-to-serve analysis is specific to the PSCo and NSP territories, however, the overall trends and qualitative findings are applicable to utilities across the US.

Both Colorado and Minnesota have established economy-wide greenhouse gas (GHG) reduction goals. Colorado is aiming to reduce GHG emissions (emissions) by 50% by 2030 compared to 2005 levels and 90 percent by 2050 (CO General Assembly 2019). Minnesota aims to reduce emissions by 30% by 2025 compared to 2005 levels and 80% by 2050 (MN State Legislature 2007). At the same time, Xcel Energy has established a goal to deliver 100% carbon-free electricity to customers by 2050 and has made progress toward that commitment (Xcel Energy 2021a). These goals will require creative approaches to substantially reduce emissions in the residential electricity sector. Two commercially viable options to achieve these reductions are conversion of water and space heating end-uses from natural gas to electricity supplied by an electric grid with increasing shares of carbon-free energy generation.

For years Demand-Side Management (DSM) programs have proven to be an effective tool for reducing energy use, customer cost and emissions in the commercial, industrial, and residential sectors. States have incentivized utilities to create plans and programs like the CO DSM Plan and the MN

[1] PLEXOS is a simulation software used for long-term and short-term supply side planning.

Conservation Improvement Program (CIP) Plan which offer cost-effective DSM programs to customers (Xcel Energy 2021b, 2021c). To date, these programs have focused on incentivizing technologies and strategies that reduce customers' energy use. Fuel-switching, including beneficial electrification[2] (BE), has typically not been allowed through these programs but with recent legislative changes, including the passing of the Colorado SB21-246 and the MN Energy Conservation and Optimization (ECO) Act, these rules are quickly being modified (CO General Assembly 2021; MN State Legislature 2021). SB21-246 and the ECO Act make it possible for Xcel Energy and other utilities to offer programs that incentivize customers to implement cost-effective fuel-switching programs that result in a reduction of source energy use and emissions.

Increasing the proportion of renewable generation on the grid can lower emissions and have negligible marginal energy costs, but these resources are also typically non-dispatchable. To better capture the cost and emissions benefits of an increasingly renewable grid, programs that encourage customers to shift their load to align with non-dispatchable generation profiles will be needed. For example, incentives can be provided to residential customers to install heat pump water heaters (HPWH) with load shifting capabilities that allow the utility to control the heating profile of a HPWH. Pre-heating water heaters to higher setpoints and allowing them to slowly decrease in temperature shifts the peak demand while still ensuring customers' hot water needs are met.

In this analysis we consider a dynamic load shifting profile that responds to the shifting generation profile on the supply side. Further, we present an analysis and assumptions used to calculate the utility cost-to-serve and customer retail cost for HPWHs with and without load shifting capabilities. We compare the cost-to-serve of HPWHs to baseline natural gas water heaters (NGWH) and electric resistance water heaters (ERWH). Cost-to-serve represents the total utility cost (generation capacity, transmission, and distribution capacity and marginal energy costs) to supply gas and electricity to customers. The customer cost is calculated using current retail rates for PSCo and NSP customers. In addition, we calculate the emissions impact using the assumptions from our latest filed DSM plans and contrast this with preliminary results of resource planning models that evaluate the impact of electrification on supply side assets.

Methodology

Water Heating Assumptions

In this analysis we considered seven water heating scenarios common in colder climates, specifically Colorado and Minnesota. The seven scenarios consider the impacts of water heating technologies with different efficiencies, fuels, controls, and locations within the home. The seven water heating scenarios, shown in table 1, were compared over a thirteen-year period from 2020 to 2032. Thirteen-years is the estimated useful lifetime of a water heater (MN DOC, 2021). Each scenario assumed the water heater is in a three-bedroom, single-family home. The non-load shifting scenarios assumed the water heater tank temperature is set to 120 degrees Fahrenheit. The load shifting scenario assumed the tank temperature varies throughout the day based on a control schedule. These assumptions are also outlined in the Xcel Energy Minnesota 2021-2023 CIP Triennial Plan.[3]

[2] The use of term "beneficial electrification" in this paper refers to natural gas to electric fuel switching that should reduce costs, emissions, and improve the efficiency of the electric grid.

[3] Available at https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Regulatory%20Filings/MN%20fillings/2021-2023-CIP-Triennial-Plan.pdf

Table 1. Water heater scenarios considered. The HPWH scenario includes a quantification of the heating penalty and cooling benefit, which is not applicable to the natural gas and electric resistance scenarios.

Technology Type	Water heater location	Control Strategy	Tank Size (gallon)	Energy Factor
Natural Gas, Federal Minimum Efficiency	N/A	None	66	0.60
Electric Resistance	N/A	None	66	0.95
Electric Heat Pump	Unconditioned	None	66	3.50
	Conditioned; electric heat			
	Conditioned; natural gas heat			
Electric Heat Pump	Conditioned; electric heat	Load shifting	66	3.50
	Conditioned; natural gas heat			

Using the assumptions in Table 1 and equations shown below, we calculated the hourly load for each scenario.

$$Hot\ water\ energy\ \left({}^{Btu}/_{hr}\right) = hot\ water\ usage\ \left({}^{gal}/_{hr}\right) x\ specific\ heat\ \left({}^{Btu}/_{lb\ F}\right)$$
$$x\ density\ \left({}^{lb}/_{gal}\right) x\ tank\ temperature\ change\ (F)$$

$$Hot\ water\ load\ \left({}^{Btu}/_{hr}\right) = \frac{hot\ water\ energy\ \left({}^{Btu}/_{hr}\right)}{energy\ factor}$$

The change in tank temperature each hour is calculated using a model developed by Xcel Energy. The model takes into consideration the city mainline water temperature given a typical meteorological year, standby losses, and the typical water usage in a three-bedroom single-family home with one kitchen and two bathrooms.

For four of the seven HPWH scenarios, we assumed the water heater is installed in a conditioned space which aligns with our Demand Side Management (DSM) plan assumptions. HPWHs pull heat from the air around them and expel cool air, resulting in a heating penalty or cooling benefit depending on the time of year. We adjusted the annual load for the HPWH scenarios to include a heating penalty or cooling benefit depending on the time of year..

Two space heating technologies were considered for the HPWH scenarios. The first assumed the water heater is in a space with electric resistance heat. The second assumed the water heater is in a space with an 80% annualized fuel utilitization efficiency (AFUE) natural gas furnace. Both scenarios assumed the home is cooled with a central air conditioner with a seasonal energy efficiency ratio (SEER) of 13. For both scenarios conservative set points are assumed, 68°F in the winter and 74°F in the summer. The annual penalty is converted to an hourly penalty using an annual weighted average degree day as well as an annual weighted average load. Hourly typical meteorological year (TMY) temperatures for both CO and MN are used to determine the heating and cooling degree days.

Cost Considerations

For each scenario we calculated the annual cost-to-serve from the utility perspective,[4] total cost from the customer perspective, and emissions impact from the equipment or power generation perspective. The annual electric cost-to-serve included the generation capacity cost, transmission and distribution (T&D) capacity cost, and marginal energy cost. In both states, the DSM plans used generation and capacity costs from recently filed resource plans. The CO DSM plan also used T&D costs from the resource plan, while the MN CIP plan used T&D costs from a statewide study published in 2017. Both plans assumed DSM offsets a natural gas combustion turbine power plant.

We used PLEXOS software to estimate the marginal energy costs in the PSCo and NSP service territories. PLEXOS is a simulation software used for long-term and short-term supply side planning. The model assumed a static set of generation assets are available for deployment. Given an hourly load profile, the model evaluated the optimal deployment of the generation assets to meet the hourly load. Outputs of PLEXOS included hourly total load for the system, hourly marginal energy cost, and emissions.

When evaluating the natural gas cost-to-serve we referenced the EIA AEO 2018 Base Case Henry Hub forecast for estimated commodity costs. Gas demand costs for PSCo were derived applying a 1% factor to the market-based natural gas pipeline reservation fee, which approximates the cost-to-serve and the percent of annual gas load that occurs on the peak day. The NSP gas demand costs used a similar calculation approach as PSCo, however, instead we referenced the Minnesota Department of Commerce's cost-benefit analysis modeling assumptions from the 2021-2023 MN CIP plans.

For the customer cost we evaluated both the incremental cost to operate the equipment (utility bill) and total cost to purchase the equipment[5]. For the cost to operate the equipment we evaluated the bill impacts using standard residential rates for PSCo ($0.11/kWh) and NSP ($0.12 / kWh). For the baseline equipment costs we referenced the National Renewable Energy Laboratory (NREL) National Residential Efficiency Measures Database. We relied on rebate applications submitted in 2020 through our PSCo and NSP DSM programs to determine the equipment cost of HPWHs.

For electric technologies, the emissions data are marginal emissions, or the estimated average emissions from the PSCo and NSP generators that are assumed to be dispatched at each given hour. The average emissions per MWh generated are provided by PLEXOS, which referenced the 2016 ERP for PSCo and the 2019 IRP Preferred Plan for NSP (Xcel Energy 2018; 2019). The natural gas water heater assumes an emission rate of 117 lb CO_2/Dth based on the Environmental Protection Agency's greenhouse gases equivalencies calculator (EPA 2021).

Load Shapes and Load Shifting Assumptions

We calculated the annual marginal energy cost per water heater using load shapes that represent the average proportion of annual energy use of a water heater that are expected to occur at each given hour of the year. The uncontrolled load shapes used load profiles consistent with the Company's cost-benefit analysis for regulatory filings that seek approval for traditional energy conservation programs. For the load shifting scenario, we assumed customers install a HPWH capable of receiving control signals from the utility that can shift water heater load based on marginal energy and peak demand periods[6]:

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[4] The cost-to-serve represents a utility's cost associated with the supply, demand, distribution, and market purchases required to delivery energy to the customer.

[5] Customer cost does not include the cost to upgrade service panels, wiring, or other electrical systems in order to convert from natural gas to electric appliances.

[6] NSP and PSCo have summer peaking systems. The period is define as weekdays 3-7 PM from June to September.

- Marginal energy price load shift – During periods of low cost marginal energy the temperature setpoint of enrolled heat pump water heaters would be increased and would be filled with hotter-than-normal water. Hot water from the water heater would be diluted with a mixing valve to deliver water at standard distribution temperatures.
- Afternoon peak demand load shift – In a peak load event, normally on hot summer afternoons, the enrolled water heaters would be turned off for the duration of the control event. Previously heated water would still be available for customer use. However, water heaters would not heat new water until the end of the event.

We used the hourly marginal energy cost data from PLEXOS to help determine when a load shifting event, as described above, would occur. We assumed low marginal energy cost indicates more renewable assets are available, and modeled load shifting events when the marginal energy cost fell below $5/MWh and increased the water heater load during those times to account for the event. Figure 1 below shows a comparison of a HPWH load with and without load shifting over 24 hours with periods of low marginal energy prices. The HPWH without loadshifting shows a greater amount of load spread out across the day, while the HPWH with loadshifting shows the load concentrated mainly during periods of low marginal energy prices (hours ending 1 and 20-22).

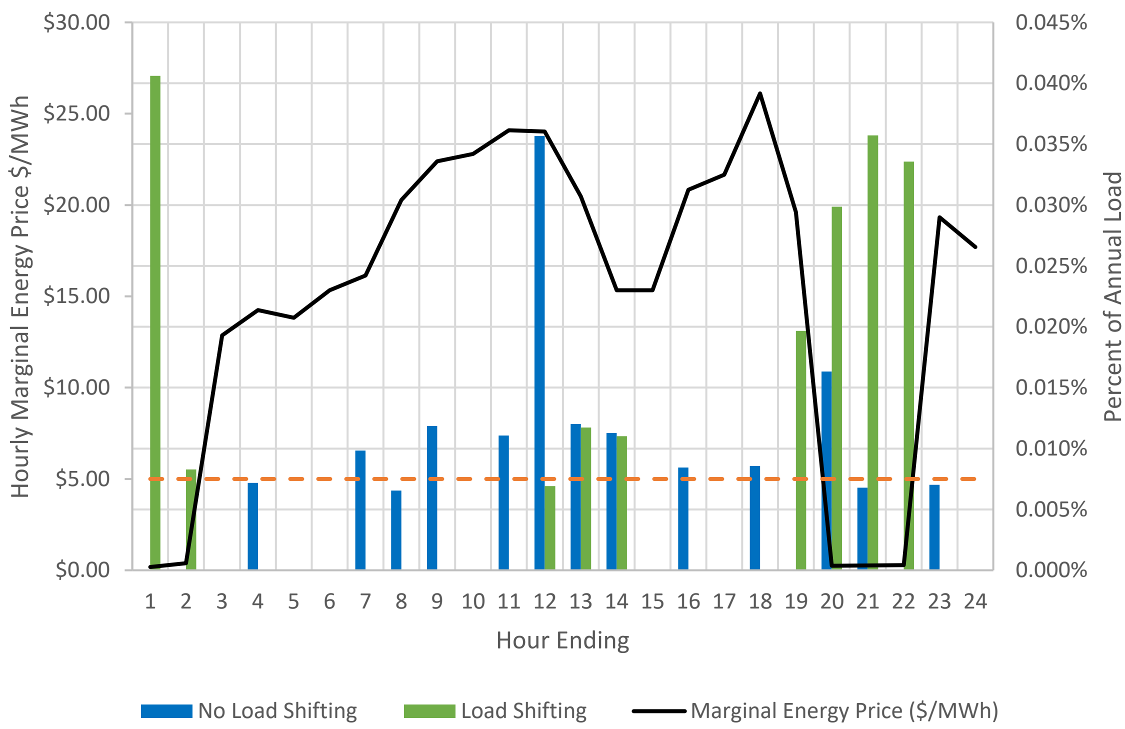

Figure 1. Example of a single day hourly load for a HPWH with and without load shifting. Bar graphs for the no load shifting and load shifting scenario represent the percent of annual total load (right axis). The orange dashed line represents the threshold at which load shifting is triggered.

Results

Utility Cost-to-Serve and Retail Costs

Table 2 below presents the lifetime net present value (NPV) utility and customer operational cost from each of the water heater technologies for PSCo and NSP[7]. We find that the load shifting control schedule, which shifts load to periods of low marginal energy costs, is effective at producing significant savings from the utility cost-to-serve perspective. HPWHs with load shifting cost approximately 20% to 25% less to serve than the uncontrolled HPWH equivalent and have the lowest cost-to-serve of all the water heatering scenarios (regardless of space heating source) in both PSCo and NSP. In PSCo the baseline NGWH costs less to serve than an uncontrolled HPWH, while in NSP with higher assumed natural gas costs the cost-to-serve a NGWH is more expensive than all the HPWH scenarios.

Table 2. A comparison of the lifetime net present vaue (NPV) utility total cost-to-serve and customer retail costs to operate a water heater in PSCo and NSP service territories.

Lifetime NPV cost-to-serve and operational cost	Natural gas water heater baseline	Electric resistance water heater baseline	Heat pump water heater with:				
			No load shifting and uncond. space	No load shifting and electric space heat	Load shifting and electric space heat	No load shifting and gas space heat	Load shifting and gas space heat
PSCo							
Utility Cost-to-serve	$619	$1,213	$559	$710	$557	$647	$486
Customer Operating Cost	$891	$3,867	$2,332	$3,035	$2,929	$2,451	$2,288
Cost-to-serve Difference	$272	$2,654	$1,773	$2,325	$2,372	$1,804	$1,802
NSP							
Utility Cost-to-serve	$980	$1,323	$623	$807	$652	$742	$578
Customer Operating Cost	$1,530	$5,018	$2,748	$3,721	$3,514	$2,967	$2,762
Cost-to-serve Difference	$550	$3,695	$2,125	$2,914	$2,862	$2,225	$2,184

Note: HPWH space heating/cooling scenarios only include the associated heating and cooling penalty/benefit, not the complete space heating/cooling load. For example, in the “HPWH with no load shifting and gas space heat” the customer operating cost of $2,451 includes the electric to operate the HPWH, minus the electric savings in the summer due to the added cooling, plus the natural gas bill to offset the heating penalty in the winter.

Looking at the costs from the current retail customer perspective, a NGWH costs much less to operate over its lifetime than any of the electric water heater scenarios. A customer with a NGWH could expect to spend about $891 in PSCo or $1,530 in NSP, but a similar customer with a HPWH and electric space heat would spend considerably more, $3,035 in PSCo and $3,721 in NSP. HPWHs using the load shifting control schedule reduced customer retail costs by approximately 10% in PSCo and NSP.

Comparing the utility cost-to-serve with the customer operating costs, we see that the energy required to serve an electric water heater load is considerably cheaper for the utility than it is for the customer to purchase the electricity. In PSCo and NSP all the HPWH scenarios on average see an increase in customer retail cost compared to the utility cost-to-serve by about 360%. Despite HPWH

[7] Discount rates based on Xcel Energy’s weighted average cost of capital of 6.53% from the 2021 CO DSM Plan and 6.43% from the 2021 MN CIP Plan.

having a relatively low cost-to-serve, the current rate structures in both PSCo and NSP are not well aligned to reflect this lower cost-to-serve for electric water heater loads. Narrowing the gap between customer costs and the utility cost-to-serve presents an opportunity for utilities to increase demand for HPWHs, possibly using specifically designed rates for HPWH customers and/or upfront and ongoing incentives (i.e., equipment rebates and bill credits). Given the gap between cost-to-serve and customer operating cost, it may be possible to implement these incentives without increasing electric rates.

Customer Equipment and Retail Costs

Table 3 below shows the total customer equipment costs along with lifetime operating costs relative to either a baseline gas or electric water heater for PSCo and NSP. The analysis does not include install cost or the cost to upgrade electrical panels or wiring which can vary significantly depending on the home location and vintage. Looking at the average equipment costs for PSCo and NSP, the NGWH ($810) and ERWH ($1,181) have substantially lower equipment cost compared to the HPWH ($1,888) and the HPWH with load shift capabilities ($2,213). When we consider the lifetime operating costs, the ERWH becomes the most expensive option to operate, costing the average PSCo and NSP customer $3,867 and $5,018, respectively.

Looking at the combined equipment costs and the NPV lifetime operational costs relative to a baseline electric or natural gas water heater two findings stand out:

- A baseline NGWH offers customers the largest savings over its lifetime compared to the other water heater technologies. The baseline NGWH saves a customer in PSCo between $2,519 and $3,441 and a NSP customer between $2,296 and $3,387 relative to a HPWH, depending on the configuration and space heating source.
- For electric customers, HPWHs provide customers with lifetime cost savings relative to an ERWH even without incentives or bill credits, except for the no load shifting HPWH with an electric space heat penalty scenario in PSCo.

Table 3. Customer equipment and NPV customer retail costs to operate a water heater in PSCo and NSP

Lifetime Equipment and NPV Customer Operating Costs	Baseline		Heat pump water heater with:				
	Natural gas water heater	Electric resistance water heater	No load shifting and uncond. space	No load shifting and electric space heat	Load shifting and electric space heat	No load shifting and gas space heat	Load shifting and gas space heat
Equipment Cost							
Total Equipment Cost	$810	$1,181	$1,888	$1,888	$2,213	$1,888	$2,213
PSCo							
Customer Operating Cost	$891	$3,867	$2,332	$3,035	$2,929	$2,451	$2,288
Total Lifetime Costs	$1,701	$5,048	$4,220	$4,923	$5,142	$4,339	$4,501
Incremental Cost versus Gas Baseline	$0	$3,347	$2,519	$3,222	$3,441	$2,638	$2,800
Incremental Cost versus Electric Baseline	-$3,347	$0	-$828	-$215	$94	-$709	-$547
NSP							
Customer Operating Cost	$1,530	$5,018	$2,748	$3,721	$3,514	$2,967	$2,762
Total Lifetime Costs	$2,340	$6,199	$4,636	$5,609	$5,727	$4,855	$4,975
Incremental Cost versus Gas Baseline	$0	$3,859	$2,296	$3,269	$3,387	$2,515	$2,635
Incremental Cost versus Electric Baseline	-$3,859	$0	-$1,563	-$590	-$472	-$1,344	-$1,224

Note: HPWH space heating/cooling scenarios only include the associated heating and cooling penalty/benefit, not the complete space heating/cooling load.

Natural gas water heaters provide the main source of hot water for approximately 80% of homes in both PSCo and NSP (Xcel Energy 2020a, 2020b). These cost comparisons make it clear that customers face substantial costs switching from using a NGWH to a HPWH. With decades of experience administering DSM programs using incentives to promote energy efficiency, utilities are uniquely positioned to help address a key market barrier to greater HPWH adoption: customer costs. Customers with an existing electric or natural gas water heater face very different costs transitioning to a HPWH and a combination of upfront incentives along with ongoing bill credits may be needed to persuade customers to make the switch.

CO2 Emissions

Figure 2 and 3 show the annual emissions by water heater technology versus the forecasted electric system emissions intensity for PSCo and NSP, respectively. The emissions trends for the PSCo and

NSP scenarios are similar with the ERWH and the HPWH emissions decreasing as the forecasted electric system emissions intensity decreases. The NGWH emissions remain constant in both figures since the NGWH are independent of the electric system's emissions intensity.

The different PSCo and NSP input assumptions for the load calcuations (e.g., water main and outdoor air temperature) along with the different annual emissions intensities of each electric system impacts when electric water heaters generate fewer emissions than the NGWH. While the crossover point for PSCo and NSP differs, the general trend is the same for both states. As the electric system emissions intensity decreases the carbon dioxide savings associated with switching from a NGWH to HPWH increases.

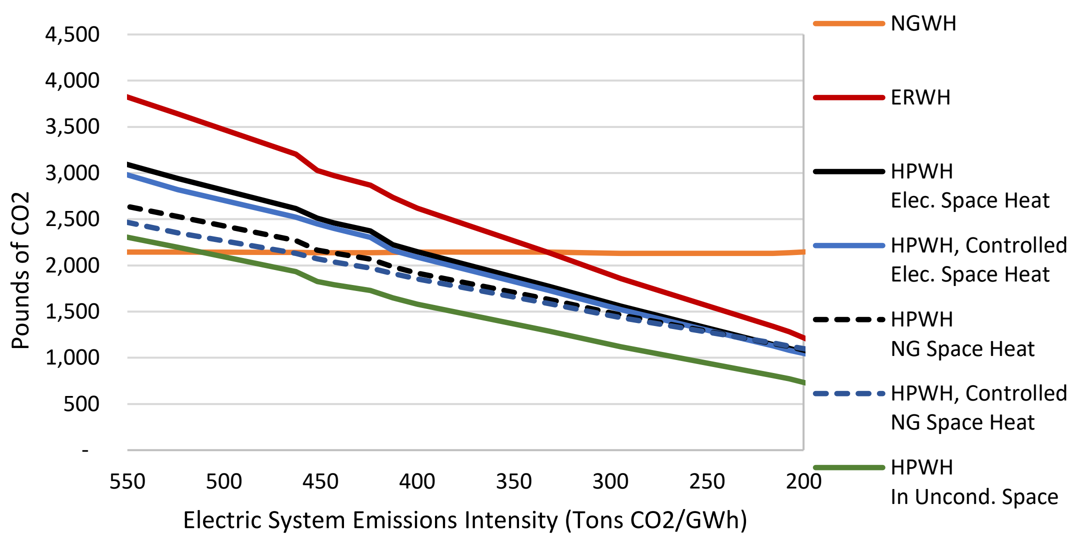

Figure 2. Modeled annual carbon dioxide emissions for water heaters installed in Colorado versus the forecasted PSCo electric system emissions intensity.

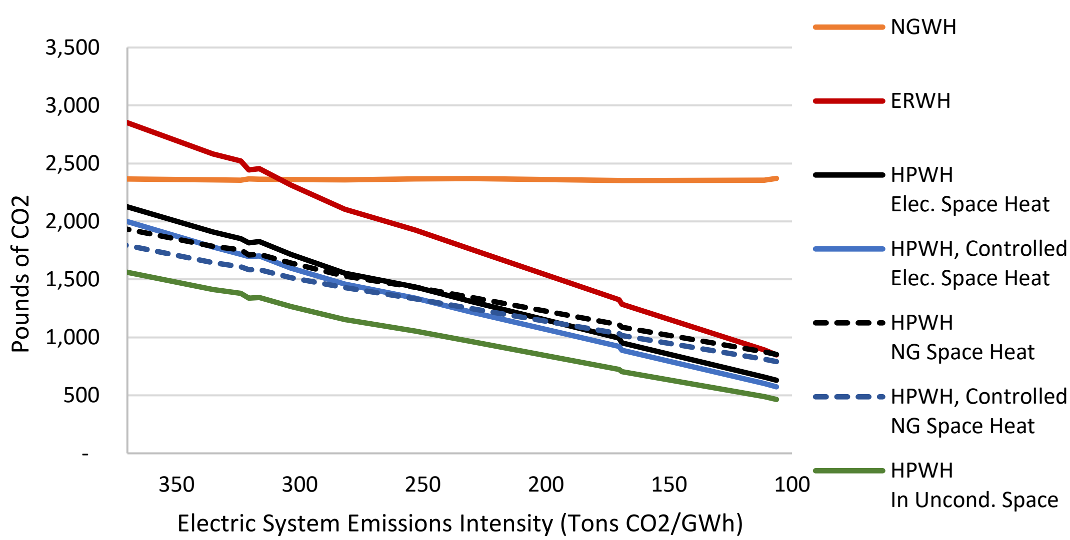

Figure 3. Modeled annual carbon dioxide emissions for water heaters installed in Minnesota versus forecasted NSP electric system emissions intensity.

While the current emissions intensities of the electric generation systems in PSCo and NSP result in different emissions outcomes compared to a baseline NGWH, the long-term trend for both states points to substantial emissions reductions. By 2032, a HPWH is expected to generate approximately 50%-70% fewer emissions compared to the NGWH in PSCo and NSP. By the end of the forecast period the emissions intensity for the PSCo and NSP electric generation systems is expected to decline so much that even the ERWH will produce large emissions savings compared to a NGWH. Even inefficient technologies such as an ERWH on a low carbon electrical grid can produce large emissions savings, which highlights the limitations of using carbon-only goals to measure the success of utility DSM or electrification programs.

Table 4 shows the cumulative emissions of a water heater installed in 2021 in the PSCo and NSP service territory. All the HPWH scenarios result in lower lifetime emissions relative to the baseline NGWH and ERWH. The HPWHs in unconditioned space are expected to achieve the most lifetime emissions savings relative to the baseline technologies.

Table 4. Lifetime emissions of a water heater installed in 2021 in PSCo and NSP service territories

	Lifetime emissions (lb CO2)	
Technology	PSCo	NSP
NGWH	27,813	30,706
ERWH	32,766	25,339
HPWH Electric space heat	27,037	18,800
HPWH, controlled Electric space heat	26,268	17,514
HPWH NG space heat	24,187	18,789
HPWH, controlled NG space heat	23,228	17,404
HPWH In unconditioned space	19,755	13,876

Resource Planning Impacts

The costs and emissions impacts presented above are all based on the approved avoided costs and emissions from the current Xcel DSM Plans in CO and MN. These assumptions for electric energy costs and emissions are based on the marginal capacity needs and hourly energy costs and system emissions given the load and portfolio of electric generation plants from the latest resource plans in both states. However, these resource plans are based primarily on historic trends and do not necessarily reflect a major electrification effort in any reference or preferred scenarios.[8] Greater electrification in the future is expected to significantly increase the electric load above the levels anticipated in the plans and change the portfolio of electric generation plants. The resulting marginal capacity needs and hourly energy costs and system emissions may vary significantly from the DSM Plan assumptions and are more appropriate for calculating the impacts of electrification.

To determine the impact on the future electric portfolio, the team also looked at the impacts of increased electrification of natural gas end-uses (i.e., space heat and water heat) from a resource planning perspective using the computer software EnCompass. EnCompass is used to develop and analyze capacity

[8] The resource plans consider electrification in some scenarios and sensitivity analyses but due to the uncertainty of these forecasts and length of time until the effects are material, they are not included in any scenarios that affect short-term investment decisions.

expansion plans and associated production costs of those plans under a variety of scenarios and sensitivities. It uses a numerical methodology called mixed-integer programming to accomplish this. EnCompass was used to model an optimized capacity expansion plan and determine the economic dispatch costs for the 2020 PSCo and NSP resource plans.

The team evaluated a low and a high electrification scenario, limited to the adoption of heat pumps for space and water heating, meant to capture the range of potential BE growth forecasts. To forecast the total number of heat pumps in the NSP service territory, we referenced scenarios from Energy and Environmental Economics' Minnesota Decarbonization Scenario report (E3 2019). For this analysis the low BE scenario is based on the Minnesota Pathways High Biofuels scenario which projects technology adoption every 5 years until 2050 needed to reduce GHG emissions by 15% below 2005 levels by 2015, 30% by 2025, and 80% by 2050. Using the same report, we reference the medium-electrification sensitivity based on NREL's Electrification Futures Study (EFS) for the high BE scenario. The technology adoption is scaled to the NSP service territory based on the ratio of households in NSP's service territory versus all of MN using US Census data. The same technology adoption is applied to the households in PSCo's service territory. The scenarios resulted in a modest increase of 90-150 GWh (0.2%-0.4% of annual system load) by 2025, growing to 1,700-6,700 GWh (3%-14% of annual system load) by 2045, compared to the baseline scenario from the most recent resource plans in PSCo and NSP (Figure 4).

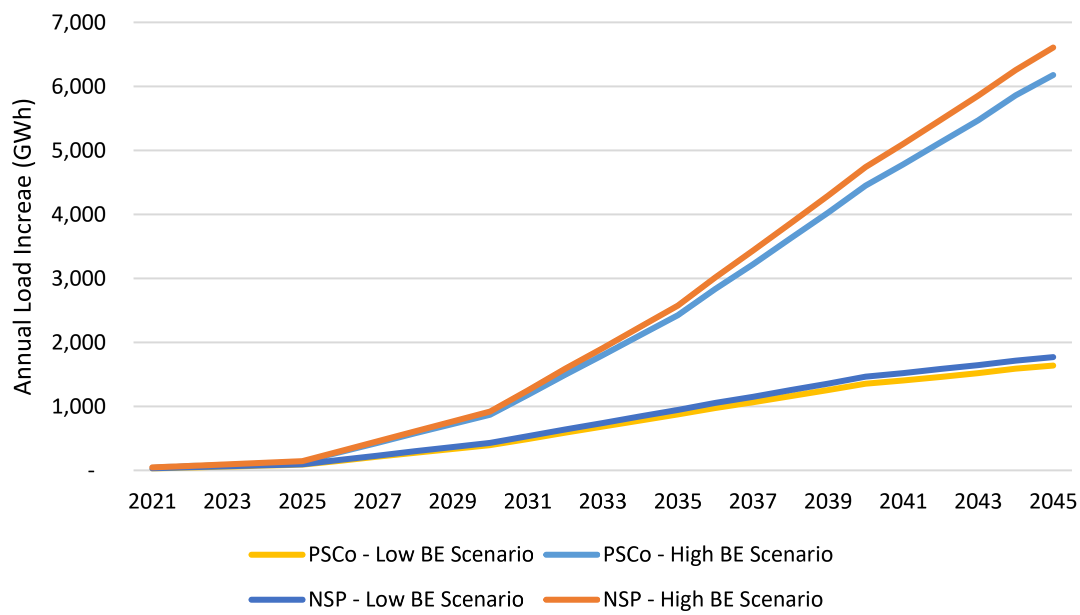

Figure 4. Assumed annual incremental heat pump load (GWh) in PSCo and NSP service territories

There is an expectation that the electric generation assets added to serve the increased load from heat pumps would be predominately renewable generation sources. This is due to the seasonal pattern of load usage from the heat pumps. Water heating heat pumps operate throughout the year, generally during the morning and early evening hours. Space heating heat pumps tend to operate during the spring and fall, times when the space heating needs are moderate and can be addressed with heat pumps.[9] The pattern of both electric end-uses matches well with renewable generation in PSCo and NSP. This resource

[9] In Xcel Energy's cold-climate service areas, the winter peak exceeds what can be efficiently and economically served with a cold-climate heat pump and it is expected that combustion backup systems will remain the preferred approach for meeting these needs.

plan modeling shows that future BE will drive changes in what generation assets are built in the future. In both PSCo and NSP, the added load from BE results in renewable generation assets being built both earlier and to a higher overall generation capacity than currently reflected in resource plans. This includes both wind and solar generation. The level of heat pump penetration will determine how strong this effect is, but it is significant in the relatively near term under either of the scenarios modeled.

The resource planning modeling resulted in estimates of marginal cost-to-serve impacts by comparing total system capacity needs and energy costs of the two BE scenarios versus a baseline scenario that did not include any future BE. These marginal cost-to-serve impacts are then divided by the increase in energy load (MWh) to compare to the cost assumptions from the approved DSM Plans. Similarly, the marginal emissions intensity is calculated by comparing total system emissions of the two BE scenarios versus a baseline scenario that did not include any future BE and divided by increase in energy load.

Table 5 below compares the resulting marginal cost-to-serve and emissions intensities from the resource planning modeling and from the approved DSM assumptions used in the analysis included in this paper. The average intensities for a representative future year (2024) and over the next 12 years are included. These results show significant differences in the emissions intensities and the cost-to-serve given different assumptions.

The results of this analysis vary significantly with some results strongly supporting the expectation of renewable generation sources serving the increased load from electrification, while some results do not. For instance, in the PSCo – low BE scenario, over the 2021-2032 period, the increase in load served by the PSCo electric generation system leads to increased renewable generation sources that produce more energy than the increase in load. This excess in carbon-free energy generation offsets some energy produced by fossil-fuel plants, leading to a net reduction in emissions even though the load served has increased. In the other scenarios, there is a net increase in system emissions to serve the increased load from electrification at an emissions intensity that is similar to the baseline assumption of the total system emissions intensity without electrification, indicating the generation assets built to serve electrification are similar in emissions as the total generation system.

Table 5. Comparison of cost-to-serve and emissions from resource planning BE and approved DSM assumptions

	Marginal emissions intensity (Tons/GWh)		Marginal cost-to-serve ($/MWh)	
Scenario	2024	2021-2032 Avg	2024	2021-2032 Avg
PSCo – Low BE Scenario	412	(157)	$24.14	$55.93
PSCo – High BE Scenario	447	216	$21.86	$28.61
PSCo – Approved DSM	443	364	$23.78	$27.44
NSP – Low BE Scenario	321	242	$25.87	$37.59
NSP – High BE Scenario	360	227	$25.21	$33.93
NSP – Approved DSM	282	243	$32.63	$35.94

These results do not show consistent differences between assumptions when using resource planning to capture changes in the generation portfolio from BE and assumptions for DSM based on a generation portfolio independent of BE. However, these results vary significantly, suggesting that resource planning modeling to determine the change in generation assets built to serve BE loads should be considered when evaluating the impacts of BE technologies. These impacts for added generation assets may be significantly different than the impacts assumed for DSM based on a static set of generation assets.

Conclusion

As the push to decarbonize gas end-uses strengthens and DSM programs adapt to incorporate electrification, it's important to understand the potential resource planning impacts as well as the potential challenges that customers face. After decades of low market adoption and limited customer interest, key market stakeholders are showing increased interest in heat pumps in colder climates like Colorado and Minnesota. Though it is uncertain when customer adoption will mirror this interest, utilities can play a key role by understanding barriers to adoption that are within their control. Through our study we identified barriers, benefits, and insights to electrifying the fossil fuel end-uses including the following:

- Natural gas decarbonization, utilizing water heating, offers the potential for substantial emissions savings and can be a powerful tool to help meet statewide emissions goals nationally.
- Costs will vary from utility to utility, but lifetime incremental cost of ownership is significantly higher (approx. $2,400-$3,300) for heat pump water heaters compared to natural gas water heaters posing a significant barrier to adoption.
- In colder climates where the heating penalty is greater than the cooling benefit, installing a heat pump water heater in a unconditioned space results in lower emissions than installing a heat pump water heater in a conditioned space..
- Providing new PSCo and NSP rate designs can better reflect the incremental utility cost-to-serve electric heat pump technologies. These may include ongoing bill credits; a shift of fixed costs to a monthly charge, reducing the volumetric charge; development of rate sub-classes for customers with heat pump technology; time-of-use rates. Each of these options comes with challenges but will be needed to induce customer demand for heat pump technology. Rates and rate design vary nationwide, but similar differences in the utility cost-to-serve heat pump loads should be applicable to many jurisdictions.
- Measuring utility DSM or BE program performance using carbon-only metrics does not necessarily align with efficient energy use as emissions intensities of regional electric generation systems continue to decline.
- Leveraging new BE load and programs may help shift system load supporting greater renewable generation capacity across the country.
- Heat pump water heaters installed in PSCo and NSP today will result in emissions savings over the lifetime of the measure when compared to a natural gas water heater. That said, measures with shorter lifetimes may not result in an emissions savings when compared to natural gas alternatives. Measure lifetimes as well as grid emissions intensity over time should be considered when timing the transition from natural gas to electric end uses.

It will be important to continue with this forecasting process to stay current with the rapid changes to the electric grid and utilities. As the resource planning results indicate, the timing and amount of BE load can impact the composition and evolution of a utility's electric generation assets, which in turn can have a significant impact on the underlying price and emissions assumptions used to inform the results of this forecast.

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